



NORTHWEST

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**SHELL OIL PRODUCTS US
PUGET SOUND REFINERY
ANACORTES, WASHINGTON**

Air Operating Permit

Statement of Basis

September 24, 2004

**STATEMENT OF BASIS
Information Page**

Prepared as per WAC 173-401-700(8)

**Shell Oil Products US, Puget Sound Refinery
8505 South Texas Road, Anacortes, Washington 98221**

SIC: 2911
EPA AFS: 53-057-0003

NWAPA ID: 005-V-S

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Shell Oil Products US, Puget Sound Refinery Air Operating Permit Statement of Basis

Introduction and General Facility Description

Puget Sound Refinery (PSR), owned by Shell Oil Products US, is required to obtain an operating permit because it has the potential to emit 100 tons or more of oxides of nitrogen and sulfur, particulate matter and carbon monoxide. These criteria pollutants are emitted in the operation of the oil refinery.

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

Facility Description

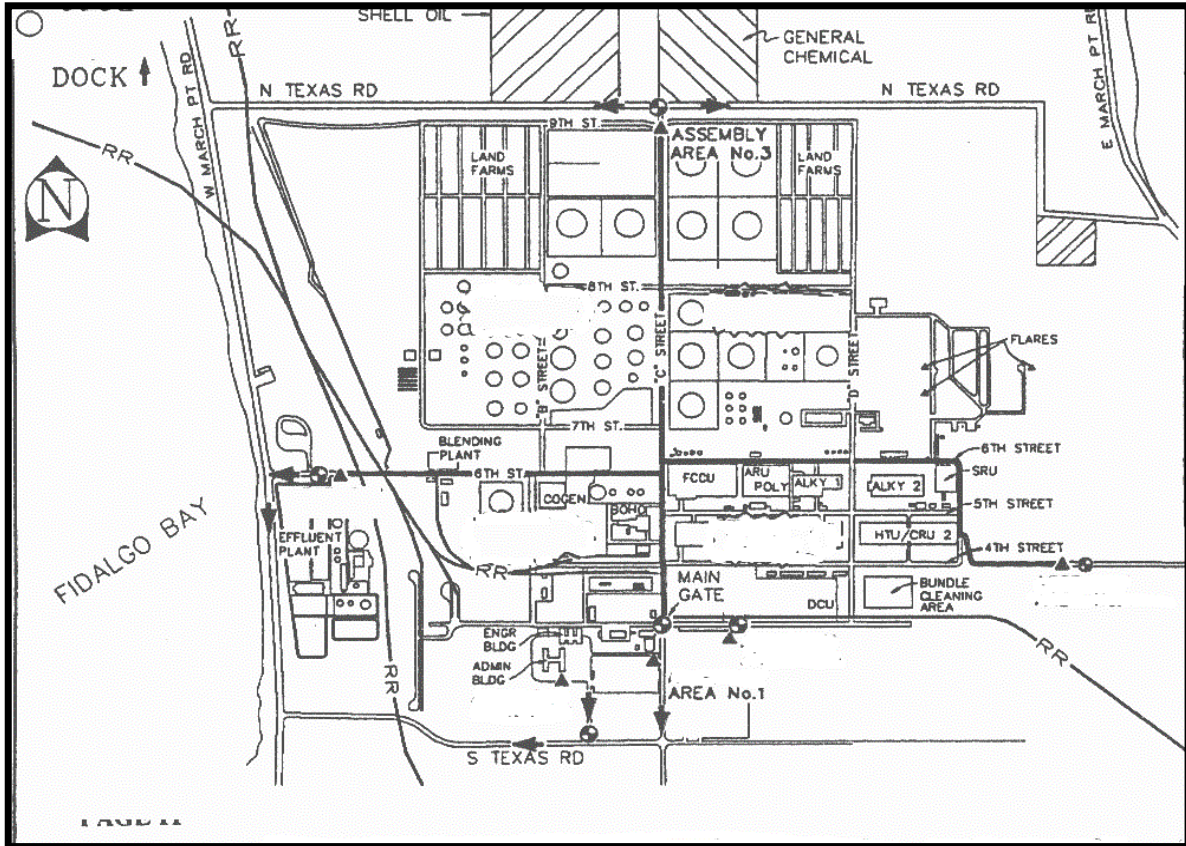
Identification

The facility produces petroleum-based fuels as classified under the Standard Industrial Classification code for this activity as 2911. It is located on March Point, a heavy industrial area, near Anacortes, Washington. The refinery was originally built by Texaco, Inc. and began operation in 1958. Texaco owned and operated the facility until Texaco formed an Alliance with Shell Oil Company January 1, 1998. The resulting Company was Equilon Enterprises LLC. In April of 2002, Shell purchased Texaco's interest in Equilon. Therefore, PSR is now owned by Shell Oil Products US.

A cogeneration facility, March Point Cogeneration Company (MPCC), is located within the PSR refinery fence line. MPCC is an independent Company and is therefore not included in this permit. A separate Title V Air Operating Permit has been completed by MPCC.

PSR is located between Highway 20 to the south and the Tesoro NW refinery to the north. The plot diagram below shows the layout of the process unit areas, storage tanks and the refinery's orientation to local roadways.

Refinery Plot Diagram



Aerial View of the Refinery



Refining Process

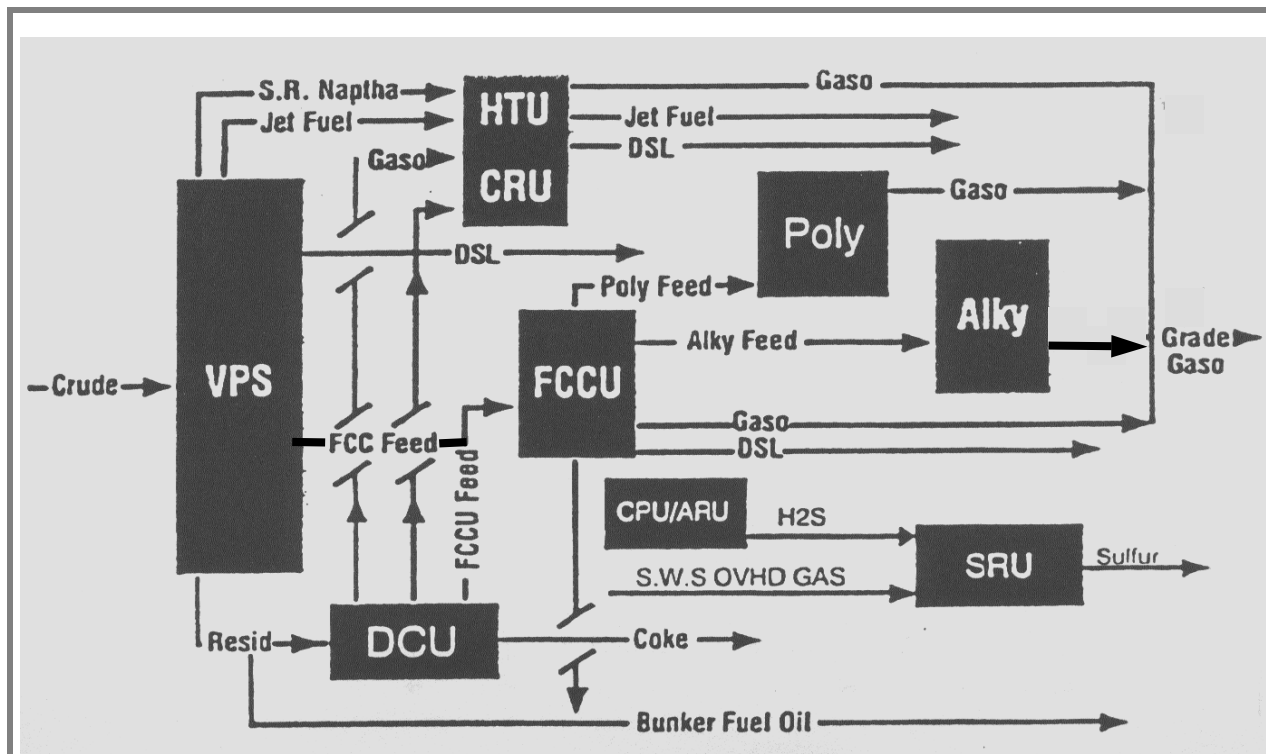
PSR refinery has an annual average crude processing rate of approximately 150,000 barrels per day. The operating of refining crude oil produces petroleum products, including gases, gasoline, distillate fuels, fuel oils, and petroleum coke. Processing will utilize any or all of the following four basic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

During the refining process waste streams and usable byproducts are generated. PSR operates a wastewater treatment facility that treats refinery wastewater and discharges the treated water into Fidalgo Bay. Some hazardous and non-hazardous materials are generated at PSR. Hazardous materials are shipped off-site to hazardous waste disposal facilities, and non-hazardous materials can be applied to landfarms located on PSR property or are sent off site. Elemental sulfur is generated during the removal of sulfur from hydrocarbon streams to produce low sulfur fuels and blending products. Elemental sulfur is a usable byproduct that is shipped off-site to companies that use the elemental sulfur as a feedstock.

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

PSR is optimized to process Alaskan North Slope (ANS) Crude, but may also run small amounts of Canadian and other crude oils purchased on the spot market. The process flow diagram below shows the main steps in processing including separation by distillation and downstream conversion by cracking, reforming and combination. This is a simplified diagram to show the processing flow from crude oil to finished products. At PSR there are duplicate Catalytic Reformer Units (CRU), Hydrotreater Units (HTU), Alkylation (Alky) and Sulfur Recovery (SRU) units to provide operational flexibility.

Process Flow Diagram



General Construction History

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

- 1976 Octane Improvement Project consisting of the installation of CO Boiler (COB) #2, the Catalytic Polymerization Unit, HTU #2, CRU #2, Alky Unit #2, #2 Cooling Tower and an expansion of the Crude processing unit.
- 1981 installation of the Sulfur Recovery Unit (SRU).
- 1983 installation of the Delayed Coking Unit (DCU).
- 1990 installation of the Nonene Unit.
- 1990/91 installation of March Point Cogeneration.
- 1998 FCCU Vertical Riser Project/POLY Expansion/Vacuum Resid Uplift.
- 1999 SRU expansion.
- 2001 installation of seven temporary 5.2 MW combustion turbine generators. Removed in 2003.
- 2001 installation of Butadiene Hydrogenation Unit (BHU).
- 2003 installation of HTU #3 to meet low sulfur gasoline requirements.
- 2004 modification of HTU #2 to facilitate the production of ultra low sulfur diesel.
- 2003 construction of a new Sulfur Recovery Unit (SRU #4). (Startup projected during 4th Quarter of 2004.)

Numerous other smaller projects have been completed at PSR and are identified within the associated process area descriptions in this Statement of Basis.

Combustion Sources

One of the main emission source categories for PSR is combustion units. The bulk of the emissions come from process heaters and boilers, however, it also includes waste processing devices such as flares, sulfur recovery incinerators and the gasoline vapor thermal oxidizer. Pollutants generated during combustion include oxides of nitrogen (NOx), carbon monoxide (CO), sulfur dioxide (SO₂) and particulate (PM and PM-10). Below is a list of the main combustion units at PSR including a description of the associated process unit, type of fuels burned, control equipment used to limit emissions and the status of applicable permit orders. The table is organized in a manner that groups combustion units by the respective refinery fuel gas system that they are serviced by.

Process Area	Unit ID	Unit Description	Fuel Type	Control Equipment	Permit Status	Notes
Combustion Equipment Serviced by the Refinery's Main Fuel Gas Mix Drum Sulfur monitoring method: CEM for H ₂ S at the main fuel gas mix drum						
VPS	1A-F4	Gas Oil Tower Heater	Gas	None	Reg Order #20 2/10/2000	
	1A-F5	VPS Charge Heater #1	Gas	Low NOx burner	Reg Order #20 2/10/2001	1A-F5 and 1A-F6 route to single stack
	1A-F6	VPS Charge Heater #2	Gas	Low NOx burner	Reg Order #20 2/10/2002	
	1A-F8	Vacuum Tower Heater	Gas	Low NOx burner	OAC #684, 6/17/99 Subpart J and 50 ppm BACT	
DCU	15F-100	DCU Charge Heater	Gas	Low NOx burner	OAC #628, 9/30/97 Subpart J	
FCCU	FCCU	FCCU Regenerator	N/A	DeSOx catalyst additive, COB1 and COB2	OAC #623a, 2/23/98 NSPS, Subpart J	Split flow to COB#1 & COB#2 for normal operation, or to 3BC2 (bypass stack)
	COB1	CO Boiler #1	Gas and Oil	Low NOx burner w/ flue gas recirculation & ESP1	OAC #623a 2/23/1998 Subpart J	ESP#1
	COB2	CO Boiler #2	Gas and Oil	Low NOx burner w/ flue gas recirculation & ESP2	OAC #623a 2/23/1998 Subpart J	ESP#2
Boiler House	ECB1	Erie City Boiler #1	Gas and Oil	None	Reg Order #21 4/14/2000	

Process Area	Unit ID	Unit Description	Fuel Type	Control Equipment	Permit Status	Notes
Combustion Equipment Serviced by the HTU #1/CRU #1 Fuel Gas Drum						
Sulfur monitoring method: CEM for SO ₂ at HTU #1 heater stack						
HTU #1	7C-F4	HTU1 Charge Heater	Gas	Low NOx burner	7/16/1990 NSPS Subpart J	7C-F4 and 7C-F5 route to single stack equipped with a SO ₂ CEM
	7C-F5	HTU1 Fractionator Reboiler	Gas	Low NOx burner	7/16/1990 Subpart J	
CRU #1	6D-F2	CRU1 Charge Heater	Gas	Low NOx burner	4/03/1987 Subpart J	6D-F2, 6D-F3, 6D-F4 route to single stack
	6D-F3	CRU1 Interheater #1	Gas	Low NOx burner	4/03/1987 Subpart J	
	6D-F4	CRU1 Interheater #2	Gas	Low NOx burner	4/03/1987 Subpart J	
Combustion Equipment Serviced by the HTU #2/CRU #2 Fuel Gas Drum						
Sulfur monitoring method: CEM for H ₂ S at the HTU #2/CRU#2 fuel gas mix drum						
HTU #2	11H-101	HTU2 Charge Heater	Gas	None	Reg Order #24 4/14/2000	11H-102 and 11H-103 route to single stack
	11H-102	HTU2 Stripper Reboiler	Gas	Low NOx burner	OAC #630a, 3/4/2004 Subpart J	
	11H-103	HTU2 Fractionator Reboiler	Gas	Low NOx burner	OAC #630a, 3/4/2004 Subpart J	
CRU #2	10H-101	CRU2 Charge Heater	Gas	None	Reg Order #22 4/14/2000	10H-101, 10H-102, 10H-103 route to single stack
	10H-102	CRU2 Interheater #1	Gas	None	Reg Order #22 4/14/2000	
	10H-103	CRU2 Interheater #2	Gas	Low NOx burner	Reg Order #22 4/14/2000	
	10H-104	CRU2 Stabilizer Reboiler	Gas and Oil	None	Reg Order #23 4/14/2000	
Combustion Equipment Serviced by the HTU #3 Fuel Gas Drum						
Sulfur monitoring method: CEM for H ₂ S at the HTU #3 fuel gas mix drum						
HTU #3		CDHDS heater	Gas	Low NOx burner	OAC #787b 3/11/2004 Subpart J and 50 ppm BACT	
Combustion Equipment Not Serviced by Refinery Fuel Gas						
SRU	16F-109	Primary Incinerator	Gas	None	OAC 693, 6/17/99 Subpart J	
	16F-108	Secondary Incinerator	Gas	None	OAC 693, 6/17/99 NSPS Subpart J	
	SRU #4	New Incinerator	Gas	None	OAC 828 5/5/03 NSPS Subpart J	
Flares	19N-F1	North Flare	Gas	None	Reg Order # 25 4/14/2000	
	19N-F2	South Flare	Gas	None	Reg Order # 25 4/14/2000	
	19N-F3	East Flare	Gas	None	Reg Order # 25 4/14/2000	
Truck Load Rack	TLR	Truck Load Rack Combustor	Gasoline Vapors/ Propane		OAC 380a 4/30/93 Subpart XX	

Note: OAC is an Order of Approval to Construct and a Reg Order is a Regulatory Order issued by the NWAPA.

Refinery Fuel Gas Systems

There are four distinct fuel gas systems that collect light gasses during refinery processing and distribute to specific heaters and boilers. The main fuel gas drum collects gasses from all but the HTU and CRU processing units and serves all heaters and boilers exclusive of those units. By and large, the co-dependent HTU/CRU units generate enough fuel gas within their own process unit boundaries to supply the needs of the heaters and boilers within those units. At times, the HTU/CRUs can become net fuel importers of fuel gas. The additional fuel requirements are met by supplementing the HTU/CRU fuel gas systems gas with gas from the refinery's main fuel gas system. If the refinery is low on fuel gas generation, fuel gas drums can also be supplemented with purchased natural gas. Each of the four refinery fuel gas systems is regulated under New Source Performance Standards (NSPS) Subpart J thereby limiting the hydrogen sulfide (H₂S) content of the gas to less than 162 ppmvd based on a 3-hour rolling average. In Subpart J the referenced fuel quality limit is 230 mg/dscm. Because H₂S CEM readout is in ppm the Subpart J standard has been converted to ppm and used in the Air Operating Permit (AOP) accordingly. Below is the conversion which uses standard conditions of 20° C and 760 mm Hg conservatively rounded to the nearest integer:

$$\frac{230 \text{ mgH}_2\text{S}}{\text{dscm}} \times \frac{\text{moleH}_2\text{S}}{34 \text{ g}} \times \frac{\text{g}}{10^6 \text{ mg}} \times \frac{24.04 \text{ dscm}}{\text{mole}} = 162 \text{ ppmvdH}_2\text{S}$$

Recent New Source Review (NSR) Best Available Control Technology (BACT) determinations under OACs #684 (VPS) and #787 (HTU #3) found that H₂S concentrations in the fuel gas can be maintained at 50 ppm. However, due to concerns about meeting compliance during short-term spikes, the averaging period for the 50 ppm limit is based on a 24-hour rolling average. Therefore, a NSPS limit of 162 ppm (3-hour rolling) and a BACT limit of 50 ppm (24-hour rolling) applies to the refinery's main fuel gas drum (VPS) and to the fuel gas system associated with HTU #3.

For the fuel gas system that services HTU#1/CRU#1, PSR choose to use an in-stack SO₂ monitor in lieu of monitoring H₂S in the fuel gas. This alternative method of monitoring is allowed in accordance with NSPS Subpart J, 40 CFR 60.104(a)(3).

Continuous Emission Monitors (CEMs)

As required by regulation, there are various CEM within the refinery that are used to monitor compliance with air pollution standards. Each is installed and operated in accordance with applicable federal requirements (40 CFR 60 appendix B and F) and the NWAPA "Guidelines for Industrial Monitoring". Below is a table of each CEM, where it is located and the pollutants monitored. Each CEM is quality assurance tested as required under appendix F. This includes conducting quarterly cylinder gas audits (CGA) and relative accuracy test audits (RATA).

Unit	Location	Pollutants Monitored
FCCU	Main Fuel Gas Drum	H ₂ S
HTU 2	HTU #2 Fuel Gas Drum	H ₂ S
HTU 3	HTU #3 Fuel Gas Drum	H ₂ S
HTU 1	Heater Stack (common stack to 7C-F4 and 7C-F5)	SO ₂ , O ₂
FCCU	CO Boiler 1 / ESP 1	NOx, SO ₂ , CO, Opacity, O ₂
	CO Boiler 2 / ESP 2	NOx, SO ₂ , CO, Opacity, O ₂
	Regenerator	SO ₂ , O ₂
SRU	Primary Incinerator Stack	SO ₂ , O ₂
	Secondary Incinerator Stack	SO ₂ , O ₂
	New Incinerator Stack (SRU4 Project)	SO ₂ , O ₂

Because PSR operates CEMs within the NWAPA “Guidelines for Industrial Monitoring” the duration and nature of CEM downtimes is reported to the NWAPA on each monthly emission report. The monthly reports also include CGA and RATA results. Under NWAPA Section 340 measured emission exceedances are reported within 12-hours and explained in monthly emission reports.

Equipment Leaks

Although minor amounts of volatile organic compounds (VOC) are released from combustion sources, the majority is emitted from fugitive VOC emission sources. There are three major areas for fugitive VOC emissions that include process equipment (valves, pumps and compressors) leaks, storage tanks and the wastewater treatment plant. A summary of the process equipment leaks monitoring programs is listed in the table below. Specifics concerning storage tanks and the wastewater treatment plant are provided in other sections of the Statement of Basis.

Fugitive VOC and hazardous air pollutants (HAPs) are emitted from leaking process equipment. These components include pumps, valves and compressors and to a lesser degree other assorted components such as flanges and open-ended lines. All process units in the refinery are periodically monitored for leaks and when leaks are identified, they are repaired in a timely manner. Although there are differing regulatory drivers for underlying applicability, the leak detection and repair (LDAR) program applied at each process unit is conducted in accordance with the work practice methods specified in NSPS 40 CFR 60 Subpart VV and instrument monitored using EPA Method 21. The only exceptions being that BHU, HTU #2 and HTU #3 are under a more stringent program enhanced LDAR program that was required by BACT during NSR. Each process unit/area is listed in the table below with a description of the approximate number of components under the LDAR program. The last column describes the regulatory drivers that prescribe the LDAR program for that unit.

