# BP Cherry Point Refinery
# Coker Heater Replacement Project
## Consolidated Air Quality Permit Application

Prepared for:
**BP West Coast Products**
**Blaine, WA**

Prepared by:
**Ramboll Environ**
**Lynnwood, WA**

Date:
**June 2016**

Project Number:
**29-30623E**

RAMBOLL ENVIRON

# Contents

**Page**

**1 Introduction ..... 1**
1.1 Organization ..... 3
1.2 Permit Application Updates ..... 3
1.3 Summary of Findings ..... 4

**2 Project Description ..... 7**
2.1 Physical Description ..... 7
2.2 Delayed Coking Process ..... 7
2.2.1 Existing Coker Heaters ..... 8
2.3 New Coker Heaters ..... 9
2.4 Crude Preheat System ..... 11
2.5 Project Effects on Existing Units ..... 12
2.5.1 Coke Drum Venting, Cutting, and Draining ..... 14
2.5.2 Green Coke Handling ..... 15
2.5.3 Calciners ..... 15
2.5.4 Hydrocracker ..... 16
2.5.5 Diesel Hydrotreaters ..... 16
2.5.6 Sulfur Plant ..... 16
2.5.7 Other Refinery Process Heaters ..... 17
2.5.8 Boilers ..... 18
2.5.9 Product Storage and Loading ..... 18
2.5.10 Flaring ..... 18
2.5.11 Wastewater ..... 18
2.5.12 Cooling Towers ..... 19
2.5.13 Crude Unloading ..... 19

**3 Project Emissions ..... 21**
3.1 New Emission Units ..... 30
3.1.1 Replacement Coker Heaters ..... 30
3.1.2 New Components ..... 36
3.2 Existing Emission Units ..... 36
3.2.1 Coke Drum Venting, Cutting, and Draining Emissions ..... 37
3.2.2 Green Coke Handling ..... 37
3.2.3 Calciners ..... 38
3.2.4 Refinery Fuel Gas Sulfur Content ..... 38
3.2.5 Hydrocracker ..... 38
3.2.6 Sulfur Plant ..... 39
3.2.7 Other Refinery Heaters ..... 40
3.2.8 High Pressure Flare ..... 42
3.2.9 Cooling Towers, WWTP, Storage Tanks, and Product Loadout ..... 42

**4 Regulatory Analysis ..... 45**
4.1 Emission Standards ..... 45

4.1.1 New Source Performance Standards ..... 45
4.1.2 National Emission Standards for Hazardous Air Pollutants for Source Categories ..... 49
4.1.3 Compliance Assurance Monitoring ..... 51
4.1.4 Chemical Accident Prevention Provisions ..... 51
4.1.5 State and Local Emission Limits ..... 51
4.2 Air Quality Permits ..... 52
4.2.1 Prevention of Significant Deterioration (PSD) ..... 52
4.2.2 Notice of Construction (NOC) ..... 55
4.2.3 Air Operating Permit ..... 56

**5 Local Air Quality Impact Assessment ..... 57**
5.1 Dispersion Model Selection ..... 57
5.2 Model Application ..... 58
5.2.1 Receptor Locations ..... 58
5.2.2 Meteorology ..... 59
5.2.3 Stack Parameters, Building Dimensions, and Good Engineering Practice ..... 61
5.2.4 Building Downwash (Prime Algorithm) ..... 62
5.3 Project Impact Assessment ..... 67
5.3.1 Significant Impact Levels ..... 67
5.3.2 AERMOD-Predicted Concentrations ..... 70
5.3.3 Toxic Air Pollutant Concentrations ..... 73
5.3.4 Secondary $PM_{2.5}$ Formation ..... 74
5.3.5 Ozone Analysis ..... 74

**6 Class I Air Quality Impact Assessment ..... 77**
6.1 Model Selection ..... 77
6.2 Modeling Procedures ..... 77
6.2.1 Model Setup and Application ..... 78
6.2.2 Emission Rates and Stack Parameters ..... 78
6.2.3 Averaging Periods ..... 83
6.2.4 Chemical Transformations ..... 83
6.2.5 Domain and Receptors ..... 84
6.2.6 Meteorological Data ..... 87
6.3 AQRV Calculation Procedures ..... 88
6.3.1 Visibility ..... 88
6.4 Analysis Results ..... 89

**7 Additional Impact Analysis ..... 101**
7.1 Class II Area Growth ..... 101
7.2 Class II Visibility ..... 101
7.3 Soils and Vegetation ..... 101

# List of Tables

Table 3-1: Project BACT Summary ....22
Table 3-2: Project Regulated Pollutant Emission Increases ....25
Table 3-3: PSD Netting Analysis ....27
Table 3-4: Project Toxic Air Pollutant Emissions ....28
Table 3-5: Coker Heater Potential to Emit ....34
Table 3-6: Coker Heater Toxic Air Pollutant Potential to Emit ....35
Table 4-1: Coker Heater – Proposed Emission Limits (per heater) ....56
Table 5-1: BP Met Site Surface Characteristics ....61
Table 5-2: Source Release Parameters ....63
Table 5-3: $PM_{2.5}$ Design Values (2012 – 2014) ....68
Table 5-4: Maximum AERMOD-Predicted Criteria Pollutant Concentrations ....70
Table 5-5: Maximum Predicted Toxic Air Pollutant Concentrations ....74
Table 6-1: Speciated Short-Term Emission Rates for AQRV Analysis ....80
Table 6-2: Speciated Long-Term Emission Rates for AQRV Analysis ....81
Table 6-3: Source Release Parameters for Class I Analysis ....82
Table 6-4: Predicted Class I Area Criteria Pollutant Concentrations ....90
Table 6-5: Predicted Class I Area Deposition Fluxes ....95
Table 6-6: Predicted Class I Area Visibility Results ....98

# List of Figures

Figure 1-1. BP Cherry Point Refinery Site .... 2
Figure 2-1. Replacement Coker Heater Locations .... 7
Figure 2-2. Simplified Coker Diagram .... 9
Figure 2-4. Refinery Process Flow Diagram ....14
Figure 5-1. Receptor Locations ....59
Figure 5-2. BP Cherry Point Wind Rose ....60
Figure 5-3. Source and Building Locations with Heights ....66
Figure 5-4. 2003 – 2014 $PM_{2.5}$ Design Value Trend (24-hour Average). ....69
Figure 5-5. 2003 – 2014 $PM_{2.5}$ Design Value Trend (Annual Average). ....69
Figure 5-6. Maximum 1-hour average $SO_2$ Concentrations ....71
Figure 5-7. Maximum 24-hour average $PM_{2.5}$ Concentrations ....72
Figure 5-8. Maximum annual average $PM_{2.5}$ Concentrations ....73
Figure 6-1. Class I Modeling Domain ....85
Figure 6-2. CALPUFF Receptors ....86
Figure 6-3. Maximum Annual Average $NO_2$ Concentrations ....91
Figure 6-4. Maximum Annual Average $SO_2$ Concentrations ....92
Figure 6-5. Maximum 3yr Average 24-hour $PM_{2.5}$ Concentrations ....93
Figure 6-6. Maximum $PM_{2.5}$ Annual Average Concentrations ....94
Figure 6-7. Maximum Annual Sulfur Deposition Rate ....96
Figure 6-8. Maximum Annual Nitrogen Deposition Rate ....97
Figure 6-9. Maximum Percent Change in Visibility Attributable to Project Emissions ....99

# List of Appendices

Appendix A: NOC and PSD Forms
Appendix B: BACT Analysis
Appendix C: Emissions Calculations
Appendix D: Secondary Aerosol Analysis
Appendix E: Regional Ozone Analysis
Appendix F: Response to Canadian Agency Comments
Appendix G: Post-Submittal Correspondence
Appendix H: Dispersion Modeling Files

# 1 Introduction

BP West Coast Products, LLC (BP) owns and operates the Cherry Point Refinery (hereafter referred to as “the Facility” or “the Refinery”) located at 4519 Grandview Road near the community of Birch Bay in Whatcom County, Washington. The location of the Facility is shown in Figure 1-1. BP proposes to replace two existing coker heaters with two new coker heaters (the Project). BP plans to commence construction in 2017 and commence operation of the new equipment by first quarter 2019.

The Facility’s Coker Unit converts residual oil from the Crude Unit to low molecular weight hydrocarbon gases, naphtha, light and heavy gas oils, and green coke. The process thermally cracks the long chain hydrocarbon molecules in the residual oil feed into shorter chain molecules, leaving behind excess carbon in the form of green coke.

The Refinery’s Coker Unit employs two heaters for the thermal cracking reaction. These heaters fire the low molecular weight hydrocarbon gases generated by the thermal cracking process (coker off gas). The rated capacity of each existing heater is 190 million British thermal units per hour (MMBtu/hr). The two heaters were installed in 1970 as part of the original refinery. Routine offline cleaning (decoking) is required up to three times per year. The heater decoking process results in flaring emissions and reduced crude throughput rates.

BP proposes to replace the existing Coker Unit heaters with new, more efficient heaters designed for a heat input rate of up to 276 MMBtu/hr (HHV). The rated burner capacity of each heater is up to 303 MMBtu/hr (HHV). Although BP does not plan to operate the heaters above the 276 MMBtu/hr design rate, all emission calculations are conservatively based on the 303 MMBtu/hr burner capacity. Each heater will have online cleaning capability (known as online spalling) to reduce frequency of offline cleaning.

BP also proposes several other changes as part of this project:

- Revising the main fractionator overhead accumulator (separates water from hydrocarbon vapor) to accommodate the additional steam condensate generated during spalling activities.
- Installing a lean oil absorption system with compressor in the coker off gas system to recover C3 (i.e. propanes) and C4 (i.e. butanes) hydrocarbons. The recovered intermediates will be processed in the light ends unit for saleable product.
- Installing additional bypasses on four existing heat exchangers in the Crude Unit preheat system.

None of the proposed changes (replacement coker heaters, fractionator overhead accumulator, lean oil absorption system, or heat exchanger bypasses) will allow an increase in the maximum short-term crude processing rate at the refinery. Rather, the Project will allow improved long term utilization of existing refinery equipment. The replacement of the coker heaters, plus projected increases in the use of existing refinery process units, will increase annual refinery emissions of oxides of nitrogen ($NO_X$), carbon monoxide (CO), sulfur dioxide ($SO_2$), sulfuric acid

mist ($H_2SO_4$), particulate matter (PM), particulate less than 10 microns ($PM_{10}$), particulate less than 2.5 microns ($PM_{2.5}$), volatile organic compounds (VOC), and greenhouse gases ($CO_2e$) by quantities deemed significant under EPA's Prevention of Significant Deterioration (PSD) permit program.

BP submitted the initial permit application to Northwest Clean Air Agency (NWCAA) and Washington Department of Ecology (Ecology) on September 29, 2014. Both NWCAA and Ecology corresponded with BP personnel in October 2014 requesting additional project information. This updated permit application addresses project updates and additional information requested by NWCAA and Ecology.

Whatcom County is expected to be the lead agency for the State Environmental Policy Act (SEPA) review. NWCAA and Ecology will receive a copy of the SEPA checklist once the document is submitted to Whatcom County.

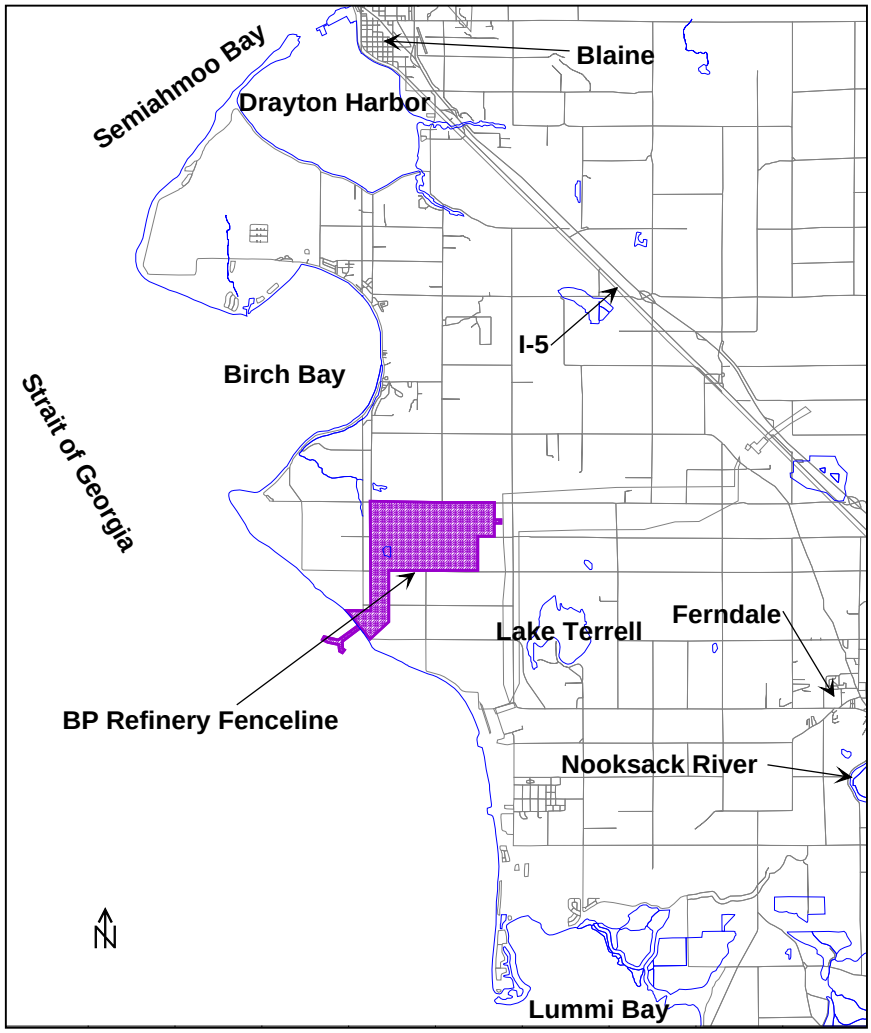



**Figure 1-1. BP Cherry Point Refinery Site**

## 1.1 Organization

Ramboll Environ (RE) prepared this air quality permit application on behalf of BP. Key components of the permit application include:

- Description of the Project, updates from initial application, and anticipated air pollutant emissions;
- A discussion of the applicable air quality regulations;
- An analysis of Best Available Control Technology (BACT);
- Analysis of air quality impacts in Class II Areas;
- Analysis of air quality impacts and air quality related values in Class I Areas; and
- Additional impact analysis in Class II Areas.

A number of appendices support the permit application:

- Appendix A includes NWCAA's standard notice of construction (NOC) forms and the PSD applicability form.
- Appendix B provides the complete BACT analysis for the new coker heaters.
- Appendix C provides the detailed emission calculations for the Project.
- Appendix D includes a secondary $PM_{2.5}$ impacts analysis.
- Appendix E provides an ozone assessment that is required for this Project based on the projected net increase in $NO_x$ emissions.
- Appendix F is a supplemental air quality analysis requested by Canadian air quality agencies. Although not required by federal, state, or local air quality regulations, BP included Canadian air quality agencies in the distribution of a proposed modeling protocol for the Project, and received requests to address specific air quality concerns in Canada.
- Appendix G provides all correspondence with regulators after March 2016 application submittal.
- Appendix H provides electronic modeling files on a DVD.

## 1.2 Permit Application Updates

This updated permit application incorporates project scope changes and addresses information requests from Ecology and NWCAA. A summary of key application updates, with application section references, includes:

- Project no longer includes vacuum quench and new heat exchangers described in September 2014 application;
- Proposed lean oil absorption system now includes a compressor (Section 2.3 of application);
- Project now includes installing bypasses of existing heat exchangers in crude preheat system (Section 2.4 of application);
- Updated PSD baseline periods and discussion of updates to baseline actual emission calculations (Section 3.2 of application);
- Additional supporting information provided in BACT analysis (Appendix B); and
- Updated Class I and Class II modelling analysis (Sections 5 and 6 of Application)

The purpose of this consolidated application is to provide all project information in a single document that can replace the original September 2014 application and the updated March 2016 application.

## 1.3 Summary of Findings

Considering emission increases related to the replacement coker heaters and increased utilization of existing process units, the Project will increase emissions of NOx, CO, $SO_2$, PM, $PM_{10}$, $PM_{2.5}$, VOC, $H_2SO_4$, and $CO_2e$ above the applicability thresholds for the PSD permitting program. RE examined contemporaneous changes in emissions for these pollutants at the refinery and determined that contemporaneous projects do not change the PSD applicability assessment.

PSD modeling analyses are required for NOx, CO, $SO_2$, $PM_{10}$, $PM_{2.5}$, and ozone. This application is intended to provide information needed for a NOC application as well as a PSD permit. Therefore, the dispersion modeling also addresses toxic air pollutant (TAP) emission increases from the replacement of the coker heaters that exceed the small quantity emission rates (SQERs). TAP emission increases above the SQERs were examined to indicate AERMOD-predictions are less than TAP screening levels, referred to as acceptable source impact levels (ASILs).

RE conducted an air quality impact assessment using five years of hourly meteorological data from an on-site meteorological tower as well as a Class I modeling analysis using three years of regional meteorology. These analyses indicate:

- AERMOD-predicted increases in local concentrations attributable to the Project are insignificant, using EPA significance criteria;
- CALPUFF-predicted increases in concentrations in National Parks and Wilderness Areas are insignificant, using EPA and federal land manager criteria;

- CALPUFF predicted deposition values are less than the deposition impact criteria established by the federal land managers;
- CALPUFF predicted extinction coefficients are less than the visibility impact criteria established by EPA;
- AERMOD-predicted concentrations of toxic air pollutants are less than the screening criteria (ASILs) established by Ecology; and
- CMAQ-predicted ozone concentrations indicate the Project emissions will have an insignificant effect on regional ozone concentrations during adverse ozone episodes.

While not required by the PSD program, CALPUFF and AERMOD were used to predict pollutant concentrations attributable to the Coker Heater Replacement Project in British Columbia. The model-predicted pollutant concentrations were much less than the Canadian and British Columbia Air Quality Objectives.

# 2 Project Description

## 2.1 Physical Description

The two new coker heaters with burners rated at 303 MMBtu/hr (HHV) will be located southeast of the existing coker heaters (Figure 2-1). The new heaters will require new tie-ins to the existing coker unit equipment and existing refinery utilities. Although the main fractionator overhead accumulator will need to be revised to accommodate additional steam condensate, no changes or modifications are proposed for the existing coke drums, cutting water and quench system, or coke drum blowdown recovery system. BP proposes to replace the boiler feedwater circulation pump to recover heat from the coker unit. The circulation pump has no effect on coker unit emissions.

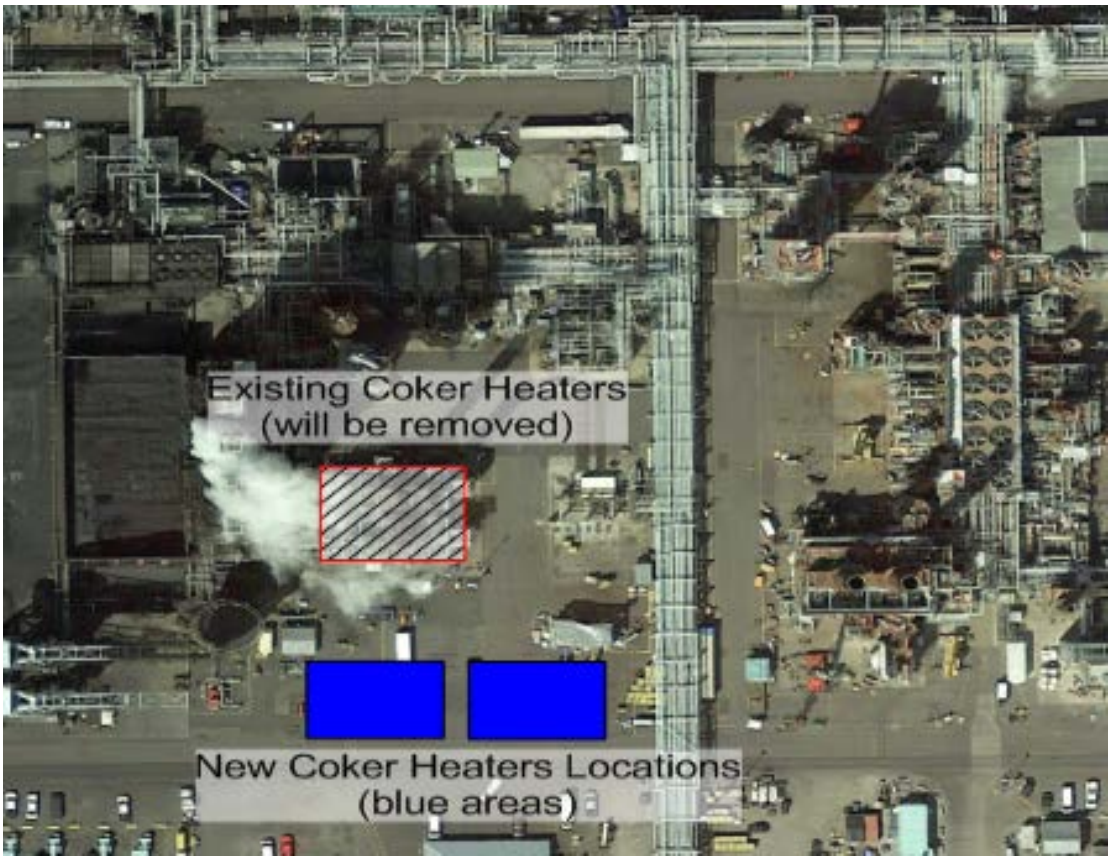



**Figure 2-1. Replacement Coker Heater Locations**

## 2.2 Delayed Coking Process

The coking process feeds are residual oil from the crude unit, cold residual oil from tankage, and recovered oil collected throughout the refinery including the refinery wastewater plant. The coker heaters heat the feed to greater than 900 degrees Fahrenheit (°F), the temperature at which long chain hydrocarbon molecules become unstable and begin breaking apart. Adequate velocity is maintained in the heater tubes and transfer line to delay the coking reaction until the heated feed reaches the coke drums. Four coke drums operate in pairs. As one drum is being filled, the other drum is being cooled and then coke is cut from the drum.

As coke is forming inside a drum, lighter hydrocarbons are routed overhead to the prefractionator and main fractionator. Intermediate streams from the fractionators are then routed to other processing units (hydrocracker, diesel hydrotreaters, and naphtha hydrotreater) to produce gas, jet, and diesel products. Non-condensable gas from the coking process (coker off gas) is treated by an amine column to remove hydrogen sulfide ($H_2S$) and is then used as fuel gas. A portion of the fuel gas is burned in the coker heaters and the remainder is sent to the refinery fuel mix drum to be used by the other heaters and boilers at the refinery.

Cooling a coke drum begins by using steam to strip the remaining lighter hydrocarbons from the coke drum. The stripping vapors are then routed to the coker blowdown system to recover hydrocarbons released during the cooling of the coke bed. Stripping steam is removed and cooling water is introduced to lower the coke temperature. The drum pressure is lowered over several hours and gases are routed through the coker compressor until the pressure falls below the minimum compressor inlet pressure (approximately 11 pounds per square inch gauge [psig]). At that point the drum is vented to the low pressure flare header until the drum pressure is less than 5 psig. Gas in the flare header is recovered in flare gas recovery system and routed to the refinery fuel mix drum. The coke drum is vented to atmosphere when drum pressure is less than 5 psig.[1]

After the drum is cool, high pressure water is used to drill a hole through the coke in the drum and then horizontal nozzles are used to cut out the coke. Green coke drops through a chute into the coke pit, where it is removed and stored for further processing (calcining) or for shipment off-site. A simplified coker unit process flow diagram is presented in Figure 2-2.

### 2.2.1 Existing Coker Heaters

BP retrofitted the existing coker heaters with flue gas recirculation (FGR) in 1999 as part of the coke drum replacement project (OAC 689a). However, with FGR installed, BP is able to fire the coker heaters at their rated capacity (190 MMBtu/hr, each) for short periods of time due to flame impingement caused by the flame shape of the burners. Annual average hourly firing rates for the existing coker heaters are approximately 140 MMBtu/hr. To maintain coker unit operation, the residual oil is sent at a high temperature (over 700ºF) from the Crude Unit to the Coker Unit. Handling the residual feed at these high temperatures can cause fouling in the Crude Unit.

[1] EPA proposed a draft new refinery sector rule on May 15, 2014 and published the final rulemaking on December 1, 2015. The final rule prohibits existing coke drum venting to the atmosphere until drum pressure is less than 2 psig (average over a 60-drum cycles). BP will comply with all applicable requirements of this rule when it becomes effective.

Each of the two existing coker heaters generates 60,000 lb of 140 pound steam per hour, which is sent to the refinery 140 pound steam header.

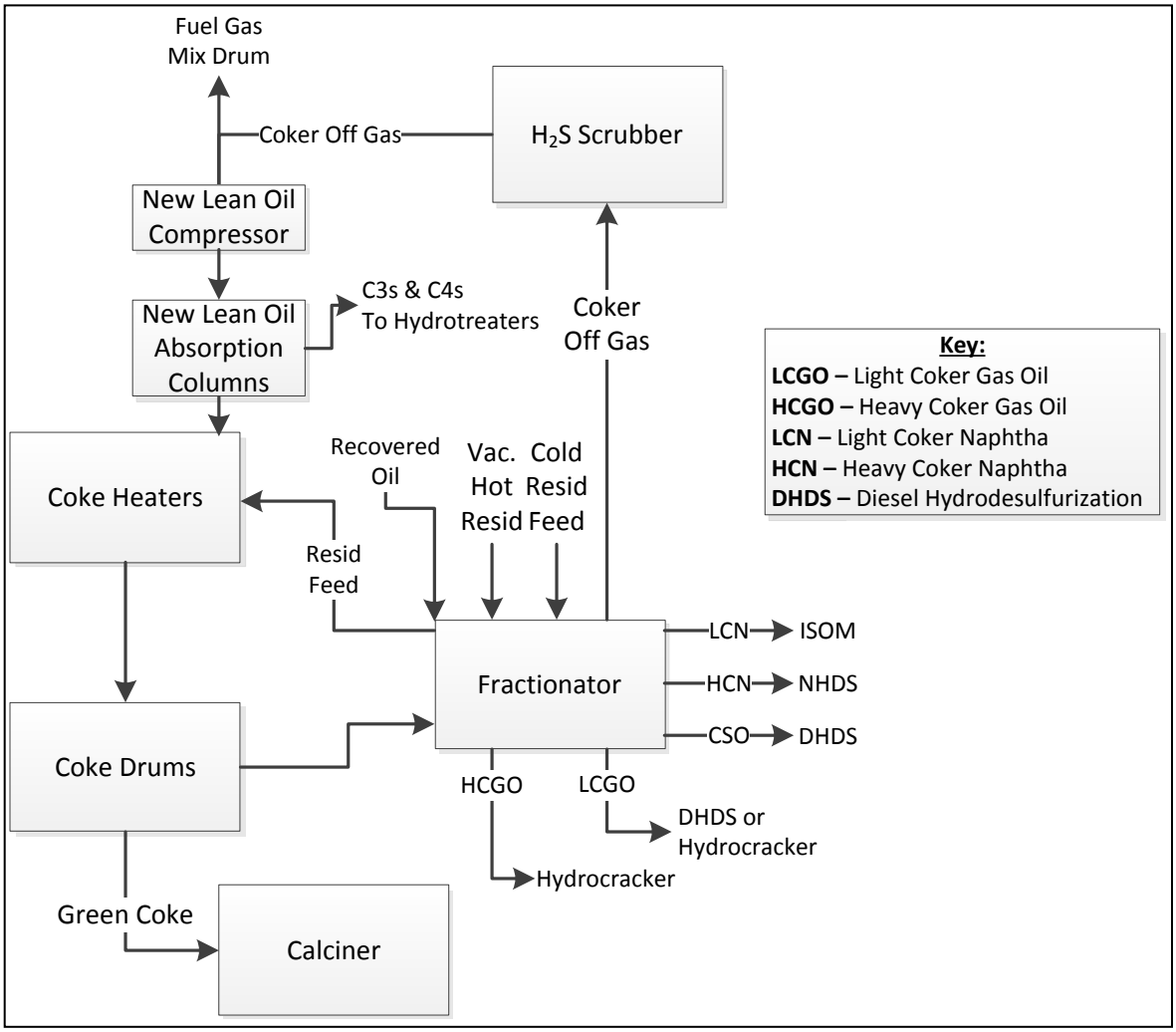



**Figure 2-2. Simplified Coker Diagram**

## 2.3 New Coker Heaters

The new coker heaters will each have burners rated at 303 MMBtu/hr heat release higher heating value (HHV). The increase in heat availability at the coker heaters will allow the residual oil to be transferred from the crude unit to the coker unit at lower temperatures (less than 700ºF). There are no modifications to the crude unit heater. To achieve the lower temps, BP plans to use an existing cooling box to transfer heat from the residual oil to the refinery cooling towers. Piping changes and a new pump will be made to the existing cooling box as part of the Project. The original application included installing new heat exchangers to transfer heat from the residual oil to incoming crude feeds (referred to as the vacuum quench), but the Project no longer includes the vacuum quench heat exchangers. BP does not expect any increase in short-term crude processing rate as a result of the Project.

Heat Recovery System

The new heaters will be a balanced draft design with overall heat efficiency (absorbed duty divided by fired duty) near 90 percent. The heater efficiency will be obtained through use of a heat recovery system to preheat combustion air and generate 25,000 pounds of steam per hour from each heater. Steam generated by the heat recovery system will be added to the refinery 140 pound steam header.

The new heaters will primarily operate in balanced draft mode (forced draft and induced draft fans); however, they will have the option to operate in natural draft mode (i.e. without the air preheater) under certain operating conditions. Operating in natural draft mode lowers the heater efficiency and constrains coker unit throughput. BP does not plan to operate the heaters in natural draft mode during normal operations, but BP also recognizes the need for operational flexibility if an air preheater (balanced draft) needs to be taken offline. BP will typically operate in balanced draft mode in order to utilize the air preheater and maximize the heater efficiency.

Online Cleaning

Each new coker heater will also have online cleaning capability (spalling) to reduce the time for periodic offline heater cleaning (decoking). During spalling two of the six passes of the coker heater tubes will be taken out of service (one cell at a time) and approximately 8,500 pounds of steam per hour will be introduced into each of the out of service passes. By adjusting the temperature of the tubes and flowing high rates of steam through the tubes coke deposits are dislodged from the tubes and transported to the active coke drum by the steam.