Puget Sound Refinery				
Fugitive VOC/HAP Leak Detection and Repair Program Summary				
Unit	Valves ¹	Pumps	Compressors	Reason for LDAR Program Applicability
VPS	2,600	19	2	40 CFR 63 Subpart CC (R-MACT)
DCU	1,700	18	2	40 CFR 63 Subpart CC (R-MACT)
FCCU	2,100	21	1	40 CFR 63 Subpart CC (R-MACT) 40 CFR 60 Subpart GGG (NSPS) OAC #684 Condition 7 (BACT)
Cat Poly	1,850	19	0	40 CFR 60 Subpart GGG (NSPS) NWAPA 580 (RACT)
Alky #1	1,800	16	1	40 CFR 63 Subpart CC (R-MACT) NWAPA 580 (RACT)
Alky #2	2,800	27	1	40 CFR 63 Subpart CC (R-MACT) NWAPA 580 (RACT)
HTU #1	1,400	9	1	40 CFR 63 Subpart CC (R-MACT)
HTU #2	1,800	20	0	40 CFR 63 Subpart CC (R-MACT) 40 CFR 61 Subpart J (NESHAP) OAC #630a Condition 6 and 7 (BACT) ²
HTU #3	3,500	14	0	40 CFR 63 Subpart CC (R-MACT) 40 CFR 60 Subpart GGG (NSPS) OAC #787 Conditions 5 and 6 (BACT) ²
CRU #1	1,000	17	0	40 CFR 63 Subpart CC (R-MACT)
CRU #2	1,600	31	0	40 CFR 63 Subpart CC (R-MACT) 40 CFR 61 Subpart J (NESHAP)

Puget Sound Refinery Fugitive VOC/HAP Leak Detection and Repair Program Summary				
Unit	Valves ¹	Pumps	Compressors	Reason for LDAR Program Applicability
BHU	200	1	0	40 CFR 63 Subpart CC (R-MACT) 40 CFR 60 Subpart GGG (NSPS) OAC #772a Condition 1 & 2 (BACT) ²
Nonene	850	16	0	40 CFR 60 Subpart GGG (NSPS) OAC #296 Condition 2 (BACT)
Flare Line	150	0	0	40 CFR 63 Subpart CC (R-MACT)
Gasoline Truck Load Rack	200	6	0	40 CFR 63 Subpart CC (R-MACT)
Diesel Railcar Load Rack	30 (heavy liquids)	0	0	40 CFR 60 Subpart GGG (NSPS) OAC #757 Condition 4 (BACT)
Other Shipping, Receiving and Storage Areas	4,400	60	1	40 CFR 63 Subpart CC (R-MACT) 40 CFR 60 Subpart GGG (NSPS)

1. Valves in gaseous or light liquid service
2. Enhanced LDAR Program

All process units at the refinery are required to meet the LDAR standards of 40 CFR 60 Subpart VV with the exception of two units, which are on an enhanced LDAR program. This NSPS work practice standard is commonly referenced by all of the underlying applicability drivers including 40 CFR 63 Subpart CC (R-MACT), 40 CFR 60 Subpart GGG (NSPS), NWAPA 580.8 and by pre-2001 OACs. Refinery MACT 63.640(p) allows for considerable consolidation of LDAR programs by stating that “equipment leaks that are also subject to the provisions of 40 CFR parts 60 and 61 are required to comply only with the provisions of this subpart”. Because of the complexity of the underlying applicability drivers, some being VOC based and some being HAP based, combined with the ability of the refinery to consolidate programs under Refinery MACT, Puget Sound Refinery has elected to monitor in accordance with Subpart VV, all equipment in gaseous, light liquid or heavy liquid (all heavy liquid is not monitored) VOC service in each particular unit. This includes equipment in fuel gas service. Defining component applicability on a VOC basis it also captures any equipment that is in HAP service. This simplifies the manner in which the terms of the AOP are written and provides consistent program implementation throughout the refinery. It should be noted that the Consent Decree requires that all LDAR programs within the refinery use an enhanced LDAR program by March 21, 2003. The enhanced program modifies the standards of Subpart VV with more stringent leak definitions and limits how the refinery can relax monitoring frequencies (see Consent Decree section for details). In addition, enhanced programs are required at HTU #2, HTU #3 and the BHU as a result of BACT determinations.

In summary, although there are numerous underlying regulatory drivers, they all point to the commonly used LDAR practices of 40 CFR 60 Subpart VV. Two units operate enhanced LDAR programs due to NSR BACT determinations and all will be under enhanced programs as required by the consent decree by March 21, 2003.

Emission Reports

Monthly Emission Reports

Monthly emissions reports are submitted to the NWAPA within 20 days following the end of each calendar month. In addition to reporting, emission data must be kept at the refinery for at least five years and made available to NWAPA personnel upon request. Monthly emission reports include:

- The duration and nature of each CEM downtime.
- All measurements in excess of a standard with an explanation for their occurrence and the corrective actions taken or planned.

Each monthly emissions report must include the following elements in accordance with the associated OAC requirements. These items are listed in the general order that they appear on the report.

OAC # and Condition Requiring the Report	Process Unit and Emission Unit(s)	Report Element
OAC #623a, Condition 14a	Refinery fuel gas, fuel oil, regenerator flue gas and WWSG combustion	Average monthly SO ₂ for the entire refinery and required subcategories (lb/hour)
OAC #693, Condition 7 NWAPA 460.5	Entire refinery	
NWAPA 460.11	Entire refinery's combustion units	Monthly average SO ₂ (lb/MMBtu)
OAC #623a, Condition 14f	FCCU CO boilers	12-month rolling SO ₂ , PM*, PM-10, CO and NOx (tons)
OAC #623a, Condition 14g	FCCU CO boilers	Monthly SO ₂ and NOx from firing up to supplemental firing rates (tons)
OAC #623a, Condition 14f	FCCU Regenerator	12-month rolling SO ₂ (tons)
OAC #693, Condition 4	SRU	Monthly average sulfur production rate (long tons/day)
OAC #693, Condition 9	SRU	Maximum daily average incinerator firing rate (MMBtu/hour)
OAC #828, Condition 5	SRU	Cumulative SO ₂ emissions over 12-month rolling basis
OAC #628a, Condition 7	DCU 15-F100 Heater	12-month rolling NOx (tons)
OAC #321a, Condition 4	CRU 6D-F2/F3/F4 Heaters	12-month rolling NOx (tons)
OAC #684, Condition 6	VPS 1A-F8 Heater	12-month rolling NOx (tons)
OAC #787b, Condition 3	CDHDS Heater	Highest daily average and 3-hour rolling average H ₂ S in fuel gas
RO #20b, Condition 3	VPS 1A-F4/F5/F6 Heaters	12-month rolling NOx (tons)
RO #21, Condition 3	Erie City Boiler	Highest daily average (lb/hour) and 12-month rolling NOx (tons)
RO #22, Condition 3	CRU #2 10H-101/102/103 Heaters	Highest daily average (lb/hour) and 12-month rolling NOx (tons)
RO #23, Condition 3	CRU #2 10H-104 Heater	Highest daily average (lb/hour) and 12-month rolling NOx (tons)
RO #24, Condition 3	HTU #2 11H-101 Heater	Highest daily average (lb/hour) and 12-month rolling NOx (tons)
RO #25, Condition 2	Flares (North, South and East)	Highest daily average (lb/hour) and 12-month rolling NOx (tons)
OAC #623a, Condition 14h	FCCU	Monthly hours in each combustion mode (hours)

* PSR assumes all PM emissions are in the form of PM-10.

Because PSR operates CEMs within the NWAPA “Guidelines for Industrial Monitoring” the duration and nature of CEM downtimes is reported to the NWAPA on each monthly emission report. The monthly reports also include CGA and RATA results. Under NWAPA Section 340 measured emission exceedances are reported within 12-hours and explained in monthly emission reports.

Various quarterly, semiannual and annual reports are submitted to the NWAPA as referenced in the AOP.

Annual Emission Inventory Reports

Each year PSR is required to submit an emissions inventory for the refinery. This report includes both criteria air pollutants and HAPs. Reports from the refinery are categorized into different source groups as well as for individual emission units. In turn the NWAPA publishes a jurisdiction wide emissions inventory report that includes a summary of annual emissions for large industrial facilities. This report lists criteria air pollutants emitted from PSR as follows:

Pollutant / Tons	1998	1999	2000	2001	2002
VOC	312	408	502	603	496
PM-10	192	136	178	263	146
NOx	1105	974	990	2172	1152
SO ₂	6889	2694	4162	4206	3494
CO	881	586	651	669	621

Consent Decree

In the late 1990s, the EPA conducted a nation-wide enforcement initiative of the petroleum refining industry, targeting alleged violations of the Clean Air Act (CAA), Resource Conservation and Recovery Act (RCRA) and the Toxic Substances Control Act (TSCA). Following this in-depth investigation, PSR's parent companies, Motiva and Equilon, entered into consent decree agreements with EPA and intervening parties that will result in a reduction of air pollution emissions at their nine petroleum refineries. Equilon now does business as Shell Oil Products US. As one of the affected refineries, PSR will implement control strategies to reduce emissions of nitrogen oxides and sulfur dioxide from refinery process units. In addition, they will adopt an enhanced fugitive emission control program and employ improved engineering practices to eliminate excessive hydrocarbon and H₂S flaring.

Because the requirements contained in the consent decree are not considered specific "requirements" under federal Title V definitions, the AOP incorporates only a compliance plan for items of the consent decree that will continue into perpetuity. This plan is listed in Section 8 of the AOP in accordance with 40 CFR 70.5(c)(8). It is recognized that the consent decree is, in and of itself, independently enforceable. Furthermore, many of the specific requirements contained in the consent decree overlap requirements found in the AOP and knowledge of its contents are important in understanding how and why the refinery conducts specific compliance programs. For this purpose the two consent decree settlement documents are provided in their entirety at the following URL: <http://nwair.org/regulated/aop.html>.

The consent decree requires the addition of new control devices at the refinery (e.g. wet gas scrubber at the FCCU and low NOx burners in heater 1A-F4). Construction of each new control device will be permitted under a future OAC. During the OAC issuance process, the NWAPA anticipates that the AOP will be opened up in a parallel permitting process to incorporate the new OAC conditions into the AOP.

It should be noted that the NWAPA is a plaintiff-intervener in the consent decree. As such, it is a signing partner in the settlement agreements and shares a role with EPA in matters of compliance enforcement and penalty assessment. A summary consent decree requirements affecting PSR are listed below. However, please refer to the actual text in the consent decree for more detailed information. The compliance plan under Section 8 of the AOP list a subset of consent decree requirements will continue into perpetuity and therefore been included in the AOP. It is anticipated that consent decree requirements not listed in the compliance plan will "sunset" upon termination of the consent decree in 2008.

Summary of the Motiva/Equilon Consent Decree Requirements for PSRC

United States of America v. Motiva Enterprises, LLC, Equilon Enterprises, LLC and Deer Park Refining LP
Civil Action Number H-01-0978
Entered August 21, 2001 in US District Court, Southern District of Texas

1. **FCCU:** Conduct a study to determine the optimum NOx adsorbing catalyst additive rates. Upon completion, the optimum additive rates are to be submitted to EPA and used thereafter to reduce NOx emissions at the FCCU. For SO₂ control, PSR shall install a Wet Gas Scrubber (WGS) at the FCCU by no later than December 31, 2006. The WGS shall be designed to achieve at least 50 ppmvd SO₂ based on a 7-day rolling average and 25 ppmvd SO₂ based on a 365-day rolling average (0% oxygen). CEMs shall be used to demonstrate compliance with these emission limits.
2. **Heaters and Boilers:** PSR shall not burn fuel oil in any process heater or boiler except for natural gas curtailments and some testing. NOx emissions will be reduced with the application of low NOx burners based on a corporate-wide reduction strategy. On December 17, 2001, Equilon submitted a heater/boiler NOx control plan that includes a 170 ton per year NOx reduction at the PSR. This reduction, based on a 1998 calendar year baseline, is planned to be completed by 2008. The plan lists credits from control strategies already completed at PSR including installation of low NOx burners on VPS Charge Heaters 1A-F5/F6, shutdown of VPS Vacuum Charge Heater 1A-F7 and construction of Vacuum Charge Heater 1A-F8. At this time, only installation of a low NOx burner on VPS Gas Oil Charge Heater 1A-F4 has yet to be completed. This retrofit is scheduled for no later than 2005.
3. **Benzene Waste NESHAP:** An audit of the waste stream inventory and TAB calculation has been conducted and submitted to EPA to determine PSR's compliance with 40 CFR 61 Subpart FF. EPA may require up to twenty waste streams to be sampled following review of the audit results. In addition, PSR shall audit each laboratory that is used for sampling analysis at least every two years.

Two carbon canisters in series or a carbon canister in series with a scrubber shall be used to control emissions from oily-water sewer and effluent plant vents. Monitoring for carbon bed breakthrough shall be determined at 50 ppm VOC at a sampling point between the two canisters. If breakthrough occurs, the primary canister shall be replaced with the secondary canister and the secondary canister replaced with a fresh one. Minimum change out times are defined, based on canister size, when breakthrough is detected.

In addition, the following items are required:

- Spills - Account for all benzene spills in the respective total annual benzene (TAB) and for benzene waste calculations with respect to the 2 Mg/yr or 6 Mg/yr waste exemptions.
 - Training - Develop and implement training for employees required to sample benzene wastes. Establish Standard Operating Procedures (SOPs) for control equipment include annual training for operators.
 - 6 Mg per year benzene waste exemption option - conduct quarterly "end of the line" benzene determinations and sample waste streams containing greater than 0.05 Mg/year benzene. Maintain record of waste/slop oil movements which are not controlled.
 - Miscellaneous monitoring – Conduct monthly visual inspections of all water traps in individual drain systems, regular instrument monitoring of vents on process sewers and, quarterly instrument monitoring for leaks at the oil/water separators.
4. **Fugitive Emissions from Process Equipment**– Develop and maintain an enhanced LDAR compliance program that includes the identification, monitoring and repair of components in HAP/VOC service. Use an electronic database and dataloggers to track leak rates and program

performance on an individual component and on a process unit basis. The program shall provide adequate training for involved personnel. An initial external audit has been performed and thereafter PSR shall, at minimum, conduct internal audits every four years or external audits every two years.

The work practice standards of the enhanced LDAR program shall be in place by no later than March 31, 2003. The program follows requirements of NSPS Subpart VV with modifications to defined leak rates and the allowable monitoring relaxation frequencies as summarized below.

- Pumps - visually inspect weekly, monitor monthly at a leak definition of 2,000 ppm with no allowance for relaxing the frequency.
 - Valves – monitor quarterly with no allowance for frequency relaxation or, monitor monthly with the following allowance for relaxation on a process unit basis; if < 2% leakers can skip to quarterly, if < 1% leakers can skip to semi-annually, if < 0.5% leakers can skip to annually. Regardless of the applied monitoring frequency the leak definition for valves is 500 ppm with an action level for first attempt at repair at 100 ppm. Valves leaking greater than 50,000 ppm and those leaking at greater than 10,000 ppm for more than three years shall undergo extraordinary repair efforts prior to putting on a “delay of repair list”. Provisions are included for adjusting the monitoring frequencies during interruptions from process unit shutdowns and turnarounds.
5. **Elevated Flares:** A study due March 21, 2002 shall determine hydrocarbon flaring reduction strategies to be implemented no later than December 31, 2006. Root cause analysis must be conducted following hydrocarbon flaring events which identify corrective action taken to prevent reoccurrence consistent with good engineering practices.

With regard to SO₂ emissions, an acid gas flaring study is to be submitted that identifies the number, duration and quantity of acid gas flaring events over the past five years. The study must provide a description of action being taken to reduce the likelihood of reoccurring events. Future acid gas flaring events are to be reported to EPA in writing within 30 days of the event that include a root cause analysis and a description of follow-up corrective action being taken. Acid gas flaring in excess of 20 pounds per hour for a period of more than 3 consecutive hours or, greater than five events within any rolling 12-month period are applicable to stipulated penalties.

6. **SRU:** Consistent with the consent decree conditions for acid gas flaring in the elevated flares, excessive SO₂ emissions from the SRU are reportable to the EPA. Reports shall include corrective action being taken and, similar to acid gas flaring, stipulated penalties may apply. In addition, all vents at the elemental sulfur pit are required to be controlled.
7. **Stipulated penalties:** The consent decree outlines stipulated penalties for various compliance failures. Listed penalties range from \$250 for missing a component in VOC/HAP service that should be included a LDAR program to \$100,000 per quarter for failing to install a WGS at the FCCU with the defined timeline. Stipulated penalties for violations at the PSR are to be apportioned between the EPA and the NWAPA at 50% each.

Enforcement History

A file review of Notice of Violations issued to the PSR or the prior owners of the facility since January 1, 1997 yielded the information provided below:

NOV #	Date Issued	Description
3351	09/12/2003	Nuisance particulate fallout (catalyst) caused during startup of FCCU.
3329	07/07/2003	Source testing the gasoline vapor combustor ant the Loading Rack indicated that the combustor exceeded the 10mg VOC per liter of gasoline transferred limited specified in 40 CFR Part 63 Subpart CC – Refinery MACT.
3302	02/11/2003	Improper operation of the Tail Gas Treating Unit resulting in SO ₂ emissions form the primary incinerator stack to exceed 250 ppm for twelve consecutive 12-hour rolling average periods.
3219A (warning)	02/06/2002	Particulate source test failure: source test performed on 10/26/01 resulted in an exceedance (0.53 lbs. PM hour) of the 0.39 lbs. PM/hour limit set forth in OAC #762 Condition 2c.
3218	01/29/2002	Carbon monoxide source test failure: source test performed on 9/25/01 resulted in an exceedance (3.7 lbs CO/hour) of the 3.2 lbs CO/hour limit set forth in OAC #762 Condition 2b.
3195	10/04/2001	Release of fine catalyst during startup of the FCCU on August 25th and 26th, 2001, in such a manner that caused a particulate fallout nuisance on nearby residences.
3133	01/18/2001	Failure to abide by Order of Approval # 684 Condition 3 which limits refinery fuel gas servicing 1A-F8 heater to 50 ppmvd H ₂ S rolling 24-hour average. This condition was exceeded from 7:00 PM, January 1 through 10:00 AM, January 3, 2001.
3038 (warning)	05/11/2000	Failure to abide by Condition 3 of Order of Approval to Construct #684.
3009 (warning)	12/07/1999	Failure to submit fugitive VOC semiannual reports for the Polymerization and Alkylolation units in a timely manner. The reports were 81 days late in accordance with 40 CFR 60.487 and NWAPA Compliance Memorandum issued February 25, 1997.
3007	11/24/1999	Sulfur dioxide emissions in excess of 1000 ppmdv from the CO Boiler stacks between 9:00 and 10:00 PM 11/18/99.
2967	08/11/1999	Failure to operate and maintain continuous emission monitoring systems according to applicable regulations and guidelines, including failure to perform required cylinder gas audits (CGA), late completion of Relative Accuracy Test Audits (RATA), and inadequate sequencing of RATAs and CGAs.
2923	02/03/1999	High S ₀₂ emissions from catalytic cracking unit in excess of permit limit.

NOV #	Date Issued	Description
2915	12/21/1998	Exceeded the 0.800 ppm 5-minute SO ₂ average for the fifth time in a twelve month period (as measured by General Chemical's ambient station). Winds were from 162 degrees at 7 miles per hour. Paid penalty of \$11,225.
2904	11/13/1998	Failure to assure that gasoline cargo tanks tested by Beall and General Transport were leak tight in accordance with requirements under Refinery MACT.
2853	06/25/1998	Exceeded the 0.800 ppm 5-minute ambient SO ₂ average for the fourth time in a twelve month period (as measured by station 32). Paid penalty of \$11,225.
2851	06/10/1998	Exceeded the 0.800 ppm 5 minute ambient SO ₂ average for the third time in a twelve month period (as measured by station 32). Paid penalty of \$11,225.
2850	06/03/1998	Exceeded the 0.800 ppm 5 minute ambient SO ₂ average for the second time in a twelve month period (as measured by station 32). Paid penalty of \$11,225.
2768	08/22/1997	Exceeded SO ₂ twelve hour rolling average at sulfur recovery unit. Violation of 40CFR60 Subpart J, Standards of Performance for Petroleum Refineries.
2736	05/05/1997	Operator error when working on DEA system at sulfur plant causing a loss of DEA. The NSPS 12 hour standard of 250 ppm SO ₂ was exceeded from noon to midnight on 4/18/97.

Each of the violations listed above has been resolved through a combination of penalty assessments and by corrective action taken by the source. In most cases corrective action taken by the source is submitted to the NWAPA as a written response to the violation. Additional information about each violation can be obtain upon request to the NWAPA.

Process Descriptions, Construction History and Regulatory Applicability

The following section provides a description of each refinery area along with a 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. 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.

Vacuum Pipe Still (VPS)

General Operation

Sometimes referred to as the Crude Unit, the VPS is considered the first stage of crude processing at the refinery. Here, crude oils are "washed" in the Desalter to remove salts and other naturally occurring contaminants. After washing, the crude is heated to about 650° F in the 1A-F5&6 charge heaters and then routed in the Atmospheric Distillation Tower where it physically separates the crude into fractions with specific boiling point ranges. Further separation is achieved by distillation under vacuum at the Vacuum Pipe Still or by steam stripping. The light fractions, such as propane, naphtha, kerosene and diesel, generated from atmospheric distillation can be further processed or used as finish product blending stocks often referred to as "straight run" products. Heavier fractions are routed to the Gas Oil Distillation Tower where gas oils are separated before routing to the FCCU as feedstock. The heaviest fractions are produced from the bottom of the VPS and are called vacuum residuum. The vacuum residuum is sent to the DCU as a feedstock or can be blended into heavy finished products such as bunker or marine fuel oils.



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

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

Construction History and Regulatory Applicability

The original crude unit was built with the refinery in 1958. Two major projects have been done on this unit since that time. The first was in 1975 when 2 new charge heaters and a gas oil heater were installed as part of the Octane Improvement project. In late 1999 the vacuum tower (1A-C103) and associated vacuum tower heater (1A-F8) were replaced. Construction related to this unit upgrade was approved by the NWAPA on June 17, 1999 under OAC #684. A shutdown of the old vacuum tower heater (1A-F7) occurred as a one-time condition of this OAC. The shutdown allowed PSR to offset NOx emissions from the project to avoid PSD permitting. Because the modification was considered a debottlenecking project for the FCCU, OAC #623a includes conditions that limit the allowable increases in SOx, NOx and CO from the FCCU/CO Boilers.

To meet the BACT requirement for NOx the vacuum tower heater was performance tested on June 20, 2000 using EPA Method 7E. Testing found the heater to be emitting NOx at a rate of 0.0285 lb/MMBtu, well below the 0.05 lb MMBtu BACT limit set in the OAC.

NSPS subpart GGG requirements were triggered for components in VOC service that were installed as a result of the VPS project. This primarily included components associated with the new heater and vacuum tower. The components in VOC/HAP service that existed prior to construction had already been under a LDAR program as of August 18, 1998, in accordance with National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR 63 Subpart CC. All components have been put on a consistent monitoring frequency following after the more intensive initial monitoring program for the new components was completed.

Installation of the new vacuum tower heater (1A-F8) triggered BACT determination for SO₂ from combustion of refinery fuel gas. The new BACT limit for refinery fuel gas burned in this heater was determined to be 50 ppm on a based on a 24-hour rolling average. Although this is generally considered more stringent than the 162 ppm limit imposed by NSPS 40 CFR 60 Subpart J, it should be noted that the Subpart J limit is based on a 3-hour rolling average. Both standards apply and either can be exceeded while maintaining compliance with the other. Refinery fuel gas servicing the vacuum tower heater is routed from the main refinery fuel gas drum. H₂S is monitored at the drum on a continuous basis. This CEM is operated under the NWAPA "Guidelines for Industrial Monitoring" and performance audited (RATA) annually using EPA Method 11.

During the second half of 1999, the PSR voluntarily installed low NOx burners on VPS heaters 1A-F5 and 1A-F6. On February 10, 2000 the NWAPA issued Regulatory Order and Emission Reduction Credit #20 to PSR. The order put an annual limit on the combined NOx emissions from heaters 1A-F4, 1A-F5 and 1A-F6 at 304 tons. It also, granted a NOx emission reduction credit of 316 tons per year to PSR that could be used for PSD offsets on future projects. Although heater 1A-F4 had not been retrofitted with low NOx burners, PSR asked that this heater be included in the order. On May 23, 2000, heaters 1A-F5 and 1A-F6, which have a common stack, were performance tested for NOx emissions as a one-time condition the order. The heaters tested at 0.075 lb/MMBtu. NOx emissions were found to be slightly above the originally credited level. On November 16, 2000 the NWAPA issued revised the Regulatory Order and Emission Reduction Credit #20A. The revision increased the allowable NOx emissions from the three heaters to 331 tons per years and lowered the allowable credit to 289 tons per year. On April 19, 2001, Regulatory Order #20 was again revised allowing PSR to use 227 tons of NOx credits to construct seven 5.2 MW Solar turbines. Regulatory Order #20b allows for 62 tons per year of NOx credits as of April 2002. It should be noted that none of the NOx credit adjustments changed the order's monitoring, recordkeeping or reporting requirements.

OAC # 684 Condition 4 requiring source compliance testing is not listed in the AOP because it is a one-time condition that has been completed. OAC # 684 Condition 8 requiring a quality assurance manual for the hydrogen sulfide monitor to be submitted and approved by the NWAPA prior to start-up is not listed in the AOP because it is a one-time condition that has been completed.

40 CFR 60 Subpart J limiting fuel gas to 162-ppm H₂S in heaters 1A-F4, 1A-F5 and 1A-F6 is required in accordance the consent decree. This requirement can be found Sections 5 and 8 of the AOP.

Delayed Coking Unit (DCU)

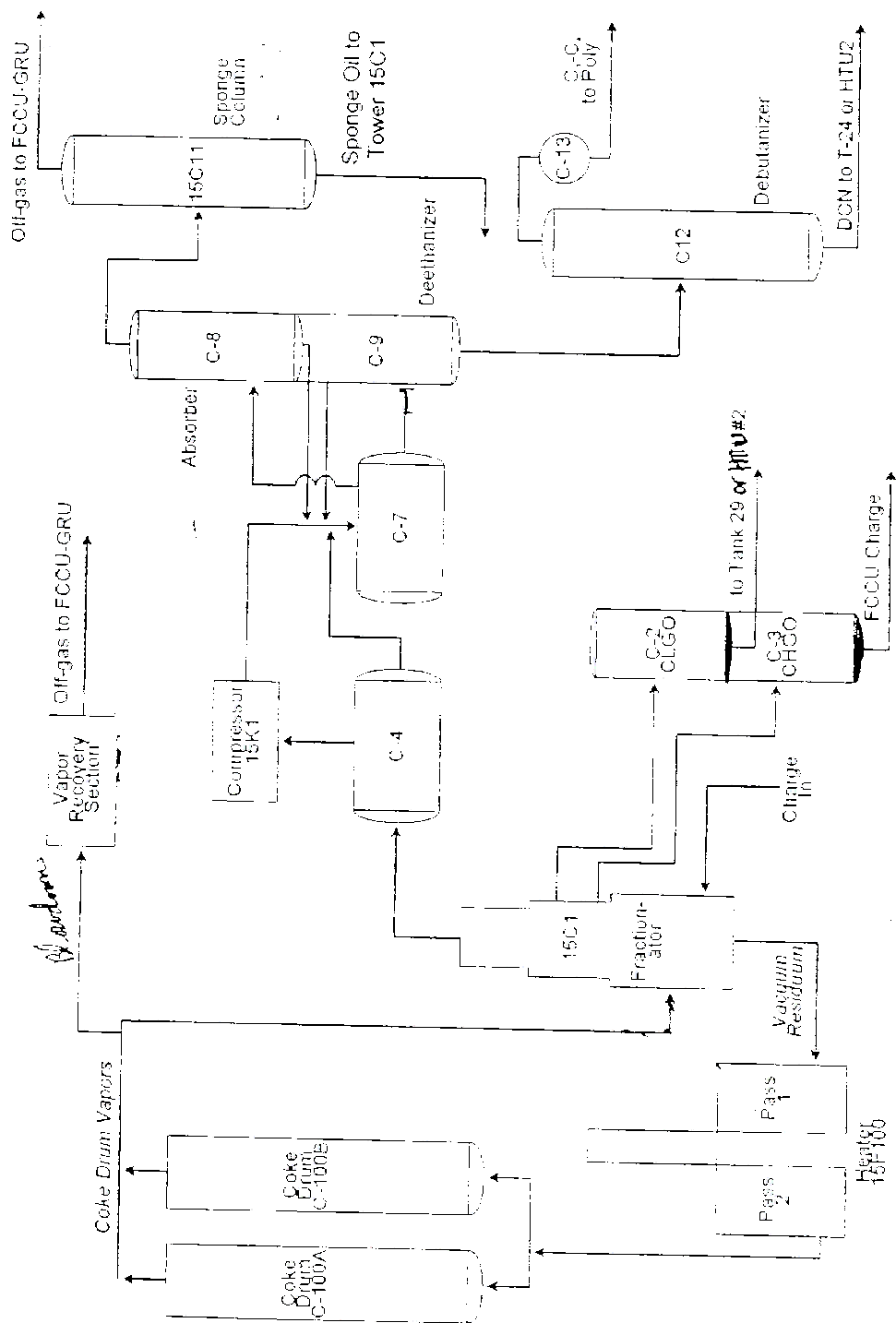
General Operation

The DCU converts vacuum residuum from the crude unit into fractions by thermal cracking and coking followed by steam stripping and fractionation. The heavy feed is first heated and then charged to large drums that provide the long residence time needed for thermal cracking and coking to proceed to completion. Cracked products from the coke drums are routed to the DCU fractionator while coked material remains behind as petroleum coke. The lighter cracked fractions are routed to the FCCU and CPU. Light to medium fractions such as the Coker Light Gas Oil (CLGO) and Delayed Coker Naphtha are sent to the HTU #2 for further processing. Coker Heavy Gas Oil is sent to the FCCU as feedstock. The residual heavy material deposits as solid petroleum coke on the inside of the coke drum. For a continuous operation, two drums are used: while one is on stream, high-pressure water is used to cut the deposited coke out of the other. Prior to cutting, the drum is cooled down using steam and water.



Coke cutting water is recycled using a pair of large settling tanks. Slop oil recovered from the drum is routed to slop oil recovery tanks located at the unit. Recovered oil is sent to the FCCU for processing. Various plant sludges can be charged to the CDU coke drums during the blowdown cycle. After the petroleum coke is removed from the drums it is stockpiled just east of the DCU. Most of the finished coke is loaded into covered trucks and hauled to the Port of Anacortes for loading onto marine vessels.

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



Delayed Coking Unit Simplified Flow Diagram

3-20

Construction History and Regulatory Applicability

The DCU was constructed in 1984 under OAC #275 issued by the NWAPA February 10, 1983. This OAC was revised on May 26, 1995 to remove a firing rate limit on charge heater 15F-100 and instead set a 39.5 tons NO_x per year limit and associated performance limit of 0.09 lb NO_x/MMBtu. The OAC specified the applicability of 40 CFR 60 Subpart J for refinery fuel gas firing in the heater. The Subpart J requirement limited H₂S to 162 ppm H₂S based on a 3-hour rolling average. PSR monitors the main fuel gas drum for compliance with this standard (see similar and more stringent requirement at VPS). OAC #275a, Condition 3 requires that operating procedures be used to prevent atmospheric venting of volatile organic compounds (VOC) from coke drums. The system currently operates as a closed system with coke drum blowdown routed to recovery compressor (15K-100) before venting to the refinery flares for control. As a result, Condition 3 was not incorporated into OAC #628 when it superceded OAC #275a.

On September 30, 1997 the NWAPA issued OAC #628 in response to a Notice of Construction (NOC) to install a new burner in DCU Charge Heater 15F-100. The new burner would increase the heater's firing rate capacity from 115 to 124 MMBtu/hour. OAC #628 included a BACT NO_x limit of 0.07 lb/MMBtu. On November 7, 1997 the heater source tested at 0.039 lb NO_x/MMBtu. OAC #628 was written to supercede the pre-existing OAC #275a and in doing so it incorporated many of the conditions of the old OAC including the 162 ppm H₂S fuel gas limit. On May 11, 1998, OAC #628 was revised (OAC #628a) to include a light-ends recovery project at the DCU. The project involved the installation of three pump drains that subject the drains and four pre-existing junction boxes to 40 CFR 60 Subpart QQQ requirements.

OAC #628a Condition 8 stating that written notification of the initial start-up date must be submitted to the NWAPA is complete and is therefore is not listed in the AOP because it is a one-time condition that has been completed. OAC # 628a Condition 9 stating that the OAC replaces in full OAC #275 issued Feb. 8, 1983 and OAC #628 issued Sept. 30, 1997 is not listed in the AOP because it is a one-time condition that has been completed.

In mid 1990s, the NWAPA received a number of complaints about fugitive coke dust released during loading, unloading and trucking of petroleum coke products from the DCU to Anacortes for shipping. The problem was investigated and on October 25, 1996, the NWAPA issued Regulatory Order 14 that requires that all trucks hauling coke products to be covered. It also required that the loading chute on the DCU coke hopper be retrofitted with a vertical height adjustment mechanism to minimize coke free fall during loading. Modifications to the coke loading area were completed on January 25, 1997. PSR and NWAPA have an agreed upon a sampling and analysis protocol to be used when coke fallout problems are suspected. Using this protocol, samples taken in 2000 and 2001 were found to contain less than 5% coke thereby validating the success of the fugitive coke emission control program. In January 2002, a citizen task force that was established to review the program's progress was voluntarily dissolved.

Fluid Catalytic Cracking Unit (FCCU)

General Operation

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

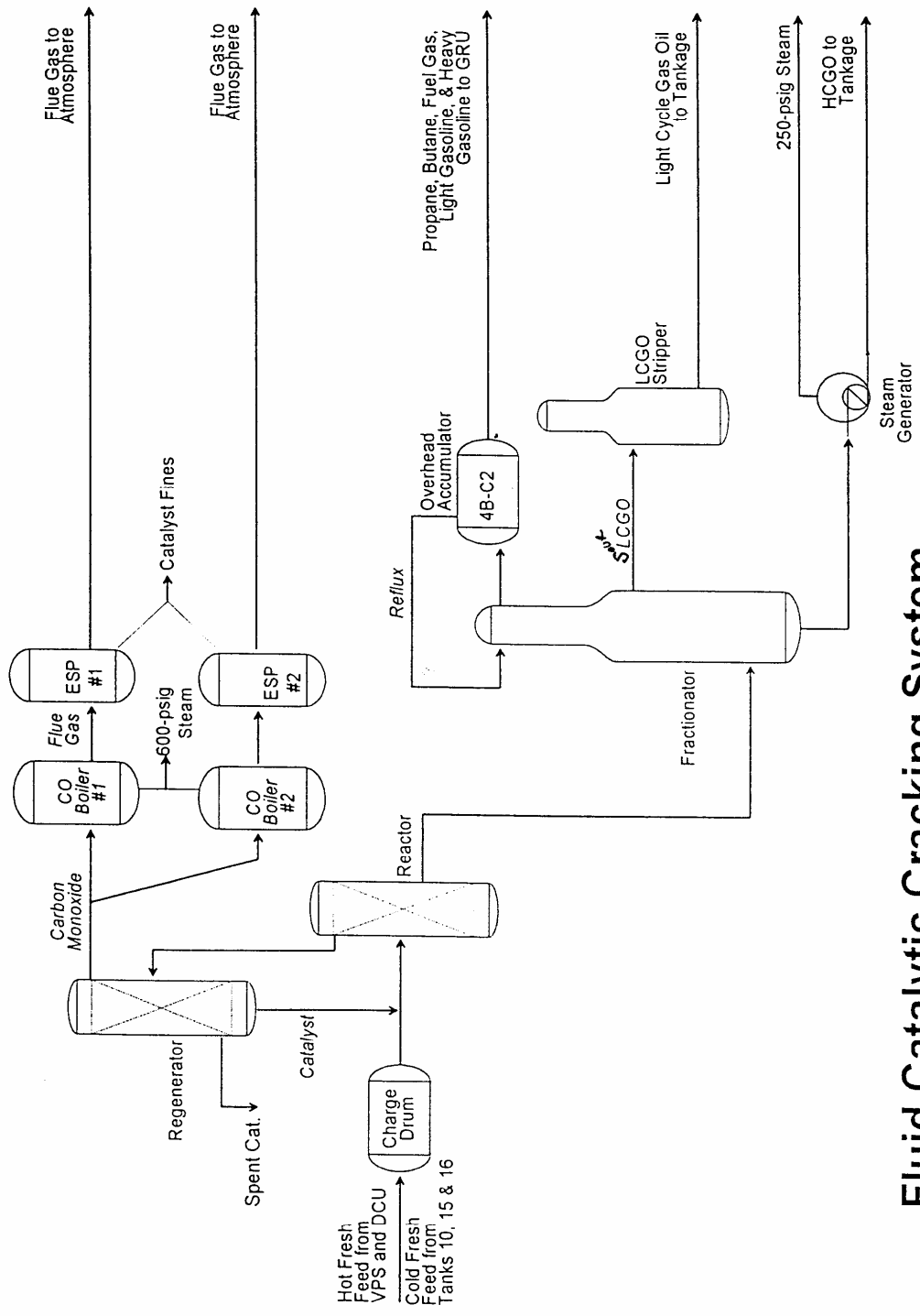
The catalyst section contains the reactor and regenerator, which together with the standpipe and riser, form the catalyst circulation portion of the unit. The FCCU uses blowers to aerate and circulate the small, spherical shaped silica-alumina catalyst in a manner that allows it to behave as a fluid.

As the catalyst comes into contact with the oil, the long-chain hydrocarbons are broken into a wide range of smaller-chain materials that are routed to the fractionation section of the FCCU. During this oil-catalyst reaction process, the catalyst accumulates carbon, called coke that must be burned-off in the regenerator to reactivate the catalyst. This process of cleaning the catalyst generates sulfur dioxide due to the sulfur content of the coke. DESOX catalyst is added to the regenerator to reduce the emissions of SO₂ from the FCCU. In addition, the regenerator can produce carbon monoxide (CO) depending on whether the unit is operating in full or partial combustion mode. In a partial combustion mode the flue gasses from regeneration contain large amounts of CO that must be combusted prior to release to the atmosphere. These flue gasses are routed into two CO Boilers where combustion takes place to convert the CO to CO₂. The combustion process produces heat for steam generation in the boilers. The boilers also have the capacity to burn supplemental fuels for additional steam production. Electrostatic precipitators (ESPs) have been added to the CO boilers to control particulate emissions. Particulate emissions are generated as the catalyst is degraded into smaller particles as a normal process in the FCCU. Primary catalyst removal occurs in the regenerator section in internal cyclones.



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

Major components at the FCCU include the feed surge drums, air blowers, reactor, regenerator, main fractionator column, air compressors, CO boilers, ESPs and waste heat steam generators. Operating temperatures range from ambient to 1375 °F. Operating pressures range from -5 to 600 psi. Equipment and emissions units are identified in the process flow diagram below. The unit also has a number of components in heavy liquid, light liquid, and gaseous service that can emit fugitive VOC and HAP emissions.



Fluid Catalytic Cracking System

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Construction History and Regulatory Applicability

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

Date Approved	Approval	Description
1958	Grandfathered	Original FCCU construction
July 19, 1972	Letter	Construct CO Boiler #2
April 11, 1985	OAC #300	Construct new fresh catalyst feed hopper at FCCU
September 19, 1988	OAC #246	FCCU modification
July 29, 1993	OAC #361	Construct ESPs on CO Boilers #1 and 2
March 18, 1994	OAC #361a	Combine OACs #246 and 361
June 13, 1995	OAC #361b	Removed requirement to establish a minimum catalyst feed rate, add requirement to establish a maximum sulfur dioxide mass emission limit
April 10, 1996	OAC #361c	Require H ₂ S instead of TRS monitoring of sulfur content of refinery fuel gas
February 23, 1998	OAC #623	FCCU vertical riser modification
June 17, 1999	OAC #623a	Add conditions of OAC #361c, Supercede OAC #361c, add new tons/year limits for NO _x , SO ₂ , and CO to provide protection from PSD and establish offsets for the new VPS heater (OAC #684), and the SRU expansion (OAC #693). Add references to Compliance Assurance Monitoring (CAM) and remove NSPS Subpart QQQ applicability
July 9, 1999	OAC #704	Install 3 portable temporary diesel fired air compressors for one year.
June 6, 2000	OAC #704a	Extend temporary approval from one year to 15 months.

The FCCU was built during original refinery construction in 1958. No substantial modifications occurred until 1976 when, as part of the Octane Improvement Project, CO Boiler #2 was constructed. An approval letter from the NWAPA was issued for this project however; the approval simply cited that the project was to meet generally applicable state and local regulations that were in effect at that time. The cited regulations included emission standards of: 1,000 ppm SO₂, 20% opacity, 1.5 lb SO₂/MMBtu and 0.05 grains particulate/scf of exhaust gas. Because the approval did not impose any new requirements under BACT, the approval letter is considered a “hollow” permit. Today, generally applicable regulations are at least as stringent as they were in 1972. On April 11, 1985 the NWAPA issued OAC #300 for a new fresh feed catalyst hopper at the FCCU. Again, approval for the hopper did not impose any new requirements that were not already in the generally applicable regulations and therefore the permit is considered “hollow”, that is without any specifically applicable requires. The AOP is therefore silent with regard to any specifically applicable requirements for either CO Boiler #2 or fresh feed catalyst hopper from either of these two early permitting activities.

On September 19, 1988, OAC #246 was issued allowing the refinery to modify the FCCU to achieve higher conversion of heavy feedstocks into gasoline. Unlike previous “hollow” permits, OAC # 246 set limits on CO (1,000 ppm one-hour average) and SO₂ (DESOX catalyst and 450 lb/hour) limits that were more stringent than the underlying generally applicable regulations. No limits were set for particulate (PM) emissions, as they were not anticipated to increase as a result of the project. After

completion of the FCCU modification it was found during an emission inventory analysis that emissions of PM had in fact increased. The discrepancy of not correctly estimating PM emission increases during new source review resulted in NOV #2286 being issued by the NWAPA on September 20, 1993. The violation cited the facility's failure to identify all known, available and reasonable methods of emission control for the increased PM emissions and for failing to obtain a NOC approval prior to construction. If these increases had been known prior to construction, electrostatic precipitators (ESPs) would have been required under BACT and NSPS.