The existing coker heaters require offline cleaning 2 to 3 times per year. Shutting down one of the heaters for a decoke event results in flare emissions and historically has required BP to reduce the Crude Unit processing rate until the coker heater decoke is complete. The coker heaters online cleaning capability will reduce flaring emissions and allow BP to conservatively process up to 1.4 percent more crude oil per year (2.9 thousand barrels per day [kbpd], annual average) compared to past actual throughput.[2]

Safety Instrumented System

Each new coker heater will be designed with a Safety Instrumented System (SIS) consisting of sensors, control valves, and software that takes the heaters to a safe state in the event of a malfunction. These additional components are included in the fugitive emission calculations for the new heaters.

[2] BP estimates that a current coker heater decoke lasts approximately 10 days and crude rate is decreased by approximately 35 kbpd during a decoke (350 kb per decoke). BP has based the increase in annual crude throughput on the assumption of going from three decokes per year (current actual) down to zero decokes per year (projected actual), which results in 2.9 kbpd increase in crude utilization for future years regardless of the crude slate.

Coker Off Gas

The Coker Unit currently has an annual average feed rate of 50.6 kbpd (24 month average). For the permit application basis, the projected Coker Unit annual average utilization is assumed to be 61.9 kbpd. This assumption results in a projected 22 percent increase in annual coker utilization, with proportional increases in coker off gas production and coker unit intermediates.

BP proposes to install a new compressor with a lean oil absorption system to recover C3 (i.e. propanes) and C4 (i.e. butanes) hydrocarbons. These hydrocarbons will be processed by the light ends unit to become a saleable product. The lean oil absorption system is designed to process approximately 44 percent of the coker off gas generated. A benefit of the lean oil absorption system is additional sulfur removal (39 percent annual average) from the coker off gas that will be used as fuel in the new coker heaters. The relative location of the lean oil absorption system within the process flow is provided in Figure 2-2.

Main Fractionator Overhead Accumulator

The overhead accumulator separates overhead vapor, distillate, and sour water from the main fractionator tower in the coker unit. Online coker heater cleaning will result in additional water vapor directed to the overhead accumulator, which requires BP to increase the size of the overhead accumulator.

In a comment on the 2014 permit application, Ecology provided information on an emergency flaring event that occurred at a refinery in Norco, Louisiana operates a residual catalytic cracking unit (RCCU). The RCCU malfunctioned and tripped a pressure relieve valve in the overhead accumulator resulting in an emergency flaring event. Ecology questions whether BP's modification to the overhead accumulator could lead to additional flaring events.

There are no atmospheric emissions from the overhead accumulator during normal operation and BP does not operate a RCCU, which was the cause of the malfunction referenced by Ecology. Increasing the overhead accumulator size to accommodate additional steam from coker heater cleaning will not increase the likelihood of an upset or a malfunction event occurring within the delayed coker at the refinery.

## 2.4 Crude Preheat System

The crude unit is designed to remove salt and sediment from crude oil, then heat and fractionate the crude into different components. The pre-fractionator section of the crude unit preheats crude using a series of heat exchangers, then salt and sediments are removed in the desalters. In recent years, the refinery has experienced increased fouling in certain heat exchangers located in the preheating train. This fouling requires heat exchanger maintenance events that reduce the supply of pre-heated crude to the crude unit on an annual basis. The Project includes two changes to reduce the number of heat exchanger maintenance events.

Several existing heat exchangers have bypasses allowing online cleaning. The Project scope includes installing new isolation valves on 10 existing heat exchangers and installing new bypasses on four existing heat exchangers. A simplified process flow diagram presenting the preheat system is presented in Figure 2-3. In addition, BP plans to reduce heat exchanger

down time by injecting cleaning chemicals into the heat exchangers, a common maintenance practice throughout the refinery.

The ability to clean the heat exchangers online will maintain heat availability in the crude preheat system throughout the crude unit cycle (period between maintenance/turnaround). Reducing the heat exchanger fouling allow processing of an additional 2.4 percent crude on an annual basis (5.1 kbpd).[3] This Project will not increase the crude unit capacity and will not modify the crude unit heater.

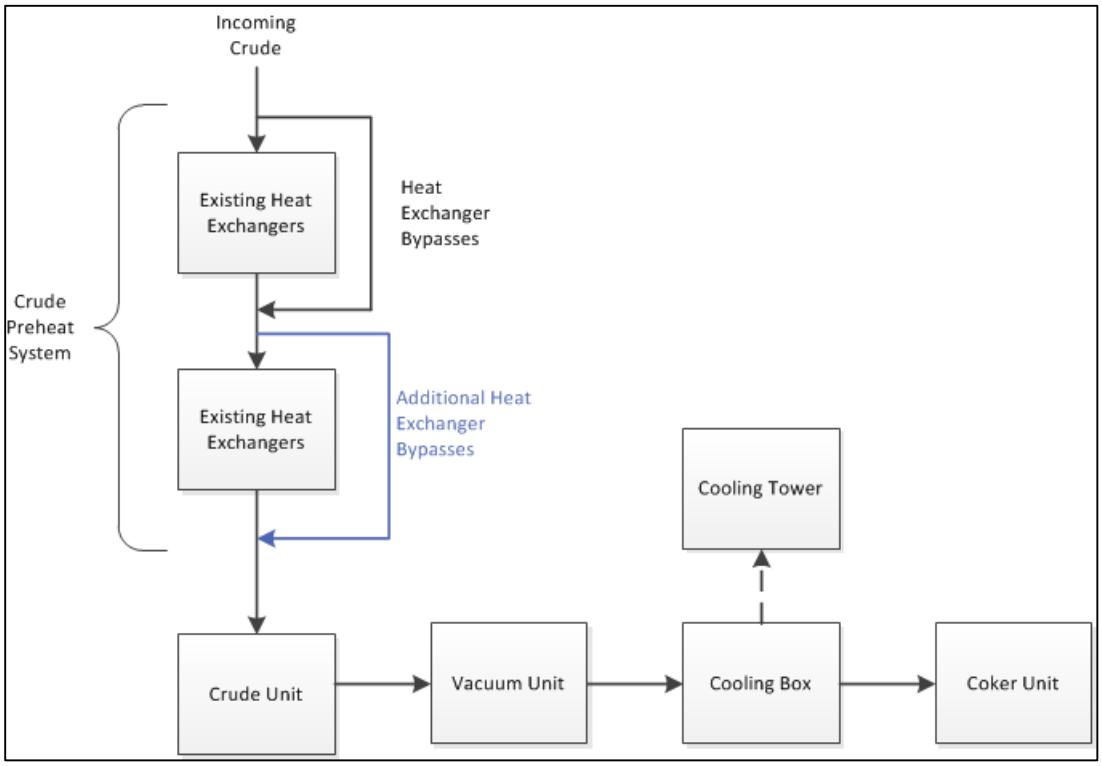



Figure 2-3. Simplified Diagram of Crude Preheat System

## 2.5 Project Effects on Existing Units

The conservative assumption that the coker unit will operate at capacity on an annual basis with the replacement coker heaters equates to a 22 percent increase in annual coker unit utilization (61.9 kbpd projected annual average throughput versus current 50.6 kbpd annual average throughput). Collectively, the online coker heater cleaning capability and new heat exchangers in crude preheat system could conservatively increase annual crude utilization by four percent (8 kbpd annual average). These projected increases in coker unit and crude unit annual utilization affect numerous other process units at the refinery, including:

- Increase utilization of cooling towers;
- Increased coke drum venting, cutting, and draining emissions;

[3] Based on historic fouling rates, BP has estimated that installing new heat exchangers in the crude preheat system could potentially recover an annual average of 5.1 kbpd over a crude unit six year cycle.

- Increased utilization of green coke handling activities;
- Increased utilization of calciners; and
- Increased utilization/heater duty for all process units at the refinery.
- Incremental increase in processing crudes with a larger residual oil component and incremental increases in coker intermediate feeds to hydrotreating units will deactivate catalysts at a faster rate than historical coker feeds. As a result, the time interval between catalyst replacements could be reduced, possibly leading to marginal increases in flaring emissions because of additional process unit shutdowns.

Figure 2-4 presents a general process flow diagram for the refinery and shows how process units are interconnected during normal operations. The colored lines represent different feeds and/or intermediates. There are multiple pathways for intermediates coming from the crude unit can take. In the projected actual emission calculations, BP has conservatively assumed each of intermediate pathway has a four percent increase in annual utilization; although this is physically impossible, this assumption presents a conservative projected actual emission calculations for the Project.

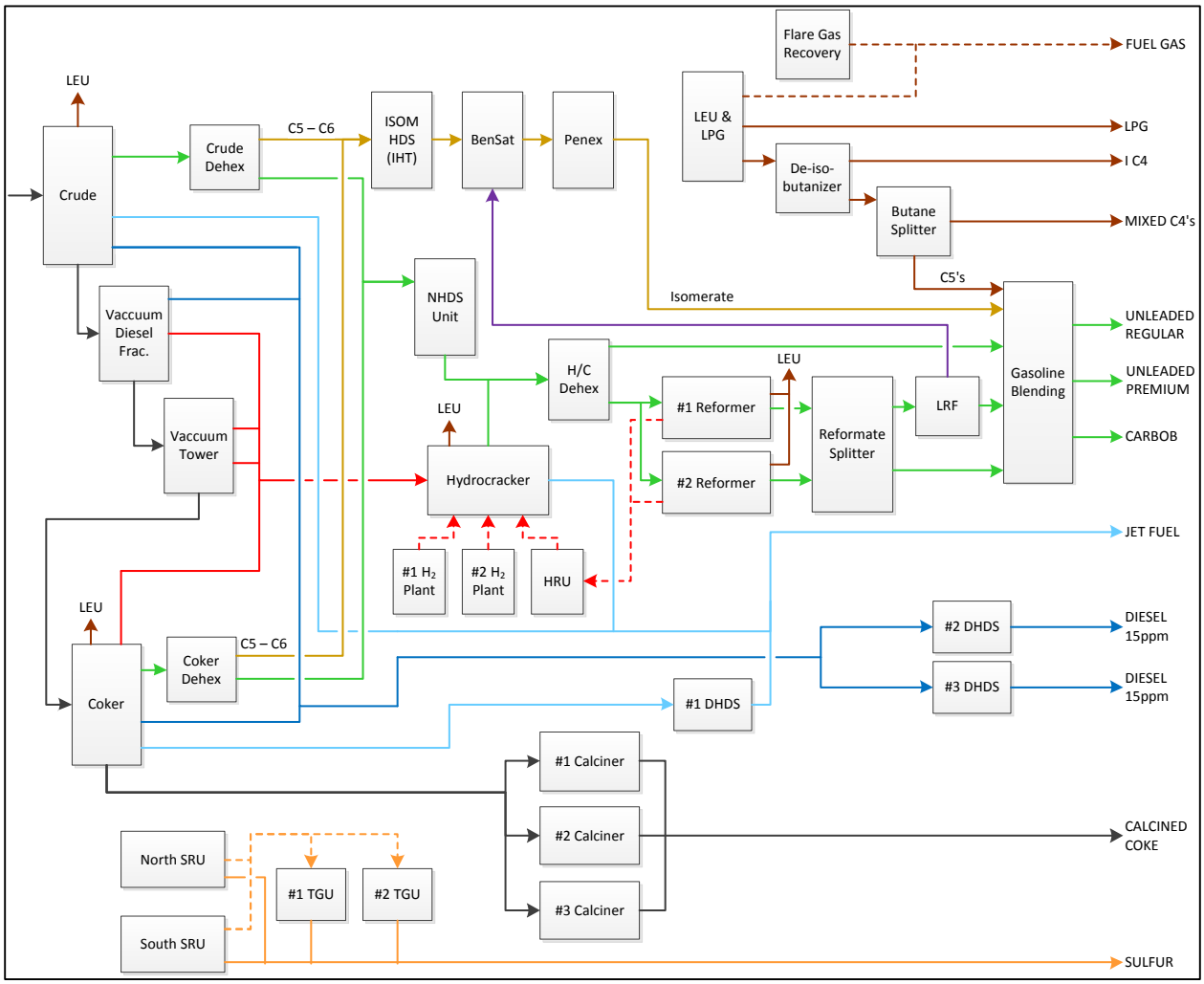



**Figure 2-4. Refinery Process Flow Diagram**

### 2.5.1 Coke Drum Venting, Cutting, and Draining

As a full coke drum is cooled the pressure within the drum begins to drop. Once the coke drum pressure is less than 5 psig, the coke drum vent valve is opened to atmosphere. Venting from the coker releases several PSD-regulated pollutants including: CO, VOC, $H_2S$, $PM_{10}$, $PM_{2.5}$, and $CH_4$. After the coke drum has vented to atmosphere, the coke is cut from the drum with a water jet. Cutting emissions include water vaporized during the cutting process and pollutants vaporized from the water (CO, VOC, $H_2S$, and $CH_4$). Particulate matter generated during the cutting process is negligible because of the amount of water used in the cutting process. Cutting water handling processes have the potential to release additional VOC and $H_2S$.

BP is conservatively projecting coker utilization will increase 22 percent on an annual basis. Higher utilization requires more frequent coke drum cycles (i.e. shorter coke drum cycle times) to handle the additional residual material on an annual basis. Coke drum cycles (filling, cooling, and cutting) will be approximately 14 hours per cycle to handle the additional crude on an

annual basis. There will be no increase in potential hourly emissions from coke drum venting, cutting, and draining because the coke drum venting pressure and associated water cutting and water handling equipment will not be modified. However, the shorter cycle times will result in more cutting/draining events thus annual emissions will increase due to the increased number of total cycles in a year.

### 2.5.2 Green Coke Handling

Green coke removed from the coke drum is transferred from the coke pit to a reclaim conveyor using cranes. The green coke is then stored inside the coke barns or shipped offsite. There are two green coke transfer points (crane conveyor to reclaim conveyor) that are not fully enclosed. BP is conservatively projecting a 22 percent increase in annual green coke throughput after the coker heaters are replaced. As a result, annual emissions will increase compared to historical emissions.

There will be no increase in potential hourly emissions from green coke handling because the system currently operates at maximum hourly capacity under certain operating conditions. Further, green coke handling equipment will not be modified. Green coke is periodically stored outside the two storage barns (typically as a result of calciner maintenance), but the Project is not expected to affect the amount of green coke that is periodically stored outside.

### 2.5.3 Calciners

BP operates three rotary hearths used to convert green coke generated by the Coker Unit into calcined coke products (anode grade). Green coke from the storage barns is transferred to the feed bin of each hearth. Inside the hearth, green coke is heated to temperatures between 2,400$^{o}$F and 2,700$^{o}$F to burn off VOCs and sulfur and to remove water. The calcined coke travels in circles until it reaches the center of the hearth and drops into coolers. After cooling, the calcined coke is transferred via enclosed conveyors to storage silos before loading into rail cars for shipment offsite.

Each hearth is equipped with a waste heat recovery system that transfers heat from hearth exhaust gas to the combustion air entering the calciner. In addition it produces 600 pound steam for the refinery. The exhaust gas is then sent to a caustic scrubber and wet electrostatic precipitator (WESP) before exhausting to atmosphere. Hearths 1 and 2 share the same scrubber, WESP, and stack. Hearth 3 has a separate caustic scrubber, WESP, and stack.

When a hearth is actively calcining coke, no supplemental fuel is necessary for operation. RFG is used as supplemental fuel during idle operation. BP is projecting a 22 percent increase in annual green coke throughput after the coker heaters are replaced. BP has assumed the calciners will operate at their maximum throughput rate for the entire year, an 18 percent increase in annual calcined coke throughput compared to past annual calciner throughput, resulting in increased annual emissions compared to historical calciner operations. Increased annual calciner usage will generate additional steam for the refinery. BP is not taking credit for the emission reductions from reduced boiler use as part of this permit application.

Calcined coke handling includes conveyors, silos, and rail loadout equipment. Dust pickups and baghouses are used to control particulate matter emissions generated during calcined coke

transfer activities. These baghouses currently operate continuously except for periodic maintenance. The baghouses will continue to operate continuously after the coker heaters are replaced (i.e., no change in operation).

There will be no increase in potential hourly emissions from the calciners or calcined coke handling equipment because they currently operate at capacity under certain operating conditions and because no part of the calciner unit will be modified.

### 2.5.4 Hydrocracker

The hydrocracker converts gas oils from the coker and vacuum section of the crude unit to diesel, jet fuel and gasoline blending stocks. The hydrocracker is comprised of two reaction stages and two fractionation stages. Reaction stages change the molecular structure of the feed. Fractionation stages use distillation to separate the material that is converted by the reactors. The hydrocracker contains four heaters, one for each stage. All heaters are fired by RFG. BP projects future emissions from the hydrocracker heaters based on each heater's rated firing rate for the entire year resulting in increased annual emissions compared to historical hydrocracker operations. The Clean Fuels Project (PSD-10-01 and OAC 1064) also conservatively projected the hydrocracker heaters will be fired at their maximum rate for the entire year.

There will be no increase in potential hourly emissions from any of the heaters because they currently fire at capacity under certain operating conditions and because the heaters will not be modified.

### 2.5.5 Diesel Hydrotreaters

There are three diesel hydro-desulfurization (DHDS) units at the refinery. The DHDS units process diesel with hydrogen in the presence of a catalyst to remove sulfur and nitrogen compounds. Each DHDS unit has a charge heater to maintain the reaction temperature. The #1 DHDS also has a stabilizer reboiler to help fractionate a portion of the process stream.

The Coker Unit provides feed (coker stove oil and light coker gas oil) to the DHDS units. BP has projected a 22 percent increase in annual coker utilization, which will increase feed into the DHDS units. However, emissions from the DHDS units will not increase because the hydro-desulfurization process is exothermic due to the energy released as part of treating feeds from the coker (one example is olefin saturation reactions). As a result, additional feed streams from the coker are expected to decrease annual charge heater duty in the hydrotreaters. BP is not taking credit for the emission reductions that will occur with higher hydrotreater utilization.

There will be no increase in potential hourly emissions from any of the heaters because they currently fire at capacity under certain operating conditions and because the heaters will not be modified.

### 2.5.6 Sulfur Plant

The sulfur plant is comprised of several units designed to recover $NH_3$, $H_2S$, and other sulfur containing compounds and then convert them to elemental sulfur, which is then sold offsite. There will not be any new tie-ins to the amine or the sour water headers as part of the Project.

BP has conservatively projected actual annual emissions based on full annual utilization of the sulfur plant at 270 long tons per day (LTD) for the entire year.

The existing sulfur plant is currently capable of operating at full capacity. In the past, the coker has operated at maximum capacity and the sulfur plant was capable of treating the sulfur intermediates from the coker. There will be no increase in potential hourly emissions from the sulfur plant because the plant is already operated at capacity under certain operating conditions. No sulfur plant modifications are required for this Project.

### 2.5.7 Other Refinery Process Heaters

As discussed previously, the 22 percent higher annual utilization of the coker unit could result in comparable increases in utilization at the ISOM and the naphtha hydrodesulfurization (NHDS) units. In addition, online cleaning of the replacement coker heaters is conservatively expected to eliminate three coker heater decokes per year. Because the crude unit operates at reduced rate for several days during each decoke, eliminating the coker shutdowns will increase the annual utilization of the crude unit and, to varying degrees, downstream process units.

Although the additional crude unit utilization will depend on the degree to which coker heater decoking events are avoided, this application conservatively assumes online cleaning in the replacement coker heaters will allow BP to process up to 1.4 percent more crude oil per year (2.9 kbpd). The addition of new heat exchanger bypasses in the crude unit is expected to reduce fouling in the crude unit and increase annual crude utilization by 2.4 percent (5.1 kbpd).[3] For all process units other than calciners, hydrocracker, #1 DHDS reboiler, ISOM, and NHDS, BP has conservatively estimated utilization will increase by four percent (8 kbpd) on an annual basis.

For process heaters other than those already addressed, projected annual emissions are calculated based on a four percent increase over the highest annual fuel usage in last ten years. Process heaters that could potentially see a four percent increase in annual fuel use include the Crude Heater, North Vacuum Heater, South Vacuum Heater, #1 & #2 Reformer Heaters, #1 Hydrogen Plant (reformer 1 & 2), and light ends unit. The higher firing rates are accounted for in the Project emissions calculations. There will be no increase in potential hourly emissions from any of the existing process heaters because they currently fire at capacity under certain operating conditions and because the heaters will not be modified.

A conservative approach is used to project emission increases for the entire refinery as a result of this Project. BP has projected a 22 percent increase in annual average coker utilization, but the cumulative increase in crude availability from online coker heater cleaning and reduced fouling in the crude unit will result in approximately 8 kbpd annual average increase in crude feed to the refinery. The increase in coker unit utilization will be greater than the projected increase in incoming crude feed. However, market conditions could lead to the four percent increase in annual crude unit utilization (8 kbpd annual average) to feed process units other than the coker unit. For this reason, projected emissions for all other refinery heaters are conservatively based on a four percent increase in utilization.

### 2.5.8 Boilers

The replacement coker heaters will require velocity steam from the 600 lb steam header during normal operation and steam will be required periodically for online cleaning and additional coke drum cycles. Overall, the Project will not require any additional steam generation from the boilers because the new coker heaters will provide steam to the 140 lb steam header and the increased utilization of the calciners will produce additional 600 lb steam. The calciners produce approximately 3,400 lb steam per ton of calcined coke. The projected increase in calcined coke production as part of the Project would add a significant amount of 600 lb steam to the refinery steam header. Overall, the utility boilers are expected to have reduced annual duty when the coker heaters are replaced. No reduction in boiler use was accounted for in the permit application or air quality modeling analysis.

### 2.5.9 Product Storage and Loading

There are a variety of tanks/vessels located at the refinery that store light liquids, crude oil, diesel, and intermediates. There are no new storage tanks proposed and no modifications to existing storage tanks proposed as part of the Project, but BP conservatively assumes online coker heater cleaning and the heat exchangers will allow BP to process up to four percent more crude oil per year. A four percent increase in annual crude utilization will result in marginal emission increases from storage tanks at the refinery.

Emissions generated during product loadout are controlled by vapor combustion units (VCUs). Projected emissions for the Project are conservatively projected a four percent increase in annual product loadout emissions from the truck loadout VCU and marine loadout VCU. No increases in short-term loadout operations or loadout emissions are anticipated and no new loadout equipment or modifications to existing loadout equipment are proposed as part of the Project.

### 2.5.10 Flaring

The ability to clean the proposed coker heaters online will reduce current flaring emissions associated with shutdown of a coker heater for offline cleaning. Offline cleaning of the existing coker heaters historically occurs approximately two to three times per year.

BP replaces catalysts in all hydrotreating units (hydrocracker, NHDS, ISOM, DHDS, etc.) on a schedule that varies between one to six years depending on the unit. With the potential of incrementally higher coker feeds to hydrotreaters that deactivate the catalysts at a higher rate than historic feeds, BP will potentially be required to replace hydrotreater catalysts on a slightly more frequent schedule. BP reviewed past flaring emissions from the shutdown and startup of the NHDS, ISOM, and DHDS process units. Projected actual flaring emissions are conservatively based on one additional process unit shutdown/startup event per year to replace catalyst due to increased utilization of the crude and coker units.

### 2.5.11 Wastewater

The wastewater treatment plant (WWTP) treats oil-contaminated water from various process units at the refinery. The replacement coker heaters will utilize velocity steam similar to the existing coker heater. The steam will be recovered as sour water, treated by the desalters in the crude unit and then sent to the WWTP. BP estimates a three percent increase in annual

wastewater plant utilization, but has conservatively based projected emission increases on seven percent increase in annual wastewater utilization resulting from the Project (coker heater velocity steam, 22 percent increased coker utilization, and four percent increase in crude utilization). BP has conservatively estimated a seven percent increase in annual fugitive emissions from the wastewater equipment, but there are no changes or modifications to any of the WWTP equipment as part of the project, and no changes to the NPDES permit are required as part of the project.[4] The increase in WWTP loading from the replacement coker heaters is expected to be minimal.

### 2.5.12 Cooling Towers

BP operates two non-contact cooling towers (#1 and #2 Cooling Towers) that are used to remove heat from refinery products. BP estimates an 8 percent increase in increased cooling tower utilization for the Project based on the following:

- One percent increase due to 31.5 million gallons per year from cooling residual oil transferred from the vacuum unit to the new coker heaters.

- Seven percent increase in annual cooling tower utilization resulting from increased coker utilization and increased crude utilization.

There are no changes or modifications to the cooling towers as part of the Project.

### 2.5.13 Crude Unloading

BP receives crude oil by ship, pipeline, and rail. BP conservatively assumes online coker heater cleaning and the new bypasses for crude unit heat exchangers will allow BP to process up to four percent more crude oil per year. Emissions generated transferring crude oil from the pipeline or rail cars to the refinery are limited to fugitive VOCs. Pumping crude oil from a vessel to the refinery requires operation of a ship engine and results in much higher secondary emissions than transferring crude from the pipeline or railcars. BP anticipates receiving additional crude through the existing pipeline, but BP has conservatively assumed a four percent increase in crude ship unloading (highest emissions of crude receiving options) as part of the Project.

Emissions from the vessel are considered secondary because they occur when a vessel is docked at the refinery. Secondary emissions are not accounted for in PSD applicability calculations, but they must be evaluated as part of the air quality impacts analysis.[5]

[4] October 21, 2015 letter correspondence from Department of Ecology to Ms. Higginson (BP).
[5] 40 CFR 52.21(b)(18)

# 3 Project Emissions

This section describes the emission rate increases attributable to the Project and the methods used to calculate potential emissions from the new coker heaters and annual emission increases from the affected emission units.

Criteria pollutants and PSD regulated pollutants include nitrogen oxides ($NO_X$); carbon monoxide (CO); sulfur dioxide ($SO_2$); particulate matter (PM); particulate matter with diameter less than 10 microns ($PM_{10}$), particulate matter with diameter less than 2.5 microns ($PM_{2.5}$), lead (Pb), volatile organic compounds (VOC), sulfuric acid mist ($H_2SO_4$), reduced sulfur compounds (hydrogen sulfide – $H_2S$), and greenhouse gases (carbon dioxide equivalent – $CO_2e$). There are other PSD regulated pollutants but they are not associated with the Project.

Washington's New Source regulations (WAC 173-400-110 and 173-460-040) require that any new source or modified source employ Best Available Control Technology for criteria pollutants (BACT) and toxic air pollutants (T-BACT). Table 3-1 summarizes the BACT analysis for the new coker heaters, and Appendix B presents an analysis of BACT for the new emission units. As discussed in Section 4.2, no existing units are physically or operationally modified as a result of the Project. Additional components will be added to accommodate the new heat exchanger bypasses and lean oil absorption system.

Table 3-2 presents the criteria and PSD regulated pollutant emission increases for the Project and compares the total emission increases to the PSD significant emission rate (SER) thresholds. The annual $NO_X$, CO, $SO_2$, PM, $PM_{10}$, $PM_{2.5}$, VOC, $H_2SO_4$, and $CO_2e$ emission rate increases are above the applicable SER thresholds, which require contemporaneous changes in emissions at the refinery be considered.[6]

When considering contemporaneous projects, both emissions increases and decreases must be considered within the contemporaneous period. The contemporaneous period begins five years prior to the anticipated date of construction and ends upon commencement of operations (180 day commissioning allowance). Because construction and operation of the new coker heaters is anticipated to be 2017 and 1st quarter 2019, the contemporaneous period extends from 2012 through 3rd quarter 2019 (with the commissioning period). A contemporaneous project is any project that has not been previously subject to PSD review.

[6] On June 23, 2014, the US Supreme Court issued a decision addressing limitations of regulating greenhouse gases within the existing federal PSD and Title V programs. The Supreme Court stated that a project cannot trigger the requirement to obtain a PSD permit for only greenhouse gases. However, if a project is already required to obtain a PSD permit for other regulated pollutants (i.e. $NO_X$, CO, etc.), then the regulating agency could continue limiting greenhouse emissions based on Best Available Control Technology (BACT) for project with emissions of $CO_2e$ over the 75,000 tpy $CO_2e$ significant emission rate. In this instance, the coker heater replacement project is already over the PSD significant emission rates for multiple regulated pollutants and BP has included $CO_2e$ in the BACT analysis for the project.

| Table 3-1: Project BACT Summary | | | |
|---|---|---|---|
| **Pollutant** | **Controls** | **BACT Limit** | **Mass Emission Rate** |
| **Coker Heater (per heater)** | | | |
| $NO_X$ | Ultra Low $NO_x$ Burners | **Balanced Draft**: 60 ppmdv (0% $O_2$) or 0.06 lb/MMBtu, 30-day rolling average<br>**Natural Draft**: 40 ppmdv (0% $O_2$) or 0.04 lb/MMBtu, 30-day rolling average | **Balanced Draft**: 18.2 lb/hr, calendar day average<br>**Natural Draft**: 12.1 lb/hr, calendar day average |
| CO | Good Combustion Practice | 33 ppmdv (0% $O_2$) or 0.020 lb/MMBtu, 30-day rolling average | 6.1 lb/hr, calendar day average |
| $SO_2$ | Fuel $H_2S$ Limits and $SO_2$ Limits | See Proposed Mass Emission Rate | 40.0 lb $SO_2$/hr (combined for both heaters), calendar day average |
| PM (filterable) | Good Combustion Practice | 0.0025 lb/MMBtu | 0.8 lb/hr |
| $PM_{10}$ (total) | Good Combustion Practice | 0.0100 lb/MMBtu | 3.0 lb/hr |
| $PM_{2.5}$ (total) | Good Combustion Practice | 0.0100 lb/MMBtu | 3.0 lb/hr |
| VOC | Good Combustion Practice | 0.0054 lb/MMBtu | 1.6 lb/hr |
| $H_2SO_4$ | Fuel $H_2S$ Limits | See Mass Emission Rate | 3.2 lb/hr (calendar day average) |
| $CO_2e$ | Heater Efficiency | 121 lb/MMBtu, annual average | 36,631 lb/hr, annual average |
| **Coker Heater and Heat Exchanger Components** | | | |
| VOC and $CO_2e$ | NSPS and Leak Detection and Repair | New Source Performance Standard Subparts GGGa and VVa | -- |

The BP Clean Fuels Project (PSD-10-01) triggered PSD review for $PM_{10}$ and addressed contemporaneous emission increases through commencement of operation of the #2 Hydrogen Plant and the #3 DHDS unit. Since commencement of #2 Hydrogen Plant and #3 DHDS operations, BP has had several minor modifications:

- Modification of the Sulfur Plant (OAC 1201a, dated April 16, 2015)
- Permit revision to increase Boiler #6 and #7 $PM_{10}$ short-term emission limits; (PSD-07-01, Amendment 2, dated February 24, 2016);
- #3 Calciner Heat Section Repair (Letter from Ecology on September 18, 2013);
- Rail Logistics Project (OAC #1142, dated January 22, 2013);
- Naphtha Reliability Improvement Project (OAC #1141, dated April 22, 2013);
- Hydrocracker Atmospheric Relief Vent Project (OAC #1122, dated April 9, 2012);
- Clean Fuels Project (OAC #1064, dated November 29, 2010);

- Hydrocracker 1st Stage Fractionator Reboiler – Burner Retrofit (OAC #1067, dated November 29, 2010); and

- The Hydrocracker R1 Heater firing rate increase (OAC #966b, dated April 21, 2011). Note that calculated potential emissions from the R1 heater are accounted for in the Coker Heater Replacement Project emission calculations as part of the projected actual hydrocracker emissions.