Following enforcement action, a NOC was submitted for installation of ESPs on CO Boilers #1 and 2. On July 29, 1993, the NWAPA issued OAC #361 allowing the facility to construct the ESPs. On June 9, 1995, OAC #361 revision A was issued. This revision combined the conditions of OAC #246 and 361 into a combined approval order and took into account more accurate SO₂ monitoring. In this re-permitting process OAC #361a superceded the two prior approval orders.

On June 13, 1995, OAC #361a was again revised (revision b) to remove the requirement that established a minimum DESOX catalyst feed rate and instead added a requirement for a maximum sulfur dioxide mass emission limit. This was done to provide the refinery with more operational flexibility while still meeting their PSD avoidance obligations. On April 10, 1996, a final revision was made to the OAC (revision c) to allow the facility to monitor the H₂S content of refinery fuel gas combusted in the FCCU in lieu of monitoring total reduced sulfur (TRS). The change was consistent with the requirements of 40 CFR 60 Subpart J (see CRU #1).

On February 23, 1998, the NWAPA issued OAC #623. This OAC allowed the refinery to commence construction of the vertical riser project at the FCCU. The project involved modifying the catalyst riser section of the FCCU resulting in a 19% increase in the hydrocarbon feed rate to the unit to 60,000 barrels per day (bpd). The increased feed rate resulted from an improvement in efficiency and an increase in catalyst circulation rates. The net increase in exhaust gas flow from the CO boiler/ESP was 5% with a corresponding 5% increase in emissions. The unit was already NSPS applicable and BACT controlled for the CO (CO Boilers) and PM (ESPs), therefore limits for these pollutants were carried over from OAC #361c. BACT determinations for the other pollutants were as follows: SO₂ - addition of DESOX catalyst to the FCCU regenerator and fuel gas scrubbing, NO_x - low NO_x burners and flue gas recirculation in the CO Boilers; PM-10 - electrostatic precipitators and ammonia injection, VOC - good combustion and a LDAR program and, HAPs - good combustion and a LDAR program.

The refinery provided an emission analysis for the vertical riser project and associated emissions units impacted by the project. An emissions netting analysis showed that the project would not be subject to PDS permitting. Specifically, PSR netted out of PSD for PM/PM-10 from contemporaneous creditable emissions as established in NOC support documents for the Vertical Riser Project dated 9/5/97. An NSPS analysis found that the project was subject to Subparts J (except 60.104(b)) and GGG. Emission limits imposed include emissions released directly from the FCCU and from the COB/ESP stacks. In addition to the emission contributions from the FCCU there are emissions from supplemental fuel gas and oil firing and waste water stripper gas combustion from the CO Boilers. All were considered in determining conditions incorporated into OAC #623.

On June 17, 1999 the NWAPA issued revised OAC #623a. This revised approval order lowered the annual tonnage limits (12-month rolling average) from the FCCU/CO boiler stacks as follows; NO_x 1464 to 1380, SO₂ 6392 to 5822 and CO 139 to 95. These reductions provided the refinery with enforceable offsets for emissions from physically modified units and debottlenecked units associated with the Vertical Riser Project specifically the new VPS 1A-F8 Heater (NOC #684), and the Sulfur Recovery Unit expansion project (NOC #693). The revision also added references to 40 CFR 64 Compliance Assurance Monitoring (CAM) under the presumption that the FCCU/CO Boiler system

was subject to CAM for SO₂, NO_x, and PM-10 because the unit has the potential to emit greater than 100 tons per year for each pollutant. However, because gaseous pollutants are monitored continuously by CEMs, the unit is exempt from submitting a CAM plan for SO₂ and NO_x under 40 CFR 64.2. PM-10 emissions, on the other hand, are not continuously monitored and therefore a CAM plan is due prior to AOP renewal in accordance with 40 CFR 64.5.

On July 9, 1999, OAC #704 was issued for construction of three portable temporary diesel fired air compressors at the FCCU. These temporary compressors were used to replace the regenerator's main air compressor so that it could be taken off-line for inspection and repair. On June 6, 2000 OAC #704 was revised (revision a) to allow the temporary compressors to remain for an additional three months pending final repair of the permanent compressor. The time limit for OAC #704a has expired and the FCCU regenerator is back in normal operation. As a result OAC #704a has no on-going requirements and is not listed in the AOP.

At this time OAC #623a is the only approval order containing specifically applicable conditions and therefore it is the only OAC incorporated into the AOP. To provide clarity and to be consistent with the presentation layout in the AOP, compliance for each pollutant group at the FCCU is presented below. Although there are monthly reporting requirements contained in OAC #623a, they are listed in the Monthly Emission Report Section of this document.

OAC # 623a Condition 17 stating Order of Approval No. 623a replaces in full OAC #361C and 623 after the Vertical Riser modification is complete is not listed in the AOP because it is a one-time condition that has been completed. OAC #623a Condition 18 requiring written notification when the modification is complete and of the anticipated start-up date is not listed in the AOP because it is a one-time condition that has been completed.

Specifically Applicable Requirements for PM/PM-10, Opacity and Ammonia at the FCCU

In accordance with OAC #623a Condition 1, particulate (PM/PM-10) emissions from either CO Boiler #1 or #2 stacks shall not exceed 0.02 grains per dry standard cubic foot (gr/dscf) corrected to seven percent oxygen when both CO boiler/ESP trains are in operation. Particulate emissions shall not exceed 0.035 gr/dscf corrected to 7% O₂ when only one CO boiler/ESP train is operating and the other is down for inspection and maintenance. These grain loading limits were derived under BACT and, although there is a specific limit for operating only one CO boiler at a time, the BACT determination set an annual 336 hour limit for each CO boiler/ESP when operated individually. This is to prevent extended use the higher grain loading limit allowed for the single boiler. Although less stringent, it should also be noted that there is a specifically applicable requirement in NWAPA 455.13 that limits particulate emissions from FCCU stacks to 0.2 grains/dscf @ 7% O₂.

OAC #623a Condition 1 includes a mass emission limit of 441 tons PM (total particulate) per 12-month rolling period and a 202 ton PM-10 (fine particulate) per 12-month rolling period. The refinery does not differentiate between PM and PM-10 emissions at this unit because there have been no source tests or analysis performed that differentiate between particles above and below 10 microns in diameter. As result, the refinery reports particulate emissions as PM-10 and uses only the 202 ton limit for determining compliance. Although included in the AOP, the 441 ton PM limit remains relatively meaningless until such time that additional information on the size characteristics of particulates being emitted from the FCCU are obtained.

In accordance with OAC #623a Condition 2, particulate matter from the FCCU regenerator shall not exceed 1.0 pound per one thousand pounds of coke burn-off as required by NSPS 40 CFR 60.102(a)(1). This NSPS subpart J requirement includes specific source test procedures under 60.106 that are to be followed including the use of EPA Method 5B or 5F. Because Method 5 is considered more restrictive than Methods 5b or 5f, as it does not allow for the removal of secondary particulates formed by sulfur compound, the refinery uses Method 5 for annual source testing.

Annual source testing combined with information gathered on coke burn-off during testing is used to determine compliance with the NSPS coke burn-off limit.

A source test Method 5 (PM) is conducted annually to demonstrate compliance with the BACT established grain loading standard of 0.02 grains/dscf at 7% O₂ and the NSPS 1.0 lb/1,000 lb coke burn-off rate. It should be noted that although the results of Method 5 testing is total particulates all are assumed to be PM-10 for the purposes of monitoring, recordkeeping and reporting. The most recent source test data is as follows.

Stack and Test Date	Concentration (grains PM/dscf @ 7% O ₂)	Mass Emission Rate (lb PM/hour)	FCCU Regenerator (lb PM/1000 lb coke burn-off)
CO Boiler/ESP #1 (8/7/2001)	0.0091	11.32	0.03
CO Boiler/ESP #2 (8/8/2002)	0.0037	3.77	0.01
Combined		15.09 (67 tons/year)	0.02 average

In January 2002, a scheduled partial refinery shutdown occurred. The FCCU was run at a reduced rate of 40,000 barrels/day and only CO Boiler # 2 operating. During this partial shutdown, a source test was performed on CO Boiler #2. The test, conducted on February 1, 2002, resulted in an emission rate of 0.0196 gr/dscf and served to document compliance with the solo CO boiler operation emission limit of 0.035 gr/dscf found in OAC 693a Condition 1. Because running the FCCU with only a single CO boiler is limited to 336 hours a year there is no on-going requirement to perform PM testing for single CO Boiler operation beyond this compliance demonstration source test.

Source test data is used to calculate the cumulative 12-month rolling particulate emission rate which, in accordance with OAC #623a Condition 14f, is reported to the NWAPA on a monthly basis. Until early 2002, the refinery calculated their 12-month particulate emissions using a mass-balance approach. This approach subtracts the weight of degraded catalyst captured in the ESPs from fresh catalyst brought into the unit. A correction is made to account for the amount of catalyst that is taken up in the hydrocarbons during processing. In reviewing this issue during AOP development it was recognized that the mass-balance approach did not account for particulates that are formed during combustion. Furthermore, methodologies for determining mass-balance are not universally accepted in the way the source test methods are. The main benefit of the mass-balance approach is that it accounts for changes in FCCU operations including startups, shutdowns and upsets when increased catalyst losses occur. For example, during FCCU startup finer grained catalysts are used to enhance catalyst circulation thereby reducing the control efficiency of the FCCU's internal multi-cyclones and CO Boiler ESPs. Furthermore, during the startup period, which generally does not exceed 48 hours, the CO Boilers and ESPs are bypassed for safety purposes routing uncontrolled PM emissions directly to the atmosphere. Because all particulate emissions must be included when calculating 12-month rolling emissions, PSR has agreed to use a hybrid approach for calculating particulates. This approach will use the lb/hour emission rates found during the most recently available source tests for calculating emissions during normal FCCU/CO boiler operations. The cumulative 12-month particulate calculations will be supplemented with mass-balance data for periods during which startups, shutdowns and upsets occur.

OAC #623a Condition 14f specifies that the refinery will report both PM and PM-10 emissions in monthly emission reports however, because PSR has agreed to take a conservative approach in assuming that all particulate emissions are in the form of PM-10, only one value representing both PM and PM-10 emissions is submitted.

With regard to monitoring the time periods allowed for scheduled inspection and maintenance of the CO boiler/ESP's to assure that the refinery does not exceed the 336 hour limit, the refinery reports any that it anticipates exceeding the 336 hour limit in accordance with NWAPA Sections 340 and 341. Furthermore, the refinery keeps records of CO boiler operating hours and provides them to the

NWAPA upon request in accordance with "Duty to Provide Information" found in the AOP's Standard Terms and Conditions.

In accordance with OAC #623a Condition 3, opacity from the CO boiler stacks may not exceed 20% (Method 9). A COM is installed and operated to assure continuous compliance with this limit. The 20% limit is not applicable during soot blowing events although the source is expected to keep records when soot blowing occurs.

Ammonia is injected into the inlet side of the ESPs to increase the surface conductance of particles thereby achieving electrical resistivities in the desired range for efficient control. In accordance with OAC #623a Condition 8, the combined ammonia injection rate for both ESPs shall not exceed 25 lb/hour. Records of ammonia injection rates are required to be kept on-site and made available to NWAPA upon request.

Specifically Applicable Requirements for CO at the FCCU

In accordance with OAC 623a Condition 5 and NSPS Subpart J (60.103(a)), CO emissions from the CO boiler stacks shall not exceed 500 ppmvd corrected to 7% oxygen based on a one-hour average. In accordance with OAC #623a Condition 12a initial source emission test was conducted at maximum capacity on each CO boiler stack. The source test results are as follows:

CO Boiler #1: Conducted October 6, 1999 resulted in 1.5 ppm CO corr. to 7% oxygen
CO Boiler #2: Conducted October 7, 1999 resulted in 0.1 ppm CO corr. to 7% oxygen

For on-going compliance and in accordance with OAC #623a Condition 10b, CO concentrations in each CO boiler stack are continuously monitored using certified CEMs. Although NSPS Subpart J allows for an alternative monitoring method under 60.105(2), PSR has chosen not to pursue this option and therefore the AOP does not include any of these alternative monitoring methods.

In order to prevent the FCCU project from triggering PSD, CO emissions from the combined CO boiler stacks are limited to 95 tons in any consecutive 12-month period in accordance with OAC #623a Condition 5. The CO emission rate is calculated based on CEM concentration values and stack flow rates. The stack flow is calculated as follows: regen flow + metered CO boiler fuel gas/oil flow + metered CO boiler combustion air flow. The formula uses input from an online Gas Chromatograph (GC) to determine fuel constituents and CO₂ composition in the flue gas. The flow and lb/hour calculations are performed by the refinery's computer system and are updated every minute. Hourly and daily averages are used to track compliance and for calculating reportable monthly CO emissions. This is the same methodology used to calculate mass emissions for monthly SO₂ and NO_x reporting.

Specifically Applicable Requirements for NO_x at the FCCU

Although there is no NO_x concentration limit specified in OAC #623a, the CO boiler stacks were source tested in accordance with Condition 12a of the OAC as a one time initial requirement. The source test results are as follows:

- CO Boiler #1: Conducted October 6, 1999 resulted in 35 ppm NO_x corr. to 7% oxygen
- CO Boiler #2: Conducted October 7, 1999 resulted in 53 ppm NO_x corr. to 7% oxygen

In accordance with OAC #623a Condition 10e, a CEM is used to continuously monitor NO_x emissions at each CO boiler stack. The CEM has been certified in accordance with Performance Specification 2 of 40 CFR 60 Appendix B and the CEM maintained and operated within the NWAPA "Guidelines for Industrial Monitoring". Condition 6 of the OAC also includes an emission limit of 1380

tons NOx from the combined CO boiler stack based on any 12-month rolling period. In accordance with OAC 623a Condition 14f, the cumulative 12-month rolling NOx tonnages are reported in PSR's monthly emission reports. It should be noted that PSR reports 12-month rolling tonnages of NOx generated from the firing of gaseous fuel or fuel oil in excess of 65 MMBtu/hour for full combustion mode and 30.4 MMBtu/hour for partial combustion mode. Firing of fuel in the CO boiler above these levels is considered supplementary, that is only for the production of extra steam and not a function of assuring good CO combustion of the FCCU regenerator flue gasses. Because emissions from supplementary fuel firing is not considered a part of the recent FCCU modification, it was not used in the PSD analysis for the Vertical Riser Project. The monthly emissions reports include NOx emissions below supplemental firing rates and total NOx emissions from the FCCU/CO boilers even though total NOx emissions are not limited by the permit.

In determining the FCCU's combustion mode, full combustion is defined as excess air in the regenerator flue gas greater than zero percent and carbon monoxide less than one percent. Whereas, partial combustion mode results in no excess air and more than one percent carbon monoxide in the regenerator flue gas. In reality, PSR has set procedures that run the FCCU only one of the two distinct combustion modes and therefore they need only to track the time periods upon which each mode is being utilized. Once set the refinery will run for months in that mode because switching is a non-routine task.

The following is used to calculate monthly and 12-month rolling NOx emissions from FCCU/CO boilers firing below the established supplemental fuel firing rates. These same equations are also found as an attachment to OAC #623a.

Tons of NOx from CO Boiler stacks calculated from CEM data

____ Tons of NOx from fuel firing above 65MMBtu/hour during full combustion mode and 30.4 MMBtu/hour during partial combustion

Where the second term:

When burning fuel gas = (MMBtu of fuel gas fired in excess of 65MMBtu/hour limit for full combustion or 30.4 MMBtu/hour for partial combustion) \times (0.07 lb NO_x/MMBtu) \times (ton/2000 lb)

When burning oil = (MMBtu of fuel oil fired in excess of 65MMBtu/hour limit for full combustion or 30.4 MMBtu/hour for partial combustion) \times 52.5 lb NO_x/1,000 gallons) \times (1,000 gallons/150MMBtu) \times (ton/2000 lb)

If oil and fuel gas are fired simultaneously, fuel gas will be considered first when comparing the firing rates to the firing limits.

Based on the above calculation method and in accordance with OAC #623a Condition 4, NOx emissions may not exceed a 12-month rolling total of 1380 tons. These 12-month rolling tonnages are reported to the NWAPA on a monthly basis in accordance with OAC #623a Condition 14f.

Specifically Applicable Requirements for SO₂ at the FCCU

In accordance with OAC #623 Condition 12c, an initial source emission test was conducted at maximum capacity on each CO boiler stack as follows:

- CO Boiler #1: Conducted October 6, 1999 resulted in 277 ppm SO₂ corr. to 7% oxygen
- CO Boiler #2: Conducted October 7, 1999 resulted in 229 ppm SO₂ corr. to 7% oxygen

In accordance with OAC #623a Condition 6, NWAPA 462 and WAC 173-400-040(6), SO₂ in the CO boiler stacks shall not exceed 1000 ppmvd corrected to seven percent oxygen based on a one-hour averaging period. In accordance with OAC #623a Condition 10d, a CEM is used to continuously monitor SO₂ emissions at each CO boiler stack. The CEM has been certified in accordance with Performance Specification 2 of 40 CFR 60 Appendix B and the CEM maintained and operated within the NWAPA "Guidelines for Industrial Monitoring". Condition 6 of the OAC also includes an emission limit of 5822 tons SO₂ from the combined CO boiler stack based on any 12-month rolling period and under Condition 7, 3651 tons from the FCCU regenerator based on any 12-month rolling period. In accordance with OAC 623a Condition 14, these cumulative 12-month rolling SO₂ tonnages are to be reported to NWAPA in PSR's monthly emission reports. It should be noted that the reported 12-month rolling tonnages include emissions of SO₂ generated from the firing of gaseous fuel or fuel oil in excess of 65 MMBtu/hour for full combustion mode and 30.4 MMBtu/hour for partial combustion mode. Firing of fuel in the CO boilers above these levels is considered supplementary, that is only for the production of extra steam and not a function of assuring good CO combustion of the FCCU regenerator flue gasses. Because emissions from supplementary fuel firing are not considered a part of the recent FCCU modification, it was not used in the PSD analysis for Vertical Riser Project. The monthly emissions reports include SO₂ emissions below supplemental firing rates and total SO₂ emissions from the FCCU/CO Boilers.

The following is used to calculate monthly and 12-month rolling SO₂ emissions from FCCU/CO boilers firing below the established supplemental fuel firing rates. These same equations are also found as an attachment to OAC #623a.

$$\frac{\text{tons of SO}_x \text{ from CO Boiler stacks calculated from CEM data}}{\text{tons of SO}_x \text{ from fuel firing above 65MMBtu/hour during full combustion mode and 30.4 MMBtu/hour during partial combustion}}$$

Where the second term when burning fuel gas:

$$= (\text{MMBtu of fuel gas fired in excess of 65MMBtu/hour limit for full combustion or 30.4 MMBtu/hour for partial combustion}) \times (\text{scf}/0.0012 \text{ MMBtu}) \times (\text{parts H}_2\text{S}^*/1,000,000 \text{ parts flue gas}) \times (\text{lb mol H}_2\text{S} / 392 \text{ scf}) \times (\text{lb mol SO}_2/\text{lb mol H}_2\text{S}) \times (64 \text{ lb SO}_2/\text{lb mol SO}_2) \times (\text{ton SO}_2/2000 \text{ lb SO}_2)$$

* PPM H₂S in main fuel gas system (instrument tag # 35AI19)

Where the second term when burning oil:

$$= (\text{MMBtu of fuel oil fired in excess of 65MMBtu/hour limit for full combustion or 30.4 MMBtu/hour for partial combustion}) \times (\text{gallon}/0.15 \text{ MMBtu}) \times (\text{lb fuel oil}^*/\text{gallon}) \times (\text{lb S}^{**}/\text{lb fuel oil}) \times (64 \text{ lb SO}_2/32 \text{ lb S}) \times (\text{ton SO}_2/2000 \text{ lb SO}_2)$$

* monthly average fuel oil density

** monthly average fuel oil sulfur content

If oil and fuel gas are fired simultaneously, fuel gas will be considered first when comparing the firing rates to the firing limits.

In addition to the 12-month rolling tonnage limit, SO₂ emissions are measured in the ductwork between the FCCU regenerator and CO boilers with a CEM to determine compliance with a 1233 lb/hour SO₂ limit. This short-term limit, imposed by OAC #623 Condition 7, was established to assure that no net emissions increases above those established prior to the Vertical Riser Project, would occur. If this emission limit is exceeded, NSPS requirements for SO₂ become applicable as a result of Vertical Riser Project modifications. Because the CEM measures SO₂ concentrations and not mass emission rates, the CEM data must be combined with regenerator duct flow rates to determine lb/hour SO₂. The PSR uses the refinery's on-line computer system to calculate continuous lb/hour SO₂ in the regenerator duct as a function of coke burn-off and inlet airflow rates. This same regenerator flow rate is added to additional parameters when calculating the CO boiler flow rates for determining compliance with CO, SO₂ and NO_x mass emission limits (see above). Installation of the regenerator CEM is required in accordance with OAC #623a Condition 11. Condition 11 also allows for an alternate sulfur dioxide monitoring system that may be approved by the NWAPA if it demonstrates equal stringency to the CEM. At this time PSR has chosen not to request an alternative monitoring system.

In order for the refinery to meet the 1233 lb/hour limit in the regenerator a DESOX catalyst is injected into the FCCU. The injection rates are adjusted based on feed back from the Regenerator CEM. It is also noted that the FCCU can be operated in either partial or full combustion modes. However, due to the high affinity of sulfur compounds to be oxidized, all sulfur emissions in the duct are assumed to be in the form of SO₂ in either combustion mode.