Retirement of the existing coker heaters will be contemporaneous change that will reduce emissions. The existing heaters will no longer operate once the replacement heaters start operation in 2019.

Table 3-3 summarizes the net $NO_X$, CO, $SO_2$, PM, $PM_{10}$, $PM_{2.5}$, VOC, $H_2SO_4$, and $CO_2e$ emission increases due to the Project and contemporaneous projects. With consideration of contemporaneous emission changes, the $NO_X$, CO, $SO_2$, PM, $PM_{10}$, $PM_{2.5}$, VOC, $H_2SO_4$, and $CO_2e$ emission increases exceed their respective SERs and these pollutants are therefore subject to PSD review (see additional discussion of PSD applicability in Section 4.2.1).

The contemporaneous period starts five years prior to commencing construction on the Project. BP plans commencing construction in 2017; therefore, the contemporaneous period will start in 2012. BP has a creditable $NO_X$ emission reduction from the Hydrocracker 1st Stage Fractionator Reboiler Burner Retrofit Project that occurred in May 2012 (startup period of reboiler with low $NO_X$ burners). BP's air quality impact analyses, presented in this application, conservatively do not include this creditable $NO_X$ emission reduction if construction on the Project does not occur until after May 2017.

In addition, the recently amended Boiler 6 and 7 short-term $PM_{10}$ emission limit increase and the recently permitted sulfur plant modification are included in the air quality impact assessment for the Project. The short-term emission limit modification for Boilers 6 and 7 does not result in changes to annual emissions so this change is not included as a contemporaneous emissions increase in Table 3-3. Both the coker heater replacement project and sulfur plant modification project assume full annual utilization of the sulfur plant; therefore, there are no contemporaneous emission increases/decreases for the sulfur plant in Table 3-3. Ecology determined the sulfur plant modification project is separate from the coker heater replacement project. [7]

Table 3-4 presents the increase in toxic air pollutant (TAP) emission rates for the proposed coker heaters compared to the existing coker heaters and compares TAP emission increases for the Project to the applicable Small Quantity Emission Rates (SQERS) prescribed by WAC 173-460. The SQER for each TAP is based on short-term (lb/hr or lb/24-hr) or long-term (lb/yr) emission increases. A TAP must be assessed in a dispersion modeling analysis if it is emitted at a rate that exceeds the applicable SQER. TAP emission rate calculations indicate that 15 TAPs emitted by the Project will exceed their respective SQERs. Section 5 of this permit application explains the methods used to model ambient TAP concentration impacts. Detailed

[7] Mr. Gary Huitsing (Ecology) issued a February 12, 2015 determination that the sulfur plant modification project should be considered separate and distinct from the Coker Heater Replacement Project.

emission rate calculations for each new and affected emission unit are included in Appendix C of this application.

**Table 3-2: Project Regulated Pollutant Emission Increases**

| | Coker Heaters [a] | Components Fugitives [a] | Coke Drum Venting Increase [b] | Green Coke Handling [b] | Calciners [b] | Hydrocracker [b] | Sulfur Plant [b] | Crude Heater [b] | North Vacuum Heater [b] | South Vacuum Heater [b] | #1 & #2 Reformer Heaters [b] | Naphtha Heaters [b] | #1 Hydrogen Plant [b] | #1 DHDS Reboiler [b] | ISOM [b] | Additional Affect Units [c] | Total Emission Increase | PSD SER [d] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Pollutant** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** |
| $NO_X$ | 159.3 | -- | -- | -- | 142.7 | 31.1 | 9.0 | 17.7 | 4.8 | 10.6 | 13.4 | 10.2 | 9.4 | 1.1 | 0.3 | 2.1 | 412 | 40 |
| CO | 90.9 | -- | 1.1 | -- | 2.7 | 28.5 | 51.4 | 1.4 | 1.0 | 0.04 | 0.041 | 8.6 | 7.9 | 0.065 | 0.04 | 1.5 | 195 | 100 |
| $SO_2$ | 132 | -- | -- | -- | 119.3 | 5.3 | 32.0 | 7.0 | -- | -- | -- | 0.03 | -- | -- | 0.02 | 0.2 | 296 | 40 |
| PM (filterable) | 6.6 | -- | 4.9 | 3.5 | 3.9 | 1.0 | 0.2 | 0.2 | 0.03 | 0.06 | 0.3 | 0.2 | 0.2 | 0.09 | 0.007 | 19.9 | 41 | 25 |
| $PM_{10}$ (total) | 26.5 | -- | 4.9 | 1.2 | 3.9 | 4.1 | 0.7 | 0.8 | 0.10 | 0.25 | 1.0 | 0.9 | 0.8 | 0.3 | 0.03 | 3.3 | 49 | 15 |
| $PM_{2.5}$ (total) | 26.5 | -- | 4.9 | 0.2 | 3.9 | 4.1 | 0.7 | 0.8 | 0.10 | 0.25 | 1.0 | 0.9 | 0.8 | 0.3 | 0.03 | 0.10 | 45 | 10 |
| VOC | 14.3 | 1.1 | 14.2 | -- | 0.2 | 2.6 | 0.3 | 0.5 | 0.06 | 0.16 | 0.2 | 0.6 | 0.5 | 0.2 | 0.02 | 13.3 | 48 | 40 |
| Pb | 1.3E-03 | -- | -- | -- | 6.4E-03 | 3.5E-04 | 3.8E-05 | 4.7E-05 | 5.8E-06 | 1.5E-05 | 5.7E-05 | 5.1E-05 | 4.7E-05 | 2.0E-05 | 1.7E-06 | 1.4E-06 | 0.008 | 0.6 |
| $H_2SO_4$ | 10.6 | -- | -- | -- | 31.8 | 0.9 | 1.3 | 0.12 | 0.014 | 0.036 | 0.14 | 0.12 | 0.12 | 0.05 | 0.004 | 0.006 | 45 | 7 |
| $H_2S$ | 0.03 | 0.1 | 4.0 | -- | -- | 0.02 | 0.1 | 0.002 | 4.0E-04 | 0.010 | 0.004 | 0.001 | 0.005 | 0.001 | 3.5E-05 | 0.2 | 4.4 | 10 |
| $CO_2e$ | 320,883 | 5.5 | 1,893 | -- | 183,866 | 87,296 | 23,220 | 11,587 | 1,432 | 3,583 | 13,932 | 12,547 | 17,432 | 4,883 | 419 | 388 | 683,367 | 75,000 |
| Fluorides | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | negligible | 3 |
| TRS | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | negligible | 10 |
| Reduced Sulfur Compounds | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | negligible | 10 |
| MW Comb. – Organics | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 0 | 3.5E-6 |
| MW Comb. – Metals | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 0 | 15 |
| MW Comb. – Acid Gases | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 0 | 40 |
| MSW Landfill – NMOC Emissions | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 0 | 50 |

Notes:

a New emission unit (Potential Annual Emission Rates). Component fugitives include new coker heater components and crude preheat system components.

b Increased utilization of existing emission unit (Projected Actual Emissions minus Baseline Emission Rates). Hydrocracker emission increases based on Potential Annual Emission Rates minus Baseline Emission Rates.

No expected increase in $SO_2$ emissions from the vacuum heaters, reformers, #1 hydrogen plant, or #1 DHDS reboiler (i.e. projected actual $SO_2$ emissions are less than baseline actual $SO_2$ emissions).

c Additional affected units include emission increases (projected actual emissions minus baseline actual emissions) for HP Flare, #1 & #2 Cooling Towers, Wastewater Treatment, storage tanks, and Product Loadout (truck, rail, and marine).

d Prevention of Significant Deterioration (PSD) Significant Emission Rates 40 CFR 52.21(b)(23).

## Table 3-3: PSD Netting Analysis

| | Project [a] | Remove Existing Coker Heaters [b] | Rail Logistics Project [c] | Naphtha Reliability Project [d] | #3 Calciner Convection Section [e] | Hydrocracker ARV Project [f] | Clean Fuels Project [g] | 1st Stage Fract. Reboiler Retrofit [h] | SRU Mod. [i] | Net Increase | PSD SER [j] | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Pollutant** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **(TPY)** | **Significant?** |
| $NO_X$ | 412 | -88.4 | -- | -- | 7.8 | -- | 22.4 | -87.7 | -- | 266 | 40 | Yes |
| CO | 195 | -10.7 | -- | -- | 0.3 | -- | 31.3 | -- | -- | 216 | 100 | Yes |
| $SO_2$ | 296 | -85.4 | -- | -- | 0.4 | -- | 10.0 | -- | -- | 221 | 40 | Yes |
| PM (filt.) | 41 | -6.5 | -- | -- | 0.2 | -- | 6.5 | -- | -- | 41 | 25 | Yes |
| $PM_{10}$ (total) | 49 | -6.5 | -- | -- | 0.2 | -- | -- | -- | -- | 43 | 15 | Yes |
| $PM_{2.5}$ (total) | 45 | -6.5 | -- | -- | 0.2 | -- | 23.4 | -- | -- | 62 | 10 | Yes |
| VOC | 48 | -4.7 | 4.5 | 0.1 | 0.02 | 0.1 | 30.3 | -- | -- | 79 | 40 | Yes |
| $H_2SO_4$ | 45 | -6.9 | -- | -- | 0.4 | -- | 0.4 | -- | -- | 39 | 7 | Yes |
| $CO_2e$ | 683,367 | -123,222 | -- | -- | 2,851 | -- | 534,796 | -- | -- | 1,097,792 | 75,000 | Yes |

Notes:

a Project (See Table 3-2 of this permit application for summary of emissions increases).

b BP will be permanently removing the existing two coker heaters as part of the proposed coker heater replacement project.

c NWCAA issued OAC #1142 for the Rail Logistics Project on January 22, 2013. BP started operation of the equipment in December 2013.

d NWCAA issued OAC #1141 for the Naphtha Reliability Project on April 22, 2013. BP has not started operation of the proposed modification.

e BP received a PSD exemption letter for the #3 Calciner Heat Section Repair Project on September 18, 2013.

f NWCAA issued OAC #1122 for the Hydrocracker ARV Project on Aril 9, 2012. BP installed the new components in May 2012.

g NWCAA issued OAC #1064 for the Clean Fuels Project on November 29, 2010. Ecology issued PSD-10-01 for $PM_{10}$ emissions from the project on December 13, 2010. BP started operation of the new equipment (#2 Hydrogen Plant and Flare and #3 DHDS Unit) in March 2013. Sulfur Plant and Hydrocracker heater emission increases projected in the Clean Fuels project are excluded from the contemporaneous netting because the same projected increases are already included in the emission calculations for the Project.

h NWCAA issued OAC #1067 for the burner retrofit on the Hydrocracker 1st Stage Fractionator Reboiler on November 29, 2010 (Rev. A on July 29, 2011). Startup of the new burner occurred in May 2012.

i NWCAA issued OAC #1201 for the sulfur plant modification on March 11, 2015 (Rev. A on April 16, 2015). Projected annual NOx, CO, $SO_2$, PM, $PM_{10}$, $PM_{2.5}$, VOC, $H_2SO_4$, and $CO_2e$ emission increases for the Coker Heater Replacement Project (Table 3-2) assume full utilization of the sulfur plant. There are no additional annual emission increases from the sulfur plant modification project to include in the PSD netting analysis.

j Prevention of Significant Deterioration (PSD) Significant Emission Rates 40 CFR 52.21(b)(23).

## Table 3-4: Project Toxic Air Pollutant Emissions

| Toxic Air Pollutant [a] | CAS # | Averaging Period | New Coker Heaters | New Components | Old Coker Heaters | Old Components | Total | SQER |
|---|---|---|---|---|---|---|---|---|
| | | | (lb/ave) | (lb/ave) | (lb/ave) | (lb/ave) | (lb/ave) | (lb/ave) |
| 1,3-Butadiene | 106-99-0 | year | -- | 0.2 | -- | -0.1 | 0.1 | 1.13 |
| Acetaldehyde | 75-07-0 | year | 63.7 | -- | -25.3 | -- | 38.4 | 71 |
| Acrolein | 107-02-8 | 24-hr | 0.25 | -- | -0.16 | -- | 0.09 | 0.00789 |
| Arsenic | 7440-38-2 | year | 1.0 | -- | -0.4 | -- | 0.6 | 0.0581 |
| Benzene | 71-43-2 | year | 10.93 | 0.40 | -4.3 | -0.2 | 6.8 | 6.62 |
| Beryllium | 7440-41-7 | year | 0.69 | -- | -0.24 | -- | 0.42 | 0.08 |
| Cadmium | 7440-43-9 | year | 5.7 | -- | -2.3 | -- | 3.5 | 0.0457 |
| CO | 630-08-0 | 1-hr | 150.0 | -- | -0.3 | -- | 149.7 | 50.4 |
| Chromium VI | 18540-29-9 | year | 0.3 | -- | -0.12 | -- | 0.18 | 0.00128 |
| Cobalt | 7440-48-4 | 24-hr | 1.2E-03 | -- | -7.5E-04 | -- | 4.5E-04 | 0.013 |
| Copper | 7440-50-8 | 1-hr | 5.1E-04 | -- | -3.2E-04 | -- | 1.9E-04 | 0.219 |
| Cumene | 98-82-8 | 24-hr | -- | 0.0017 | -- | -0.0010 | 6.7E-04 | 52.6 |
| Cyclohexane | 110-82-7 | 24-hr | -- | 0.0047 | -- | -0.003 | 0.0019 | 789 |
| Dichlorobenzene | 106-46-7 | year | 6.2 | -- | -2.5 | -- | 3.8 | 17.4 |
| Diethanolamine | 111-42-2 | 24-hr | -- | 0.0012 | -- | -0.0007 | 0.0005 | 0.394 |
| Ethylbenzene | 100-41-4 | year | 84.9 | 1.08 | -33.7 | -0.65 | 51.7 | 76.8 |
| Formaldehyde | 50-00-0 | year | 390.3 | -- | -154.8 | -- | 235.5 | 32 |
| Hexane | 110-54-3 | 24-hr | 25.7 | 0.004 | -16.1 | -0.002 | 9.6 | 92 |
| Hydrogen Sulfide | 7783-06-4 | 24-hr | 0.2 | 0.5976 | -0.2 | -0.4 | 0.3 | 0.263 |
| H2SO4 | 7664-93-9 | 24-hr | 77.3 | -- | -57.8 | -- | 19.6 | 0.131 |
| Lead | 7439-92-1 | year | 2.6 | -- | -1.0 | -- | 1.6 | 16 |
| Manganese | 7439-96-5 | 24-hr | 0.005 | -- | -0.003 | -- | 0.002 | 0.00526 |
| Mercury | 7439-97-6 | 24-hr | 0.004 | -- | -0.002 | -- | 1.4E-03 | 0.0118 |
| Naphthalene | 91-20-3 | year | 3.2 | 5.1 | -1.3 | -3.1 | 3.9 | 5.64 |
| Nickel | 7440-02-0 | year | 10.9 | -- | -4.3 | -- | 6.6 | 0.806 |
| NOx | 10102-44-0 | 1-hr | 36.4 | -- | -30.4 | -- | 6.0 | 1.03 |
| Phenol | 108-95-2 | 24-hr | 0.06 | -- | -0.04 | -- | 0.022 | 26.3 |
| Propylene | 115-07-1 | 24-hr | 2.2 | 0.05 | -1.4 | -0.03 | 0.8 | 394 |

## Table 3-4: Project Toxic Air Pollutant Emissions

| Toxic Air Pollutant [a] | CAS # | Averaging Period | New Coker Heaters | New Components | Old Coker Heaters | Old Components | Total | SQER |
|---|---|---|---|---|---|---|---|---|
| | | | (lb/ave) | (lb/ave) | (lb/ave) | (lb/ave) | (lb/ave) | (lb/ave) |
| Selenium | 7782-49-2 | 24-hr | 1.3E-02 | -- | -8.0E-03 | -- | 4.8E-03 | 2.63 |
| SO2 | 7446-09-05 | 1-hr | 40.0 | -- | -29.9 | -- | 10.1 | 1.45 |
| Toluene | 108-88-3 | 24-hr | 0.05 | 0.007 | -0.03 | -0.004 | 0.02 | 657 |
| Vanadium | 7440-62-2 | 24-hr | 0.03 | -- | -0.02 | -- | 0.012 | 0.0263 |
| Xylenes | 106-42-3 | 24-hr | -- | 0.012 | -- | -0.007 | 0.005 | 29 |
| Benz(a)anthracene | 56-55-3 | year | 0.117 | -- | -0.046 | -- | 0.070 | 1.74 |
| Benzo(a)pyrene | 50-32-8 | year | 0.303 | -- | -0.120 | -- | 0.183 | 0.174 |
| Benzo(b)fluoranthene | 205-99-2 | year | 0.143 | -- | -0.057 | -- | 0.086 | 1.74 |
| Benzo(k)fluoranthene | 207-08-9 | year | 0.090 | -- | -0.036 | -- | 0.054 | 1.74 |
| Chrysene | 218-01-9 | year | 0.008 | -- | -0.003 | -- | 0.005 | 17.4 |
| Dibenzo(a,h)anthrancene | 53-70-3 | year | 0.006 | -- | -0.002 | -- | 0.004 | 0.16 |
| Indeno(1,2,3-cd)pyrene | 193-39-5 | year | 0.377 | -- | -0.149 | -- | 0.227 | 1.74 |
| 3-Methylcholanthrene | 56-49-5 | year | 0.009 | -- | -0.004 | -- | 0.006 | 0.0305 |
| 7,12-Dimethylbenz[a]anthracene | 57-97-6 | year | 0.08 | -- | -0.03 | -- | 0.05 | 0.00271 |

Notes:

a Toxic Air Pollutants defined in WAC 173-460.

lb/s/ave = pounds per averaging period

## 3.1 New Emission Units

This section discusses how maximum short term and potential annual criteria pollutant and TAP emissions are calculated for each new emission unit. As discussed in Project Description, no existing emission units at the refinery are being modified as part of the Project. Fugitive VOC emissions will be generated due to component leaks.

The primary source of emissions from the replacement coker heater is combustion of gaseous fuels, which include coker off gas and RFG. Coker off gas is generated by the Coker Unit, and RFG is generated at the refinery and supplemented with natural gas.

### 3.1.1 Replacement Coker Heaters

Each of the two replacement coker heaters have burners rated at 303 MMBtu/hr (HHV) maximum heat input and can be fired by coker off gas, refinery fuel gas or natural gas. The replacement coker heaters will also have some additional components compared to the existing coker heaters because BP is implementing Safety Instrumented System (SIS) and a new heater design.

Combustion emissions from the coker heaters are based on coker off gas sulfur content, RE's BACT analysis and AP-42 Section 1.4, natural gas combustion (July 1998), emission factors. The AP-42 Section 1.4 emission factors are provided in pound pollutant per million cubic feet (lb/MMscf) natural gas. RE divided the AP-42 emission factors by the referenced natural gas heat content (1020 Btu/scf) to normalize the emission factors by heat input rate.[8] Short-term potential emissions from the coker heaters are based on the maximum heat input rate, and annual emissions are based on continuous operation (8,760 hours per year).

Criteria pollutant emissions for the proposed new coker heaters are presented in Table 3-5. $NO_X$ emissions for balanced draft and natural draft operations modes are based on NSPS Ja emission limits of 60 ppmdv 0% $O_2$ (0.06 lb/MMBtu) and 40 ppmdv 0% $O_2$ (0.04 lb/MMBtu), respectively. CO emissions of 33 ppmdv 0% $O_2$ (0.02 lb/MMBtu) are based on vendor guarantees for the expected burners at normal operation. The heaters will normally be operating as balanced draft with the same emissions as a forced draft furnace and this is the basis for the potential emission calculations. However, the heaters can also operate in natural draft mode. If the induced draft fan is not available, the heater will operate in natural or forced draft mode. The balanced draft heater design is based on the use of an air preheater that will allow the heater to have a thermal efficiency close to 90 percent.

During the initial heater commissioning, BP will be required to slowly dry the heater refractory before the coker unit can startup and begin processing residual oil. This is a one-time event that will occur over approximately one week. Subsequent refractory drying may occur over a couple days after a turnaround/maintenance on the coker heaters, which is only planned to occur every 5 to 6 years. EPA has clarified that certain pre-startup activities are required to ready heaters for service and do not qualify as "startup" of an emission unit.[9] Pre-startup

[8] The method used to convert natural gas combustion emission factors from "lb/MMscf" to "lb/MMBtu" is discussed in AP-42 Section 1.4.

[9] Manual for Clarification of Startup in Source Categories Affected by New Source Performance Standards (EPA-68-01-4143) and EPA Applicability Determination Index (ADI) Control Number 0700030.

activities include curing refractory, general mechanical checkout of equipment, instrument system review, pressure testing, and purging equipment.

Heater startup will be short in duration, approximately 12 hours per startup event. The first step in the heater startup is to operate a few of the main burners in the heater and all the burner pilots. Hot residual oil will be recycled through the heater tubes to warm-up the unit. Then, all of main burners in the heater will be fired to start the coking process and send material to the coke drums. The heater startup process must occur quickly once the heater burners are fired or BP risks sending un-coked residual oil into the coke drums. During heater startup, $NO_X$ and CO concentrations in the heater exhaust will be higher than normal operations.

CO concentration and mass emissions from the heaters will be higher during startup/shutdown (400 ppm and 75 lb/hr, per heater) compared to normal operation (33 ppm and 6.1 lb/hr, per heater). BP proposes an alternative startup and shutdown CO emission limit of 75.0 lb/hr per heater.[10] BP proposes to comply with the same $NO_X$ concentration and mass emissions limits (calendar day average mass emission limits and 30-day rolling average concentration limits) during startup/shutdown and normal operations.

Coker unit and the crude unit maintenance generally occur during a turnaround. However, a scheduled or unscheduled shutdown of the crude unit requires the coker unit to operate in standby mode. Standby operation includes operating only one coker heater, limiting heater firing rate to less than 120 MMBtu/hr, and recycling hot residual oil through the coker fractionator column. No coking occurs while the unit is in standby operations. If both heaters are shutdown and the fractionator column cools, heavy material in the column will solidify and BP personnel will need to enter the column and manually shovel the solids out before the coker unit can restart operation.

In standby operations, the one coker heater at reduced firing rate would have higher $NO_X$ and CO concentrations in the coker heater exhaust compared to concentrations during normal operation. BP proposes standby $NO_X$ and CO mass emission limits of 8.0 lb/hr and 75.0 lb/hr per heater, respectively.

In addition to the BACT limits established in the PSD permit, NSPS Subpart Ja includes a $NO_X$ concentration limit and BP will submit a separate request to the NSPS Subpart Ja Administrator for an alternative mass-based $NO_X$ emission limit for coker heater standby operations.

BP estimates the coker unit would operate in standby mode two – four times during a six year period. Standby operations could last for a few days or weeks. BP tries to avoid conditions where the coker unit is in standby operations, but BP also recognizes the need to propose emission limits covering a range of potential coker unit operation modes.

The existing coker heaters require offline cleaning two or three times per year and require maintenance (turnaround) every three years. Each replacement coker heaters will have online cleaning capability (spalling) to reduce the frequency and time required for offline cleaning.

[10] Washington Startup and Shutdown limit regulations discussed in WAC 173-400-081.

BP's estimates that each replacement coker heater will require offline cleaning once per year and heater maintenance will be completed every three years.

Calculation of $SO_2$ emissions from the new heaters are based on measured coker off gas sulfur with an allowance for mercaptan concentration fluctuations. Short-term and annual $SO_2$ emissions are based on sulfur in coker off gas after passing through the lean oil absorption system. BP estimates an annual average $SO_2$ emission factor of 36 ppmdv 0 percent $O_2$ (0.050 lb $SO_2$/MMBtu) based on computer modeling of future operating scenarios.

The sulfur content of the coker off gas can fluctuate with feed stocks, heater temperatures, residence time in coke drums, and the new lean oil absorption system operating conditions. The coker unit operates as a batch process, with coke drum switches two times per day, and coker off gas composition can change with each coke drum switch. The lean oil absorption system included with this Project reduces $SO_2$ emissions from the coker heaters during normal operations by recovering hydrocarbons (including mercaptans) from the coker off gas for additional downstream processing into products. BP as a company only has one operational lean oil absorption system recovering products from coker off gas.

Lean oil absorption technology is based on recovering liquids from the off gas. Higher molecular weight sulfur compounds (i.e. mercaptans) will be recovered with liquids in the coker off gas. Low molecular weight sulfur compounds will not be recovered in the lean oil system and will be burned as coker off gas in the coker heaters. The residual feed to the coker unit is the primary source of low molecular weight sulfur compounds, and the coking process will also generate some additional low molecular weight compounds. Computer based modeling of future coker operating scenarios indicates a high level of confidence the replacement coker heaters will comply with the proposed short-term and long-term $SO_2$ emission limits.

There will be instances when regular maintenance of the lean oil system (column, compressor, cooler, etc.) or a downstream unit (i.e. naphtha unit handling recovered gas from lean oil absorption system) precludes operation of the lean oil absorption system, resulting in possible higher sulfur concentrations in the coker off gas fuel to the coker heaters.

Instead of proposing a short-term $SO_2$ emission limit of 20 lbs per hour for each heater, BP requests a 40 lb/hr (daily average) combined $SO_2$ emission limit for the two coker heaters. The combined short-term emission limit allows BP operational flexibility when sulfur concentrations in the coker off gas increase due variability in feedstock, lean oil absorption system operation, etc. When such elevated sulfur concentrations in the coker off gas occur, the aggregate $SO_2$ limit would provide BP the flexibility to reduce coker heater firing rates/throughput rates or operate a single coker heater (two coke drums) to reduced combined $SO_2$ emissions from the coker heaters.

BP requests a daily averaging period for short-term $SO_2$ emissions because of the time required to safely adjust coker unit flows. Batch process operation limits how quickly the coker operators can reduce the coker unit throughput if elevated sulfur concentrations are measured in the coker off gas. Coker unit operations are changed over the course of several hours to reduce the chance of causing an upset condition in upstream process units.

$H_2SO_4$ emissions are based on 2.63 percent sulfur emitted as $H_2SO_4$ based on source tests of RFG combustion units at the Refinery.

Particulate matter emission factors are based on source test of the #2 and #3 DHDS charge heaters fired on RFG. BP conducted $PM_{10}$ source tests (EPA Methods 5 and 202/OTM28) of the RFG -fired charge heaters in 2009 and 2013. The average $PM_{10}$ emission factors (filterable and condensable portions) reported from the source tests range from 0.008 – 0.009 lb/MMBtu heat input. The condensable fraction of $PM_{10}$ averages 78 percent of total $PM_{10}$. Individual test runs were as high as 0.01 lb/MMBtu. The $PM_{10}$ emission factor used in this permit application (0.010 lb/MMBtu) is conservatively based on the higher range of the BP source test results and includes both filterable and condensable particulate matter. Because both AP-42 guidelines and BP source tests indicate the condensable fraction is about 75 percent of total $PM_{10}$, PM emissions are calculated with an emission factor of 0.0025 lb/MMBtu (25 percent of the total $PM_{10}$). $PM_{2.5}$ emissions are conservatively based on the $PM_{10}$ emission factor. No change in emissions is expected during online cleaning of the coker heaters because all material is sent to the coke drums and results in green coke or overhead gas.

$H_2S$ emissions are based on the average of 2012 and 2013 measurements of H2S in coker off fuel gas and assuming 99 percent control through heater combustion (one percent remaining in coker heater exhaust gas). $CO_2$ emissions are based on sampling the carbon content of the coker off gas and assuming all carbon in the off gas converts to $CO_2$. Methane ($CH_4$) and nitrous oxide ($N_2O$) emissions are based on AP-42 Section 1.4 emission factors converted to "lb/MMBtu". $CO_2e$ emissions are calculated based on global warming potential (GWP) for each greenhouse gas from EPA's mandatory greenhouse gas reporting rule.[11]

TAP emissions are based on emission factors for heaters combusting natural gas/refinery fuel gas summarized in EPA's refinery emission calculation protocol, which includes AP-42 Section 1.3 emission factors and test data collected by the American Petroleum Institute (API) in conjunction with the Western States Petroleum Association (WSPA).[12] TAP emissions from the coker heaters are presented in Table 3-6.

[11] 40 CFR Part 98, Subpart A specifies GWP values for all regulated greenhouse gases ($CO_2$ = 1; $CH_4$ = 25; and $N_2O$ = 298).

[12] EPA's Refinery Emission Calculation Protocol can be found at http://www3.epa.gov/ttnchie1/efpac/protocol/

## Table 3-5: Coker Heater Potential to Emit

| Pollutant | Emission Factor | | Potential Emissions (1 Heater) [a] | | Potential Emissions (2 Heaters) [a] | |
|---|---|---|---|---|---|---|
| | (ppmvd) | (lb/MMBtu) | (lb/hr) | (tpy) | (lb/hr) | (tpy) |
| $NO_X$ [b] (balanced draft) | 60 (0% $O_2$) | -- | 18.2 | 79.6 | 36.4 | 159.3 |
| $NO_X$ [b] (natural draft) | 40 (0% $O_2$) | -- | 12.1 | 53.1 | 24.2 | 106.2 |
| CO (normal) [b] | 33 (0% $O_2$) | -- | 6.1 | 45.4 | 12.1 | 90.9 |
| CO (su/sd/standby) [b] | -- | -- | 75.0 | | 150.0 | |
| $SO_2$ (1-hr & 24-hr) [c] | -- | -- | -- | -- | 40.0 | -- |
| $SO_2$ (annual) [c] | 36 (0% $O_2$) | 0.050 | -- | 66.0 | -- | 132 |
| PM (Filterable) [d] | -- | 0.0025 | 0.76 | 3.3 | 1.5 | 6.6 |
| $PM_{10}$ (Total) [d] | -- | 0.0100 | 3.0 | 13.3 | 6.1 | 26.5 |
| $PM_{2.5}$ (Total) [d] | -- | 0.0100 | 3.0 | 13.3 | 6.1 | 26.5 |
| VOC [e] | -- | 0.0054 | 1.6 | 7.2 | 3.3 | 14.3 |
| Lead [e] | -- | 4.9E-07 | 1.5E-04 | 6.5E-04 | 3.0E-04 | 1.3E-03 |
| $H_2SO_4$ [f] | -- | -- / 0.0040 | -- | 5.3 | 3.2 | 10.6 |
| $H_2S$ [f] | -- | -- | 0.005 | 0.016 | 0.010 | 0.033 |
| $CO_2$ [g] | -- | 120.2 | 36,419 | 159,514 | 72,837 | 319,028 |
| $CH_4$ [e] | -- | 0.0023 | 0.68 | 3.0 | 1.37 | 5.99 |
| $N_2O$ [e] | -- | 0.0022 | 0.65 | 2.9 | 1.31 | 5.72 |
| $CO_2e$ [g] | -- | 120.9 | 36,631 | 160,442 | 73,261 | 320,883 |

Notes:

a Potential short-term emission rates (lb/hr) based on maximum burner capacity (303 MMBtu/hr) per heater, and annual emissions based on continuous operation (8,760 hours/year).

b $NO_x$ and CO emissions based on proposed BACT. CO startup/shutdown/standby emissions based on 75 lb/hr and conservative estimate of 504 hours of operation in startup/shutdown/standby modes per year.

c $SO_2$ emission factors based on short-term and long-term expected sulfur concentration in coker off gas. BP proposes a combined short-term $SO_2$ emission limit of 40 lb/hr for the two replacement coker heaters.

d $PM_{10}$ and $PM_{2.5}$ emission factor based on refinery source test data. PM emission factors based on 25 percent of $PM_{10}$ emission rate (No.2 Diesel and No.7 Boiler Source Test Results, fraction of filterable particulate in total particulate).

e VOC, Lead, $CH_4$, and $N_2O$ emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf).

f $H_2SO_4$ emission factors based on 2.63 percent of sulfur in fuel gas converting to $H_2SO_4$ (source testing results for #1 Reformer fired by RFG). $H_2S$ emissions based on 2012 and 2013 average ratio of $H_2S$ emissions to $SO_2$ emissions (0.0002 $H_2S$:$SO_2$).

g $CO_2$ emission factor based on coker off gas fuel analysis and 100 percent conversion of carbon in fuel to $CO_2$. CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: $CO_2$ = 1; $CH_4$ = 25; and $N_2O$ = 298 (40 CFR Part 98, Subpart A).

## Table 3-6: Coker Heater Toxic Air Pollutant Potential to Emit

| Toxic Air Pollutant | CAS # | Emission Factor [a] | Potential Emissions (2 Heaters) [b] | | |
|---|---|---|---|---|---|
| | | (lb/MMBtu) | (lb/hr) | (lb/day) | (tpy) |
| Acetaldehyde [e] | 75-07-0 | 1.2E-05 | 7.3E-03 | 1.7E-01 | 3.2E-02 |
| Acrolein [e] | 107-02-8 | 1.7E-05 | 1.0E-02 | 2.5E-01 | 4.5E-02 |
| Arsenic | 7440-38-2 | 2.0E-07 | 1.2E-04 | 2.9E-03 | 5.2E-04 |
| Benzene | 71-43-2 | 2.1E-06 | 1.2E-03 | 3.0E-02 | 5.5E-03 |
| Beryllium [e] | 7440-41-7 | 1.3E-07 | 7.9E-05 | 1.9E-03 | 3.5E-04 |
| Cadmium | 7440-43-9 | 1.1E-06 | 6.5E-04 | 1.6E-02 | 2.9E-03 |
| CO [c] | 630-08-0 | -- | 150.0 | 3,600 | 90.9 |
| Chromium VI [d] | 18540-29-9 | 5.5E-08 | 3.3E-05 | 8.0E-04 | 1.5E-04 |
| Cobalt | 7440-48-4 | 8.2E-08 | 5.0E-05 | 1.2E-03 | 2.2E-04 |
| Copper | 7440-50-8 | 8.3E-07 | 5.1E-04 | 0.012 | 2.2E-03 |
| Dichlorobenzene | 106-46-7 | 1.2E-06 | 7.1E-04 | 0.017 | 3.1E-03 |
| Ethylbenzene [e] | 100-41-4 | 1.6E-05 | 9.7E-03 | 2.3E-01 | 4.2E-02 |
| Formaldehyde | 50-00-0 | 7.4E-05 | 0.045 | 1.07 | 0.195 |
| Hexane | 110-54-3 | 1.8E-03 | 1.07 | 25.67 | 4.68 |
| $H_2S$ [c] | 7783-06-4 | -- | 0.01 | 0.24 | 0.04 |
| $H_2SO_4$ [c] | 7664-93-9 | 0.0053 / 0.0046 | 3.22 | 77.32 | 10.6 |
| Lead | 7439-92-1 | 4.9E-07 | 3.0E-04 | 7.1E-03 | 1.3E-03 |
| Manganese | 7439-96-5 | 3.7E-07 | 2.3E-04 | 5.4E-03 | 9.9E-04 |
| Mercury | 7439-97-6 | 2.5E-07 | 1.5E-04 | 3.7E-03 | 6.8E-04 |
| Naphthalene | 91-20-3 | 6.0E-07 | 3.6E-04 | 8.7E-03 | 1.6E-03 |
| Nickel | 7440-02-0 | 2.1E-06 | 1.2E-03 | 0.030 | 5.5E-03 |
| $NO_X$ [c] | 10102-44-0 | 6.0E-02 | 36.36 | 872.64 | 159.26 |
| Phenol [e] | 108-95-2 | 4.0E-06 | 2.4E-03 | 5.8E-02 | 1.1E-02 |
| Propylene [e] | 115-07-1 | 1.5E-04 | 9.1E-02 | 2.2E+00 | 4.0E-01 |
| Selenium [e] | 7782-49-2 | 8.8E-07 | 5.3E-04 | 1.3E-02 | 2.3E-03 |
| $SO_2$ [c] | 7446-09-05 | -- | 40.00 | 960.00 | 132 |
| Toluene | 108-88-3 | 3.3E-06 | 2.0E-03 | 0.04848 | 8.8E-03 |
| Vanadium | 7440-62-2 | 2.3E-06 | 1.4E-03 | 0.033 | 6.0E-03 |
| Benz(a)anthracene [e] | 56-55-3 | 2.2E-08 | 1.3E-05 | 3.2E-04 | 5.8E-05 |
| Benzo(a)pyrene [e] | 50-32-8 | 5.7E-08 | 3.5E-05 | 8.3E-04 | 1.5E-04 |
| Benzo(b)fluoranthene [e] | 205-99-2 | 2.7E-08 | 1.6E-05 | 3.9E-04 | 7.2E-05 |
| Benzo(k)fluoranthene [e] | 207-08-9 | 1.7E-08 | 1.0E-05 | 2.5E-04 | 4.5E-05 |
| Chrysene [e] | 218-01-9 | 1.6E-09 | 9.7E-07 | 2.3E-05 | 4.2E-06 |
| Dibenzo(a,h)anthrancene | 53-70-3 | 1.2E-09 | 7.1E-07 | 1.7E-05 | 3.1E-06 |
| Indeno(1,2,3-cd)pyrene [e] | 193-39-5 | 7.1E-08 | 4.3E-05 | 1.0E-03 | 1.9E-04 |
| 3-Methylcholanthrene | 56-49-5 | 1.8E-09 | 1.1E-06 | 2.6E-05 | 4.7E-06 |
| 7,12-Dimethylbenz[a]anthracene | 57-97-6 | 1.6E-08 | 9.5E-06 | 2.3E-04 | 4.2E-05 |

Notes:

a TAP emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf).

b Potential hourly emission rates (lb/hr) based on maximum burner capacity (303 MMBtu/hr per heater) and two coker heaters, daily emission rates (lb/day) based on 24 hours operation per day, and annual emissions based on continuous operation (8,760 hours/year).

c $NO_X$, CO, $SO_2$, $H_2S$, and $H_2SO_4$ emissions discussed in Table 3-5. CO short-term emissions based on startup/shutdown/standby operations.

| Table 3-6: Coker Heater Toxic Air Pollutant Potential to Emit | | | | | |
|---|---|---|---|---|---|
| Toxic Air Pollutant | CAS # | Emission Factor [a] | Potential Emissions (2 Heaters) [b] | | |
| | | (lb/MMBtu) | (lb/hr) | (lb/day) | (tpy) |
| d EPA's 2002 National-Scale Air Toxics Assessment (NATA) released June 2009 includes a chromium speciation profile for gas-fired process heaters, which indicates 4 percent of total chromium is chromium VI and 96 percent is chromium III. RE assumed 4 percent of total chromium emissions were emitted as chromium VI. | | | | | |
| e TAP emission factors from Hansell and England, 1998 (EPA's Emissions Estimation Protocol for Petroleum Refineries, August 2014). | | | | | |

### 3.1.2 New Components

In addition to combustion emissions, there will be fugitive VOC and TAP emissions from components that carry streams of VOCs through the replacement coker heaters, lean oil absorption system, cooling box, and new bypass components in the preheat section of the crude unit. Appendix C documents the emission calculation procedure, which is based on the estimated component counts, actual Refinery leak rate data, and chemical speciation. BP anticipates maximum fugitive emissions from leaking coker heater components of 1.0 tons VOC per year. An additional 10 percent increase in fugitive VOC emissions (0.1 tpy) is calculated to account for components associated with the cooling box, lean oil absorption system, and heat exchanger bypasses. The majority of the new components will be part of the coker off gas system, and the worst-case chemical composition from RFG is used to calculate TAP emission rates from component leaks. Potential fugitive $H_2S$ emissions from the new components are calculated based on the VOC leak rate for each component and a conservative 10 percent $H_2S$ concentration in the leaking VOC refinery streams.

## 3.2 Existing Emission Units

A number of existing emission units at the refinery will be affected by the increase in coker unit and crude unit utilization. Projected emission increases or decreases are calculated for each affected emission unit by subtracting baseline actual emissions from the projected actual or potential annual emissions (i.e. emissions after implementation of the Project). RE excluded emissions from the projected actual emission rates that 1) could have been accommodated prior to the Project and 2) that are unrelated to the Project.[13] The market for different petroleum products changes from season to season and year to year. These market demand changes affect process unit utilization and result in higher or lower emissions from emission units throughout the refinery.

The baseline is a rolling 24-month annual average emission rate for each regulated pollutant. The baseline periods for this evaluation are selected from within a 10 year period ending once a complete permit application is received by the reviewing agency (assumed 2007 – 2016). Baseline actual emissions for each affected emission unit are included in Appendix C. The baseline periods selected for this PSD applicability evaluation include:

- $NO_X$ – 2011 through 2012;

[13] 40 CFR 52.21(b)(41)(ii)(c)

- CO, PM, $PM_{10}$, $PM_{2.5}$, $CO_2e$, and lead – 2010 through 2011;
- $SO_2$ – 2008 through 2009;
- $H_2SO_4$ – 2013 through 2014; and
- VOC and $H_2S$ – 2012 through 2013.

Projected emissions and baseline emissions are calculated based on historical operating data, projected operation activity, and emission factors for each regulated pollutant. Emission calculation methodologies for each affected emission unit are discussed in the sections below.

### 3.2.1 Coke Drum Venting, Cutting, and Draining Emissions

BP has developed emission calculation methodology for coke drum venting, coke cutting, and draining operations at the coker process unit. Emissions from coke drum venting operations include CO, PM, $PM_{10}$, $PM_{2.5}$, VOC, $CH_4$, and $H_2S$. Data used to develop the emission calculations were obtained from EPA-requested source tests conducted at multiple refineries, including the BP-Husky refinery in Toledo.

BP started calculating baseline actual emissions for coke drum venting in 2009. Emissions for 2005 – 2008 were estimated from 2013 actual emissions based on the annual average coker throughput in these years compared to throughput during 2013. In general coke drum venting emissions are function of coke drum cycle times: higher coker unit utilization leads to more coke drum cycles in a year. Coke drum venting emissions are also influenced by the drum pressure at the time the drum is vented to atmosphere.

Each year BP updates their coke drum venting emission calculation methodology based on the best available information. In 2013 additional information on $H_2S$ emissions from coke drum venting was incorporated into the emission calculation methodology and BP has revised baseline actual $H_2S$ emissions with the more accurate information.

BP developed a range of drum venting scenarios to project a conservative estimate of coke drum venting emissions in the future, considering a 22 percent increase in annual coker utilization. Excludable emissions are based on emissions during 2009, a period that had high coker unit utilization. The projected increase in annual emissions for coke drum venting, cutting, and draining are presented in Table 3-2, and emission calculations details are included in Appendix C.

### 3.2.2 Green Coke Handling

Emissions from green coke handling are based on the annual mass of green coke transferred each year and emission factors (lb pollutant per ton material transferred) from EPA's "drop equation" in AP-42, Section 13.2.4 Equation 1. BP uses an average wind speed of 9 miles per hour from BP's meteorological tower and a green coke moisture content of 4.8 percent (upper bound of emission calculation method) to develop the emission factors for PM, $PM_{10}$, and $PM_{2.5}$.

Projected emissions are based on transferring 1,798,383 tons of green coke, the highest annual throughput from 2003 – 2011 with a 22 percent increase to represent higher projected utilization

of the coker unit after the project. The projected increase in annual emissions for green coke handling are presented in Table 3-2, and emission increase calculations for the coke handling operations are included in Appendix C.

### 3.2.3 Calciners

BP is projecting a 22 percent increase in annual green coke production from the coker unit. BP expects to process the additional green coke through the calciners. Alternatively, the green coke could be shipped offsite. From an emission calculation standpoint, processing the green coke through the calciners is a much more conservative approach for the Project.

Baseline calciner emissions are based on continuous emission monitoring system (CEMS) data for NOx and $SO_2$. Emissions of other pollutants are based on annual calciner utilization and emission factors developed from source tests. Calciner hearths 1 and 2 share a common stack and hearth 3 has a separate stack.

BP projected future calciner emissions based on annual permit limits or calciner utilization and emission factors (lb pollutant per ton calcined coke). Projected calcined coke utilization is based on the maximum hourly capacity of each hearth. Excludable emissions are based on the highest 2-month average daily throughput rate for hearths 1 & 2 and hearth 3, extrapolated to a full 12-month period. The average daily production rate during the two month period was multiplied by 365 days per year to represent Calciners utilization rates that could have been accommodated during the baseline period.

The projected increase in annual emissions from the calciner hearths are presented in Table 3-2, and emission increase calculations for the calciner hearths are included in Appendix C.

### 3.2.4 Refinery Fuel Gas Sulfur Content

Additional annual coker utilization could increase the amount of coker off gas routed to the RFG mix drum. The increased size of the new coker heaters (compared to existing coker heaters) is assumed to consume a portion of the additional coker off gas generated. However, a 22 percent increase in coker off gas generation means additional coker off gas (not burned by the replacement coker heaters) will be routed to the RFG mix drum and conservative calculations estimate a 15 percent increase in RFG sulfur concentration from the additional coker off gas (from 200 ppm S to 230 ppm S, annual average). BP has calculated projected actual annual $SO_2$ emissions from all RFG-fired heaters based on 0.0317 lb $SO_2$/MMBtu (230 ppm S, annual average).

BP expects no increase in short-term sulfur concentrations in the RFG as a result of the Project. The quantity of coker off gas routed to the RFG mix drum on a short-term basis will not change as part of the Project. The increase in annual RFG sulfur concentration is based on increased annual utilization of the coker unit.

### 3.2.5 Hydrocracker

Baseline hydrocracker heater emission rates are based on available CEMS data, RFG use, and emission factors developed from source tests or AP-42 Section 1.4 (Natural Gas Combustion). Instead of projecting actual emission rates for the Hydrocracker heaters after the project, BP

calculated potential annual emission rates for each heater. Potential annual emission rates are based on emission limits and continuous operation (8,760 hours per year), or potential annual firing rates multiplied by applicable emission factors from source tests or AP-42 Section 1.4.

BP excluded a portion of the Project emissions for each of the four hydrocracker heaters based on annual heater utilization that were already accommodated in the 10 year baseline look back period. The projected increase in annual emissions from the hydrocracker heaters are presented in Table 3-2, and emission increase calculations for the hydrocracker heaters are included in Appendix C.

In May 2012 BP installed a ULNB in the 1st Stage Fractionator Reboiler Baseline and accepted a $NO_X$ emission limit of 0.05 lb/MMBtu as part of OAC #1067a. PSD regulation 40 CFR 52.21(b)(48)(ii)(c) requires the baseline actual emissions to be adjusted downward to account for an emission limit that the source must currently comply. BP adjusted the baseline actual emissions for this heater as if the emission unit was required to comply with the current 0.05 lb/MMBtu $NO_X$ emission limit.

Historically, and in the 2014 permit application, BP calculated actual $NO_X$ emissions from the R4 heater based on an AP-42 natural gas combustion emission factor of 0.098 lb/MMBtu (100 lb/MMscf natural gas normalized to a heat input basis using 1020 Btu/scf) and annual heat input to the R4 heater. BP has since updated the baseline actual $NO_X$ emissions from the R4 heater using an emission factor developed with actual engineering test data (0.014 lb/MMBtu). The engineering test data for the heater are more accurate than an AP-42 natural gas emission factor.

### 3.2.6 Sulfur Plant

BP is conservatively projecting actual annual sulfur plant emissions on operating the sulfur plant at annual average utilization (270 lt/day) after the project (scaling baseline actual emissions to 270 lt/day for an entire year).

$NO_X$ and CO source tests have been conducted on each tail gas unit (TGU) stack. RE applied the sum of the source test results from the two TGUs and scaled the hourly mass emission rates by the ratio of projected annual sulfur production rate to the annual average sulfur production rate during the pollutant-specific baseline periods. Particulate matter and VOC emission rate increases are based on the projected increase in annual heat input and emission factors from both refinery source testing and AP-42 Section 1.4. The projected heat input to the sulfur plant is calculated using the baseline heat input rate multiplied by the ratio of projected annual sulfur production rate to the annual average sulfur production rate during the pollutant-specific baseline periods.

Each of the two tail gas unit (TGU) stacks is equipped with a CEMS for $SO_2$ emissions. Baseline $SO_2$ emissions for the sulfur recovery plant are based on CEMS measurements. Projected $SO_2$ emissions are based on the 99 tpy combined sulfur plant emission limit from OAC 890c. The $H_2SO_4$ emission increase assumes 2.63 percent of the sulfur in tail gas emitted as $H_2SO_4$ based on source tests results for combustion units at the refinery.

Greenhouse gas emissions are based on past actual and projected gas processing in the sulfur plant. GHG emission factors for natural gas combustion are based on AP-42 Section 1.4, and $CO_2$ emissions from the sulfur plant incinerator and #2 TGU are based on $CO_2$ measurements during past source tests. Projected actual $CO_2e$ emissions are based on projected natural gas usage, projected incinerator exhaust flow rate, and projected clean acid gas processed by the #2 TGU when the sulfur plant is processing 270 lt/day. All projected annual emission rates assume continuous operation (8,760 hours/year) of the sulfur plant.

The projected increases in annual emission rates for the sulfur plant are presented in Table 3-2, and detailed emission calculations for the sulfur plant are included in Appendix C.

### 3.2.7 Other Refinery Heaters

BP is projecting 22 percent higher annual utilization of the coker unit, which directly feeds the calciner, hydrocracker, #1 DHDS, ISOM, and NHDS process units. BP has conservatively assumed all other process units (Crude Heater, North Vacuum Heater, South Vacuum Heater, #1 & #2 Reformer Heaters, #1 Hydrogen Plant, and light ends unit) will have a four percent increase in annual utilization.

Baseline process heater emission rates are based on available CEMS data, RFG use, and emission factors developed from source tests or AP-42 Section 1.4 (Natural Gas Combustion). No emission increases are calculated for #1 DHDS charge heater, #2 DHDS charge heater, or #3 DHDS charge heater because the reactions with feeds from the coker unit are exothermic (olefin saturation reaction), which means higher coker feed requires less process heat.

Projected actual emissions for the process heaters are based on the highest annual actual throughput for each heater (in terms of annual fuel gas consumption) with a 22 percent or four percent increase in emissions to account for increased annual utilization of the coker unit or the crude unit, respectively. Projected emissions for process heaters directly downstream of the coker unit (DHDS 1 Reboiler, NHDS, and ISOM) are based on the 22 percent increase in annual utilization; and projected emissions for all other process heaters are based on the four percent increase in annual utilization.

Annual utilization of each process unit varies each year based on market projections and demand. BP excluded a portion of projected actual emissions for each process heater based on annual process throughput (represented as fuel gas usage) that was already accommodated in the 10 year baseline look back period. The projected increase in annual emissions from each process heater is presented in Table 3-2, and emission increase calculations for each heater is included in Appendix C.

Baseline actual emissions for emission units that have not been in operation for at least two years are set to potential emissions. The #2 Hydrogen Plant and #3 DHDS unit commenced operation in 2013. Baseline actual emissions are set to potential and projected actual emissions are set to potential and there is no calculated emission increase for the #2 Hydrogen

Plant and #3 DHDS as part of the project. The Clean Fuels Project (includes #2 Hydrogen Plant and #3 DHDS) is included as a contemporaneous project in the PSD netting analysis.[14]

BP updates emission inventories as new data are available. BP has updated emission calculation methodology for several heaters affected by the Project. The baseline actual emission updates presented in this application are described below.

Crude Heater

Reported baseline actual VOC emissions from the crude heater were based on an AP-42 natural gas combustion emission factor of 5.5 lb/MMscf and the actual volumes of refinery fuel gas and vacuum tail gas combusted in the crude heater. The heat contents of refinery fuel gas and vacuum tail gas are higher than the heat content of natural gas (1020 Btu/scf). AP-42 Section 1.4 recommends normalizing the natural gas emission factors from a volume basis (lb/MMscf) to an heat input basis (lb/MMBtu) using a natural gas heat content of 1020 Btu/scf. Normalizing the emission factor to an energy basis allows the emission factors to be used for gases with different heat contents.

BP updated the baseline actual VOC emissions using the normalized AP-42 natural gas emission factor of 0.0054 lb/MMBtu and annual refinery fuel gas and vacuum tail gas heat inputs to the crude heater. Normalizing the AP-42 natural gas emission factors to an energy input basis is an improved emission calculation approach and is recommended in the AP-42 documentation.

North Vacuum Heater

Reported baseline actual $NO_X$ emissions from the north vacuum heater were based on an AP-42 natural gas combustion emission factor of 0.049 lb/MMBtu (small boilers with low $NO_X$ burners, 50 lb/MMscf normalized to heat input basis using 1020 Btu/scf) and annual heat input to the north vacuum heater.

BP updated the baseline $NO_X$ emissions using 2013 source test data (0.1576 lb/MMBtu) for the heater. The emission factor developed from source test data is more accurate than an AP-42 emission factor.

South Vacuum Heater

The south vacuum heater is equipped with a $NO_X$ continuous emission monitoring system (CEMS). The September 2014 PSD/NOC permit application inadvertently had 2007 $NO_X$ emissions based on a newer 2013 emission factor for the heater. BP has corrected the baseline actual $NO_X$ emissions from the south vacuum heater using annual CEMS data for each respective baseline year.

[14] $PM_{10}$ emissions associated with the Clean Fuels project are not included as contemporaneous because the project obtained a PSD permit for $PM_{10}$ emissions.

No. 1 Reformer

Reported baseline actual VOC emissions from the No. 1 reformer were based on 0.0013 lb carbon/MMBtu emission factor developed from a 2007 source test. BP updated the baseline actual VOC emissions by correcting the 2007 VOC emission factor from a carbon basis to an "as propane" basis (0.0019 lb/MMBtu).

No. 2 Reformer

Reported baseline actual $NO_X$ emissions from the No. 2 reformer were based on a 1997 engineering test (0.07 lb/MMBtu). BP updated the baseline actual reformer $NO_X$ emissions using an emission factor developed from 2011 source test data (0.084 lb/MMBtu). The 2011 source test results are more accurate of recent reformer emissions than the 1997 engineering test.

### 3.2.8 High Pressure Flare

BP has conservatively assumed one additional catalyst replacement per year in a hydrotreater unit (hydrocracker, NHDS, ISOM, DHDS, etc.). Projected annual flaring emissions are based on historical flaring emissions during NHDS, ISOM, and DHDS shutdown/startup events. BP reviewed historical flaring events associated with catalyst replacements and selected the event with the maximum flaring emissions to represent projected actual flaring emissions for the project. The projected increase in annual high pressure flare emissions are presented in Table 3-2, and emission increase calculations for the high pressure flare are provided in Appendix C.

### 3.2.9 Cooling Towers, WWTP, Storage Tanks, and Product Loadout

BP has conservatively assumed the cooling towers and WWTP will have an eight percent and seven percent increase in annual emissions as a result of the Project, respectively. BP calculates annual cooling tower emissions based on cooling water recirculation rates, estimated drift rates, and a VOC emission factor from AP-42, Table 5.1.2 (petroleum refining). VOC emissions from the cooling towers were updated starting in 2011 with actual VOC measurement data instead of using the AP-42 VOC emission factor. BP has projected cooling tower emissions based on an eight percent increase from baseline emissions to account for the additional cooling water requirements for the Project.

BP calculates annual WWTP VOC emissions using EPA's Water 9 emission calculation model, which incorporates wastewater throughput rates, WWTP design, and measured or estimated VOC concentrations in the wastewater. BP has projected WWTP emissions based on a seven percent increase from baseline emissions to account for the additional wastewater that may be generated by the Project.

Annual storage tanks and product loadout (controlled by VCUs) throughput could increase four percent due to higher annual crude utilization. Emissions from storage tanks are based on EPA's TANKS 4.09d model and annual throughput for each storage tank. Product loadout emissions are based on annual loadout rates, VCU source testing, and supplemental natural gas for the VCU. BP has projected annual storage tank and product loadout emissions based

on a four percent increase from baseline actual emissions.  BP excluded a portion of projected actual loadout emissions for each VCU based on annual throughput that was already accommodated in the 10 year baseline look back period.

The projected increase in annual emissions from cooling towers, WWTP, storage tanks, and product loadout are presented in Table 3-2, and emission increase calculations for each emission unit are provided in Appendix C.

# 4 Regulatory Analysis

This section identifies and discusses federal, state, and local air quality regulations and guidelines that potentially apply to the Project.

## 4.1 Emission Standards

### 4.1.1 New Source Performance Standards

New Source Performance Standards (NSPS) are nationally uniform standards applied to specific categories of stationary sources that are constructed, modified, or reconstructed after the standard was proposed. NSPS are found in Title 40, Part 60 of the Code of Federal Regulations (CFR). NSPS usually represent a minimum level of control that is required on a new source. The following portions of the NSPS regulations potentially apply to the project, and applicability will be discussed in the following sections.

- Subpart A – General Provisions (40 CFR Part 60.1-60.19)
- Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60.40b-60.49b)
- Subpart J – Standards of Performance for Petroleum Refineries (40 CFR Part 60.100-60.109)
- Subpart Ja – Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (40 CFR Part 60.100a-60.109a)
- Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced after November 7, 2006 (40 CFR Part 60.590a-60.593a)
- Subpart NNN – Standards of Performance for VOC Emissions from Synthetic Organic Chemical Manufacturing Industry (40 CFR Part 60.660-60.668)
- Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems (40 CFR Part 60.690-60.669)

*Subpart A – General Provisions*

Any stationary source that is subject to any NSPS regulation is also subject to the general notification, recordkeeping, and monitoring requirements of 40 CFR Part 60 General Provisions, unless the applicable Part 60 Subpart regulation specifically exempts the source from the provisions of Subpart A. As detailed below, some of the equipment proposed to be added or modified with this application will be subject to NSPS rules; therefore, the general provisions will apply with respect to those sources.

*Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*

Subpart Db of the NSPS applies to steam generating units that are installed after June 19, 1984. The new coker heaters will generate approximately 35,000 lbs of steam per hour for each heater. However, the coker heaters are defined as a process heater in 60.41b, "device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst." As discussed in section 2 of this application, the primary purpose of the coker heaters is to convert residual oil to coke and gas products. Consequently, Subpart Db does not apply to the new coker heaters.

*Subpart J – Standards of Performance for Petroleum Refineries*

Subpart J of the NSPS applies to fluid catalytic cracking unit catalyst regenerators and fuel gas combustion devices constructed, reconstructed or modified between June 11, 1973 and May 14, 2007; as well as Claus sulfur recovery plants (except Claus plants of 20 long tons per day or less) that are constructed, reconstructed or modified between October 4, 1976 and May 14, 2007. The Project will not trigger any requirements under Subpart J because any modifications would occur after May 14, 2007.

*Subpart Ja – Standards of Performance for Petroleum Refineries*

This subpart regulates affected facilities within a petroleum refinery, including fluid catalytic cracking units, fluid coking units, delayed coking units, fuel gas combustion devices, including flares and process heaters, and sulfur recovery plants. Except for flares, the provisions of this subpart apply to affected facilities that commence construction, modification, or reconstruction after May 14, 2007. The provisions of this subpart apply to flares that commence construction, modification, or reconstruction, after June 24, 2008. Each affected facility is addressed separately in the following sections.

<u>Fuel Gas Combustion Devices- Process Heaters</u>

Subpart Ja limits either 1) $SO_2$ emissions to 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling average basis and $SO_2$ in excess of 8 ppmv (dry basis, corrected to 0-percent excess air), determined daily on a 365 successive calendar day rolling average basis; or 2) the $H_2S$ content of fuel gas to 162 parts per million (ppmv), on a 3-hour rolling average basis and to 60 ppmv on a 365-day basis. Additionally, the rule includes the following $NO_x$ limits for process heaters with a rated capacity greater than 40 MMBtu/hr: 1) forced/balanced draft heaters must comply with 60 ppmv (corrected to 0-percent excess air), or 0.06 lb/MMBtu, both determined daily on a 30-day rolling average basis, and 2) natural draft heaters must comply with 40 ppmv or 0.04 lb/MMBtu. The new coker heater burners will each have a maximum heat input rate of 303 MMBtu/hr and will combust coker off gas. The new heaters will primarily operate in balanced draft mode; however, they will have the option to operate in natural draft mode as needed.