OAC #623a Condition 14a requires PSR to submit monthly reports that include the monthly average lb/hour SO₂ from the regenerator flue gas. This allows the NWAPA to examine general SO₂ trends at the regenerator. If there is an exceedance of the 1233 lb/hour SO₂ limit, PSR would report the exceedance within 12-hours in accordance with NWAPA Section 340 and 341.

In addition to SO₂ monitoring, OAC #623a Condition 9 and NSPS Subpart J requires that refinery fuel gas combusted in the CO boilers meet a 162 ppm H₂S limit and be continuously monitored with a CEM. Details on refinery fuel gas monitoring can be found in the General Facility Description section of this document.

On May 29, 2002, PSR submitted to EPA, a proposal to reroute the merichem off-gas stream from the elevated flare system to the CO boilers for combustion. This diversion will eliminate excessive corrosion in the flare system due to the caustic nature of the gas. In order to facilitate this change the refinery obtained approval from EPA Region 10 to use an alternative monitoring plan (AMP) that demonstrates compliance with the fuel gas monitoring requirements of 40 CFR 60 Subpart J, which is applicable at the FCCU. The AMP requires the refinery to conduct twice a week sampling for the H₂S content of the merichem off-gas vent. The sampling must be conducted for a period of at least six months, upon which time the sampling frequency can be relaxed if readings are constantly found to be below 81 ppm. In addition, amine strength is to be sampled twice a week and the regenerated caustic strength is to be sampled once per week. The AMP becomes invalid upon construction and operation of a wet gas SO₂ scrubber at the FCCU. Under the Consent Decree this new control device shall be installed by December 31, 2006.

Specifically Applicable Requirements for VOC/HAPS at the FCCU

In accordance with OAC #623a Condition 19 components on VOC service are required to implement NSPS subpart GGG for leak detection and repair. Details about this program can be found in the LDAR section of this document.

Catalytic Polymerization and Nonene Units

General Operation - Catalytic Polymerization Unit

The Catalytic Polymerization Unit (CPU) is charged with light feedstock that originates as a byproduct of cracking at the DCU, FCCU and CRU 1. These propylene and butylenes, also known as C3/C4 olefins, are first treated to remove reduced sulfur compounds. The charge is then fractionated to separate C3s from C4s. The C4s are sent to the Alkylation (Alky) Unit and the C3s are kept for further processing at the CPU. In the CPU's catalytic reactor, propylene (C3) is passed through a solid phosphoric acid catalyst bed. The reaction converts C3s into a long chain product called polymer gasoline. Finally, the polymer gasoline is sent to depropanizer and debutanizer fractionation towers to separate out propane and butanes before sending the polymer gasoline out for finished product blending. The CPU also produces nonene (see Nonene Unit).



Major components at the CPU include the treating section, splitter tower, Reactors, Depropanizer and Debutanizer towers. Operating temperatures range from -32 to 620 °F. Operating pressures range from 1 to 550 psi. Other activities that may result in emissions to the air are conducted periodically to properly operate and maintain the equipment.

Construction History and Regulatory Applicability - Catalytic Polymerization

The CPU was constructed during the 1976 Octane Improvement Project and has not had any modifications since original construction that would require NSR. As a grandfathered unit, there are no applicable OACs. The CPU is unique in that it does not have any process streams with HAP greater than 4% that would trigger Refinery MACT requirements for fugitive equipment leaks. Instead leaking components are monitored and repaired as required by NWAPA 580.8. Since August 31, 1998, the facility has been operating the LDAR program under the standards set forth in NSPS 40 CFR 60 Subpart VV as required by NWAPA 580.83.

General Operation - Nonene Unit

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

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

Construction History and Regulatory Applicability – Nonene Unit

The Nonene unit was constructed at the refinery in 1991 following issuance of Order of Approval #296 by the NWAPA on November 20, 1990. The order requires that the process unit be monitored under a LDAR program consistent with NSPS 40 CFR 60 Subpart VV. The truck rack is required to use bottom loading practices when technically feasible and Tanks 80, 81 and 82 are to be external floating roof (EFR) tanks equipped with primary and secondary seals. It should be noted that under the OAC, the tanks are only required follow an equipment standard but are not obligated to undergo routine monitoring that would have been required under an NSPS program. This is due to the fact that nonene has a low vapor pressure and therefore tank construction did not trigger NSPS at the time. To assure that the NSPS does not apply, the OAC requires that PSR monitor product vapor pressure and give written notice to the NWAPA if the MTVP of the VOL exceeds 0.75 psia. In the AOP, Section 5 is written requiring the nonene tanks to meet the equipment, monitoring, and recordkeeping requirements of 40 CFR 60 Subpart Kb (NSPS). This allows PSR to monitor these tanks consistent with the NSPS and R-MACT requirements of other EFR tanks at the refinery.

Construction of the nonene processing unit and nonene railcar and truck loading facilities involved the installation new drains that subject the drains to 40 CFR 60 Subpart QQQ requirements. Although not issued as a condition of the OAC #296, all oily water refinery drains constructed after May 4, 1987 trigger this NSPS requirement.

OAC # 296 Condition 1 stating that the project shall be constructed and operated in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements.

Catalytic Reforming Units (CRU)

General Operation

Catalytic reforming converts low octane naphthas into high-octane gasoline blending stocks. In reforming, straight-chain hydrocarbons and cyclo-paraffins are converted to aromatics by dehydroisomerization and dehydrogenation. The naphtha feed is mixed with hydrogen (H_2), vaporized and passed through a series of heaters and fixed bed reactors containing a platinum bimetallic catalyst. The reactor effluent is sent to a separator where the pressure is reduced and the mixture cooled. H_2 is removed from the top of the high-pressure separator and higher molecular weight products are withdrawn for the bottom of the separator and fractionated. Hydrocarbon products for the CRUs are gas, LPG, and light and heavy platformate. A byproduct of reforming is hydrogen gas. This excess hydrogen is sent to the HTU's for use in hydrotreating.



Major components at the CRU #1 include heaters, reactors, compressor, product separator, absorber tower, debutanizer tower, rerun tower and caustic wash drum. Operating temperatures range from ambient to 980 °F. Operating pressures range from 100 to 450 psi.

Major components at the CRU #2 include heaters, reactors, a compressor, high and low pressure separators, low-pressure flash drum, stabilizer tower, platformate splitter tower, debutanizer and C3/C4 splitter tower. Operating temperatures range from ambient to 980 °F. Operating pressures range from 150 to 400 psi.

Both units also contain a number of components in heavy liquid, light liquid, and gaseous service that can emit fugitive VOC and HAP emissions. Other activities that may result in emissions to the air are conducted periodically to properly operate and maintain the equipment.

Construction History and Regulatory Applicability - CRU #1

CRU #1 was built with the original refinery construction in 1958. No significant modifications to the unit occurred until 1987 when all three of the original heaters were replaced with three new heaters having a common stack (heaters 6D-F2, 6D-F3 and 6D-F4). OAC #321 was issued by the NWAPA for this project on April 3, 1987. During NSR, BACT for SO_2 was determined to be equivalent to NSPS Subpart J, refinery fuel gas not to exceed 162 ppm H_2S based on a 3-hour rolling average. This limit was established in the OAC as Condition 5. Condition 6 set forth a requirement to install a CEM to continuously monitor H_2S in the fuel gas to assure that the limit was not exceeded. In a July 7, 1988, approval letter the NWAPA allowed PSR to monitor H_2S in the refinery's main fuel gas drum to meet the requirements set forth in OAC #321 Conditions 5 and 6. However, upon investigation it was found that CRU #1 and HTU #1 run co-dependently and that most of the fuel gas combusted in these units is generated from within the CRU #1/HTU #1 units themselves. Because fuel gas from the CRU#1/HTU#1 is not being routed to the refinery's main fuel gas drum, monitoring H_2S at that location was not considered representative of fuel gas being combusted at CRU #1/HTU #1.

On September 29, 1991, the NWAPA issued OAC #286 for construction of two new heaters with a common stack at HTU#1 (7C-F4/F5). As Condition 4 of the order, the refinery was required to install a H₂S CEM at the fuel gas drum that specifically services the CRU#1/HTU#1. On September 10, 1991, OAC #286 was amended to allow PSR to install a SO₂ monitor instead of the H₂S CEM as originally planned. This change was facilitated with recent amendment of Subpart J published on October 2, 1990 (55 FR 40175). The amended Subpart J allowed SO₂ monitoring of the heater exhaust gas in lieu of monitoring H₂S in the fuel gas and established an equivalency between 20 ppm SO₂ in the heater exhaust to 162 ppm H₂S in the fuel gas. The federal amendment was made in response to challenges encountered in H₂S monitoring at that time.

Fortunately, installation of a SO₂ CEM at the HTU#1 heater allowed the refinery to address the issue of monitoring NSPS Subpart J compliance with the fuel gas quality standards for the three new CRU#1 heaters (6D-F2, 6D-F3 and 6D-F4). Because co-dependent CRU#1/HTU#1 units have a dedicated fuel gas mix system separate from the rest of the refinery, PSR was able to declare that SO₂ emissions at the HTU#1 heater stack (7C-F4/F5) are indicative of those at CRU #1 heater stack (6D-F2/F3/F4) thereby allowing the use of a single monitoring point to demonstrate compliance with the NSPS standard. This alternative monitoring strategy is allowed under 40 CFR 60.105(a)(3)(iv).

It should be noted that, in the rare and short-term event that the HTU #1 is shut down while CRU #1 continues to operate, there would be no SO₂ monitoring data to show compliance with Subpart J requirements. Because the CRU #1 is operated with a catalyst bed that is poisoned by sulfur, only hydrotreated products having an extremely low sulfur content can be processed at the CRU. As a result, there would be little chance that the fuel gas generated at the CRU would have a H₂S content of concern. As with any CEM, periods of monitor downtime occur which are acceptable within reason under the NWAPA "Guidelines for Industrial Monitoring". The lack of SO₂ data that results from a HTU #1 shutdown would be acceptable as long as it did not exceed the data acquisition criteria of NWAPA's "Guidelines for Industrial Monitoring Equipment and Data Handling". If the loss of monitoring data exceeded the criteria in the guidelines, it would be reported as an AOP monitoring deviation.

OAC #321 established a BACT for PM at 0.05 grains/dscf corrected to 7% oxygen and a visual opacity limit of 10% for CRU #1 6D-F2, 6D-F3 and 6D-F4 heaters. Based on the fact that the source is comprised of large combustion units and that no source tests were done to identify particle size distributions, all particulate emissions are assumed to be PM-10. An initial emissions source tests for PM was conducted on December 21, 1987 using EPA Method 5. The test resulted in a stack concentration of 0.0000 PM (front half only), that is, particulate levels were undetectable at less than a part per billion.

In May 26, 1995, OAC 321 revision "a" was issued to allow more operational flexibility for the three CRU #1 heaters. This flexibility was afforded by removing a maximum firing rate limit on the heaters and instead relying on a 39.9 tons per year annual NO_x emission limit and monthly reporting to assure that the PSD trigger of 40 tons was not exceeded. During NSR it was determined that PTE for all other pollutants were below PSD thresholds. On December 21, 1987, the 6D-F2, 6D-F3 and 6D-F4 common heater stack was source tested for NO_x emissions resulting in 8.14 lb NO_x /hour. Based on this source test the cumulative PTE for the three heaters is 35.63 tons per year and therefore below the 39.9 tons per year limit specified in OAC 321a Condition 3.

OAC #321 Condition 7 and NWAPA 455.11 specifies a 0.05 grains per dscf particulate limit for heaters in CRU #1. Because all three heaters burn only refinery fuel gas or natural gas they will inherently met this limit and therefore the source is only required to keep records of fuel use.

OAC #321 Condition 1 stating that construction be done in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements. OAC # 321

Condition 8 requiring that an initial source test be performed is not listed in the AOP because it is a one-time condition that has been completed.

Construction History and Regulatory Applicability - CRU #2

CRU #2 was constructed as part of the 1976 Octane Improvement Project. Since original construction, there have been no significant modifications that would require NSR. On April 14, 2000, two regulatory orders were issued by the NWAPA to create a federally enforceable cap on NOx emissions at CRU #2. Regulatory Order 22 limits NOx emissions from heaters 10-H101, 10-H102 and 10-H103, which have a common stack, to 117 tons based on a 12-month rolling average and 32.9 tons per hour based on a calendar day average. Similarly, the Stabilizer Reboiler (10H-104) was issued Regulatory Order 23 that limits NOx emissions to 42 tons based on a 12-month rolling average and 12.8 tons per hour based on a daily average.

Because both Regulatory Orders 22 and 23 were voluntarily requested by PSR, the refinery is not required to source test to determine actual emissions. Instead, the orders allow emissions to be calculated using AP-42 emission factors. If more accurate emission factors become available they will be incorporated into a revised regulatory order in accordance with Condition 4 of each order. Compliance is documented by including the 12-month rolling average and maximum daily hourly average for these heaters in the refinery's monthly emissions reports.

Prior to AOP issuance, the light platformate section of CRU#2 was under a specialized LDAR program in accordance 40 CFR 61 Subpart J (Benzene NESHAP). Upon review of the Refinery MACT regulations it was found that the 60.640(p) eliminated overlap of the two regulations thereby requiring the source to comply only with the provisions specified in Refinery MACT provisions. As such, only one LDAR program performed in accordance with 40 CFR 60 Subpart VV is conducted at CRU #2.

40 CFR 60 Subpart J limiting fuel gas to 162-ppm H₂S in heaters 10H-101, 102 & 103 is required in accordance the consent decree. This requirement can be found Sections 5 and 8 of the AOP.

Alkylation Units (Alky)

General Operation

In the Alky units, low molecular weight olefins (C3/C4) are combined with isobutane using sulfuric acid as a catalyst in the reaction. The hydrocarbons and acid are mixed in a reactor called a contactor. Following reaction, the acid is separated from the resultant emulsion in a settler and the acid is returned to the contactor. The resulting product is called crude alkylate. The crude alkylate is fractionated to remove impurities such as traces of organic sulfates, sulfonates, and some of the less valuable propanes and butanes. The final alkylate is a high-octane blending component used in lead-free premium gasolines.

Major components at the Alky #1 include contactors, settlers, depropanizer, debutanizer, deisobutanizer, refrigeration compressor and caustic washes. Operating temperatures range from -32 to 620 °F. Operating pressures range from -5 to 350 psi.

Major components at the Alky #2 include contactors, settlers, refrigeration compressor and four fractionators. Operating temperatures range from -32 to 700 °F. Operating pressures range from 0 to 600 psi.

The Butadiene Hydrogenation Unit (BHU) is co-located at Alkylation Unit #1 and acts as a feedstock pre-treater for Alky #1. The BHU hydrogenates butadiene compounds that are found in the alkylation unit feedstock that originates from the FCCU. The hydrogenation of butadiene contained in the alkylation unit feedstock is beneficial because it consumes less sulfuric acid during alkylation processing.

Construction History and Regulatory Applicability

Alkylation Unit #1 was built with the refinery in 1958 and has not had any modifications triggering NSR since that time. Alkylation Unit #2 was constructed during the 1976 Octane Improvement Project and likewise has had no significant NSR modifications since original construction. As grandfathered units, there are no applicable OACs for either process unit.

The BHU was constructed during the summer of 2001 and began operation on November 13, 2001. OAC #772 was issued for this unit on May 24, 2001 and revised as OAC #772a on March 18, 2004. The OAC requires that an enhanced LDAR program be implemented at the BHU consistent with NSPS 40 CFR 60 Subpart VV standards as modified with lower leak definitions as BACT.



Hydrotreater Units (HTU #1, #2 and #3)

General Operation

Hydrotreating Units #1 and #2 are charged with distillates and naphthas. HTU #1 feed originates from the VPS whereas feedstock for HTU #2 (characterized as cracked) originates from the VPS, FCCU and DCU. HTU #3 treats gasoline products prior to blending into final product. In general, hydrotreating removes unwanted sulfur and nitrogen contaminants from petroleum hydrocarbons. During the process, hydrocarbons are reacted with hydrogen under high pressure and in the presence of a catalyst. Hydrogen sulfide driven off in the reaction is sent to the SRU via the amine system. Desulfurized hydrocarbon products are distilled to produce low octane naphtha, jet fuel and diesel. The products from the HTU also serve as high quality feedstocks for CRUs.



Major components at the HTU #1 include the feed surge drum, heaters, reactor, high and low pressure separators, fractionator tower, JET and heavy straight run (HSR) sidecut strippers and fractionator overhead drum. Operating temperatures range from ambient to 620 °F. Operating pressures range from ambient to 475 psi.

Major components at the HTU #2 include the hot and cold feed surge drum, heaters, reactors, high pressure separator, low pressure flash drum, H₂S stripper tower and accumulator, HSR sidecut stripper and treating section for light hydrocarbons. Operating temperatures range from ambient to 710 °F. Operating pressures range from ambient to 1000 psi

The third HTU was designed and built to remove sulfur from gasoline products (primarily cracked gasoline streams from the FCCU) in thereby allowing the refinery to comply with future federal low sulfur gasoline standards. HTU #3 uses a continuous batch reactor process employing a series of catalyst beds to displace sulfur from the gasoline grade feedstocks sent over from the FCCU. The catalytic distillation process is specifically designed and operated to remove sulfur from the feed stock while minimizing the octane reduction normally resulting from saturating olefinic compounds prevalent in FCCU gasoline. As with the other HTUs, HTU #3 for the most part will generate most of the fuel gas needed to operate combustion devices in the unit. Any make up fuel will be supplemented on an as needed basis with gas from the refinery's main fuel gas mix drum or with purchased natural gas (see fuel gas systems under combustion units).

Construction History and Regulatory Applicability – HTU #1

HTU #1 was built with the refinery in 1958. All three of the original heaters were replaced in 1991 with two new heaters (7C-F4 and 7C-F5) having a common stack. The heater replacement project was approved by NWAPA on July 16, 1990 under OAC #286. Conditions 3 and 4 of the OAC were revised in a letter from the NWAPA dated September 10, 1991. The revision allowed PSR to continuously monitor SO₂ emissions in the 7C-F4/7C-F5 heater stack in lieu monitoring H₂S in the refinery fuel gas. This revision was acceptable under NSPS Subpart J, which had been amended on October 2, 1990 specifically allowing SO₂ to be monitored as an alternative to H₂S monitoring of the fuel gas. The amendment established an implied equivalency of 162 ppm H₂S in the fuel gas to 20 PPM SO₂ in the

combustion device exhaust stack. The 20 ppm limit for SO₂ based on a 3- hour rolling average. The federal amendment was made in response to challenges encountered with continuous H₂S monitoring at that time.

The OAC #286 sets a NO_x BACT required of 0.07 lb/MMBtu. The stack was source tested on June 9, 1993 resulting in an emission level of 0.063 lb NO_x/MMBtu. It should be noted that NO_x, CO, PM-10 and VOC emission reduction credits were granted for permanently shutting down the three original heaters (7C-F1, 7C-F2 and 7C-F3). Some of these credits, along with credits acquired from a permanent shutdown of Erie City Utility Boiler #3 were used to offset emission increases from the construction of March Point Cogeneration Company's Phase I and II projects to keep the projects from triggering PSD permitting requirements.

OAC # 286 Condition 1 stating that the project shall be constructed and operated in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements. OAC # 286 Condition 5 stating that initial compliance source testing must be conducted is not listed in the AOP because it is a one-time condition that has been completed. OAC # 286 Condition 7 stating that a plan and examination fee of \$2500 was due and payable prior to construction is complete is not listed in the AOP because it is a one-time condition that has been completed.

Construction History and Regulatory Applicability – HTU #2

HTU #2 was constructed during the 1976 Octane Improvement Project. On November 16, 1997 OAC #630 was issued allowing PSR to install higher capacity, low NO_x burners in heaters 11H-102 (H₂S stripper) and 11H-103 (fractionator). The modification increased the combined maximum firing rate of the heaters from 230 MM Btu/hour to 241 MM Btu/hour. The project did not trigger PSD thresholds for any pollutant. In the minor new source review process BACT for NO_x emissions was determined to be 0.06 lb/MMBtu. BACT for SO₂ was determined to be equivalent to NSPS Subpart J - 162 ppm H₂S in the refinery fuel gas. On April 4, 1998 the heater stack, which is common to both heaters, was source tested resulting in an emission rate of 0.026 lb NO_x/MMBtu. No oil burning is allowed in either heater. OAC #630 Condition 6 stating that written notification of the initial start-up date must be submitted to the NWAPA is not listed in the AOP because it is a one-time condition that has been completed. OAC #630 was revised to OAC #630a on March 4, 2004. The revised OAC added conditions 6 through 8 to address modifications to the unit that accommodate the production of ultra low sulfur diesel (ULSD). This project involved adding some additional hydrocarbon processing components, thereby triggering a BACT determination requiring enhanced LDAR. Condition 8 was added to recognize the addition of a NSPS subpart QQQ applicable drain system. The revision also removed a one-time only startup notification for heaters 11H-102 and 11H-103 and removed the requirement to conduct initial NO_x source testing on the heaters because these OAC obligations were met in 1998.