The heaters will be subject to these limits of Subpart Ja, as well as all applicable monitoring, recordkeeping, and reporting requirements. BP proposes to comply with the $H_2S$ limits and $NO_X$ emission limits for balanced draft and natural draft process heaters.

In standby coker unit operation, one coker heater will be operating at reduced firing rate and $NO_X$ concentrations in the coker heater exhaust would be higher than during normal operation. BP will submit a separate request to the NSPS Subpart Ja Administrator for an alternative mass-based $NO_X$ emission limit during standby operations. NSPS Subpart Ja includes submittal criteria for process heaters operating at reduced firing conditions (i.e. turndown mode) and requesting an alternative $NO_X$ emission limit.[15]

Sulfur Recovery Plants

Subpart Ja includes sulfur dioxide limits for SRUs. Modifications to the sulfur plant in 2015 (OAC 1201a) triggered Subpart Ja applicability. This Project will not result in any additional Subpart Ja requirements for the sulfur plant.

Flares

The new lean oil absorption column will include a new pressure safety valve (PSV) connection to the low pressure flare. New connections to flares are considered a modification of flares, but the high pressure and low pressure flares are already subject to Subpart Ja from earlier modifications. BP developed a flare management plan for both flares and complies with the applicable NSPS Ja requirements.

Delayed Coker

Subpart Ja includes coke drum depressurization limits for new, modified, or reconstructed delayed coking units. The Subpart Ja definition of delayed coking units include coke drums, fractionator, bottoms receiver, overhead condenser, coke cutting water and quench system, and coke drum blowdown recovery compressor system. As discussed earlier in the project description, BP is proposing to make changes to the main fractionator overhead accumulator to allow for additional steam flow through the delayed coker during online cleaning of the replacement coker heaters. Project changes do not constitute a modification of the delayed coker because the the delayed coker capacity will not increase and the changes will not increase hourly emissions from the delayed coker unit.

*Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries*

A facility within a petroleum refinery is subject to this subpart if construction, reconstruction, or modification of the facility is commenced after November 7, 2006. The affected facilities for this subpart are defined as: (1) the group of all equipment (each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector) within a process unit; and (2) a compressor. Key to the applicability of this subpart, a piece of

[15] 40 CFR 60.102a(i)

equipment or compressor must be *in VOC service*, which means that the piece of equipment or compressor contains a process fluid that is at least 10 percent VOC by weight, in order to be included in the identification of an affected facility.

Specific fugitive components proposed to be installed with the Project will be in VOC service, and the installation of these components does not represent routine maintenance, repair, or replacement (RMRR), as such applicability of this subpart was considered. The new components proposed to be installed with the Project will result in additional components in the coker unit and crude unit. Additional components have the potential to increase fugitive emissions to the atmosphere from the coker and crude units.

The coker and crude units are subject to Subpart GGG requirements. Typically, BP will conduct an evaluation to determine if the addition of new components triggers a capital expenditure, and therefore a modification, under subpart GGGa. However, NWCAA has instructed BP that units already subject to Subpart GGG are exempt from Subpart GGGa through 40 CFR 60.590(d). BP is requesting NWCAA and Ecology's concurrence that the coker unit and crude unit are exempt from Subpart GGGa.

*Subpart NNN – Standards of Performance for VOC Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations*

Subpart NNN applies to affected facilities that commence construction, modification, or reconstruction on distillation units that produce any of the chemicals listed in 40 CFR 60.667 as a product, co-product, by-product, or intermediate. The new lean oil absorption system will produce both propane and butane, which are listed as chemicals affected by Subpart NNN. Accordingly, NSPS Subpart NNN will apply to the new lean oil absorption system and BP will comply with the applicable NSPS requirements.

NSPS Subpart NNN requires that emissions from atmospheric vents from distillation columns be routed to a control device or the firebox of a heater. Coker off gas routed to the lean oil absorption system is burned as fuel gas in the coker heaters or routed to the refinery mix drum and burned as refinery fuel gas throughout the refinery. This specific operation is not directly addressed in the monitoring and testing requirements provided in Subpart NNN. BP plans to request an alternative monitoring plan approval consistent with similar requests made and approved at other refineries with similar operations.

*Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems*

Subpart QQQ applies to each individual drain system, oil-water separator, and aggregate facility at a petroleum refinery that commences construction, modification, or reconstruction after May 4, 1987. No new drain systems are proposed as part of the Project.

### 4.1.2 National Emission Standards for Hazardous Air Pollutants for Source Categories

The National Emission Standards for Hazardous Air Pollutants (NESHAPs) regulations contained in 40 CFR part 61 – 63 establish emission standards for certain source categories of hazardous air pollutant (HAP) emissions. This part represents the federal regulatory mechanism used to regulate HAPs under the Clean Air Act (CAA) after the CAA was amended November 15, 1990. A key component of regulatory applicability under this part is the distinction between a "major source" and an "area source" of HAPs. In short, a major source is a stationary source that emits or has the potential to emit considering controls, in the aggregate, 10 tpy or more of any HAP or 25 tpy or more of any combination of HAPs. An area source means any stationary source of HAPs that is not a major source as defined in this part. The refinery is a major source under this part.

*Subpart FF – National Emission Standard for Benzene Waste Operations.*

40 CFR Part 61, Subpart FF applies to petroleum refineries that treat, store, or dispose of equal to or greater than 10 megagrams (11 tpy) of benzene-containing waste. The only benzene-containing stream affected by the Project is an increase in the amount of sour water generated by the coker unit. The sour water stripper stream is already included in the facility's total annual benzene quantity, and annual quantities will be calculated and reported as required.

*Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries*

This subpart applies to petroleum refining process units and to related emission points that are located at a plant site that meets the following criteria: (1) located at a plant site that is a major source as defined in Section 112(a) of the Clean Air Act; and (2) emits or has equipment containing or contacting one or more of the hazardous air pollutants listed in Table 1 of the subpart. For the purposes of this subpart, the affected source shall comprise all emission points, in combination, listed below that are located at a single refinery plant site that is a major source and contain or contact one or more hazardous air pollutant listed in Table 1 of the subpart.

- All miscellaneous process vents from petroleum refining process units;
- All storage vessels associated with petroleum refining process units;
- All wastewater streams and treatment operations associated with petroleum refining process units;
- All equipment leaks from petroleum refining process units;
- All gasoline loading racks classified under SIC code 2911;
- All marine vessel loading operations located at a petroleum refinery meeting the applicability criteria of 40 CFR part 63, subpart Y, § 63.560;

- All storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station classified under SIC code 2911 located with a contiguous area and under common control with a petroleum refinery; and

- All petroleum refinery heat exchange systems with heat exchangers "in organic hazardous air pollutant service," as the term is defined in the subpart. The heat exchange system consists of a cooling tower, all heat exchangers that are serviced by that cooling tower, and all lines to and from the heat exchangers

This subpart was originally promulgated on August 18, 1995, and identified each of the emission points listed above, with the exception of heat exchange systems. The subpart was amended on October 28, 2009 to add heat exchange systems to the list of regulated emission points. The heat exchange system provisions include monitoring, leak repair, recordkeeping, and reporting requirements. Existing refinery heat exchange systems which include exchangers in organic HAP service were required to comply with the applicable provisions of Subpart CC by October 29, 2012.

The only affected sources from the list above that will be added with the Project are equipment leaks from component leaks that will be "in organic HAP service," which means that the components will contain or contact a volatile fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP listed in the Table 1 of the Subpart. Therefore, the new components in organic HAP service will be subject to the equipment leak requirements of this subpart. Per the reference in this regulation, the Refinery complies with 40 CFR 60 Subpart VV or VVa for equipment leaks so any new components will be added to that program. The lean oil absorption column and compressor will be in organic HAP service.

<u>Finalized Refinery Sector Rule</u>

On December 1, 2015 EPA amended NESHAP Subpart CC (petroleum refineries) and Subpart UUU (catalytic cracking, catalytic reforming, and sulfur plants).[16] The final rule places limit on coke drum pressure/temperature prior to venting to the atmosphere. The new limits for existing coke drums include average vessel pressure of 2 psig (rolling 60-event average), or an average vessel temperature of 220 degrees Fahrenheit (60-event average). The NESHAP amendments are effective on February 1, 2016; and the compliance date for meeting the existing delayed coker unit requirements is three years from the effective date. BP will comply with the updates to Subpart CC within the specified timeframes.

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

Subpart DDDDD applies to industrial process heaters at major sources of HAP. The new replacement coker heaters will be subject to the requirements for new process heaters designed to burn gas 1 fuels, including refinery fuel gas. New gas 1 process heaters with a heat input greater than 10 MMBtu/hr are required to conduct annual process heater tune-ups as specified in 40 CFR 63.7540(a)(10). Burner inspection can be delayed until the next scheduled

[16] 80 FR 75

shutdown. Heaters equipped with oxygen trim controls must have an initial tune-up within 61 months of startup and subsequent tune-ups no more than 61 months from the previous tune-up.

### 4.1.3 Compliance Assurance Monitoring

EPA established the Compliance Assurance Monitoring (CAM) program to regulate emission sources that employ a control device to maintain compliance with an enforceable emission limit. 40 CFR Part 64.2 establishes the three applicability criteria for the CAM program:

- The unit is subject to an emission limit,
- The unit uses a control device to achieve compliance with that limit, and
- The unit has pre-control emissions of 100 percent of the major source threshold.

BP is anticipating the replacement coker heaters will be subject to multiple emission limits as part of the BACT process. However, no control devices are being proposed to achieve those emission limits. Low $NO_X$ burners are not included in the definition of a control device in 40 CFR 64.1.

### 4.1.4 Chemical Accident Prevention Provisions

40 CFR Part 68 sets the requirements for owners and operators of stationary sources concerning the prevention of accidental releases of regulated substances, and the State accidental release prevention programs approved under Clean Air Act section 112(r). This regulation is designed to prevent the accidental release of the toxic and flammable substances regulated under 40 CFR 68.130. A stationary source that has more than a threshold quantity of a regulated substance in a process must develop a Risk Management Plan (RMP).

The Refinery stores and uses on-site one or more of the substances regulated by 40 CFR 68.130 above the threshold quantity and has developed and submitted a RMP. The RMP required under 40 CFR Part 68 will not need to be updated because the quantity of regulated substances stored onsite will not increase as a result of the Project.

### 4.1.5 State and Local Emission Limits

NWCAA Section 455.1 limits particulate matter emissions from gaseous fuel burning equipment (such as the boilers, hydrogen heaters, and process heaters) to 0.05 grains/dscf (at 7% oxygen). WAC 173-400-050 establishes a limit of 0.1 grains/dscf (at 7% oxygen) for combustion units and general process units. Both NWCAA Section 451 and WAC 173-400-040 limit opacity from such sources to no more than 20 percent for an aggregate of 3 minutes in any hour period.

NWCAA Section 462 and WAC 173-400-040 limit emissions of sulfur compounds (calculated as sulfur dioxide) to a 60-minute average of 1,000 ppmv (at 7% oxygen). NWCAA also limits gaseous fuels to less than 50 grains sulfur per 100 standard cubic feet (NWCAA Section 520.14).

NWCAA has specific regulations related to refinery operation and emissions. NWCAA Section 580.2 addresses VOC emission control at petroleum refineries; however, the new emission

units are exempt because they are subject to federal refinery NSPS and NESHAPs. Additional regulations (580.3 through 580.10) also govern VOC emissions from refineries and related sources but generally do not apply to the Refinery because sources subject to federal refinery NSPS and NESHAPs are exempted from these sections.

As a key part of the NOC and PSD permit reviews, NWCAA and Ecology will review BP's proposed emission control technologies. The BACT analysis identifies pollutant-specific alternatives for emission control, and the pros and cons of each alternative. The determination of which control constitutes BACT is made on a case-by-case basis and considers the economic, energy and environmental costs. The requirement for new and modified emission sources to achieve BACT virtually always results in emission rates lower than the general state and local agency emission requirements noted in the preceding paragraphs. The BACT analysis can be found in Appendix B.

WAC 173-460 also requires that BACT be employed to control emissions of toxic air pollutants (called T-BACT). Generally, the same technologies or operations that reduce criteria pollutants also reduce toxic air pollutants. For example, the use of natural gas or refinery fuel gas instead of fuel oil reduces emissions of most criteria and toxic air pollutants because gaseous fuel burn cleaner and have less contaminants (e.g., metals). The use of combustion controls to optimize combustion also reduces both criteria (specifically VOC) and thereby toxic air pollutants. The T-BACT analysis identifies the use of sulfur removal technology for the coker off gas and proper combustion as the best available control for toxic air pollutants from the new coker heaters.

## 4.2 Air Quality Permits

### 4.2.1 Prevention of Significant Deterioration (PSD)

Ecology administers the PSD air quality permit process that applies to major sources. The refinery is already a major source (as defined in PSD regulations) because it emits more than 100 tons per year of a regulated pollutant. A project at an existing source is subject to PSD review only if 1) the existing source that is modified is a major source and 2) the net emission increase of any pollutant emitted by the source, as a result of the project, exceeds prescribed “Significant Emission Rates” (SERs). The net emission change resulting from a project is the sum of emission increases associated with the project, source-wide creditable contemporaneous emissions decreases, and source-wide contemporaneous emissions

To determine emission increases associated with the Project, the emission increases attributable to the following were considered 1) new emission units (i.e. replacement coker heaters); 2) existing emission units that are modified (i.e., physical or operational changes that increase emissions); and 3) increases in emissions resulting from greater utilization of other existing emission units attributable to the Project.

<u>New Emission Units</u>

The Project includes the replacement of the two existing coker heaters with two new coker heaters. PSD applicability is conservatively based on the “potential to emit” (PTE) of the new heaters. PTE is defined as the maximum capacity of the unit to emit under its physical and operational design, taking into account any operational restrictions the applicant accepts to limit

emissions. The PTE for the new heaters is based 8,760 hours of annual operation and the BACT emission rates presented in Table 3-2.

The increases in coker heater emissions could have been calculated based on projected actual emission for the new heaters minus baseline actual for the existing heaters because the new coker heaters are functionally equivalent to the existing heaters that are being replaced. However, a more conservative route of calculating potential emissions for the new heaters and assuming baseline actual emissions of zero has been taken.

Modified Emission Units

The CAA defines a "modification" as a physical change or change in the method of operation of an existing emissions unit. Existing units that are modified as part of the Project must be identified and increases in emissions must be quantified. From a federal (EPA/PSD) perspective, the increase is measured as an increase in annual emissions (tons per year) compared with a baseline period. The baseline period may be any consecutive 24-month period in the ten year period preceding the date a permit application is deemed complete; different 24-month periods may be selected for different pollutants but the same period then applies to all emission units at the stationary source.

Some activities are specifically excluded from the concept of modification, including:

- Routine maintenance, repair and replacement.
- A switch to a fuel or raw material which (a) the source was capable of accommodating before January 6, 1975, so long as the switch would not be prohibited by any federally enforceable permit condition …. or (b) the source is approved to make under a PSD permit.
- Any increase in the hours or rate of operation of a source, so long as the increase would not be prohibited by any federally-enforceable permit condition ….

The increase in emissions from modified units is determined by subtracting a baseline emission rate (a two-year average from the last ten years) from a future operating scenario. The projected emissions may be adjusted to account for emissions that could have been accommodated during the baseline period and are not a result of the project. Future emissions can be based on the modified unit's potential emissions or on a future anticipated emission rate. Any increases in emissions from modified units are added to potential emissions from new emission units.

Increased Utilization and Debottlenecking

"Debottlenecking," for purposes of the CAA, means increased utilization of process units that results from the removal of a production bottleneck upstream or downstream from the debottlenecked unit. The debottlenecked unit has not been modified, but its throughput (and emissions) increases as a result of the removal of a bottleneck elsewhere in the production line.

Emissions from debottlenecked units are counted toward PSD applicability and are included in the air quality impact analysis, but BACT is not required for debottlenecked units. The replacement coker heaters will allow increased throughput/production from existing process units and will send additional intermediates to the sulfur plant; therefore the increase in emissions resulting from the higher throughput/production and sulfur processing must be added to emission increases from new and modified units to determine if the project (and each pollutant) is subject to PSD review. The increase in emissions for each unit has been calculated by subtracting its baseline emissions from its anticipated future (annual) emissions (with the Project). The same baseline methodology that is applied to modified units is applied to debottlenecked units (i.e., a 10-year baseline period).

Similar to calculation procedures for modified units, the increase in emissions from debottlenecked units is determined by subtracting baseline emissions from the unit's projected actual or potential to emit. All increases in emissions from debottlenecked units are added to the potential emissions from the new units and increases from modified units.

Does the Project Trigger PSD Review?

Table 3-2 presents potential emissions from the new coker heaters and new components. The table also includes increases in emissions (projected actual minus baseline actual) from other emission units at the refinery. The total emission increases expected from the Project are above the applicable PSD Significant Emission Rates for $NO_X$, CO, $SO_2$, PM, $PM_{10}$, $PM_{2.5}$, VOC, $H_2SO_4$, and $CO_2e$.

EPA regulations require that emissions of $NO_X$, CO, $SO_2$, PM, $PM_{10}$, $PM_{2.5}$, VOC, $H_2SO_4$, and $CO_2e$ from other "contemporaneous" projects at the refinery be included in the PSD permit analysis as part of the netting analysis. The contemporaneous period extends from a time five years prior to the expected date construction of the project will commence and ending when the emission increase from the project will occur (with allowances for a commissioning period). Construction is expected to commence in 2017 so the contemporaneous period begins in 2012. The new units are expected to start operating in the first quarter of 2019, so the contemporaneous period will end in the 3rd quarter of 2019 (allowing for a 6-month commissioning period). Pollutants that have already been reviewed as part of a PSD permitting process do not need to be included in another PSD permit review.

As discussed earlier in this application, there are multiple projects that occurred in the contemporaneous period that have not already been included in a PSD permit review. Of recent projects, only the Clean Fuels Project went through PSD review and then only for $PM_{10}$ emissions. Emission increases and decreases from the contemporaneous projects (other than $PM_{10}$ from the Clean Fuels Project) are included in Table 3-3. The netting analysis indicates $NO_X$, CO, $SO_2$, PM, $PM_{10}$, $PM_{2.5}$, VOC, $H_2SO_4$, and $CO_2e$ are still subject to PSD review for the coker heater replacement project.

BP included the permanent shutdown of the existing coker heaters and the retrofit of the Hydrocracker 1st stage fractionator reboiler burners as creditable contemporaneous emission reductions. However, the creditable contemporaneous emission reductions do not affect PSD applicability for the project.

EPA established the PSD regulations to ensure that new or modified sources do not cause air quality in areas that currently meet the standards to deteriorate significantly. These regulations set "increments" which limit the increases in $SO_2$, $NO_X$, and PM concentrations that may be produced by a new source. Increments have been established for three land classifications.

The most stringent increments apply to "Class I" PSD areas, which include wilderness areas and national parks. The Class I Area nearest the refinery is the North Cascades National Park, approximately 80 km east of the facility. The current requirement for consideration of air quality related values (AQRV) impacts is within 100 km of the facility (NPS, 1993). RE also considered other Class I Areas within about 300 km of the refinery, including the Alpine Lakes Wilderness, Glacier Peak Wilderness, Goat Rocks Wilderness, Mount Adams Wilderness, Mount Baker Wilderness, Mount Rainier National Park, North Cascades National Park, Olympic National Park, and the Pasayten Wilderness.

The vicinity of the site is designated "Class II," where less stringent PSD increments apply. There are no Class III Areas in Washington so those increments are not pertinent to this analysis.

### 4.2.2 Notice of Construction (NOC)

NWCAA Regulation Section 300 and WAC 173-400-110 require a NOC be filed and approved prior to the construction or modification of an air contaminant source or emission unit. To obtain an approval of an NOC, the applicant must demonstrate that BACT has been employed to control criteria pollutants and T-BACT to control toxic air pollutants, that ambient air quality standards are protected, and that new sources of toxic air pollutants do not generate ambient concentrations that exceed applicable Acceptable Source Impact Levels (ASILs). In addition to meeting PSD permit requirements, this permit application is intended to fulfill the requirements for a NOC application for the NWCAA.

For modifications, state law determines whether an emission increase occurs based on maximum hourly emissions from the modified unit. Consistent with the definition of modification in the New Source Performance Standards, Washington's definition of modification depends on a change in the maximum throughput or capacity of a unit when determining whether there is an "increase" in hourly emissions.

Based on this definition, there are no modified units associated with the Project because there is no physical or operational change to, or increase in potential hourly emissions from, the existing emission units at the refinery. The only emissions units subject to NOC review by NWCAA are the replacement coker heaters. Because the criteria pollutant increases associated with the Project are all addressed in the PSD process, the minor new source review will be limited to the net increases in toxic air pollutants from the replacement coker heaters.

BP proposes the coker heater emission limits shown in Table 4-1.

| Table 4-1: Coker Heater – Proposed Emission Limits (per heater) | | | | |
|---|---|---|---|---|
| **Pollutant** | **BACT, NSPS, or NESHAP Basis for Limits** | **Short-Term Limit** | **Long-Term Limit** | **Compliance Method** |
| $NO_X$ | Ultra Low $NO_X$ Burners and NSPS Ja Requirements | Balanced Draft:<br>60 ppmdv (0% $O_2$) 30-day rolling ave.<br>18.2 lb/hr, calendar day average<br>Natural Draft:<br>40 ppmdv (0% $O_2$), 30-day rolling ave.<br>12.1 lb/hr, calendar day average<br>Standby:<br>8.0 lb/hr, standby period average | None | $NO_X$ CEMS<br>$O_2$ CEMS |
| CO | BACT | Normal:<br>33 ppmdv (0% $O_2$) 30-day rolling ave<br>6.1 lb/hr, calendar day average<br>Startup/Shutdown/Standby:<br>75.0 lb/hr, period average | None | Source test |
| $SO_2$ | Coker Fuel Gas | 40.0 lb/hr (combined for two heaters), calendar day average | 132 tons per year (two heaters combined), 12-month rolling total | $SO_2$ CEMS<br>$O_2$ CEMS |
| $PM_{10}$ / $PM_{2.5}$ | Design Basis (0.0100 lb/MMBtu) | 3.0 lb/hr, calendar day average | None | EPA Method 5 & 202, or EPA OTM 27 & 28 |
| VOC | Design Basis (0.0054 lb/MMBtu) | 1.6 lb/hr, calendar day average | None | EPA Method 18 or 25 |
| $H_2SO_4$ | Fuel $H_2S$ limits | 3.2 lb/hr (combined for two heaters), calendar day average | None | EPA Method 8 or 8A |
| $CO_2e$ | Energy Efficiency | None | 320,883 tons per year (two heaters combined), 12 month rolling total | Fuel Tracking and 40 CFR Part 98, Subpart C |

### 4.2.3 Air Operating Permit

The refinery currently operates under an Air Operating Permit (AOP) issued by the NWCAA. BP does not expect the approval of the project will contravene any of the existing Air Operating Permit conditions.

# 5 Local Air Quality Impact Assessment

RE applied computer-based dispersion modeling techniques to simulate dispersion of $NO_X$, CO, $SO_2$, $PM_{10}$, $PM_{2.5}$, and toxic air pollutant emissions attributable to the Project. The results of the modeling are used to assess compliance with the PSD increments, the National (and Washington) Ambient Air Quality Standards (NAAQS and WAAQS), and Ecology's ASILs for toxic pollutants.

RE used different dispersion modeling techniques to also assess Class I increments and potential secondary aerosol impacts to Class I Areas, including degradation of regional visibility and other AQRVs. The Class I assessment is described in Chapter 6.

For projects with net $NO_X$ and/or $SO_2$ emission increases above 40 tpy, PSD regulations also require an evaluation of secondary $PM_{2.5}$ formation (as nitrates and sulfates). The secondary $PM_{2.5}$ analysis for the Project is included in Appendix D. The net increase of $NO_X$ emissions for the Project is also above 100 tpy, which requires an ozone assessment, which is included in Appendix E.

The dispersion modeling techniques employed in the analysis follow a basic set of EPA regulatory guidelines (40 CFR Part 51, Appendix W; called the Guidelines) and EPA modeling guidance for 1-hour $NO_2$, 1-hour $SO_2$, and $PM_{2.5}$.[17] The Guidelines include recommendations for model selection, data preparation, and model application, but allow flexibility on a case-by-case basis.

Section 5.1 discusses the selection and application of the dispersion model. Section 5.2 discusses the meteorological data used in the dispersion modeling and summarizes stack parameters for emission sources associated with the Project. Section 5.3 identifies the maximum model-predicted ambient concentrations of criteria pollutants and TAPs and compares these predictions with appropriate regulatory criteria. The modeling files are provided on DVD in Appendix H.

## 5.1 Dispersion Model Selection

RE based its selection of dispersion models on the characteristics of the Project emission points and dispersion phenomena that might produce the maximum ground level concentrations. In RE's experience, highest concentrations tend to occur under two circumstances:

- When stack plumes intersect elevated terrain

[17] See http://www.epa.gov/ttn/scram/guidance/clarification/ClarificationMemo_AppendixW_Hourly-NO2-NAAQS_FINAL_06-28-2010.pdf
See http://www.epa.gov/ttn/scram/guidance/clarification/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf
See http://www.epa.gov/ttn/scram/guidance/clarification/ClarificationMemo_AppendixW_Hourly-SO2-NAAQS_FINAL_08-23-2010.pdf
See http://www.epa.gov/ttn/scram/guidance/clarification/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf
See http://www.epa.gov/ttn/scram/guidance/guide/Guidance_for_PM25_Permit_Modeling.pdf

- When wind flowing across nearby structures cause downwash effects that bring the plume to the surface

AERMOD is currently the preferred dispersion model recommended by the Guideline for complex source configurations, emission units subject to exhaust plume downwash, and situations where there is the potential for exhausts plumes to interact with complex terrain.

AERMOD was utilized for the modeling analysis primarily because it is the most-up-to date near-field dispersion model available. Additionally, the modeling domain and source configuration suggest the potential for exhaust plume downwash and/or plume impacts on intermediate terrain.

## 5.2 Model Application

RE applied the most recent version of AERMOD (version 15181) using the model options discussed below. Pollutant concentrations predicted by AERMOD were averaged over short-term (1-, 3-, 8-, and 24-hour) and annual averaging periods as required by the applicable ambient air quality standard averaging period(s) for each modeled pollutant.

### 5.2.1 Receptor Locations

RE used four nested receptor grids in our simulations of the Project. The receptor grids are designed to assess both potential impacts to terrain above the level of the stack and local concentrations caused by building downwash effects. The modeling domain is 40 km by 40 km and includes receptor grids of 25-meter, 50-meter, 250-meter, and 500-meter resolution and receptors spaced 25 meters apart on the property boundary, as shown in Figure 5-1. Elevation data for the receptor grids were obtained using terrain elevations from the USGS National Elevation Dataset (NED) 1/3 Arc-Second data set available on the USGS Internet site.[18] These data have a horizontal spatial resolution of about 9×10-5 degrees.

Additional receptor grids with 25 meter spacing were used to resolve maximum AERMOD predictions for each averaging period.

RE also created an “X, Y, Z” DEM file for receptors located in British Columbia by converting available Canadian Digital Elevation Data (CDED) and Shuttle Radar Topography Mission version 2 (SRTM V2) elevation data into a 7.5 minute USGS DEM file format. The CDED quadrangle (092G01) was obtained from the internet (http://www.geobase.ca), and two SRTM datasets (N49W123 and N48W123) were obtained from the internet (http://dds.cr.usgs.gov/srtm/). The CDED and SRTM data have horizontal resolutions of 23 m and 30 m, respectively.

[18] Data accessed through http://viewer.nationalmap.gov/viewer/

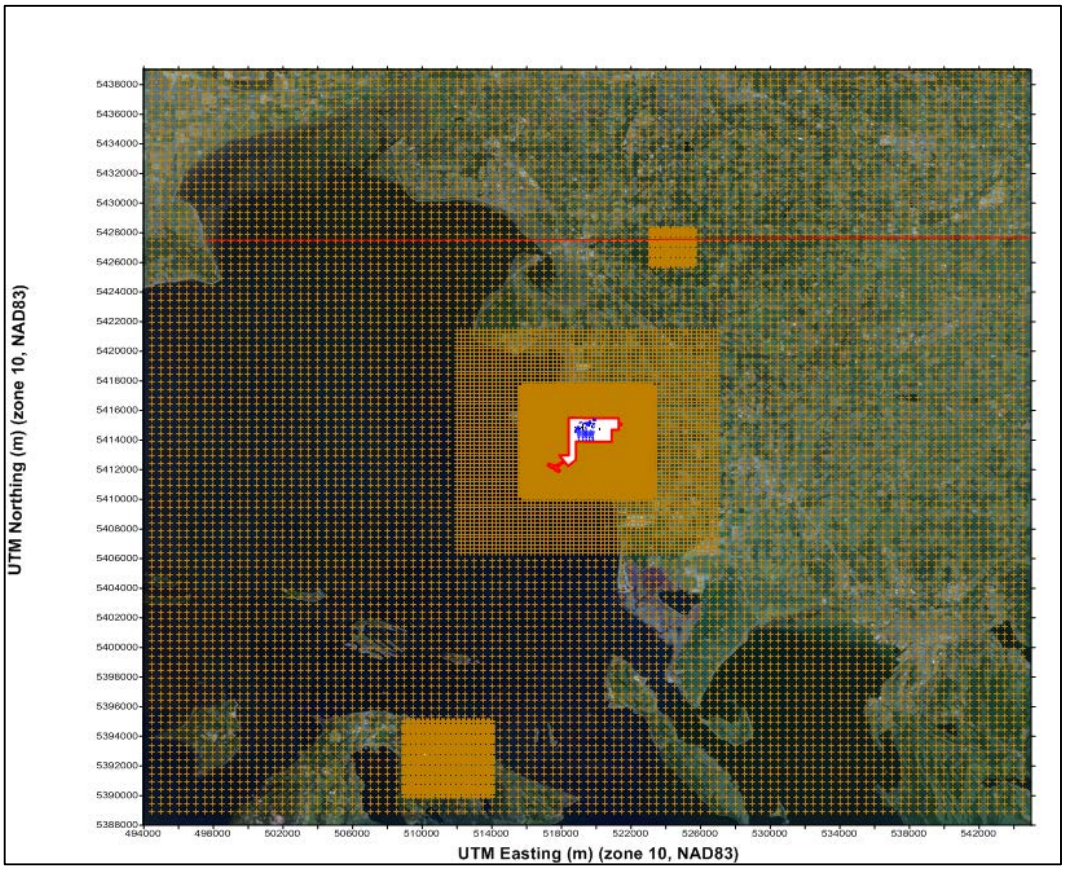



**Figure 5-1. Receptor Locations**

### 5.2.2 Meteorology

Local meteorological data are needed to characterize dispersion conditions near the site. The dispersion modeling techniques used to simulate transport and diffusion require an hourly meteorological database. In this case, representative meteorological data are available from an on-site 10-meter tower operated by BP. The data meet PSD-quality specifications, as specified in Part 51 of the Guidelines. BP submits to NWCAA quality assured meteorological data monthly, a "Meteorological Program Calibration Report" quarterly, and a "Quarterly Meteorological Data Summary" quarterly. Reports for the tower instrumentation are available upon request.

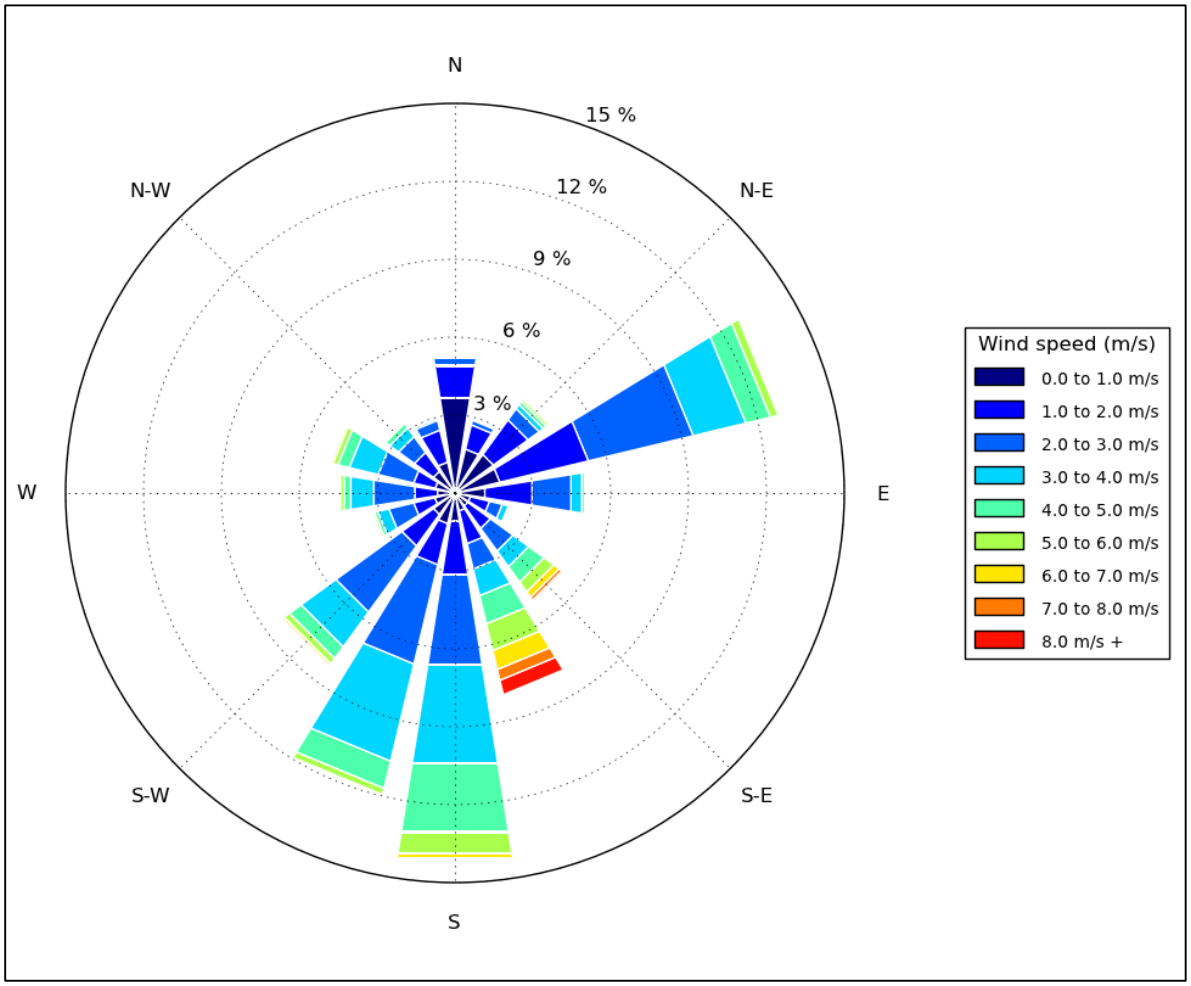
A five-year meteorological database (2009 – 2013) was prepared using onsite surface data observations from a 10-meter meteorological tower operated by BP, surface observations from National Weather Service (NWS) station in Bellingham, Washington, and upper air data from the NWS site Quillayute, Washington. BP meteorological tower data includes wind speed, wind direction, sigma theta, temperature, temperature difference (10 m minus 2 m), and solar radiation.

The meteorological data was processed using the AERMOD meteorological preprocessor, AERMET (version 15181). A wind rose describing the wind speed and wind direction data recorded at the BP meteorological site over the five-year period is shown in Figure 5-2. The

wind rose indicates winds are generally from the east-northeast and south directions, influenced by the regional terrain.

AERMET and AERMOD runs were conducted using the friction velocity correction beta option, ADJ_U*, to correct known deficiencies in the model during low windspeed conditions.[19] Ecology also confirmed the use of ADJ_U* during recent Project discussions.[20]

**Figure 5-2. BP Cherry Point Wind Rose**




EPA guidance indicates that surface parameters (albedo, Bowen ratio, and surface roughness) surrounding the meteorological site should be used in AERMET to construct the meteorological profiles used by AERMOD. Seasonal surface parameters will be calculated for the BP meteorological site using the AERMET preprocessor, AERSURFACE (version 13016) and EPA guidance.[21] EPA guidance recommends surface roughness at the primary and secondary

[19] 80 FR 45340, Revision to the Guideline on Air Quality Models: Enhancement to the AERMOD Dispersion Modeling System and Incorporation of Approaches to Address Ozone and Fine Particulate Matter. July 29, 2015.

Mr. Herman Wong (EPA Region 10) to Mr. Alan Schuler (ADEQ), October 20, 2015, Surface Friction Velocity (U*) Non-Default/Beta Option in AERMET Version 15181.

[20] November 19, 2015 meeting with Ecology, NWCAA, BP, and Ramboll Environ staff.

[21] The AERMOD Implementation Guide (EPA, 2009) and the AERSURFACE User's Guide (EPA-454/B-08-001, January 2008).

surface measurement sites should be estimated using AERSURFACE applying directional sectors with arcs no smaller than 30°, extending to 1 km from the measurement site. AERSURFACE computes the surface roughness for each sector using an inverse-weighted geometric mean of typical roughness values assigned to each land-use category. The guidance recommends the Bowen ratio and albedo should be estimated using a geometric mean of values over a 10 km by 10 km region using typical values assigned to each land use category per season. AERSURFACE was applied using the following assumptions:

- Seasonal temporal resolution
- No continuous winter snow cover, given the low frequency of snow cover events in the Whatcom County lowlands.
- Site location not at an airport – the BP onsite meteorological dataset is not located at an airport or similar area with land-use that would qualify for use of the "airport" surface roughness adjustment algorithm used within AERSURFACE. The Bellingham NWS is located at an airport.
- Average surface moisture characteristics over the 5-year period of the meteorological database.

Table 5-1 presents the AERSURFACE calculated seasonal albedo, Bowen ratio, and surface roughness length values for the Refinery meteorological site.

**Table 5-1: BP Met Site Surface Characteristics**

| | | Winter | Spring | Summer | Autumn |
|---|---|---|---|---|---|
| **Albedo** | | 0.14 | 0.13 | 0.14 | 0.14 |
| **Bowen Ratio** | | 0.37 | 0.27 | 0.24 | 0.37 |
| **Surface Roughness Length by Sector (meter)** | 1 | 0.040 | 0.058 | 0.223 | 0.223 |
| | 2 | 0.044 | 0.065 | 0.240 | 0.240 |
| | 3 | 0.035 | 0.053 | 0.211 | 0.211 |
| | 4 | 0.028 | 0.042 | 0.182 | 0.182 |
| | 5 | 0.069 | 0.103 | 0.290 | 0.290 |
| | 6 | 0.062 | 0.087 | 0.185 | 0.185 |
| | 7 | 0.047 | 0.075 | 0.249 | 0.249 |
| | 8 | 0.051 | 0.078 | 0.260 | 0.260 |
| | 9 | 0.078 | 0.111 | 0.285 | 0.285 |
| | 10 | 0.094 | 0.139 | 0.368 | 0.368 |
| | 11 | 0.100 | 0.148 | 0.393 | 0.393 |
| | 12 | 0.039 | 0.058 | 0.221 | 0.221 |

### 5.2.3 Stack Parameters, Building Dimensions, and Good Engineering Practice

In addition to emission rates (discussed in Section 3), the modeling analysis requires information regarding stack heights, building dimensions, and other exit parameters that characterize exhaust flow from refinery emission points. These release characteristics have an important influence on the results of the analysis. Fugitive emissions from green coke handling

were modeled as volume sources located next to the coke pit. RE used the source release parameters shown in Table 5-2 for the dispersion modeling simulations.

RE conducted a Good Engineering Practice (GEP) stack height design analysis based on EPA procedures and the latest design specifications for the new coker heater structures. Releases below the GEP stack height are potentially subject to building wake effects, which can produce relatively high ground level predictions from EPA regulatory models. For the purposes of PSD review, the EPA does not credit the added dispersion associated with releases above the GEP stack height and restricts the simulated heights in the modeling to the GEP stack height. However, none of the modeled stacks exceeded their associated GEP stack heights. All sources were therefore modeled using their actual stack heights, with the exception of the #2 hydrogen plant flare and the high pressure flare, which are not subject to GEP height limitations.

Flare Stack Parameters

Flare release parameters were calculated using EPA Guidance Document: EPA-450/4-88-010 (Screening Procedures for Estimating the Air Quality Impact of Stationary Sources). The high pressure flare stack parameters are based on one hydrotreater startup/shutdown per year to account for a catalyst replacement. The high pressure flare is not considered a new or modified emission unit as part of the Project and therefore only the annual emission increases from the high pressure flare were evaluated.

### 5.2.4 Building Downwash (Prime Algorithm)

RE used the EPA's Building Profile Input Program for the PRIME algorithm (BPIP PRIME, version 04274) for the GEP analysis. RE also used BPIP PRIME to prepare the wind direction-specific building profile information required by the dispersion model. The configuration and heights of buildings (in meters) are presented in Figure 5-3. BPIP PRIME assesses the area of influence for each structure based on the wind direction, structure heights, and the projected structure widths. BPIP PRIME also applies EPA guidance for multi-tiered structures and assesses whether structures are sufficiently close to be considered a single structure.

| Table 5-2: Source Release Parameters | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Point Sources | | | | | | | | |
| Source ID | UTMx [a] (meters) | UTMy [a] (meters) | Base Elev. [a] (meters) | Stack Height (ft) | Exit Temp. (°F) | Exit Velocity (ft/sec) | Stack Diameter (ft) | Description |
| WCOKE | 519230.0 | 5414722.0 | 32.5 | 189.3 | 350.0 | 23.9 | 8.6 | New Coker Heater (West) |
| ECOKE | 519253.0 | 5414722.0 | 32.5 | 189.3 | 350.0 | 23.9 | 8.6 | New Coker Heater (East) |
| CVENT | 519190.0 | 5414780.0 | 32.5 | 182.0 | 220.0 | 161.7 | 1.0 | Coke Drum Venting |
| CALC1N2 | 519092.5 | 5414786.7 | 32.1 | 234.0 | 235.1 | 95.9 | 5.5 | Calciner #1 & #2 |
| CALC3 | 519090.2 | 5414744.8 | 32.7 | 250.0 | 175.0 | 38.5 | 8.5 | Calciner #3 |
| CRUDEHTR | 519560.3 | 5414734.0 | 34.2 | 200.1 | 287.3 | 14.1 | 11.9 | Crude Heater |
| NVACHTR | 519562.6 | 5414846.2 | 33.3 | 129.9 | 281.9 | 4.6 | 6.5 | North Vacuum Heater |
| SVACHTR | 519563.1 | 5414825.3 | 34.3 | 160.1 | 391.7 | 13.8 | 8.2 | South Vacuum Heater |
| HCREBLU | 519234.6 | 5414909.4 | 32.9 | 160.0 | 286.4 | 37.3 | 9.4 | Hydrocracker 1st and 2nd Stage Frac. Heaters |
| HCR1HTRU | 519239.8 | 5414992.8 | 32.8 | 140.0 | 775.1 | 12.8 | 6.7 | Hydrocracker R1 Heater |
| HCR4HTRU | 519239.7 | 5414980.3 | 32.8 | 150.0 | 501.5 | 5.0 | 3.7 | Hydrocracker R4 Heater |
| REF1HTR1 | 519315.9 | 5414740.8 | 34.1 | 200.0 | 467.3 | 6.3 | 10.3 | #1 Reformer - Heater 1 |
| REF1HTR2 | 519325.1 | 5414740.2 | 34.1 | 200.0 | 467.3 | 6.3 | 10.3 | #1 Reformer - Heater 2 |
| REF2HTR | 519598.9 | 5414907.9 | 33.2 | 83.0 | 709.0 | 29.7 | 10.1 | #2 Reformer Heater |
| DHDS1RBL | 519447.8 | 5414828.1 | 36.1 | 100.0 | 697.7 | 18.2 | 4.6 | #1 DHDS Reboiler |
| NAPHTR | 519366.8 | 5414731.9 | 34.3 | 100.0 | 595.1 | 6.1 | 6.2 | Naphtha Heater |
| NAPRBOIL | 519353.7 | 5414731.8 | 34.1 | 100.0 | 577.1 | 14.0 | 5.2 | Naphtha Reboiler |
| IHTHTR | 519653.0 | 5414711.0 | 34.5 | 56.0 | 457.0 | 2.7 | 3.0 | Isom Heater |
| REF1FUR1 | 519504.9 | 5414993.3 | 32.8 | 80.0 | 546.5 | 33.1 | 5.6 | #1 Hydrogen Furnace 1 |
| REF1FUR2 | 519504.9 | 5414985.8 | 32.8 | 80.0 | 546.5 | 33.1 | 5.6 | |
| REF2FUR1 | 519504.7 | 5414948.1 | 32.8 | 80.0 | 586.1 | 36.7 | 5.6 | |
| REF2FUR2 | 519504.4 | 5414940.5 | 32.8 | 80.0 | 586.1 | 36.7 | 5.6 | |
| SRU1 | 519189.8 | 5414878.3 | 33.0 | 213.3 | 550.1 | 60.0 | 3.6 | Sulfur Plant Incinerator |
| TGU2 | 519169.4 | 5414966.3 | 32.8 | 165.0 | 85.0 | 28.0 | 3.0 | #2 Tail Gas Unit |
| DOCKVCU | 517677.1 | 5412226.0 | 0.0 | 97.6 | 1400.0 | 19.4 | 12.6 | Dock Vapor Combustor |

| Table 5-2: Source Release Parameters | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Point Sources** | | | | | | | | |
| **Source ID** | **UTMx [a] (meters)** | **UTMy [a] (meters)** | **Base Elev. [a] (meters)** | **Stack Height (ft)** | **Exit Temp. (°F)** | **Exit Velocity (ft/sec)** | **Stack Diameter (ft)** | **Description** |
| TRUCKVCU | 518813.4 | 5414774.0 | 33.5 | 35.0 | 1200.0 | 24.4 | 8.0 | Truck Vapor Combustor |
| COOL1C1 | 519074.8 | 5414971.7 | 31.0 | 75.0 | 90.0 | 38.8 | 26.0 | #1 Cooling Tower Cells 1 - 9 |
| COOL1C2 | 519074.8 | 5414981.0 | 31.0 | 75.0 | 90.0 | 38.8 | 26.0 | |
| COOL1C3 | 519074.8 | 5414990.2 | 31.0 | 75.0 | 90.0 | 38.8 | 26.0 | |
| COOL1C4 | 519074.8 | 5414999.5 | 31.0 | 75.0 | 90.0 | 38.8 | 26.0 | |
| COOL1C5 | 519074.8 | 5415008.8 | 31.0 | 75.0 | 90.0 | 38.8 | 26.0 | |
| COOL1C6 | 519074.8 | 5415018.1 | 31.0 | 75.0 | 90.0 | 38.8 | 26.0 | |
| COOL1C7 | 519074.8 | 5415027.1 | 31.0 | 75.0 | 90.0 | 38.8 | 26.0 | |
| COOL1C8 | 519074.8 | 5415036.2 | 31.0 | 75.0 | 90.0 | 38.8 | 26.0 | |
| COOL1C9 | 519074.8 | 5415045.5 | 31.0 | 75.0 | 90.0 | 38.8 | 26.0 | |
| COOL2C1 | 520220.6 | 5414718.3 | 38.9 | 75.0 | 90.0 | 27.0 | 30.0 | #2 Cooling Tower Cells 1 - 4 |
| COOL2C2 | 520220.6 | 5414732.9 | 38.9 | 75.0 | 90.0 | 27.0 | 30.0 | |
| COOL2C3 | 520220.6 | 5414747.5 | 38.9 | 75.0 | 90.0 | 27.0 | 30.0 | |
| COOL2C4 | 520220.6 | 5414762.1 | 38.9 | 75.0 | 90.0 | 27.0 | 30.0 | |
| HPFLR | 518763.2 | 5414890.8 | 27.2 | 225.6 | 1831.7 | 65.6 | 0.6 | HP Flare (Project) |
| SHIPPMPN | 517383.6 | 5412290.2 | 0.0 | 164.0 | 308.9 | 19.9 | 3.9 | Crude Ship Pumping |
| O_NCOKE | 519234.2 | 5414763.5 | 32.5 | 175.0 | 550.0 | 18.2 | 9.0 | Old Coker Heater - North |
| O_SCOKE | 519234.1 | 5414751.2 | 32.5 | 175.0 | 550.0 | 18.2 | 9.0 | Old Coker Heater - South |
| BOIL6 [b] | 519574.1 | 5414986.9 | 33.2 | 150.0 | 335.0 | 62.3 | 6.0 | #6 Boiler (Contemporaneous) |
| BOIL7 [b] | 519603.4 | 5414986.7 | 33.0 | 150.0 | 335.0 | 62.3 | 6.0 | #7 Boiler (Contemporaneous) |
| CALC3_R [c] | 519090.2 | 5414744.8 | 32.7 | 250.0 | 175.0 | 38.5 | 8.5 | #3 Calciner (Contemporaneous) |
| HPFLR_CA [c] | 518763.2 | 5414890.8 | 27.2 | 229.2 | 1831.7 | 65.6 | 2.0 | HP Flare (Contemporaneous) |
| DHDS3 [d] | 519785.0 | 5414890.2 | 34.3 | 100.0 | 850.0 | 21.0 | 3.9 | #3 DHDS Heater (Contemporaneous) |

## Table 5-2: Source Release Parameters

**Point Sources**

| Source ID | UTMx [a] (meters) | UTMy [a] (meters) | Base Elev. [a] (meters) | Stack Height (ft) | Exit Temp. (°F) | Exit Velocity (ft/sec) | Stack Diameter (ft) | Description |
|---|---|---|---|---|---|---|---|---|
| H2SMR [d] | 519737.9 | 5414963.6 | 33.7 | 120.0 | 299.9 | 58.0 | 6.8 | #2 Hydrogen Plant (Contemporaneous) |
| H2FLR_ST [d] | 519739.7 | 5414963.6 | 33.7 | 158.0 | 1831.7 | 65.6 | 10.2 | #2 Hydrogen Plant Flare - st (Contemporaneous) |
| H2FLR_LT [d] | 519739.7 | 5414963.6 | 33.7 | 127.5 | 1831.7 | 65.6 | 1.9 | #2 Hydrogen Plant Flare - lt (Contemporaneous) |
| HPFLR_CF [d] | 518763.2 | 5414890.8 | 27.2 | 229.2 | 1831.7 | 65.6 | 0.1 | HP Flare (Contemporaneous) |
| SRU1_M [e] | 519189.8 | 5414878.3 | 33.0 | 213.3 | 550.1 | 60.0 | 3.6 | Sulfur Plant Incinerator (Contemporaneous) |

**Volume Sources**

| Source | UTMx [a] (meters) | UTMy [a] (meters) | Base Elev. [a] (meters) | Release Height (ft) | $\sigma_y$ initial (ft) | $\sigma_z$ initial (ft) | Description |
|---|---|---|---|---|---|---|---|
| N_COMP | 519241.5 | 5414722.0 | 32.5 | 75.0 | 76.3 | 69.8 | New Component Fugitives |
| O_COMP | 519234.2 | 5414757.4 | 32.5 | 50.0 | 15.3 | 46.5 | Old Component Fugitives |
| GCOKE1 | 519160.0 | 5414780.0 | 32.5 | 14.8 | 45.8 | 13.7 | Green Coke Handling |
| GCOKE2 | 519160.0 | 5414750.0 | 32.5 | 14.8 | 45.8 | 13.7 | Green Coke Handling |

Notes:

a UTM Zone 10, Datum = NAD 83

b Boiler 6 & 7 PM10 Emission limit modification (PSD 07-01, Amendment 2)

c #3 Calciner Heater Repair

d Clean Fuels Project (OAC #1064 and PSD-10-01)

e Sulfur Plant Modification (OAC #1201a)

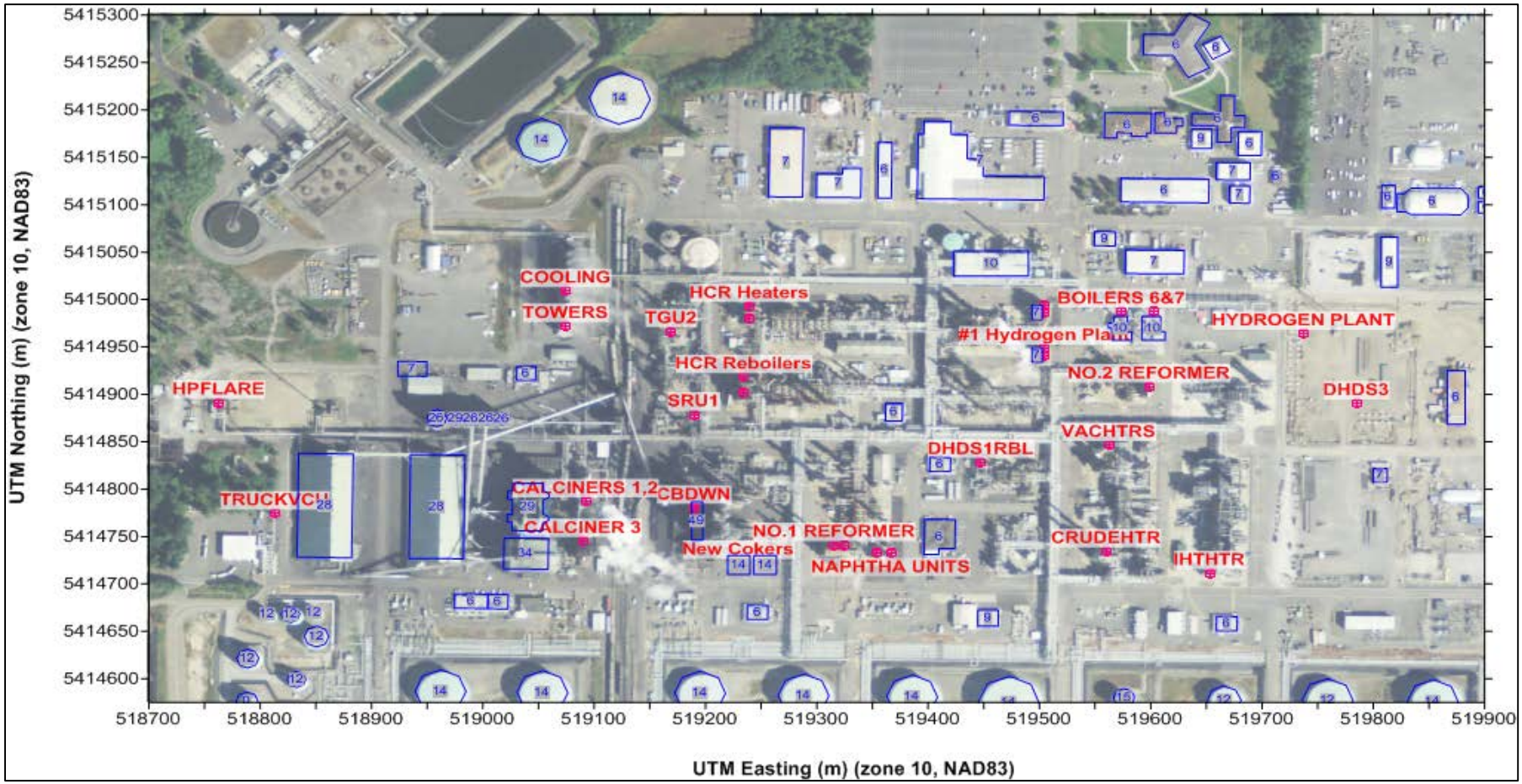



**Figure 5-3. Source and Building Locations with Heights**

## 5.3 Project Impact Assessment

This section assesses the magnitude and spatial extent of ground level concentrations resulting from $NO_X$, CO, $SO_2$, $PM_{10}$, $PM_{2.5}$, and toxic air pollutant emissions from the Project, including, as appropriate, increases due to the new emission units, increased utilization of existing emission units, and contemporaneous emission increases and decreases, but excluding other (external) increment-consuming sources or background sources. If a model-predicted concentration exceeds the EPA significant impact levels (SIL) for that pollutant, the impacts of the facility must be assessed in the context of other increment consuming-sources to evaluate total increment consumption. Exceeding a SIL also requires that the facility's compliance with the applicable NAAQS and PSD increments be evaluated.

As discussed above, RE applied AERMOD to simulate pollutant dispersion for five years of hourly meteorological conditions measured at an on-site monitoring station. This section discusses the results of the modeling assessment.

### 5.3.1 Significant Impact Levels

RE modeled the project-related emissions presented in Tables 3-2 and 3-3. The reductions in emissions from removing the existing coker heaters were modeled as negative emissions with the current coker heater stack parameters.

In order to assess the significance of the model predictions, RE compared the AERMOD-predicted criteria pollutant concentrations with the applicable Class II PSD SILs. Class II receptors with concentrations below the SILs are considered to be "insignificantly affected" and these pollutants do not require assessments of the Class II PSD Increments or NAAQS. SILs have not been formally defined for all pollutants and averaging periods. EPA's interim SIL values of 7.5 micrograms per meter cubed ($\mu g/m^3$) and 7.8 $\mu g/m^3$ for 1-hour $NO_2$ and 1-hour $SO_2$, respectively were included in the significance analysis.

<u>$PM_{2.5}$ SIL Evaluation</u>

Although the $PM_{2.5}$ 24-hour and annual SILs were rejected in a recent court ruling, EPA's May 2014 Guidance on $PM_{2.5}$ permit modeling allows permitting authorities to continue to select and apply SIL values for $PM_{2.5}$ to support PSD permitting decisions with proper justification. According to the guidance, "If preconstruction monitoring data are sufficiently representative of the air quality in existence before the increase in emissions from the proposed source and the difference between the $PM_{2.5}$ NAAQS and the measured $PM_{2.5}$ background concentrations in the area is greater than the SIL value selected from the vacated Sections 51.166(k)(2) and 52.21(k)(2), then the EPA believes it will be sufficient in most cases for permitting authorities to conclude that a source with an impact equal to or below that SIL value will not cause or contribute to a violation of the NAAQS and to forego a cumulative modeling analysis for $PM_{2.5}$ with respect to the NAAQS." This means that if the $PM_{2.5}$ NAAQS minus the measured background concentration is greater than the SIL, then the SIL can be used to show that a source will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS.

EPA publishes design value concentrations for air quality monitors across the country, and these design value concentrations are compared against the NAAQS to determine if an area is

in attainment with applicable air quality standards. The design concentrations for 24-hour and annual $PM_{2.5}$ NAAQS are based on the 3-year average 98th percentile 24-hour $PM_{2.5}$ concentrations and 3-year average of annual $PM_{2.5}$ concentrations, respectively. $PM_{2.5}$ design values from 2003 – 2014 were obtained for ten $PM_{2.5}$ monitors in the region, including: Anacortes, Beacon Hill, Bellingham, Darrington, Kent, Lake Forest Park, Lynnwood, Marysville, Mount Vernon, Oak Harbor, and Seattle-Duwamish.

A summary of the EPA-reported $PM_{2.5}$ design values for 2012 – 2014 are presented in Table 5-3. The maximum 24-hour and annual $PM_{2.5}$ design values for the region (Table 5-3) indicate the SILs will be sufficiently protective of the NAAQS and could be used as a screening tool for modeling direct $PM_{2.5}$ emissions. $PM_{2.5}$ design value trends for the region are presented in Figures 5-4 and 5-5 for 24-hour and annual average $PM_{2.5}$, respectively.

**Table 5-3: $PM_{2.5}$ Design Values (2012 – 2014)**

| Description | 24-Hour $PM_{2.5}$ Design Value | Annual $PM_{2.5}$ Design Value |
|---|---|---|
| | ($\mu g/m^3$) | ($\mu g/m^3$) |
| Ten Station-Average [a] | 17 | 6 |
| Minimum | 6 | 3 |
| Maximum | 27 | 10 |
| Significant Impact Level | 1.2 | 0.3 |
| NAAQS | 35 | 12 |

Notes:

a Average of design values from Anacortes, Beacon Hill, Bellingham, Darrington, Kent, Lake Forest Park, Lynnwood, Marysville, Mount Vernon, Oak Harbor, and Seattle-Duwamish $PM_{2.5}$ monitoring stations.

Figure 5-4 illustrates the average 24-hour $PM_{2.5}$ design value trend, the design value plus the 24-hour $PM_{2.5}$ SIL (1.2 $\mu g/m^3$), and the NAAQS (35 $\mu g/m^3$). Figure 5-5 illustrates the average annual $PM_{2.5}$ design value trend, the design value plus the annual $PM_{2.5}$ SIL (0.3 $\mu g/m^3$), and the NAAQS (12 $\mu g/m^3$). The 24-hour and annual $PM_{2.5}$ trends show an overall improvement in regional $PM_{2.5}$ design values, which further strengthens the position that continued use of EPA SILs is appropriate in this area.

Other PSD-regulated pollutant SILs are provided in the federal regulations (40 CFR 51.165(b)(2)) and there are no changes to EPA's interim 1-hour $NO_2$ and 1-hour $SO_2$ SILS.