The third heater at HTU #1, the Charge Heater (11H-101), has had no significant modifications that would require NSR since its original construction. On April 14, 2000, Regulator Order 24 was issued establishing a NO_x limit of 32 tons based on a 12-month rolling average and 7.5 tons per hour limit based on a daily average. Because the Regulatory Order was voluntarily requested by PSR, the refinery is not required to source test to determine actual emissions. Instead, the orders allowed emissions to be calculated using AP-42 emission factors. If more accurate emission factors become available they will be incorporated into a revised regulatory order in accordance with Condition 4 of the order. Compliance is therefore documented by including the 12-month rolling average and maximum daily hourly average for the heater in the refinery's monthly emissions reports.

40 CFR 60 Subpart J limiting fuel gas to 162-ppm H₂S in heater 11H-101 is required in accordance the consent decree. This requirement can be found Sections 5 and 8 of the AOP.

Construction History and Regulatory Applicability – HTU #3

OAC #787 was issued January 20, 2003 for the construction of HTU#3. Construction was completed in October 2003 with startup following shortly thereafter. The process unit includes a 62.2 MMBtu per hour Catalytic Distillation Technology Hydrodesulfurization (CDHDS) heater and associated hydrocarbon processing equipment. The unit's CDHDS heater has a BACT limit of 0.035 lb. NO_x/MMBtu. The heater was source tested on December 17, 2003 (within 180 days of startup) and demonstrated compliance with this limit. The OAC incorporates a number of BACT determinations previously applied at other process units at the refinery. These include a requirement that the fuel gas burned in the heater not exceed either the 162 ppm based on a 3-hour rolling limit (NSPS Subpart J) and 50 ppm based on a 24-hour rolling average. BACT for NO_x was determined to be 0.035 lb NO_x /MMBtu. BACT for PM-10 was determined to be combustion of only gaseous fuel and an opacity limit of 5%. BACT for the control of VOC/HAP from new hydrocarbon processing equipment was determined to be enhanced LDAR as BACT.

A PSD analysis conducted during NSR permitting included emissions increases that would occur from increased steam requirements for the new HTU#3. Because steam demands would be satisfied by an increase in duct burner utilization at March Point Cogeneration Company (MPCC), emission increases at MPCC were added to those from the HTU #3 heater to complete the PSD analysis. The analysis found all pollutants to be under PSD triggers and that the project did not result in any debottlenecking of existing processing capacity at the refinery.

Prior to completing construction of HTU3#, OAC 787 was revised (revision A) to allow SO₂ emissions to be monitored using a stack CEM. In March 2004 the OAC was again revised (revision b) because the CDHDS heater could not consistently meet the 6 ppm SO₂ (24-hour average) limit specified in the OAC #787a. This problem occurs not because of high sulfur in the hydrotreater's fuel gas, but because of the hydrogen rich nature of fuel gas being generated at HTU#3. This hydrogen rich flue gas effectively concentrates the SO₂ in stack was due to the fact that no CO₂ is produced during hydrogen combustion. The resulting combustion products are much lower in volume than for carbon based fuel gas (methane, ethane, etc.). OAC #787b issued on March 11, 2004, requires the CDHDS heater to meet a H₂S limit for fuel gas burned at the heater with these limits based on NSPS (162 ppm) limits and BACT (50 ppm).

In conjunction with the HTU #3 project, PSR contracted with Air Liquide to construct a steam-methane reformer to supply hydrogen to the new hydrotreater. OAC #813 was issued to Air Liquide for their hydrogen plant on October 7, 2002 and provides the operating requirements for this separate facility. Although the facility is located within the boundaries of Puget Sound Refinery, it is considered a separate emission source and is registered and regulated by NWAPA as such. It should be noted however, that because Air Liquide's hydrogen plant was constructed as a support facility for HTU #3, the increased emissions from this plant were considered under in combination with the PSD analysis for HTU #3.

Sulfur Recovery Unit (SRU)

General Operation

The Sulfur Recovery Unit converts acid gas laden with H_2S and sour water gas to liquid elemental sulfur. The gases are routed to the SRU via three amine regeneration units (ARUs). The SRU reduces emissions to the atmosphere by converting the H_2S in the acid gas to elemental sulfur. This allows the refinery to process crude oil with a higher sulfur content into finished products with a low sulfur content. The resulting liquid sulfur is sold as a commodity chemical product.



At the time of this drafting AOP permit modification 1, the refinery was in the process of constructing an additional sulfur recovery reactor (Unit #4). This facility is designed to produce 170 tons of elemental sulfur per day. Modifications will also be made to the existing sulfur processing equipment which will include decommissioning of Thermal/Claus Units #1 and #2. A new tail gas treating unit (TGTU #2), a new incinerator and a new sulfur pit will be built as part of the project. The new equipment will provide 100% spare capacity, thereby improving the overall reliability of the SRU, reducing acid gas flaring and allowing the refinery to handle higher sulfur loads resulting from increased hydrodesulfurization of intermediate product streams to produce lower sulfur fuels as required by recent federal regulation. The new facility is expected to start operations in the fourth quarter of 2004. When the project is completed, the two sulfur recovery trains will operate in parallel, each at approximately 50% capacity.

The current operating system is comprised of three parallel thermal reactors where hydrogen sulfide is converted to SO_2 through controlled, sub-stoichiometric combustion. (After the completion of construction, there will be two reactor trains operating in parallel.) The off gas is cooled and the sulfur condenses as a liquid. The remaining gasses are reheated and passed through a series of catalyst beds to increase the conversion to elemental sulfur. Conversion from H_2S to elemental sulfur in the thermal reactor section of the SRU is about 98%.

Any unconverted acid gas leaving the thermal reactors is sent to the Tail Gas Treating Unit (TGTU) for final scrubbing. Here all remaining sulfur is converted back to H_2S and then absorbed as it comes in contact with a MDEA (methyldiethanolamine) solution in the amine absorber. The absorbed H_2S creates a rich MDEA mixture that is regenerated using steam. At the MDEA regenerator concentrated H_2S is liberated and the H_2S stream is sent to the SRU thermal reactors for reprocessing. Conversion from H_2S to elemental sulfur for the thermal reactors and TGTU combined is estimated at 99.99%. Because the remaining gases contain with H_2S , they are combusted in incinerator stacks for full conversion to SO_2 before they are emitted to the atmosphere. There are two incinerator stacks, normally of which only one is used at any given time, while the other is kept on hot stand-by.

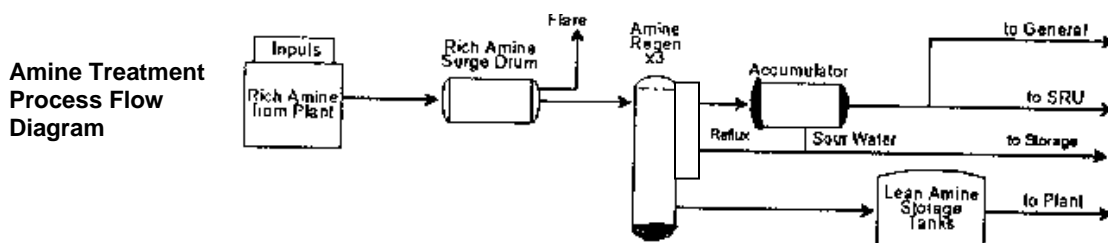
For contingency purposes, the main acid gas line from the refinery to the SRU can be diverted to either the elevated flares or to General Chemical. General Chemical, which is located just east of the PSR, operates a sulfuric acid production plant under its own AOP. It should be noted that, PSR sends a portion of their acid gas stream to General Chemical on an ongoing basis. General

Chemical in turn uses it to convert PSR's spent sulfuric acid from the Alkylation Unit into a concentrated acid that can be reused.

As part of the overall H₂S handling system, the refinery is equipped with a number of amine absorbers and regenerators to collect waste H₂S at various process units. Instead of using MDEA however, the amine system in the refinery uses a DGA (diglycol amine) solution (may be switch to an DEA (a HAP) system in 2002). The lean DGA is circulated throughout the refinery and is used to absorb H₂S. There are nine H₂S absorbers located in the following areas.

Process Area	Lean MDEA H ₂ S Absorbing Towers
FCCU	2
CPU	2
HTU #1	1
HTU #2	2
HTU #3	2

As the lean MDEA becomes saturated with H₂S it must be regenerated back to a lean state to enhance its affinity of H₂S. There are three Amine Regenerating Units (ARU) located adjacent to the CPU. The ARUs convert the rich MDEA into lean MDEA by driving H₂S out of solution by heating with steam. The concentrated acid gas is then routed to the SRU for control. All three ARUs operate on a continuous rich lean header system that run in parallel and on a continuous cycle removing acid gases (H₂S) from sour gas and liquid streams. The operation of the ARUs is very similar to the operation of the TGTU at the SRU.



Major components at the SRU include three thermal reactors, boilers, condensers, catalytic reactors, two incinerator stacks, steam generators, quench tower, amine stripper tower, amine absorber tower, and a MDEA storage tank. Operating temperatures can reach 2700 °F. Operating pressures range can reach 600 psi

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

Construction History and Regulatory Applicability

On June 17, 1999, the NWAPA issued OAC #693 for a modification to the SRU. The OAC superseded all other OACs for the SRU. Specifically, it replaced in full the approval conditions of OACs issued by the NWAPA on February 27, 1981, February 22, 1982, February 3, 1984, February 18, 1987, March 9, 1989, November 27, 1990, and October 27, 1994. The modification allowed the refinery to almost double their H₂S processing rates thereby alleviating their prior need to send H₂S off-site for processing by General Chemical. It also prepared the refinery to handle H₂S increases upon startup of HTU #3. The modification included adding a third, oxygen-enriched sulfur train, a new 34.23 MMBtu/hour primary incinerator and a sulfur tank sweep eductor. As a result elemental sulfur production capacity increased from 100 to 175 long tons per day. Following project completion, the original two sulfur trains and smaller 13.7 MMBtu/hour incinerator were re-designated for back-up use only. The modification is linked to the FCCU Vertical Riser Project (OAC #623a) in regard to the PSD netting analysis. The modification subjects the SRU to the applicable requirements of NSPS Subpart J because the SRU has a capacity of more than 20 long tons a days and the capital cost of the project exceeded the NSPS threshold. In addition, because the tail gas treating unit (TGTU) is considered an active control device for SO₂ emissions at a source with a PTE over 100 tons/year, the SRU could be the subject to the Compliance Assurance Monitoring (CAM) requirements of 40 CFR 64. As with the FCCU, because SO₂ is monitored continuously by a CEM, the unit is exempt from submitting a CAM plan as allowed under 40 CFR 64.2.

During NSR, BACT for PM, VOC, CO, and air toxics were determined to be good combustion practices and fuel selection. For NO_x, BACT was determined to be fuel selection and low NO_x burners in the incinerator. For SO₂, BACT was considered tail gas treating with a control efficiency of 99%. A CEM is installed on each incinerator stack and serve as the primary method for monitoring compliance at the unit. As with other required CEMs, they must conform to all applicable federal CEM requirements and to the NWAPA "Guidelines for Industrial Monitoring".

OAC #693 Condition 8 stating that OAC #693 replaces in full conditions of approval issued by NWAPA on prior dates is not listed in the AOP because it is not a requirement of the source.

On May 5, 2003 NWAPA issued OAC #828 for the most recent modification to the Sulfur Recovery Unit. This project involved constructing a new 170 LPTD sulfur recovery reactor train (SRU #4) and a new tail gas treating unit (TGTU #2) and associated equipment. These facilities will allow PSR to have 100% backup capacity for acid gas processing and eliminate flaring of acid gas. It will also allow some additional capacity for the plant to handle higher sulfur loads in the future. The existing Claus Units #1 and #2 must be decommissioned within twelve months of startup of the new facility.

The new SRU #4 is subject to NSPS, and emission of SO₂ from the incinerator stack is limited to 250 ppm by volume, dry basis corrected to 0% oxygen. Stack SO₂ and oxygen will be monitored continuously in accordance with 40 CFR 60 Subpart J. In addition, SO₂ emissions from the SRU shall not exceed 53 tons on a 12-month rolling average. Nitrogen oxides from the new SRU incinerator stack are limited to a maximum of 0.08 lb/MMBtu/hr which was determined by BACT analysis for low NO_x burners in the incinerator. BACT for PM, VOC, CO, and air toxics were determined to be good combustion practices and fuel selection. OAC #828 further specified CO limits for the new incinerator stack of 2.4 lbs/hr and 100 ppvd at 0% oxygen.

Utilities

General Operation

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

Construction History and Regulatory Applicability

Erie City Boiler

Erie City Boiler provides steam to refinery units. In addition, the Boiler House area provides operations with pneumatic air, boiler feedwater, fire water and service water. The Erie City Boiler is the only boiler operating in this process area. There are no emissions to the atmosphere released from steam use or from steam generation, or other emissions associated with combustion in the boiler. Although the MCPP cogeneration plant is located in this area, it is regulated under a separate AOP which was issued by the NWAPA on February 15, 2001.

The Erie City Boiler was built with the original refinery construction in 1958. Since that time there have been no modifications to the boiler triggering NSR or NSPS requirements. Another boiler in this area, Erie City Boiler #3, was permanently shut down to provide NO_x, CO, PM-10, and VOC emission reduction credits that were used to offset emission increases from the construction of March Point Cogeneration Companies Phase I and II projects.

On April 14, 2000, at the request of PSR, a voluntary NO_x emission limit under Regulatory Order (RO) #21 was issued for the Erie City Boiler. Emissions factors used to define the NO_x emission limits were based on AP-42 emission factors for combustion of both gaseous and liquid fuels. The RO was written to allow the emission limits to be adjusted if more accurate information became available. Therefore, if source testing is conducted, source test results could be used to redefine new NO_x emission limit and subsequently a revision to RO #21. Because of the voluntary nature of the RO, a revision would be made only at the request of PSR. The basis for the current NO_x limits originate from emissions that would occur from firing the Erie City Boiler at full capacity for eight months on refinery fuel gas and four months burning #6 oil. Because the consent decree eliminates the refinery's ability to burn liquid fuels, other than for monthly testing or natural gas curtailments, there is little chance that the NO_x emission limits of the RO will be exceeded. As required by RO #21, NO_x emissions are reported to the NWAPA on a monthly basis to demonstrate that the unit is operating within their voluntary emission limits. Along with emission from normal operations, reportable emissions include those resulting from startup, shutdown, malfunction, accidental releases, breakdown, venting and/or leakage.

It is noted that on May 8, 1992, another Erie City Boiler (# 3) was permanently shutdown as a condition of MPCC OAC #475. This shutdown allowed emission reduction credits to be granted for the construction of MPCC thereby allowing the project to avoid PSD for NO_x under creditable offsets.

Stand-by Wharf Generator

On February 27, 2002 the NWAPA issued OAC #797 for the construction of a emergency stand-by electrical generator to serve as backup power in the event of an electrical power disruption. This effort to assure reliability for marine terminal operations will reduce the potential for oil spills. The generator was installed and commissioned for operation in 2002. The OAC limits the number of operating hours which enabled the unit to meet the air toxics in accordance with WAC 173-460. The OAC also limits opacity to 5% and fuel to ultra-low sulfur diesel. There are no applicable NSPS or NESHAP requirements.

Cooling Towers

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

Cooling Tower #1 was constructed during original refinery construction in 1958. Cooling tower #2 was installed with the 1976 Octane Improvement Project. Hydrocarbon contamination is monitored in the riser pipe in each cooling tower. These monitors are accurate to within 1 ppm VOC. Although there is no requirement to monitor hydrocarbon concentrations, monitoring provides information that can be used to prevent a fire hazard in the tower and to reduce the potential for biological (algae) growth. Furthermore, the refinery is allowed to use a lower VOC emission factor when estimating emissions from the tower. Hexavalent chromium was originally used as a biological growth inhibitor in the cooling water but was phased out in the 1990s to reduce HAP emissions. Because there are no specifically applicable requirements for the cooling towers they are listed as Insignificant Emissions Units (IEU) in the SOB.

Receiving, Pumping and Shipping

General Operation

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

Gasoline/Diesel Truck Loading Terminal
Diesel Railcar Loading Rack
Nonene Loading Rack
Coke loading*

* Coke loading activities are specifically regulated under a regulatory order. Because these operations are located at the DCU, they are listed in the AOP under the DCU. Likewise, Statement of Basis information can be found in the DCU section of the SOB.

The marine terminal was constructed with the original refinery in 1958 and there have been no modifications since that time triggering NSR. As such, there are no OACs or NSPS regulations apply. Refinery MACT, 40 CFR 63.651, states that the marine terminal must meet the applicable provisions of 40 CFR 63 Subpart Y (NESHAP for Marine Terminal). However, because PSR's marine terminal is more than 0.5 miles from shore, it is exempt from Subpart Y in accordance with the 63.560(d)(6) and Subpart Y is listed as an inapplicable requirement in the AOP. Even though the marine terminal has significant emissions, there are no applicable regulations that apply other than those that are generally applicable.

Construction History and Regulatory Applicability

Diesel/Gasoline Truck Loading Terminal

The gasoline/diesel truck loading terminal has a dispensing rack with the capacity to load up to four cargo tanks at a time. In 1993 the rack was retrofitted with a John Zinc (Z-TOF) Vapor Combustion Unit to control the emissions of gasoline vapors displaced during loading in accordance with NWAPA 580.4. On April 30, 1993, OAC #380a was issued for construction of this new emission unit and because the project was considered a significant upgrade to the truck rack the OAC calls out the applicability of NSPS 40 CFR 60 Subpart XX. OAC # 380a Condition 1 stating that the project shall be constructed and operated in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements.

Although sometimes called a flare, for regulatory purposes the gasoline vapor combustor is considered a thermal oxidation unit, because the oxidation process is enclosed and combustion temperatures monitored. The vapor combustion device uses propane as a supplemental fuel to assure that the temperature in the oxidizing zone is at or above 1,400 °F at all times when vapors are being routed from the rack. This temperature set point is determined during source testing in accordance with NSPS and NESHAP specified procedures for determining continuous monitoring requirements. In addition, automatic interlock devices are in place to prevent loading unless appropriate thermal oxidation temperatures are met and to assure that the tanks loaded all have a valid leak tighten test certification on record. It should be noted that all cargo tanks are assumed to be in non-dedicated service and therefore displaced vapors are controlled whether loading gasoline or diesel.

The 1993 retrofit project triggered NSPS Subpart XX requirements including a 35-mg VOC/liter of gasoline transferred emission limit. In 1998, Refinery MACT became applicable thereby reducing the

emission limit to 10-mg/liter gasoline transferred. Emissions from the vapor combustion unit are source tested biannually in accordance with NWAPA 580.424. Emissions from the March 9, 2000 source test, using EPA Method 25A, were found to be 3.4 mg VOC/liter gasoline transferred. Co-located with the gasoline/diesel truck loading rack is a propane truck loading system. Because handling propane is a non-regulated activity, there are no specifically applicable regulations that apply.

There are a number of overlapping regulations that apply to the gasoline/diesel truck loading terminal. These include; NWAPA 580.4 because the terminal loads more than 7,200,000 gallons of gasoline annually, WAC 173-491-040 (2) because the terminal loads more than 7,200,000 gallons of gasoline annually and is located in an ozone attainment area and NSPS Subpart XX because the terminal was modified in 1993. In addition, Refinery MACT regulations apply a modified version of NESHAP Subpart R for gasoline terminals. As such, specifically applicable regulations cited in the AOP only include those in Subpart R that are specifically called out as applicable in 40 CFR 63.650 (Subpart CC).

There are no applicable regulations controlling NO_x or SO₂ emissions at the gasoline/diesel truck terminal. However, due to concerns that the NO_x PTE for the thermal oxidizer could be over the 40 ton PSD trigger, PSR source tested the unit for NO_x. The test, performed on January 9, 2001 found emissions to be 0.0033 lb/hour and therefore under the PSD threshold. Recent EPA applicability investigations indicate that NSPS Subpart J for SO₂ is applicable to the thermal oxidizer because it is combusting hydrocarbon gas generated at the refinery. PSR submitted to EPA an alternative monitoring plan for monitoring SO₂ emissions from the thermal oxidizer to show compliance with 40 CFR 60 Subpart J requirements, which has been approved. To date this alternative monitoring strategy has not been approved.

As with most process units, components in VOC/HAP service are under a LDAR program pursuant to NWAPA 580 and Refinery MACT regulations. In addition, and unique to the truck rack, a monthly visual inspection is required under NSPS Subpart XX. This visual inspection allows the use of sight, smell and audio clues to find leaks. Similar to other LDAR programs, leaks identified must be repaired in a timely manner.

OAC # 380a Condition 1 stating that the project shall be constructed and operated in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements.

Diesel Railcar Loading Rack

On February 5, 2001 the NWAPA issued OAC #757 for construction of a diesel railcar loading rack. At that time, BACT was determined to be submerged loading and limiting loading of railcars to those in dedicated distillate service. BACT for equipment leaks was determined to be 40 CFR 60 Subpart GGG and BACT for the sewer system was determined to be 40 CFR 60 Subpart QQQ. As such, the loading rack has LDAR and drain inspection requirements consistent with other applicable units at the refinery. However, because the diesel railcar loading rack has no components in light or gaseous VOC service, no instrument monitoring is required.

OAC# 757 Condition 6 that requires the Diesel Railcar Loading Rack meet ambient air toxics requirements in accordance with WAC 173-460 is not listed in the AOP because a screening analysis was completing during NSR and therefore there is no on-going requirement. OAC #757 Condition 7 requiring notification of project completion is not listed in the AOP because it is a one-time condition that has been completed.