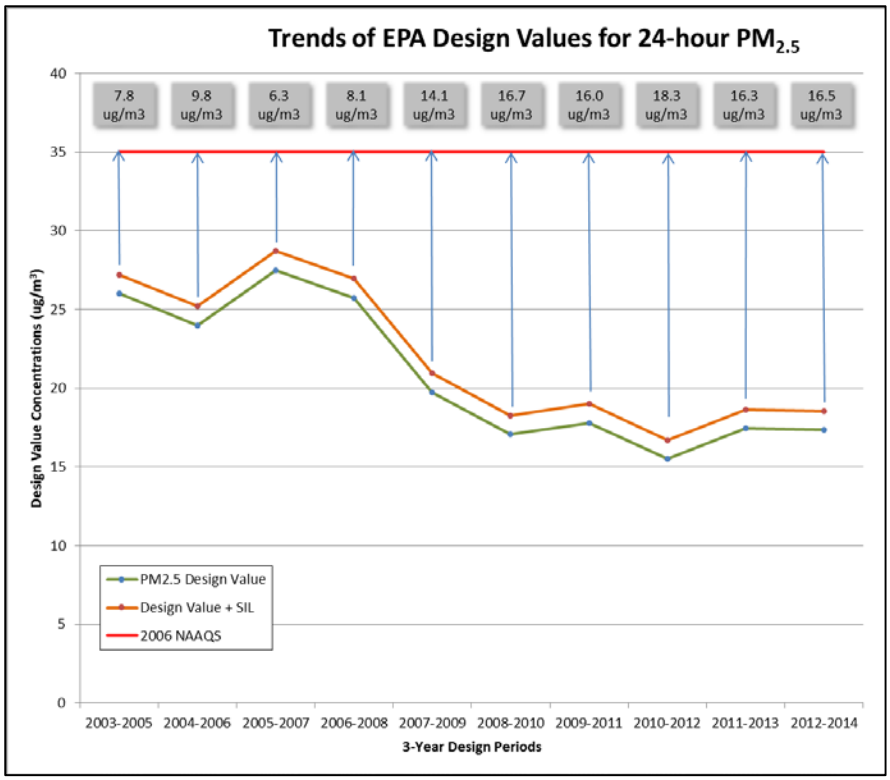



**Figure 5-4. 2003 – 2014 $PM_{2.5}$ Design Value Trend (24-hour Average).**

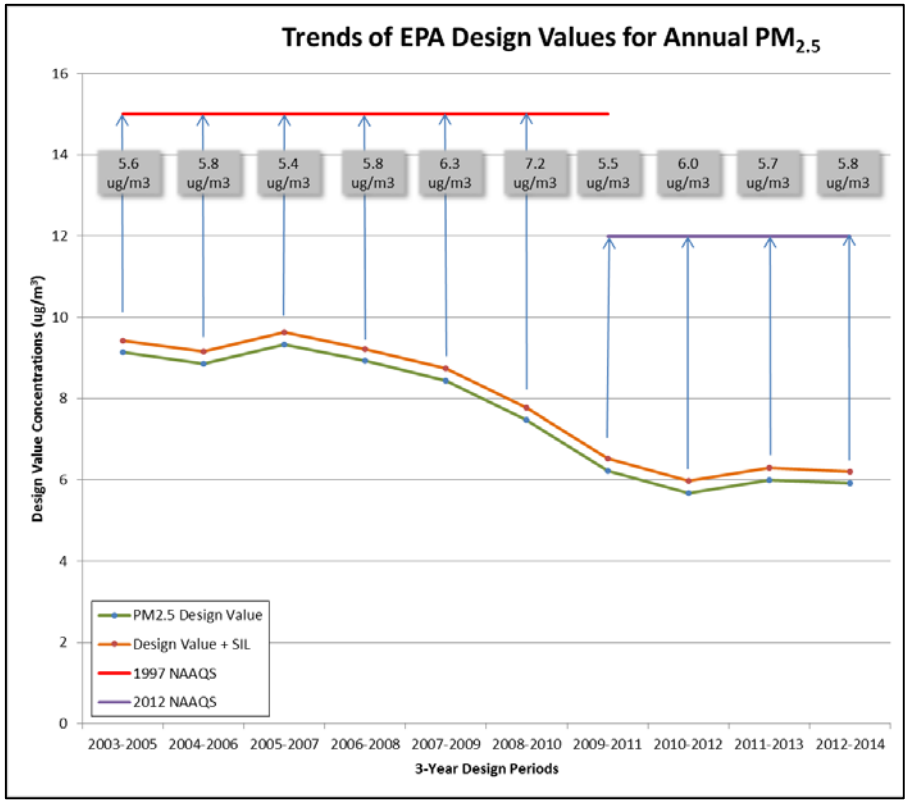



**Figure 5-5. 2003 – 2014 $PM_{2.5}$ Design Value Trend (Annual Average).**

### 5.3.2 AERMOD-Predicted Concentrations

The results of the criteria pollutant analysis are compared to the SILs in Table 5-4. Because the maximum model-predicted concentration of all modeled criteria pollutants for all averaging periods are less than the SILs, the Project is deemed to not cause or contribute to a violation of the NAAQS or PSD increments for these pollutants.

The Ambient Ratio Method (ARM) converts model-predicted $NO_X$ concentrations to $NO_2$ by applying a 80 percent ratio and a 75 percent ratio to 1-hour and annual average $NO_X$ concentrations.

EPA's May 20, 2014 $PM_{2.5}$ modeling guidance describes the process of comparing a project-related $PM_{2.5}$ model prediction to an applicable SIL. EPA guidance calls for comparing the 5-year average of the maximum model-predicted 24-hour or annual $PM_{2.5}$ concentrations each year at each receptor. The same approach is applied to the hourly $NO_2$ and $SO_2$ predictions. The project-related 24-hour and annual $PM_{2.5}$, 1-hour $NO_2$, and 1-hour $SO_2$ model-predictions presented in the table below are based on EPA's recommended approach.

**Table 5-4: Maximum AERMOD-Predicted Criteria Pollutant Concentrations**

| Criteria Pollutant | Averaging Period | Max. AERMOD Concentration (µg/m³) | Modeling Significance Level (µg/m³) | Monitoring De Minimus Concentration (µg/m³) |
|---|---|---|---|---|
| $NO_2$ [a] | 1-hr [c] | 5.7 | 7.5 [b] | None |
| | Annual | 0.9 | 1 | 14 |
| $SO_2$ | 1-hr [c] | 7.2 | 7.8 [b] | None |
| | 3-hr | 5.1 | 25 | None |
| | 24-hr | 1.6 | 5 | 13 |
| | Annual | 0.8 | 1 | None |
| CO [e] | 1-hr | 44.0 (normal) | 2,000 | None |
| | | 164.7 (su/sd/sb) | | |
| | 8-hr | 8.9 | 500 | 575 |
| | | 31.7 (su/sd/sb) | | |
| $PM_{10}$ | 24-hr | 1.0 | 5 | 10 |
| $PM_{2.5}$ | 24-hr [c] | 0.9 | 1.2 [d] | 4 [d] |
| | Annual [c] | 0.24 | 0.3 [d] | None |

Notes:

a $NO_2$ 1-hour and annual concentrations are assumed to be 80 percent and 75 percent of $NO_X$ based on ARM.

b The 1-hour $NO_2$ standard has been set (188 µg/m3, or 100 ppb) EPA provided an interim SIL of 7.5 ug/m3.

For the 1-hour SO2 standard (196 µg/m3, or 75 ppb), EPA provided an interim SIL of 7.8 µg/m³ (1-hr)

c 1-hour $NO_2$, 1-hour $SO_2$, 24-hour $PM_{2.5}$, and annual $PM_{2.5}$ model predictions based on the maximum five year average of the 100th percentile values at each receptor.

d The $PM_{2.5}$ significance and monitoring de minimus levels were vacated on January 22, 2013 from the Federal PSD regulations, but are presented here for comparison purposes.

e AERMOD-predicted CO concentrations for both normal operation and startup, shutdown, and standby (su/sd/sb) scenarios.

To present the spatial distribution of AERMOD-predicted concentrations, the maximum AERMOD-predicted 1-hour $SO_2$, 24-hour $PM_{2.5}$, annual $PM_{2.5}$ concentrations are presented in Figures 5-6 through 5-8. The maxima are located on the south edge of the refinery property for 1-hour average model-predictions and the northern edge of the refinery property for 24-hour and annual average model-predictions.

NWCAA has established $SO_2$ standards of 655 µg/m$^3$ (one-hour average) and 2,096 µg/m$^3$ (five-minute average). The maximum 1-hour $SO_2$ concentration is 12.8 µg/m$^3$. Using the Turner method to scale the 1-hour average concentration to a 5-minute average, $X_5 = X_{60} \times (5/60)^{-0.17}$, the maximum 5-minute $SO_2$ concentration is 19.5 µg/m$^3$. Both of these concentration predictions are far less than the NWCAA standards.

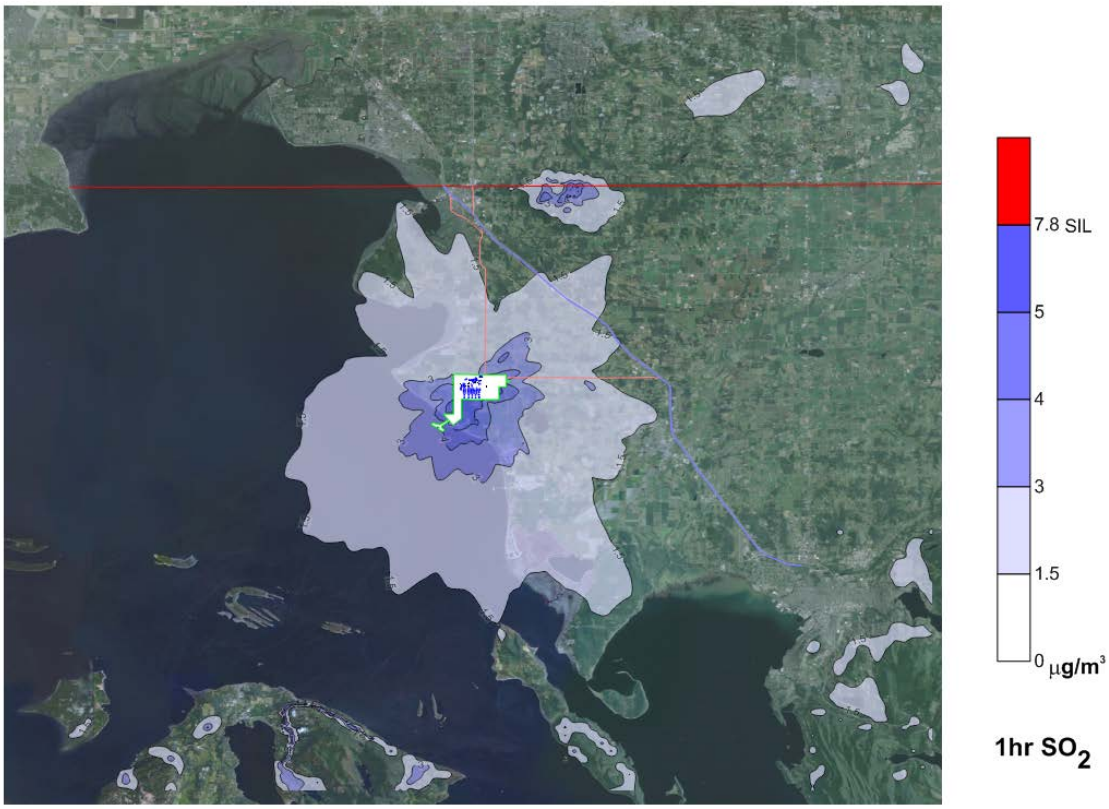



**Figure 5-6. Maximum 1-hour average $SO_2$ Concentrations**

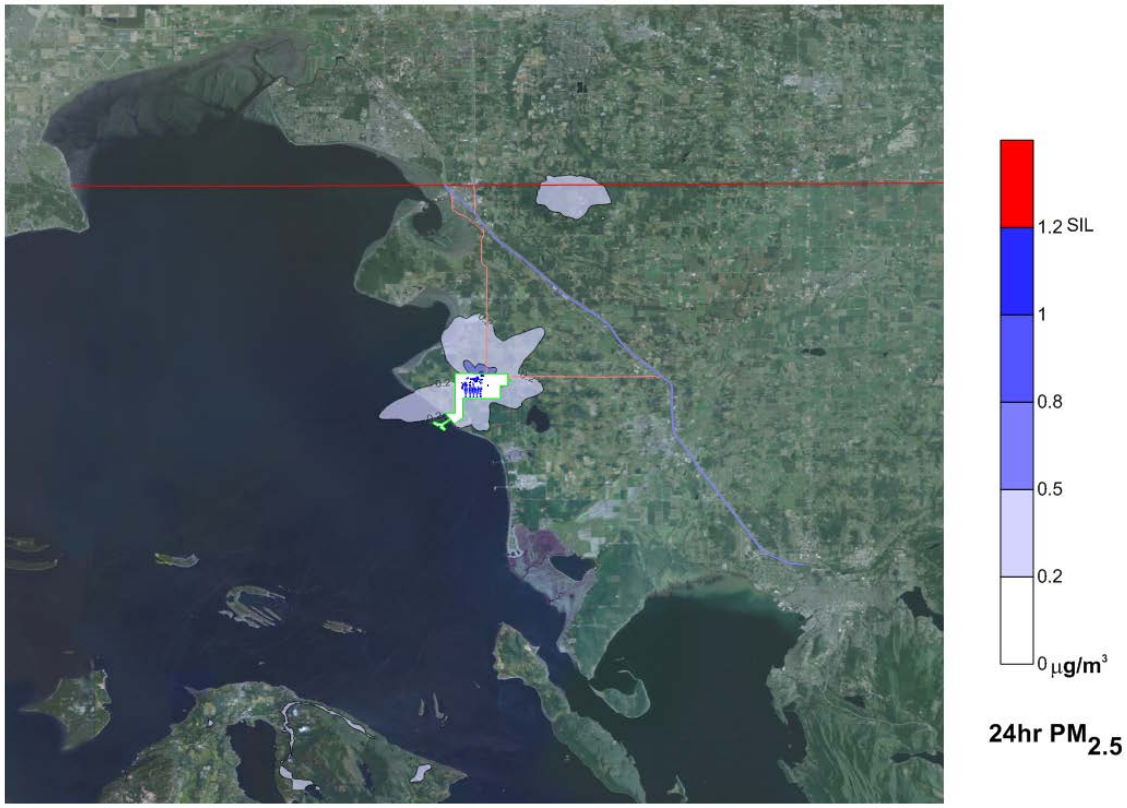



**Figure 5-7. Maximum 24-hour average $PM_{2.5}$ Concentrations**

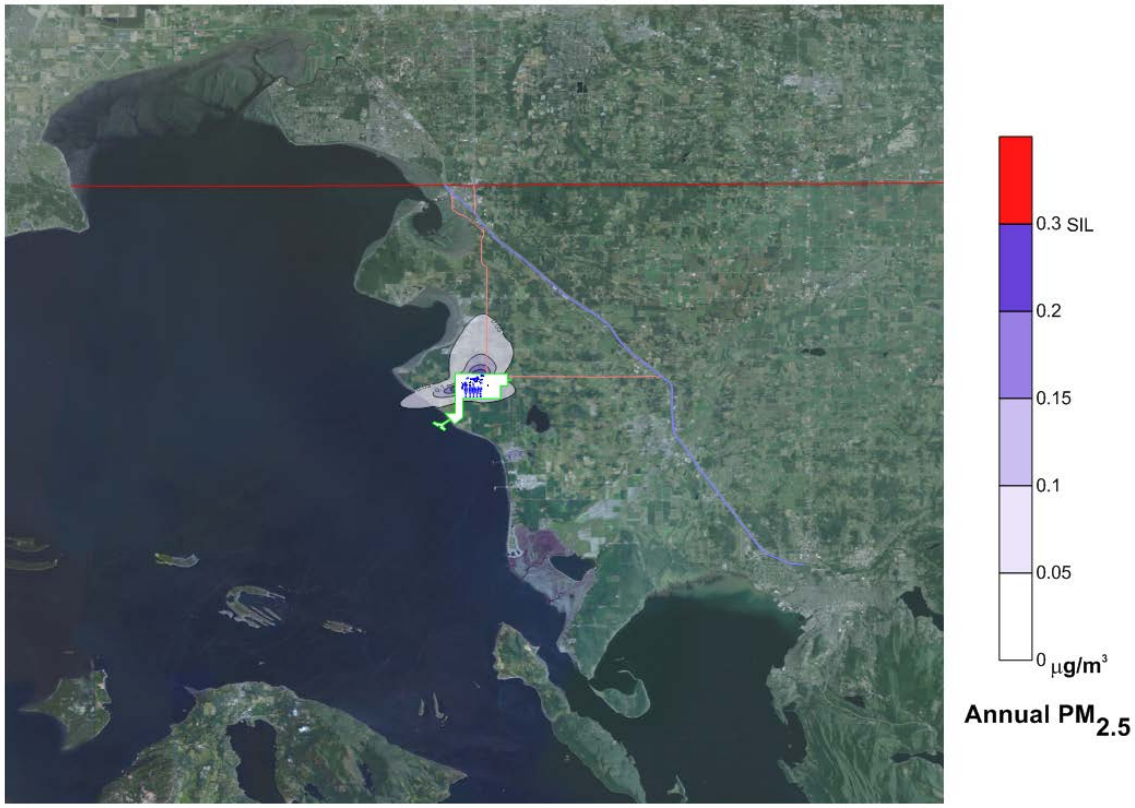



**Figure 5-8. Maximum annual average $PM_{2.5}$ Concentrations**

### 5.3.3 Toxic Air Pollutant Concentrations

WAC 173-460 regulates toxic air pollutants from new and modified air pollution sources and requires permit applications to include dispersion modeling of toxic air pollutants if emissions exceed certain thresholds. Maximum model-predicted TAP concentrations are then compared with the applicable ASILs. Concentrations below the ASILs indicate insignificant potential for adverse health effects from these chemicals and a permit can be granted without further analysis. If concentrations are above the ASIL, the applicant must revise the Project or submit a health risk assessment demonstrating that toxic emissions from the source are sufficiently low to protect human health.

RE conducted a dispersion modeling analysis for 15 toxic air pollutants whose emissions exceeded the SQERs. Depending on the TAP, RE used the 1-hour, 24-hour, or annual concentrations for comparison with ASILs. Emission rates are listed in Table 3-4.

AERMOD-predicted concentrations are compared to ASILs in Table 5-5. All predicted 1-hour, 24-hour, and annual maximum predictions attributable to the increase in TAP emissions are less than the ASILs. Consequently, no adverse impacts attributable to TAP emissions from the Project are anticipated.

NWCAA established a 24-hour formaldehyde standard of 0.05 ppmv. The maximum AERMOD-predicted formaldehyde concentration for the Project is 0.0021 µg/m$^3$ (1.7×10-6 ppmv), far less than the standard.

**Table 5-5: Maximum Predicted Toxic Air Pollutant Concentrations**

| TAP | Averaging Period | Max. AERMOD Concentration (µg/m³) | ASIL (µg/m³) | Over ASIL? |
|---|---|---|---|---|
| Acrolein | 24-hour | 2.80E-04 | 0.060 | No |
| Arsenic | annual | 9.42E-07 | 3.03E-04 | No |
| Benzene | annual | 1.01E-05 | 0.0345 | No |
| Beryllium | annual | 6.23E-07 | 4.17E-04 | No |
| Cadmium | annual | 5.19E-06 | 0.000238 | No |
| CO | 1-hour | 44.0 (normal) | 23,000 | No |
| | | 164.7 (su/sd/sb) | | No |
| Hexavalent Chromium | annual | 2.64E-07 | 6.67E-06 | No |
| Formaldehyde | annual | 0.00035 | 0.167 | No |
| $H_2SO_4$ | 24-hour | 0.057 | 1 | No |
| $H_2S$ | 24-hour | 0.014 | 2 | No |
| Nickel | annual | 0.00001 | 0.0042 | No |
| $NO_X$ | 1-hour | 11.0 | 470 | No |
| $SO_2$ | 1-hour | 12.8 | 660 | No |
| Benzo(a)pyrene | annual | 2.74E-07 | 9.09E-04 | No |
| 7,12-Dimethylbenzanthracene | annual | 7.54E-08 | 1.41E-05 | No |

### 5.3.4 Secondary $PM_{2.5}$ Formation

Formation of secondary $PM_{2.5}$ within the project region was assessed using three approaches: a review of the regional historic $PM_{2.5}$ sulfate and nitrate composition, a comparison of the region's $SO_2$ and $NO_X$ emissions to $PM_{2.5}$ composition, and the use of inter-pollutant trading ratios to estimate impacts from secondary $PM_{2.5}$. The assessments indicate that secondary $PM_{2.5}$ formation is minimal within the project region. Conservative modeling of emissions indicates the cumulative impact of primary and secondary $PM_{2.5}$ is below both the 24-hour and annual SILs, negating the need for regional modeling. Details of the secondary $PM_{2.5}$ analysis can be found in Appendix D.

### 5.3.5 Ozone Analysis

RE conducted an ozone modeling study using the increase in emissions from the refinery attributable to the Project. This simulation used the US EPA's Community Multi-scale Air Quality model (CMAQ) to simulate July 25-30, 1998. This is one of the more severe historical ozone episodes, and similar modeling analyses have been used in several analyses to estimate the effects on ozone concentrations from Project increases in emissions of $NO_X$ and VOCs greater than 100 TPY.

The modeling simulations were based on those developed by Washington State University (WSU) Laboratory for Atmospheric Research in support of a state implementation

plan (SIP) for Ozone for the Portland, OR and Vancouver, WA region.[22] The WSU database was used as the base case scenario to analyze future emission scenarios for the Puget Sound Clean Air Agency (PSCAA).[23] In those analyses and the current analysis, a three-day period beginning July 26, 1998 was selected because the episode had the highest observed ozone levels in recent years for the Seattle/Portland airshed.

Appendix E details the ozone modeling. Two cases were run: a base case using all the sources in the emission inventory used by WSU and a "PTE" case that also include the increased emissions associated with the project. The difference between the ozone concentrations predicted by the two runs is used to evaluate the implications to regional ozone due to the Project.

Generally speaking, ozone concentrations decreased in the region close to the facility due to "NOx titration," where $NO + O_3 \rightarrow NO_2 + O_2$. Elsewhere, increases in ozone concentration are predicted to be very small, typically less than 1 ppb, and limited to the area within about 75 km of the facility. The model-predicted increase in ozone concentration at the Enumclaw monitoring site, which for the period 2006-2008 did not attain the NAAQS of 75 ppb, is less than 0.1 ppb.

RE concludes that the Project will have an insignificant effect on regional ozone concentrations.

[22] *Historical and Future Ozone Simulations using the MM5/SMOKE/CMAQ System in the Portland/Vancouver Area*, Ying Xie and Brian Lamb, Laboratory of Atmospheric Research, Department of Civil & Environmental Engineering, WSU. December 31, 2005.

[23] *Modeling Analysis of Future Emission Scenarios for Ozone Impacts in the Puget Sound Area*, Brian Lamb and Ying Xie, Laboratory of Atmospheric Research, Department of Civil & Environmental Engineering, WSU; Clint Bowman, Sally Otterson, and Doug Schneider, Washington State Department of Ecology; and Kathy Himes, John Anderson, Kwame Agyei, and Beth Carper, PSCAA. August, 2006.

# 6 Class I Air Quality Impact Assessment

PSD guidance requires an analysis of potential impacts to air quality in certain National Parks and Wilderness Areas that are designated as “Class I Areas.” The analysis must examine compliance with NAAQS, PSD increments, and AQRVs. Although the regulations require assessment of Class I Areas within 100 km (62.1 miles) of the facility subject to PSD review, Federal Land Managers (FLMs) and Ecology typically request analyses of AQRV impacts for Class I Areas within 200 km (124 miles) of the site. EPA’s Regional Haze Regulations require that Class I Areas within 300 km (186 miles) be included. A larger CALPUFF domain was used for this AQRV analysis, resulting in the inclusion of Class I Areas beyond those usually required for a PSD analysis.

Olympic National Park and North Cascades Wilderness Area are Class I Areas within 100 km of the facility. Three other Class I Areas are within 200 km. Mount Rainier National Park and the Goat Rocks and Mount Adams Wilderness Areas are beyond the 200-km range, but all three were included in the analysis. Although they are not Class I Areas, the Mount Baker Wilderness Area and San Juan Islands are also included in the analysis because Ecology and the FLMs requested their inclusion in AQRV assessments.

The AQRVs of concern include visibility, soil, flora, fauna, and aquatic resources. The CALPUFF modeling system is currently recommended for evaluating impacts to AQRVs in Class I Areas affected by long-range transport. Potential impacts are characterized based on predictions of total nitrogen and/or sulfur deposition flux, change in light extinction, and pollutant concentrations. Pollutant concentration predictions were also used to assess Class I Area increment consumption for pollutants subject to PSD review.

## 6.1 Model Selection

On April 15, 2003 EPA adopted the CALPUFF modeling system as the EPA’s preferred model for long-range transport assessments and for evaluating potential impacts to Class I Areas by including CALPUFF in Appendix A of the Guidelines. Features of the CALPUFF modeling system include the ability to consider: secondary aerosol formation; gaseous and particle deposition; wet and dry deposition processes; complex three-dimensional wind regimes; and the effects of humidity on regional visibility. As is currently required, CALMET and CALPUFF Version 5.8.4 (release date July 31, 2013) was used, and CALPOST version 6.221, level 080724 was used for post processing.

## 6.2 Modeling Procedures

The modeling procedures followed Federal Land Managers’ Air Quality Related Workgroup (FLAG) and Interagency Workgroup on Air Quality Modeling (IWAQM) recommendations - in particular, FLAG (2000, revised October 2010) and IWAQM (1998) guidance documents, as well as a clarification memo posted on the EPA SCRAM website on August 31, 2009 (Fox, 2009). FLAG (2010) revised some procedures in the FLAG (2000) report, with the most significant revisions related to visibility impact calculations. In addition, FLAG (2010) includes a methodology to “screen” some projects from AQRV review. From a regulatory standpoint, Fox (2009) prescribes specific CALMET/CALPUFF settings recommended for permit applicants.

### 6.2.1 Model Setup and Application

Although the CALPUFF modeling system is equipped with a host of modeling options, RE used the procedures and defaults recommended by the FLAG Phase I Report and the EPA-FLM CALMET Clarification Memo.

### 6.2.2 Emission Rates and Stack Parameters

For the regional haze assessment using the CALPUFF modeling system, $PM_{10}$ emission rates must be speciated into six fractions: soot or elemental carbon (EC), PM fine (PMF), PM coarse (PMC), organic carbon (OC), sulfate ($SO_4$), and nitrate ($NO_3$). Tables 6-1 and 6-2 shows the speciated $PM_{10}$ emission rates used in the short-term and long-term analyses. The speciation was accomplished using a database prepared by Ecology based on speciation profiles recommended for aerosol modeling by the EPA. Sources in the database are referenced by Source Classification Code (SCC), and the database provided information for partitioning between the coarse and fine particulate fractions as well as information for speciating the fine fraction into the other components required by CALPUFF.

The CALPUFF modeling evaluated maximum short-term emissions from the replacement coker heaters and increases in annual emissions for affected existing emission units. For the modeling analyses, emission reductions from removal of the existing coker heaters were subtracted from potential emissions from the proposed coker heaters.

In order to shorten CALPUFF simulation run times, it is accepted practice to combine emissions from similar sources into a single CALPUFF emission source with the average source release parameters. For example, the four cells of cooling tower #2 were combined into a single source. The CALPUFF sources include:

- The new coker heaters (WCOKE & ECOKE);
    - Existing coker heater emissions were subtracted from new coker heater potential emissions.
- Increased utilization of coke drum venting operations (CVENT)
- Increased utilization of #1, #2, and #3 calciner hearths
    - All stacks combined into a single stack for modeling (CALCNS)
- Increased utilization of crude heater (CRUDEHTR)
- Increased utilization of north and south vacuum heaters
    - Vacuum heater emissions combined into a single stack for modeling (VHTRS)
- Increased utilization of the hydrocracker R-1 reactor, 1st stage fractionator, 2nd stage fractionator, and R-4 reactor heaters
    - Reactor heaters combined into a single stack (HC_RHTRS)

- 1st and 2nd Stage Fract. Heaters have a combined stack (HCREBLU)

- Increased utilization of #1 and #2 Reformer Heaters
  - #1 and #2 Reformer Heaters were combined to a single stack (REF_HTRS)
- Increased utilization of the sulfur and tail gas units (SRU1 & TGU2)
- Increased utilization of cooling tower #1 and cooling tower #2
  - 9 cells of cooling tower #1 were combined to a single stack (COOL1)
  - 4 cells of cooling tower #2 were combined to a single stack (COOL2)
- Increased utilization of #1 hydrogen plant and contemporaneous increase from #2 hydrogen plant
  - Furnaces from #1 and #2 hydrogen plants were combined to a single stack (H2_FURNS)
- Increased utilization of product loadout and vapor combustion units
  - Dock VCU and truck loading VCUs combined to a single stack (VCUS)
- Increased utilization of high pressure flare for catalyst changeouts and contemporaneous emission increases from #2 hydrogen plant flare and high pressure flare
  - Flare emissions combined to a single stack (FLARES)
- Increased utilization and contemporaneous emission increases from all other heaters
  - #1 DHDS reboiler, NHDS charge heater, NHDS reboiler, ISOM heater, and #3 DHDS heater were combined to a single stack (OTHTRS)
- Secondary emissions from crude ship pumping (SHIPPMPN)

The CALPUFF emission sources are presented in Tables 6-1 and 6-2 with $NO_X$, $SO_2$, and speciated $PM_{10}$ emission rates. The CALPUFF source release parameters are presented in Table 6-3. RE calculated the average exit velocity from each combined stack and then calculated a combined stack exit diameter based conserving an average air flow rate from the combined stacks. Building downwash parameters, which are considered optional by Ecology, were not included in the analysis.