Nonene Loading Rack

On 11/20/99 the NWAPA issued OAC #296 for construction of a nonene processing unit, nonene storage and loading rack. Because nonene storage and loading operations are not located with the processing unit, the processing and loading areas are in separate areas of the refinery, they have been listed in different parts of the AOP. BACT for the nonene loading rack was determined to be submerged loading and limiting loading of railcars to those in dedicated distillate service. BACT for equipment leaks was determined to be 40 CFR 60 Subpart GGG and VV. BACT for the sewer system was determined to be 40 CFR 60 Subpart QQQ. As such, the loading rack has LDAR and drain inspection requirements consistent with other applicable units at the refinery. Because the nonene railcar loading rack has no components in light or gaseous VOC service, no instrument monitoring is required under the Subpart VV standard.

Flares

General Operation

Three elevated flares are used to combust waste gases at the refinery. All are located northeast of the refinery's process unit area. Generally, flaring volumes are low to non-existent except during process unit startups, shutdowns and upsets. Steam is injected at each flare tip to create turbulence needed to enhance mixing of flared hydrocarbon gases with ambient air for better combustion. If done properly, visible emissions from flaring are kept below 20%. However, high flare loading can cause smoking, especially if steam injection rates are not properly adjusted. There is a liquid knockout drum located in the flare line to prevent liquids from entering flares. In 1991, with the construction of MPCC, flaring was reduced by routing some of the previously flared FCCU gases to the new cogeneration facility as fuel. Furthermore, flare gas compressor (15K-100) located at the DCU recovers hydrocarbon gases in the flare gas stream. Upon recovery, hydrocarbon gases are routed to the DCU for processing. It should be noted that the 15K-100 compressor is dedicated to recovering coker drum blowdown at the DCU for a period of approximately two hours each day. During this time, the compressor does not recover excess refinery gases entering the flare gas system.

A special "Peabody" smokeless flare tip is installed on the East Flare, which has been designated as the refinery's primary flare. This tip was installed in the late 1980s after opacity violations were issued to the refinery for exceeding the 20% visual opacity limit (NWAPA 451). Although the North and South flares do not have specialized smokeless tips, manually operated steam injection is available on each. A mass flow meter located on the flare line combined with a video camera directed at each flare tip assists operators in making proper adjustments to the steam injection rate during flaring to avoid visual emissions.

Construction History and Regulatory Applicability

A design analysis was completed on the flares and submitted to the NWAPA as part of the source's Refinery MACT Initial Notification of Compliance Status Report submitting January 1999. The report satisfied the initial performance test requirements for each flare in accordance with 40 CFR 60 Subpart A, 60.18 and 40 CFR 63 Subpart A, 63.11. The analysis was required because the refinery uses the flares as control devices for Refinery MACT Group 1 process vents and for control of leaks from pump seals regulated under Refinery MACT equipment leaks in HAP service. There are no NSPS provisions required directly because the flares were not built or rebuilt after the NSPS Subpart J applicability trigger date of June 11, 1973 .

The BTU content of flare gasses have been checked periodically, however, due to safety reasons there is no on-going requirement written in the AOP for sampling. Based on engineering judgment, the most likely source of low BTU gas would come from the CRU's due to the high hydrogen content of the waste gas generated there.

A voluntary NOx emissions cap was requested for the flares by PSR. On April 14, 2000, the NWAPA issued Regulatory Order #25 thereby limiting NOx emissions from all three flares combined to 2,200 lb/hour, daily average. Because of the difficulty in conducting a source test and concerns about safety, source testing of the elevated flares was not a requirement of the order. Instead, NOx emissions are calculated from AP-42 emission factors adjusted for the expected BTU content of the flared gas.

Wastewater and Effluent Plant

General Operation

The Effluent 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. Oil that is recovered at the Effluent Plant is sent back to the VPS for processing. Left over solids are either land farmed or dewatered for shipment off-site.



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

Process wastewater is generally routed through uncontrolled drains. These drains however, often flow into controlled sewer systems especially as they approach the effluent plant. Drains systems located under each process unit are allowed to be uncontrolled under the BQ6 exemption in accordance with 40 CFR 61.342(e). The BQ6 exemption (benzene quantity of 6 Mg/year) allows the refinery to exempt process water that contains up to 6 Mg of benzene per year. To track the BQ6 quantity the refinery conducts an annual TAB (total annual benzene) analysis which identifies the total annual quantity of benzene contained in the wastewater for both the controlled and uncontrolled streams. The TAB/BQ6 analysis demonstrates that the uncontrolled streams do not exceed 6 Mg during the calendar year. PSR has chosen to exempt most of the process streams and instead focus their control strategy on drain systems associated with the tank farm. It should be noted that the BQ6 exemption does include a caveat that the benzene waste stream in the program must include remediation and process turnaround wastes. Without the BQ6 exemption these streams would otherwise not be regulated in this manner.

The controlled oily wastewater stream originates at the tank farm area and extends through the process units and until it reaches the effluent plant where it is treated. In areas where the sewer system must "breathe", closed vents are installed and routed to carbon canisters which capture the hydrocarbon emissions. At junction boxes water seals are used to prevent the sewer system from venting directly to atmosphere. When the oily process water arrives at the effluent plant it is routed into a gravity based API oil/water separator. Here flow rates are reduced allowing oils to float to the surface and are skimmed off with an automated raking device. Following the API further physical oil water separation occurs at the Dissolved Air Flotation units (DAFs). The DAF units inject air bubbles into the oil/water solution, oil accumulates on the rising bubbles and skimming takes place at the surface to complete the separation process. After the API and DAFs the remaining contaminants are removed through biological treatment prior to discharge into Fidalgo Bay. Because of the potential for VOC/HAP emissions, 40 CFR 61 Subpart FF requires that both the API and DAF units must be covered and sealed. The API forebays are covered with a fixed roof routed to activated carbon. The API main bays are covered with a floating roof. As with the forebays, the DAF units are covered with a fixed roof with any vapor emissions routed through activated carbon.

Construction History and Regulatory Applicability

The entire oily water sewer system and effluent plant were vented to the atmosphere until 1990 at which time NWAPA 580.23 required that the API forebays be covered. Shortly thereafter, 40 CFR 61 Subpart FF was promulgated requiring the refinery to control emissions from applicable wastewater systems having benzene concentrations greater than 10 ppm. As a result, covers were installed on the API mainbays and afterbays, the trickling filter was removed and a new biological treatment system was installed. In order to bring benzene concentrations down to acceptable levels prior to open air biological treatment, DAF units were installed after the API. In addition, the main oily water sewer line running from the tank farm to the effluent plant was sealed and where “breathing” was necessary carbon canisters were installed on the vent lines. Benzene contaminated wastewater that was being stored (or treated) in tanks was also controlled by installing either IFR tanks or by having fixed roof tanks that vent through a closed vent system to activated carbon. Major projects constructed to meet NWAPA 580 and 40 CFR 61 Subpart FF requirements were permitted under various OACs by the NWAPA. These include:

- OAC #241 issued January 14, 1988 for construction of IFR Tank 70
- OAC #316 issued May 18, 1990 for construction of IFR Tank 71
- OAC #332 issued September 30, 1991 for API covers
- OAC #341 issued September 12, 1991 to convert Tank 60 from to an IFR
- OAC #345 issued November 1, 1991 to convert Tanks 72 and 73 to EFR and Tanks 74 and 76 to fixed roof tanks with activated carbon.
- OAC #416 issued January 12, 1993 for DAF units 1 and 2
- OAC #417 issued January 6, 1993 for the oily water sewer system
- OAC #514 issued July 11, 1994 for DAF unit #3

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 used for controlling vents from the sewer and effluent systems 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. Vessels used to storage or treat wastewater containing benzene include:

Tank	Product	Gallons (x1000)	Internal Heater	Type
60	Ship Ballast Water	1,134	No	IFR with primary and secondary seals
61	DAF Skimmings	126	Yes	IFR with primary and secondary seals
62	API Skimmings	420	Yes	IFR with primary and secondary seals
70	Emulsion Breaker Tank	168	Yes	IFR with primary and secondary seals
71	API Skimmings	504	Yes	IFR with primary and secondary seals
72	Post API Surge	3,780	No	EFR with primary and secondary seals
73	Post API Surge	3,780	No	EFR with primary and secondary seals
74	Equilization Tank (EQ)	1,008	No	Fixed roof with activated carbon
76	API sludge	42	No	Fixed roof with activated carbon

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 HTU #3, drains at the Diesel Railcar Loading Rack and drains in the light-ends portion of the DCU. 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.

All OAC conditions issued for wastewater handling and control have been incorporated into the AOP except as follows. OAC #514 Condition 1 states that the DAF #3 project shall be constructed and operated in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements. OAC # 514 Condition 5 states that “all other applicable requirements have been satisfied” is not listed in the AOP because it contains no substantive requirements. OAC # 417 Condition 1 stating that the modifications to the oil water sewer shall be constructed and operated in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements. OAC # 416 Condition 1 stating that the DAF #1 and #2 project shall be constructed and operated in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements. OAC # 332 Condition 1 stating that the API cover be constructed and operated in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements.

Storage Tanks/Vessels

Regulatory Drivers

The level of VOC and HAP control employed is dependent on the size of the tank or vessel 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 at actual storage temperatures are required to use VOC/HAP control equipment and maintain equipment in accordance with underlying inspection and repair requirements. The type of storage vessels with emission controls include internal and external floating roof tanks and fixed roof tanks equipped with activated carbon. Uncontrolled tanks are those with fixed roofs that do not have internal floating roofs. Uncontrolled tanks are allowed if they store heavy products such as distillates, or aqueous based materials such as sulfuric acid. 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. Tanks storing volatile organic liquids (VOL) are located in the tank farm area with the exception of three slop oil tanks at the DCU. Common VOLs that are required to be stored in controlled tanks include crude oils, refinery intermediates and finished products such as gasoline. Under NSPS regulations, control equipment is required when storing VOLs with maximum true vapor pressure of 0.75 psia. Otherwise control requirements generally trigger at 1.5 psia. The table below describes the regulatory triggers when storing VOLs. Tanks storing VOLs below the vapor pressure 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.

Regulatory Trigger	kPa	Psia
NSPS control for tanks $\geq 151 \text{ m}^3$	5.2	0.75
R-MACT and NWAPA 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
NWAPA control for MTVP $\geq 10.4 \text{ kPa}$	151	39,900
R-MACT control for MTVP $\geq 10.4 \text{ kPa}$	177	46,800

* Federal regulations use IS units, whereas the NWAPA regulation uses English units

Because high vapor pressure VOLs must be stored in “controlled” tanks, the underlying requirements define how these tanks are constructed and monitored. VOL tanks constructed after July 23, 1984 are required to operate in accordance with NSPS 40 CFR 60 Subpart Kb and are exempt from Refinery MACT requirements as allowed under the overlap provisions of 63.640(n). Tanks constructed before that date and holding VOLs containing HAPs are required to meet the applicable Refinery MACT requirements of NESHAP 40 CFR 63 Subpart CC, which refers to the control standards of 40 CFR 63 Subpart G. It should be noted that, Refinery MACT Subpart CC defines applicability and reporting requirements whereas Subpart G defines equipment and monitoring requirements for storage tanks. Furthermore, specific sections found within Subpart G are specific for each tank design (i.e., different portions apply to EFR verse IFR tanks). Although, Refinery MACT, Subpart CC is applicable to vessels storing HAPs, for all practical purposes, all VOLs having vapor pressures over 1.5 psia are likely to contain HAPs greater than the 4% by weight

Subpart CC trigger and therefore will be controlled. 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 that have driven emission control strategies for product storage at PSR. In 1989, the NWAPA adopted Section 580 requiring the installation of secondary seals on all EFR tanks storing VOLs with MTVP equal to or greater 1.5 psia. The deadline for completing all secondary seal retrofits under NWAPA 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 NWAPA 580, the Refinery MACT required secondary seals on EFR tanks however, it allowed for a phase-in period that extends into 2008. Because secondary seal were already in place, PSR began implementing the new monitoring, recordkeeping and reporting requirements of the Refinery MACT. 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 NWAPA 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 NWAPA 580 include references to the equipment specifications and maintenance sections of 40 CFR 60 Subpart Kb.

Under the current version of NWAPA Section 580 (50.26 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 NWAPA 580 citations are found in the AOP.

In addition to the underlying NWAPA and federal regulations, there are some tanks at that were constructed under a NWAPA 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. Some of the OACs or their specific conditions are not applicable. Of these, OAC #301 issued June 14, 1985 for three DCU Slop Oil Tanks is considered a "hollow" as it states that "a NOC and Application for Approval, together with the filing fee and completed Environmental Checklist were received by the NWAPA and that the source is required to notify the NWAPA upon startup". This

OAC is not listed in the AOP because it contains no substantive requirements other than a notification requirement that is a one-time requirement that has been completed.

There are two IFR tanks used to hold sour water at the refinery. Although these tanks are not subject to specific regulation, controls are in place to limit their potential for odorous emissions.

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

Inspection and Maintenance

Seals are inspected in accordance with the frequencies specified in the underlying regulation. For EFR tanks, secondary seals must be inspected and gap tested annually and the primary seal is inspected and gap tested following tank refilling. 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 NWAPA is notified of all annual inspections and gap tests on a schedule developed by PSR at the beginning of each calendar year. Adjustments to the schedule are 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 extension is used) and reported to the NWAPA 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. PSR takes monthly temperature readings on all tanks storing VOLs and these temperatures are used to calculate the products TVP. 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).

External Floating Roof Tanks

The majority of high vapor pressure (>1.5 psia) VOLs at PSR are stored in external floating roof (EFR) tanks. All EFR tanks use a double seal system between the tank wall and floating roof cover as required by the underlying regulations. The normal double seal configuration at PSR is a metallic shoe primary seal and a rim mounted secondary seal. EFR tanks regulated under NSPS Subpart Kb are exempt from the requirements of Refinery MACT in accordance with the overlap provisions of 63.640(n). Therefore, in the AOP, NSPS applicable tanks are listed in a separate table in Section 5 from those regulated under Refinery MACT. Although there are subtle differences in the underlying rules, compliance for EFR tanks can be summarized into the following conditions.

External 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. The report shall be made to the NWAPA within 12 hours of discovering the condition in accordance with NWAPA 340.

Semiannually, conduct a visual inspection of the tank to assure that openings, including bleeder vents (vacuum breakers), are closed.

Semiannually, conduct a visual inspection of the secondary seals to assure that:

- The secondary seal is installed above the primary seal and completely covers the space between the floating roof and the tank wall.
- There are no holes, tears, or other openings in the seal or seal fabric.

Annually, conduct a visual inspection of the floating roof, seals and fittings, and measure the secondary seal gaps to assure that:

- The measured area of gaps between the secondary seal and the tank wall does not exceed 1 in² per foot of tank diameter.
- The width of any gap between the secondary seal and the tank wall does not exceed 1/2 inch.
- Roof drains are covered by a slotted fabric that covers at least 90% of the opening.
- Rim space vents are set at the manufacturers' recommended settings and that the bleeder vents (vacuum breakers) are gasketed and set to open when the roof is being floated off the roof leg supports.

Once every five years, measure the primary seal gaps to assure that:

- The measured gap area between the primary seal and the tank wall does not exceed 10 in² per foot of tank diameter.
- The width of any gap between the primary seal and the tank wall does not exceed 1.5 inches.

Each time the tank is emptied and degassed, 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 and that there are no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.
- If a mechanical shoe primary seal is in use, assure that it extends into the liquid and that it extends at least 24 inches above the liquid surface.
- That, except for openings that are automatic bleeder vents and rim space vents, each opening in a non-contact floating roof has a projection below the liquid surface.
- Each roof opening has a cover, lid or is otherwise sealed (except for leg sleeves, automatic bleeder vents, rim space vents, and roof drains).
- Bleeder vents are gasketed and closed except when the roof is being floated off, landed on, or resting on the roof leg supports.

Notice of Refill

- Notify the NWAPA at least 30 days in advance that a tank will be refilled. If refilling is unplanned, a 7-day 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 occur, 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 and Gap Test Reports

- On semiannual Refinery MACT Periodic Reports, submit information including the date of seal gap measurement, the raw data obtained and if seal gaps were found, the calculations of gap width and accumulated gap area. Submit a list of defects/failures discovered during inspections 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.

There are a number of EFR tanks that have OACs issued by the NWAPA for construction or reconstruction. Some conditions listed in the OACs are not listing in the AOP for the following reasons.

Tank 15: OAC #262 Condition 1 stating that the project shall be constructed and operated in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements.

Tank 38: OAC # 295 Condition 1 stating that the project shall be constructed and operated in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements. OAC # 295 Condition 3 stating that all other permits shall be in force prior to start-up is not listed in the AOP because it is a one-time condition that has been completed. OAC # 295 Condition 4 stating that the NWAPA shall be notified prior to placing the tank in service is not listed in the AOP because it is a one-time condition that has been completed. OAC # 295 Condition 5 stating that a plan and examination fee of \$1,200 is due and payable prior to commencing construction is not listed in the AOP because it is a one-time condition that has been completed.

Tank 45: OAC # 297 Condition 1 stating that the project shall be constructed and operated in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements. OAC # 297 Condition 3 stating that all other permits shall be in force prior to start-up is not listed in the AOP because it is a one-time condition that has been completed. OAC # 297 Condition 4 stating that the NWAPA shall be notified prior to placing the tank in service is not listed in the AOP because it is a one-time condition that has been completed. OAC # 297 Condition 6 stating that a plan and examination fee of \$1,200 is due and payable prior to commencing construction is not listed in the AOP because it is a one-time condition that has been completed.

Tanks 80, 81 and 82: OAC # 296 Condition 1 stating that the project shall be constructed and operated in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements.

Internal Floating Roof Tanks

Internal floating roof (IFR) tanks are also used to store high vapor pressure VOLs 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). Therefore, in the AOP, NSPS applicable tanks are listed in a separate table in Section 5 than those regulated under Refinery MACT. Although there are subtle differences in the underlying rules, compliance for IFR tanks can be summarized into the following conditions.

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. The report shall be made to the NWAPA within 12 hours of discovering the condition in accordance with NWAPA 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 NWAPA at least 30 days in advance that a tank will be refilled. If refilling is unplanned, 7 day 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 occur, 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.

There is one IFR tank (not including wastewater tanks) that has an OAC issued by the NWAPA which contains a condition that is not listed in the AOP. Tank 39, OAC #337 Condition 1 stating that the project shall be constructed and operated in accordance with the information submitted in the NOC is not listed in the AOP because it contains no substantive requirements.

Pressurized Vessels

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. 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.

List of Insignificant Emission Units

Insignificant activities and emissions as defined in WAC 173-401-532 and 173-401-533 and that have no federally applicable requirements are not listed as emission units. These activities listed by process unit area as follows.

Vacuum Pipe Still

Delayed Coking Unit

Fluid Catalytic Cracking Unit

Catalytic Polymerization and Nonene Units

Catalytic Reformer Units 1 and 2

Alkylation Units 1 and 2 and Butadiene Hydrogenation Unit

Hydrotreater Units 1, 2 and 3

Sulfur Recovery Unit

Utilities

Offplot Area (Flares, Receiving, Pumping and Shipping, Storage Tanks/Vessels, and Effluent Plant/Wastewater Handling)

Vacuum Pipe Still

Insignificant Activities and Emissions Units Vacuum Pipe Still		
Exempt Unit	WAC Citation	Comment
Pressure Relief Valves	WAC 173-401-532 (87)	Except for LDAR requirements
Totes	WAC 173-401-532 (42)	
Small Tanks	WAC 173-401-532 (4)	
Analyzer Shed and Vents	WAC 173-401-532 (8)	
Caustic Storage Tank	WAC 173-401-533 (2)(s)	
Maintenance Activities	WAC 173-401-532 (74)	
Sample Points	WAC 173-401-532(51)	Except for LDAR requirements
Sewer/Blowdown	WAC 173-401-532(120)	
Lube Oil Storage and Use	WAC 173-401-532(3) and (69)	
Product Sampling, Handling	WAC 173-401-532(73)	

Delayed Coking Unit

Insignificant Activities and Emissions Units Delayed Coking Unit		
Exempt Unit	WAC Citation	Comment
Pressure Relief Valves	WAC 173-401-532(87)	Except for LDAR requirements
Totes	WAC 173-401-532(42)	
Small Tanks	WAC 173-401-532(4)	
Maintenance Activities	WAC 173-401-532(74)	
DCU Clean Water Tanks 15D-101A and 15D-101B	WAC 173-401-532(94)	
Sour Water Tank 15D-102	WAC 173-401-532(94)	
Sludge Injection Tank 15D-206	WAC 173-401-532(117)	

Insignificant Activities and Emissions Units Delayed Coking Unit		
Exempt Unit	WAC Citation	Comment
Sample Points	WAC 173-401-532(51)	Except for LDAR requirements
Sewer/Blowdown	WAC 173-401-532(120)	
Lube Oil Storage and Use	WAC 173-401-532(3) and (69)	
Product Sampling, Handling	WAC 173-401-532(73)	
Analyzer Sheds and Vents	WAC 173-401-532(8)	
Coke Drums 15C100A, B		Steam-out cycle (steam)

Fluid Catalytic Cracking Process Unit

Insignificant Activities and Emissions Units Fluid Catalytic Cracking Process Unit		
Exempt Unit	WAC Citation	Comment
Pressure Relief Devices	WAC 173-401-532(87)	Except for LDAR requirements
Totes	WAC 173-401-532(42)	
Small Tanks	WAC 173-401-532(4)	
Process Vent/Analyzer Building	WAC 173-401-532(8)	Except for Refinery MACT Controlled
Fresh Catalyst Hopper	WAC 173-401-532(60)	
Catalyst Storage Shed		
Catalyst Handling Silos, Bunker	WAC 173-401-532(60)	
Catalyst Transfer (new and spent)	WAC 173-401-532(60)	
Spent Catalyst Bins	WAC 173-401-532(60)	
Sample Points	WAC 173-401-532(51)	Except for LDAR requirements
Misc. Tanks (Cesco Cleanup, Seal Oil, Anti-Corrosive)	WAC 173-401-532(4)	
Propane Dryers	WAC 173-401-533(2)(d) and/or (e)	
Wastewater Strippers		
Oil Sumps		
Sewer/Blowdown	WAC 173-401-532(120)	
Maintenance Activities	WAC 173-401-532(74)	
Lube Oil Storage and Use	WAC 173-401-532(3) and (69)	
Product Sampling, Handling	WAC 173-401-532(73)	

Catalytic Polymerization and Nonene Units

Insignificant Activities and Emissions Units Catalytic Polymerization and Nonene Units (including Amine Regeneration)		
Exempt Unit	WAC Citation	Comment
Pressure Relief Devices	WAC 173-401-532(87)	Except for LDAR requirements
Totes	WAC 173-401-532(42)	
Small Tanks	WAC-173-401-532(4)	
Spent Catalyst Handling	WAC 173-401-532(60)	
Catalyst Transfer (new and spent)	WAC 173-401-532(60)	
Sample Points	WAC 173-401-532(51)	Except for LDAR requirements
Misc. Tanks (Cesco Cleanup, Seal Oil, Anticorrosive)	WAC 173-401-532(4)	
Propane Dryers	WAC 173-401-533(2)(d) and/or (e)	
Caustic Storage Tank 5JD1	WAC 173-401-533(2)(s)	
Amine Storage Tank TK104	WAC 173-401-530(4)(q)	Vapors to flare system after being scrubbed with lean DGA
Emergency Generator	WAC 173-401-530(4)	
Reclaimer Sludge Blowdown	WAC 173-401-532(120)	
Carbon Fines Blowdown		
Amine Pit with Vent Sorb 5JD16	WAC 173-401-530(4)(q)	Amine pit air emissions are controlled with a charcoal scrubber
Maintenance Activities	WAC 173-401-532(74)	
Product Sampling, Handling	WAC 173-401-532(73)	
Three Tanks Out of Service		
Amine Storage Tank 5JD2	WAC 173-401-530(4)	DGA 100%
Lean Amine Storage Tank 5JD205	WAC 173-401-530(4)	DGA 40%
Lean Amine Storage Tank 5JD15	WAC 173-401-530(4)	DGA 40%
Amine Regeneration Units	WAC 173-401-530(4)	

Catalytic Reformer Units 1 and 2

Insignificant Activities and Emissions Units Catalytic Reformer Units 1 and 2		
Exempt Unit	WAC Citation	Comment
Pressure Relief Valves	WAC 173-401-532 (87)	Except for LDAR requirements
Totes	WAC 173-401-532 (42)	
Small Tanks	WAC 173-401-532 (2)	
Analyzer Shelter	WAC 173-401-532 (8)	
Sample Points	WAC 173-401-532 (51)	Except for LDAR requirements
Product Sampling, Handling	WAC 173-401-532 (73)	
Lube Oil Storage and Use	WAC 173-401-532 (3) and (69)	
Maintenance Activities	WAC 173-401-532 (74)	
Sewer/Blowdown	WAC 173-401-532 (120)	

Alkylation Units 1 and 2

Insignificant Activities and Emissions Units Alkylation Process Units 1 and 2		
Exempt Unit	WAC Citation	Comment
Analyzer Shelter	WAC 173-401-532(8)	
Additive Totes	WAC 173-401-532(42)	
Small Tanks	WAC 173-401-533(b)	
Pressure Relief Devices	WAC 173-401-532(87)	Except for LDAR requirements
Instrument Air Compressor	WAC 173-401-532(88)	
Emergency Generator	WAC 173-401-530(4)	
Acid Storage Tanks Tanks 401, 402, 403, 405 (42,000 gallons each)	WAC 173-401-533(2)(s)	402 and 403 are spent acid tanks with a nitrogen blanket for explosion control, 401 and 405 are fresh acid tanks
Sample Points	WAC 173-401-532(51)	Except for LDAR requirements
Pressure Safety Valves	WAC 173-401-532(87)	Except for LDAR requirements
Product Sampling, Handling	WAC 173-401-532(73)	
Lube Oil Storage and Use	WAC 173-401-532(3) and (69)	
Maintenance Activities	WAC 173-401-532(74)	
Sewer/Blowdown	WAC 173-401-532(120)	

Hydrotreater Units 1, 2 and 3

Insignificant Activities and Emissions Units Hydrotreater Units 1, 2 and 3		
Exempt Unit	WAC Citation	Comment
Pressure Relief Valves	WAC 173-401-532 (87)	Except for LDAR requirements
Totes	WAC 173-401-532 (42)	
Small Tanks	WAC 173-401-532 (2)	
Analyzer Shelter	WAC 173-401-532 (8)	
Sample Points	WAC 173-401-532 (51)	Except for LDAR requirements
Product Sampling, Handling	WAC 173-401-532 (73)	
Lube Oil Storage and Use	WAC 173-401-532 (3) and (69)	
Maintenance Activities	WAC 173-401-532 (74)	
Sewer/Blowdown	WAC 173-401-532 (120)	

Sulfur Recovery Unit

Insignificant Activities and Emissions Units Sulfur Recovery Unit (including Tail Gas Treating Unit)		
Exempt Unit	WAC Citation	Comment
Analyzer Enclosure	WAC 173-401-532(8)	
Totes	WAC 173-401-532(42)	
Small Tanks	WAC 173-401-532(3)	Lube oil storage tank.
Anhydrous Ammonia Bottles	WAC 173-401-533(a)	
Liquid O ₂ Tank	WAC 173-401-532(5)	
Sampling Points	WAC 173-401-532(51)	
Filter Changes on ARUs	WAC 173-401-532(74)	
Sulfur Pits	WAC 173-401-530(4)(i), (j)	Sulfur pit emissions are routed to the combustor as a safety procedure.
Lean MDEA Tank	WAC 173-401-530(4)	17D101
Sample Points	WAC 173-401-532(51)	
Pressure Safety Valves	WAC 173-401-532(87)	
Product Sampling, Handling	WAC 173-401-532(73)	
Maintenance Activities	WAC 173-401-532(74)	
Sewer/Blowdown	WAC 173-401-532(120)	

Utilities

Insignificant Activities and Emissions Units Utilities		
Exempt Unit	WAC Citation	Comment
Boiler House Lubrication Oil Storage Tank	WAC 173-401-532(3)	
Boiler House Storage Tank	WAC 173-401-532(4) and WAC 173-401-533(2)(s)	Emission Point ID: 31G-D12, 6,000 gal 50% NaOH
Boiler House Storage Tank	WAC 173-401-532(4)	Emission Point ID: 31G-D13
Boiler House Storage Tank	WAC 173-401-533(2)(s)	Emission Point ID: 31G-D11, 3,000 gal sulfite
Boiler House Storage Tank	WAC 173-401-532(117)	Emission Point ID: 31G-D10, 3,000 gal polymer
Boiler House Portable Tank	WAC 173-401-532(42)	Cesco portable
Boiler House Water Conditioning Tanks	WAC 173-401-532(4), (42) and WAC 173-401-533(2)(s)	Emission Point IDs: 31G-D14, 31G-D15, 31G-C8, 31G-C7, 31G-C37A, 31G-C37B, 31G-C37C
Boiler House Pressure Safety Valves	WAC 173-401-532(87)	
Boiler House Maintenance/Startup	WAC 173-401-532(74)	
Cooling Towers	WAC 173-401-532(121)	No chromium-based water treatment chemicals are used

Offplot Area

Insignificant Activities and Emissions Units		
Offplot Area		
(Flares, Receiving, Pumping and Shipping, Storage Tanks/Vessels, and Effluent Plant/Wastewater Handling)		
Exempt Unit	WAC Citation	Comment
Tanks/Vessels		
Chevron Additive Tank	WAC 173-401-530(4)	OGA 4920
Exxon Additive Tank-23NC6	WAC 173-401-530(4)	755 A
Generic Additive Tank	WAC 173-401-530(4)	TC-13000
Additive Tank	WAC 173-401-530(4)	NAP 93
System 3 Additive Tank-23ND4	WAC 173-401-530(4)	
Cleaning and Painting	WAC 173-401-533(2)(q)	
Miscellaneous Tanks	WAC 173-401-532(4)	
Tanks 201 and 202	WAC 173-401-532(94), (96)	Boiler feedwater and condensate, respectively.
Tank #7, EFR Tank	WAC 173-401-532(87)	This tank has a pressure relief valve and stores no product; it is used as a crude oil safety confinement tank.
Garage Fuel Tanks: 1,000-Gallon Diesel Tank 2,000-Gallon Unleaded Gasoline Tank	WAC 173-401-533(2)(c) WAC 173-401-530(4)	Underground storage tanks for plant vehicle use
Tank 63	WAC 173-401-530(4)	Nalco 5403 corrosion inhibitor
Tank 64	WAC 173-401-530(4)	Nalco 5300 stabilizer oil additive
Tank 65	WAC 173-401-530(4)	Nalco 5375 cold flow improver
Tanks 66 and 67	WAC 173-401-530(4)	Morton Automate dye
Tank 68	WAC 173-401-530(4)	Diesel ignition improver
Tank 69	WAC 173-401-530(4)	Automate red dye
Tank 105	WAC 173-401-530(4)	Wastewater bullet tank
Tank 301, 303, and 305	WAC 173-401-533(S)	Spent caustic
Tanks 302 and 304	WAC 173-401-533(S)	Caustic
Tank 15D-102	WAC 173-401-533(S)	
Effluent Plant		
Polymer Tank	WAC 173-401-532(117)	
Caustic Totes	WAC 173-401-533(2)(s)	
Tank 9NQD 23	WAC 173-401-533(2)(5)	Caustic storage
Pressure Safety Valves	WAC 173-401-532(87)	
Stormwater System	WAC 173-401-533(3)(d)	
Spill Basin	WAC 173-401-533(3)(d)	
Dewatering Sludge Press	WAC 173-401-532(114)	
Biosludge Dewatering Tank	WAC 173-401-532(117)	S-16
Remediation Activities		
Groundskeeping Equipment and Activities	WAC 173-401-532(43)	
Landfarms	WAC 173-401-530(1)(d)	

Insignificant Activities and Emissions Units		
Offplot Area		
(Flares, Receiving, Pumping and Shipping, Storage Tanks/Vessels, and Effluent Plant/Wastewater Handling)		
Exempt Unit	WAC Citation	Comment
Other		
Octane Test Engines	WAC 173-401-533(2)(f)	Engines, which are used, for fuel testing are located in refinery lab.
Refinery Laboratory	WAC 173-401-530(4)	
Lab Water Heaters	WAC 173-401-533(2)(r)	
Maintenance Activities	WAC 173-401-532(7)	
Vehicle Exhaust from Maintenance Shops	WAC 173-401-532(7)	
Welding Activities	WAC 173-401-532(12)	
Warehouse Drum Storage	WAC 173-401-532(42)	
Warehouse Forklift Propane Tanks	WAC 173-401-532(10) and (2)	
Painting	WAC 173-401-532(33)	
Infirmary	WAC 173-401-532(53)	
Drum Storage	WAC 173-401-532(42)	
Caustic Railcar Loading System	WAC 173-401-533(z)(s)	
Fire and Emergency Response Training Activities	WAC 173-401-532(52)	Excluding the drill pit which requires a fire permit from the NWAPA
Trucks, Forklifts, Autos, etc.	WAC 173-401-532(10)	
Fuel Truck	WAC 173-401-532(2)	
Mobile Transport Tanks	WAC 173-401-532(2)	
Turnaround Equipment (Diesel Cranes, Air Compressors, Diesel Generators, Diesel Aggregate Blaster-Painting)	WAC 173-401-532(33)	
Personal Cars	WAC 173-401-532(54)	
Barbecues, Crab Boilers	WAC 173-401-532(11)	
Emergency 150-kW Diesel Generator	WAC 173-401-530(1)(a)	Unit operated less than 643 hours per year. 643 hours equates to emission rates less than the threshold values specified in WAC 173-401-530(4) as calculated using EPA AP-42 Table 3.3-2.
Emergency 100-kW Steam Generator	WAC 173-401-530(4)	Unit powered by steam.
Emergency 200-kW Steam Generator	WAC 173-401-530(4)	Unit powered by steam.
Emergency 600-hp Outfall Pump	WAC 173-401-530(4)	Unit operated 52 hours per year.

Permit Assumptions

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.

Federal Enforceability

Federally enforceable requirements are terms and conditions required under the Federal Clean Air Act or under any of its applicable requirements. Local and state regulations may become federally enforceable by formal approval into the State Implementation Plan or through other delegation mechanisms. Federally enforceable requirements are enforceable by the EPA and citizens. All applicable requirements in this 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. If two different versions of the same regulatory citation apply, one version is federally enforceable and the other version is only enforceable by the state. Both are listed as separate applicable requirements. If a regulation has both federally enforceable and state-only enforceable versions and the text is the same, the cited date is the most current available. The citation for each applicable requirement in the permit includes a date; this date may be the filing date (in the case of WACs) or it may be the approval date or the publication date for NWAPA Regulation sections and federal regulations, respectively.

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 permit terms based on Chapter 173-401 WAC will become federally enforceable.

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.

Compliance Options

PSR 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.

Permit Elements

The permit is organized in the following sequence:

- Permit Information
- Attest
- Table of Contents
- Emission Unit Identification
- Standard Terms and Conditions
- Generally Applicable Requirements
- Specific Requirements for Emissions Units
- Inapplicable Requirements
- Insignificant Emission Units

Within the Standard Terms and Conditions, Generally Applicable Requirements, and Specific Applicable Requirements sections, applicable regulations and OACs issued to the facility are listed. After each is a date in parenthesis. When the date is associated with a regulation, it represents the current version date for that regulation. Specifically, for a federal Subchapter regulation (e.g. 40 CFR 60 Subpart GG) this date represents the date of publication in the Federal Register. For Washington Administrative Code (WAC) regulation this date represents the date filed with the State Code Reviser. For NWAPA regulation, it represents the Board of Directors adoption date. In the case of an OAC, it represents the issuance date of the order.

Permit Information, Attest, and Emissions Unit Description Sections

The General Information section identifies the source, the responsible corporate official, and the agency personnel responsible for permit preparation, review, and issuance. The Attest section provides authorization by the NWAPA for the source to operate under the terms and conditions contained in the permit. The Emissions Unit Identification section lists the significant emissions units, associated control equipment, fuel type, and installation dates. This section is a general overview of the facility. Detailed information about the plant can be found in the permit application and supporting files.

Standard Terms and Conditions

The Standard Terms and Conditions section contains administrative requirements and prohibitions that do not have ongoing compliance monitoring requirements. The citations 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 understanding and readability, the terms and conditions have been grouped by function. Where possible, similar requirements by both the state and the NWAPA have been grouped together. There are several requirements included that are not applicable until triggered. Examples of these would be the requirement to file a "Notice of Construction and Application for Approval".

Generally Applicable Requirements

The Generally Applicable Requirements section identifies requirements that apply broadly to the facility. These requirements are generally not called out in OACs and instead are found as general air pollution rules in the NWAPA 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 "test method" column is the legal test method that the enforcement agency would use to confirm compliance with the requirement. However, It is not a requirement of the source unless stated in the last column, which lists the monitoring, recordkeeping and reporting (MR&R) requirements. The MR&R column is a summary of the underlying requirement cited in the "citation" column and is not directly enforceable. If there is a statement in the MR&R column that states "directly enforceable" than that MR&R requirement is enforceable and represents gap filling done by the NWAPA during writing of the AOP. 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.

Gap Filling

There are some air pollution rules and regulations and OAC conditions that do not specifically call out a monitoring, reporting, or recordkeeping method(s) to demonstrate compliance with the applicable requirement. In this case the permitting agency would develop a site-specific requirement that the source must follow. The inclusion of these customized requirements is called "gap filling". PSR has many specific monitoring, reporting, and recordkeeping requirements in the form of continuous emission monitors and periodic reporting. In some instances however, gap filling has been used. For instance, nuisance rules and opacity requirements have site specific gap filled obligations for the source. Any areas where gapfilling has taken place, the monitoring, recordkeeping and reporting for that term will state "directly enforceable".

Specific Requirements for Emissions Units

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

PSR uses CEMs and COMs to continuously monitor various emission units for SO₂, NO_x, CO, O₂ and opacity. In these cases continuous compliance for concentration and mass emission limits is a straightforward determination. Pollutants not continuously monitored are VOCs and fine particulates. Periodic opacity observations and source test data assure that the permit conditions for fine particulate are not exceeded. Low carbon monoxide emissions measured by a CEM are an indicator of good combustion and consequently can serve as a surrogate monitoring parameter for VOC compliance.

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. Table 5 in the Air Operating Permit lists requirements that are deemed inapplicable to the facility. The basis for each determination of inapplicability is included.

Insignificant Emissions Units

Categorically exempt emissions units listed in WAC 173-401-532 are present at PSR. These emission units have very low, if any, emissions associated with their use and are therefore considered insignificant by regulation.

Permit History

The original air operating permit was issued to Puget Sound Refinery on November 26, 2002. This section provides a summary of subsequent permit openings and renewals. The incorporation of new or revised Orders of Approval to Construct (OACs) is a common activity occurring during permit openings and renewals. Please refer to the subsections entitled "Construction History and Regulatory Applicability" under the applicable process unit in this Statement of Basis for greater detail on the history of each OAC issued or revised.

PSR Air Operating Permit History

Opening Type and Associated Dates	General Description
AOP #014 Application received June 7, 1995 and revised: December 17, 1997 Issued November 26, 2002	Original permit issuance
AOP #014 Modification 1 Requests dated August 18, 2003, February 9, 2004 and May 3, 2004 Draft Issued June 15, 2004	The permit was modified to incorporate OAC #772a (BHU), OAC #630a (HTU #2), OAC #787b (HTU #3) and OAC #828 (SRU #4). Changes were made to include upgrades to the flare system consistent with the EPA's consent decree approved hydrocarbon flaring reduction plan as a method for meeting 1000-ppm SO2 limits for flares. And, 40 CFR 63 subpart A requirements for flares were added to Section 5.10.

Public Docket

Copies of PSR's Air Operating Permit, permit application and technical support documents are available at the following location:

Northwest Air Pollution Authority
1600 South Second Street
Mount Vernon, WA 98273-5202

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 NWAPA 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:

AIRS	Aerometric Information Retrieval System
AMP	Alternative Monitoring Plan
AOP	Air Operating Permit
ASTM	American Society for Testing and Materials
ASIL	Acceptable Source Impact Level
Avjet	aviation jet fuel
BACT	best available control technology
BHU	Butadiene Hydrogenation Unit
BQ6	Benzene waste Quantity under 6 Mg/yr (wastewater)
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring

CD	Consent Decree
CEM	continuous emission monitor
CGA	cylinder gas audit
COM	continuous opacity monitor
CFR	Code of Federal Regulations
CRU	Catalytic Reforming Unit
DAF	Dissolved Air Floatation (wastewater)
DCU	Delayed Coking Unit
EFR	External Floating Roof (tank)
ESP	Electrostatic Precipitator
FCAA	Federal Clean Air Act
FCCU	fluid catalytic cracking unit
HAP	Hazardous Air Pollutants
HC	Hydrocarbon
HON	Hazardous Organic NESHAP
HTU	Hydrotreater Unit
H ₂ S	hydrogen sulfide
HRSG	heat recovery steam generator
HSR	Heavy Straight Run
IFR	Internal Floating Roof (tank)
ISO	International Standards Organization
kPa	kilopascals (10 ³ pascals pressure)
LDAR	leak detection and repair
MACT	Maximum Achievable Control Technology
MDEA	Methyl-Diethyl-Amine
Mg	megagrams (10 ⁶ grams mass)
MMBtu	million British thermal units
MPCC	March Point Cogeneration Company
MRRR	monitoring, recordkeeping and reporting requirements
MTVP	maximum true vapor pressure
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOC	Notice of Construction
NO _x	oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review

NWAPA	Northwest Air Pollution Authority
O ₂	oxygen
OAC	Order of Approval to Construct
PM	particulate matter
PM ₁₀	particulate matter less than 10 microns in diameter
ppmvd	parts per million by volume, dry
psia	pounds per square inch atmospheric
PSR	Puget Sound Refinery
PTE	Potential to Emit (annual, unless otherwise noted)
PRD	Pressure Relief Device
QA/QC	quality assurance/quality control
RATA	relative accuracy rest audit
RCW	Revised Code of Washington
RMACT	Refinery MACT per 40 CFR 63 Subpart CC
RO	Regulatory Order (under WAC 173-400-091)
SCR	selective catalytic reduction
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
LDAR	Leak Detection and Repair
VPS	Vacuum Pipe Still (Crude Unit)
VOC	Volatile Organic Compounds
VOL	Volatile Organic Liquid
WAC	Washington Administration Code
WDOE	Washington State Department of Ecology
WWSG	Waste Water Stripper Gas