## Table 6-1: Speciated Short-Term Emission Rates for AQRV Analysis

| CALPUFF Sources | $SO_2$ | $NO_X$ | Speciated $PM_{10}$ (lb/hr) [a] | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Coarse Mass | Fine Sulfate (as $SO_4$) | Fine Nitrate (as $NO_3$) | Fine Elemental Carbon | Fine Organic Carbon | Fine Crustal Material |
| WCOKE [b] | 5.1 | 3.0 | 0 | 0.4 | 0.005 | 0 | 0.09 | 0.5 |
| ECOKE [b] | 5.1 | 3.0 | 0 | 0.4 | 0.005 | 0 | 0.09 | 0.5 |
| BOIL6 [b] | 0 | 0 | 0 | 0.5 | 0.007 | 0 | 0.13 | 0.7 |
| BOIL7 [b] | 0 | 0 | 0 | 0.5 | 0.007 | 0 | 0.13 | 0.7 |
| DHDS3 [b] | 3.0 | 1.0 | 0 | 0.10 | 0.001 | 0 | 0.02 | 0.1 |
| H2SMR [b] | 2.8 | 3.5 | 0 | 1.7 | 0.021 | 0 | 0.4 | 2.2 |
| H2FLR_ST [c] | 0.0 | 13.0 | 0 | 0 | 0 | 0 | 1.9 | 0 |
| SRU1_M [d] | 0.1 | 2.9 | 0 | 0 | 0 | 0 | 0 | 0 |

Notes:

a $PM_{10}$ speciated using a speciation database provided by Ecology based on speciation profiles recommended by EPA aerosol modeling. $PM_{10}$ is the sum of coarse mass and the fine PM ($PM_{2.5}$) components: ammonium sulfate, ammonium nitrate, fine crustal material, elemental carbon and organic carbon.

b $PM_{10}$ speciation calculated using SCC speciation profile: 30600106 (Process heaters, process gas-fired).

c $PM_{10}$ speciation calculated using SCC speciation profile: 30600904 (Flares, process gas).

d $PM_{10}$ speciation calculated using SCC speciation profile: 30603301 (Sulfur recovery units).

## Table 6-2: Speciated Long-Term Emission Rates for AQRV Analysis

| CALPUFF Sources | $SO_2$ | $NO_X$ | Speciated $PM_{10}$ (lb/hr)[a] | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Coarse Mass | Fine Sulfate (as $SO_4$) | Fine Nitrate (as $NO_3$) | Fine Elemental Carbon | Fine Organic Carbon | Fine Crustal Material |
| WCOKE [b] | 5.3 | 8.1 | 0 | 0.8 | 0.010 | 0 | 0.19 | 1.0 |
| ECOKE [b] | 5.3 | 8.1 | 0 | 0.8 | 0.010 | 0 | 0.19 | 1.0 |
| CALCNS [c] | 27.2 | 32.6 | 0 | 0.2 | 0.002 | 0 | 0.04 | 0.6 |
| VHTRS [b] | 0 | 3.5 | 0 | 0.028 | 0.0003 | 0 | 0.0068 | 0.04 |
| HC_RHTRS [b] | 0.5 | 2.9 | 0 | 0.1 | 0.002 | 0 | 0.03 | 0.2 |
| REF_HTRS [b] | 0 | 3.1 | 0 | 0.077 | 0.0010 | 0 | 0.02 | 0.10 |
| OTHTRS [b] | 0.7 | 3.6 | 0 | 0.2 | 0.002 | 0 | 0.05 | 0.2 |
| H2_FURNS [b] | 1.4 | 5.7 | 0 | 1.8 | 0.022 | 0 | 0.43 | 2.3 |
| VCUS [d] | 0.0008 | 0.4 | 0 | 0.0017 | 0 | 0 | 0.0070 | 0.002 |
| FLARES [d] | 0.3 | 2.4 | 0 | 0 | 0 | 0 | 0.13 | 0 |
| CVENT [e] | 0 | 0 | 0 | 0.2 | 0.002 | 0 | 0.05 | 0.8 |
| CRUDEHTR [b] | 2 | 4.0 | 0 | 0.064 | 0.0008 | 0 | 0.0156 | 0.08 |
| HCREBLU [b] | 0.8 | 4.7 | 0 | 0.2 | 0.002 | 0 | 0.05 | 0.3 |
| SRU1 [f] | 3.7 | 1.0 | 0 | 0.013 | 0.0002 | 0 | 0.0032 | 0.05 |
| TGU2 [f] | 3.7 | 1.0 | 0 | 0.013 | 0.0002 | 0 | 0.0032 | 0.05 |
| SHIPPMPN [g] | 0.2 | 0.3 | 0 | 0.034 | 0.00003 | 0.007 | 0.0091 | 0.02 |
| COOL1 [h] | 0 | 0 | 0 | 0.088 | 0.00112 | 0 | 0.0217 | 0.37 |
| COOL2 [h] | 0 | 0 | 0 | 0.043 | 0.0006 | 0 | 0.0107 | 0.18 |
| GCOKE1 [i] | 0 | 0 | 0 | 0.024 | 0.0003 | 0 | 0.0059 | 0.10 |
| GCOKE2 [i] | 0 | 0 | 0 | 0.024 | 0.0003 | 0 | 0.0059 | 0.10 |

Notes:

a $PM_{10}$ speciated using a speciation database provided by Ecology based on speciation profiles recommended by EPA aerosol modeling. $PM_{10}$ is the sum of coarse mass and the fine PM ($PM_{2.5}$) components: ammonium sulfate, ammonium nitrate, fine crustal material, elemental carbon and organic carbon.

b $PM_{10}$ speciation calculated using SCC speciation profile: 30600106 (Process heaters, process gas-fired).

c $PM_{10}$ speciation calculated using SCC speciation profile: 30601401 (Coke Calciner).

d $PM_{10}$ speciation calculated using SCC speciation profile: 30609904 (Flares, process gas).

e $PM_{10}$ speciation calculated using SCC speciation profile: 30600402 (petroleum blowdown system).

f $PM_{10}$ speciation calculated using SCC speciation profile: 30603301 (Sulfur recovery units).

g $PM_{10}$ speciation calculated using SCC speciation profile: 30600103 (Oil-Fired Process).

h $PM_{10}$ speciation calculated using SCC speciation profile: 30600701 (Cooling towers).

i $PM_{10}$ speciation calculated using SCC speciation profile: 30601402 (Delayed Coker).

| Table 6-3: Source Release Parameters for Class I Analysis | | | | | | |
|---|---|---|---|---|---|---|
| **Point Sources** | | | | | | |
| **Source** | **Base Elev. [a] (meters)** | **Stack Height (ft)** | **Temperature (°F)** | **Exit Velocity (ft/sec)** | **Stack Diameter (ft)** | **Description** |
| **Short-Term CALPUFF Analysis** | | | | | | |
| WCOKE | 33.0 | 189.3 | 350.0 | 23.9 | 8.6 | New Coker Heater (West) minus old Coker Heater |
| ECOKE | 33.1 | 189.3 | 350.0 | 23.9 | 8.6 | New Coker Heater (East) minus old Coker Heater |
| BOIL6 | 35.7 | 150.0 | 335.0 | 62.3 | 6.0 | #6 Boiler (Contemporaneous) |
| BOIL7 | 36.0 | 150.0 | 335.0 | 62.3 | 6.0 | #7 Boiler (Contemporaneous) |
| DHDS3 | 37.2 | 100.0 | 850.0 | 21.0 | 3.9 | #3 DHDS Heater (Contemporaneous) |
| H2SMR | 36.9 | 120.0 | 299.9 | 58.0 | 6.8 | #2 Hydrogen Plant (Contemporaneous) |
| H2FLR_ST | 36.9 | 158.0 | 1831.7 | 65.6 | 10.2 | #2 Hydrogen Plant Flare (Contemporaneous) |
| SRU1_M | 32.9 | 213.3 | 550.1 | 60.0 | 3.6 | Sulfur Plant Incinerator (Contemporaneous) |
| **Long-Term CALPUFF Analysis** | | | | | | |
| WCOKE | 33.0 | 189.3 | 350.0 | 23.9 | 8.6 | New Coker Heater (West) minus old Coker Heater |
| ECOKE | 33.1 | 189.3 | 350.0 | 23.9 | 8.6 | New Coker Heater (East) minus old Coker Heater |
| CALCNS | 32.0 | 242.0 | 205.1 | 67.2 | 6.5 | Calciners #1 - #3 |
| VHTRS | 35.5 | 145.0 | 336.8 | 9.2 | 7.8 | Vacuum Heaters |
| HC_RHTRS | 33.4 | 145.0 | 638.3 | 8.9 | 6.0 | Hydrocracker R1 & R4 Heaters |
| REF_HTRS | 34.4 | 161.0 | 547.9 | 14.1 | 10.2 | #1 & #2 Reformer Heaters |
| OTHTRS | 35.2 | 91.2 | 635.4 | 12.4 | 4.7 | #1 DHDS Reboiler, #3 DHDS, Naphtha, and ISOM Heaters |
| H2_FURNS | 35.6 | 88.0 | 513.0 | 39.6 | 6.0 | #1 & #2 Hydrogen Plant Furnaces |
| VCUS | 23.2 | 66.3 | 1300.0 | 21.9 | 10.3 | Dock and Truck VCUs |
| FLARES | 33.4 | 178.3 | 1831.7 | 65.6 | 1.9 | #2 Hydrogen Plant and HP Flares |
| CVENT | 32.7 | 182.0 | 220.0 | 161.7 | 1.0 | Coke Drum Venting |
| CRUDEHTR | 35.4 | 200.1 | 287.3 | 14.1 | 11.9 | Crude Heater |
| HCREBLU | 33.2 | 160.0 | 286.4 | 37.3 | 9.4 | Hydrocracker Frac. Heaters |
| SRU1 | 32.9 | 213.3 | 550.1 | 60.0 | 3.6 | Sulfur Plant Incinerator |
| TGU2 | 32.8 | 165.0 | 85.0 | 28.0 | 3.0 | #2 Tail Gas Unit |
| SHIPPMPN | 13.9 | 164.0 | 308.9 | 19.9 | 3.9 | Crude Pumping |
| COOL1 | 32.2 | 75.0 | 90.0 | 38.8 | 26.0 | #1 Cooling Tower Cells 1 - 9 |
| COOL2 | 40.3 | 75.0 | 90.0 | 27.0 | 30.0 | #2 Cooling Tower Cells 1 - 4 |

| Volume Sources | | | | | |
|---|---|---|---|---|---|
| Source | Base Elev. [a] (meters) | Release Height (ft) | $\sigma_y$ initial (ft) | $\sigma_z$ initial (ft) | Description |
| GCOKE1 | 32.5 | 14.8 | 45.8 | 13.7 | Green Coke Handling |
| GCOKE2 | 32.5 | 14.8 | 45.8 | 13.7 | Green Coke Handling |

Notes:

a Base elevations from CALMET terrain file

### 6.2.3 Averaging Periods

CALPUFF-predicted hourly pollutant concentrations were averaged for comparison with 3-hour, 24-hour, and annual Class I PSD Increments. Predicted extinction coefficients and total deposition fluxes were calculated as 24-hour and annual averages, respectively. Comparisons with regulatory criteria were based on the highest model-prediction of the three-year simulation for each averaging period except for $PM_{2.5}$, which is based on the highest three-year average concentrations.

### 6.2.4 Chemical Transformations

The $NO_X$ chemistry in CALPUFF depends on the ambient ammonia concentration to establish the equilibrium between gaseous nitric acid and ammonium nitrate. However, ambient ammonia concentrations are not explicitly simulated by CALPUFF and the user must select an appropriate background concentration. The IWAQM Phase II Recommendations suggest typical ammonia concentrations as: 10 parts per billion (ppb) for grasslands, 0.5 ppb for forests, and 1 ppb for arid lands during warmer weather.

An ammonia monitoring program conducted at Abbotsford and Chilliwack, British Columbia (BC) observed average concentrations of 8 and 16 ppb, respectively. The average concentration observed by Environment Canada (17 ppb) was used in the current study and is considered a conservative background ammonia concentration since the majority of the land use in the domain is forest and actual ammonia concentrations are likely lower. The 17 ppb background concentration has been used for past AQRV studies in the same region, and its use is also considered conservative because it ensures the conversion of $NO_X$ to ammonium nitrate is not limited by a lack of ammonia for the range of $NO_X$ concentrations predicted in this study. More recent ammonia measurements were obtained from BC's Air Data Archive[24] and show a modest decrease in ammonia concentrations, leading to the decision to retain the use of 17 ppb for the current modeling effort.

Reaction rates in the CALPUFF chemistry algorithms are also influenced by background ozone concentrations. RE has obtained ozone data collected concurrent with the modeled period at various NPS, Ecology, Oregon Department of Environmental Quality (ODEQ), and British Columbia Ministry of Water, Land, and Air Protection (MWLAP) stations within and around the study area. CALPUFF uses a background ozone value (BCK03) for hours when none of the supplied ozone stations have valid data. A conservative value of 60 ppb was specified, to avoid

[24] http://envistaweb.env.gov.bc.ca/

artificially limiting chemical transformations (e.g. $NO_X$ titration). However, there are no hours with all stations reporting only missing values in the given ozone dataset.

### 6.2.5 Domain and Receptors

The terrain for the CALPUFF simulations is shown in Figure 6-1. The 452 km-by-412 km domain is large enough to include the Class I Areas of interest with at least a 50 km allowance for complex flows that might cause recirculation of plumes originating at the Refinery. A Lambert conformal coordinate system was used and selected to be a sub-domain of the coordinate system used by the University of Washington (UW) for their MM5 simulations of Pacific Northwest Weather.[25] The UW MM5 simulations were used to construct the three dimensional meteorological data used in the CALPUFF analysis.

The CALPUFF dispersion model simulations assessed AQRVs at discrete receptors obtained from the National Park Service (NPS). Figure 6-2 shows these receptor locations within each Class I Area.[26] For the Mount Baker Wilderness Area, which is not a Class I Area and therefore has no NPS-developed receptor file, a 1-km grid was created within the area's boundary, and receptor elevations were calculated from the 4-km spacing terrain data used by CALMET to develop the wind fields and by CALPUFF to estimate the height of puffs above terrain. Two receptors were also placed on San Juan Island at the request of the NPS.[27]

In addition to the discrete Class I Area receptors described above, AQRV predictions were obtained at each of the 4-km spacing grid points throughout the CALPUFF computational domain. The 4-km receptor grid was also used to construct plots showing the spatial variation of the calculated parameters throughout the modeling domain. Such plots are used for diagnostic purposes and to develop the figures presented in this application for Ecology and the FLMs. When summarized by area of interest, the AQRV impact results provided in this application were taken from the NPS discrete receptors within each area (or those developed from the 4-km terrain data for the Mount Baker Wilderness Area).

Land use and terrain data were prepared from the USGS 1:250,000 scale data sets available on the internet resulting in 4-km spacing fields. As described above, the same terrain grid was used to develop the CALMET wind fields and internally by CALPUFF was also used to obtain receptor and source base elevations.

[25] http://www.atmos.washington.edu/mm5rt/mm5info.html
[26] http://www2.nature.nps.gov/air/Maps/Receptors/index.cfm
[27] Email from Tonnie Cummings (NPS) to Kyle Heitkamp (RE) on April 2, 2014 with coordinates to American Camp and British Camp on San Juan Island.

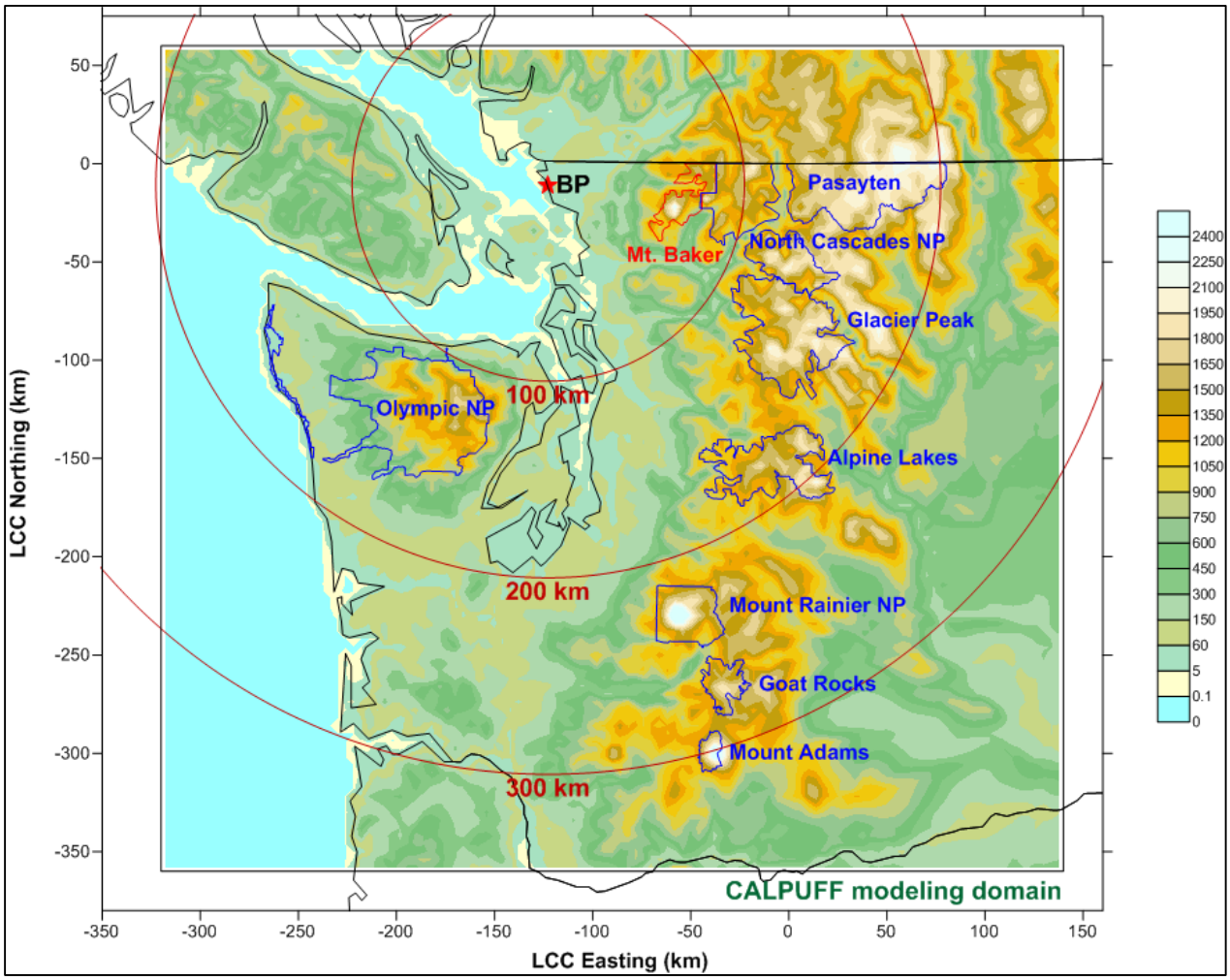



**Figure 6-1. Class I Modeling Domain**

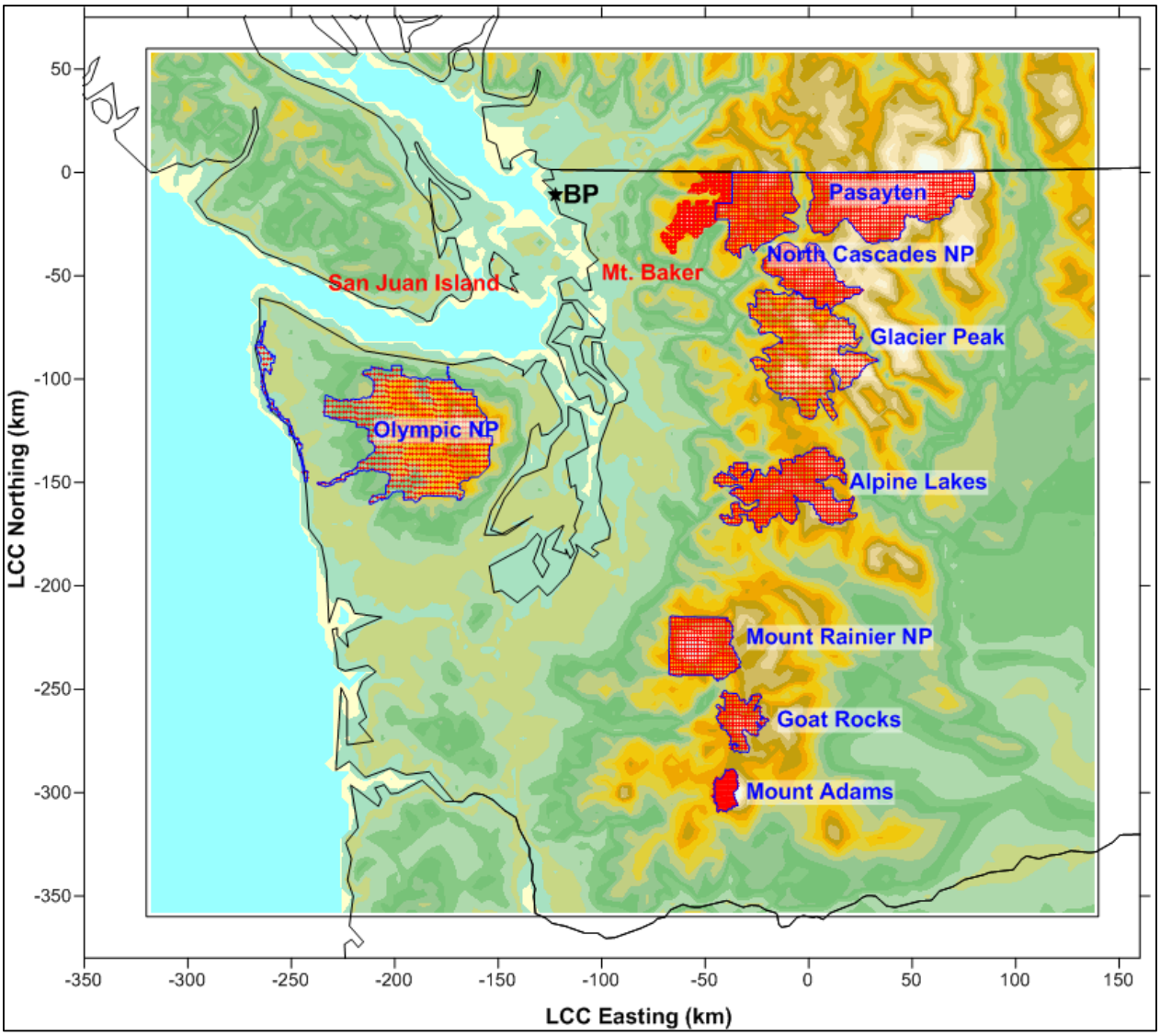



**Figure 6-2. CALPUFF Receptors**

### 6.2.6 Meteorological Data

Meteorological data sets were obtained from the UW's numerical simulations of Pacific Northwest weather with the Penn State and National Center of Atmospheric Research Mesoscale Model (MM5). The AQRV analysis used three years of hourly 4-km horizontal mesh size MM5 output data from January 2003 to December 2005. The UW MM5 datasets with a 12 km horizontal mesh size have also been used to assess industrial sources subject under the EPA Regional Haze Rule. For the current analysis the 4-km mesh size simulations were used in order to better resolve the flow in the complex terrain.

CALMET (Version 5.8.4), the meteorological preprocessor component of the CALPUFF system, was used to combine the MM5 simulation data, surface observations, terrain elevations, and land use data into the format required by the dispersion modeling component CALPUFF. In addition to specifying the three-dimensional wind field, CALMET also estimates the boundary layer parameters used to characterize diffusion and deposition by the dispersion model.

The techniques used to construct the meteorological database follow the recent August 31, 2009 clarification memo from the USEPA and the FLMs (Fox, 2009). Major features of the CALMET application and input data preparation are as follows:

- The model domain is a subset of the UW's 4-km mesh size MM5 domain as shown in Figure 6-1. The horizontal mesh size is 4 km, with each CALMET grid point matched to a MM5 grid point. In order to match the MM5 simulations, a Lambert Conformal Conic (LCC) coordinate system was used with an origin of 49N, 121W and standard latitudes of 30N and 60N.

- MM5 winds based on a 4-km grid spacing for January 2003 to December 2005 were used to initialize the three-dimensional wind field predictions. The MM5 data were processed with the CALMM5 utility for use by CALMET.

- Land use and terrain data were prepared using the processing tools accompanying the CALPUFF modeling system and the USGS GTOPO30 elevation data sets available on the Internet. Figure 6-2 shows the 4-km mesh size terrain used in the simulations.

- Surface weather observations were extracted from the National Climatic Data Center (NCDC) Integrated Surface Hourly Observations (ISHO) dataset (TD-3505) for an area that extended 50 km beyond the study domain boundary.

- Twice daily upper air soundings from Quillayute, Washington were used.

- Buoy observations from seven stations off the Pacific Coast (Washington and Southern British Columbia) were obtained from the National Data Buoy Center. These data are used by CALMET to characterize winds, sea-air temperature differences, and air temperatures over marine areas of the domain. The buoy data were processed by the BUOY utility from the CALPUFF modeling system.

- Hourly precipitation data were obtained from the NCDC's TD-3240 (COOP) dataset and from Environment Canada, and processed with the CALMET utility PMERGE. Sites were selected based on the criteria that the locations must be near (within 50 km) or in the model domain and there must be at least a 50 percent data recovery.

A sample CALMET input file was submitted to the FLMs and subsequently approved as part of their review of the modeling protocol submitted for the Project.

Selected hours of the three-year CALMET/MM5 three-dimensional data set were examined by extracting data from the CALMET output files and plotting the meteorological fields with the CALDESK software package. Wind vector plots were examined for different times of year, different times of day, and for all 10 vertical levels.

## 6.3 AQRV Calculation Procedures

The CALPUFF modeling system was used to predict criteria pollutant concentrations, total deposition fluxes, and light extinction coefficients attributable to project emissions in regional Class I Areas. These parameters were calculated from CALPUFF output files using the post-processor programs CALPOST and POSTUTIL.

Predictions of $NO_X$, $SO_2$, $PM_{10}$, and $PM_{2.5}$ concentrations in the Class I Areas of interest were extracted from the CALPUFF output files using the CALPOST post-processor. $PM_{10}$ and $PM_{2.5}$ predictions include both primary and secondary aerosols and account for the molecular weights of each resulting compound. The conversion to account for molecular weight and summing of species are accomplished using the POSTUTIL processor. Total nitrogen and sulfur deposition fluxes are similarly calculated by summing and converting the various species included in the wet and dry deposition CALPUFF output files. The nitrogen deposition fluxes include the nitrogen from the background ammonia to some extent. For comparison to FLM deposition criteria, the fluxes were converted to kilograms per hectare per year.

### 6.3.1 Visibility

Potential Project impacts to regional haze in the Class I Areas, Mount Baker Wilderness, and San Juan Island were assessed using predictions of the 24-hour change to extinction. CALPOST was used to calculate both the extinction coefficient attributable to the proposed emission increases as well as the background extinction coefficients following the FLAG 2010 guidance. The annual average natural conditions tables in FLAG 2010 for monthly species background concentrations and relative humidity adjustment factors were used in the visibility calculations.[28]

[28] The necessary monthly relatively humidity adjustment factors and background aerosol concentrations for Mount Baker WA were assumed to be the same as recommended for the Pasayten Wilderness. The monthly factors for San Juan Island were assumed to the same as recommended values for Olympic National Park.

## 6.4 Analysis Results

The CALPUFF modeling system was used to predict concentrations of $NO_2$, $SO_2$, $PM_{10}$, and $PM_{2.5}$ in regional Class I Areas. Table 6-4 summarizes the predicted maximum concentrations and compares them to the proposed Class I SILs and the Class I PSD Increments. Table 6-4 indicates all predicted concentrations are less than the SILs and PSD increments. Figures 6-3 through 6-6 present the spatial variation of predicted $NO_X$, $SO_2$, and $PM_{2.5}$ maximum concentrations attributable to the Project for applicable averaging periods.

## Table 6-4: Predicted Class I Area Criteria Pollutant Concentrations

| Class I Area of Interest | Maximum Predicted Concentration ($\mu g/m^3$) | | | | | |
|---|---|---|---|---|---|---|
| | $NO_2$ [a] | $PM_{2.5}$ | | $SO_2$ | | |
| | Annual Average | 24-Hour Average [c] | Annual Average | 3-Hour Average | 24-Hour Average | Annual Average |
| Alpine Lakes Wilderness | 0.0003 | 0.015 | 0.0010 | 0.02 | 0.0071 | 0.0006 |
| Glacier Peak Wilderness | 0.0028 | 0.026 | 0.0029 | 0.09 | 0.0234 | 0.0029 |
| Goat Rocks Wilderness | 0.00003 | 0.004 | 0.0003 | 0.004 | 0.0010 | 0.0001 |
| Mount Adams Wilderness | 0.00002 | 0.003 | 0.0002 | 0.004 | 0.0008 | 0.0001 |
| Mount Rainier National Park | 0.0001 | 0.007 | 0.0005 | 0.01 | 0.0017 | 0.0002 |
| N Cascades National Park | 0.0070 | 0.042 | 0.0056 | 0.14 | 0.0392 | 0.0071 |
| Olympic National Park | 0.0068 | 0.050 | 0.0085 | 0.08 | 0.0275 | 0.0066 |
| Pasayten Wilderness | 0.0032 | 0.025 | 0.0039 | 0.07 | 0.0200 | 0.0038 |
| Class I Maximum Concentration | 0.0070 | 0.050 | 0.0085 | 0.14 | 0.0392 | 0.0071 |
| EPA Proposed Class I SIL [b] | 0.1 | 0.07 | 0.06 | 1 | 0.2 | 0.1 |
| Mount Baker Wilderness [e] | 0.0115 | 0.053 | 0.0073 | 0.21 | 0.0688 | 0.0108 |
| San Juan Islands [e] | 0.0170 | 0.066 | 0.0124 | 0.18 | 0.0745 | 0.0154 |
| Class I Area PSD Increment [d] | 2.5 | 2 | 1 | 25 | 5 | 2 |

Notes:

a $NO_x$ was conservatively assumed to be 75 percent converted to $NO_2$, per Section 6.2.3 of EPA's Guideline on Air Quality Models (Appendix W to 40 CFR Part 51).

b SIL = Significant Impact Level; EPA proposed and FLM recommended from the Federal Register, Vol. 61, No. 142, p. 38292, July 23, 1996.

c 24-hour PM2.5 concentrations based on the highest 3-year average PM2.5 concentration in each area.

d PSD = Prevention of Significant Deterioration; from 40 CFR 52.21(c), adopted by reference in WAC 173-400-720(4)(a)(v)

e Mount Baker Wilderness Area and San Juan Islands are not Class I Areas, results are included in the analysis because FLMs have requested its inclusion in previous permit applications.

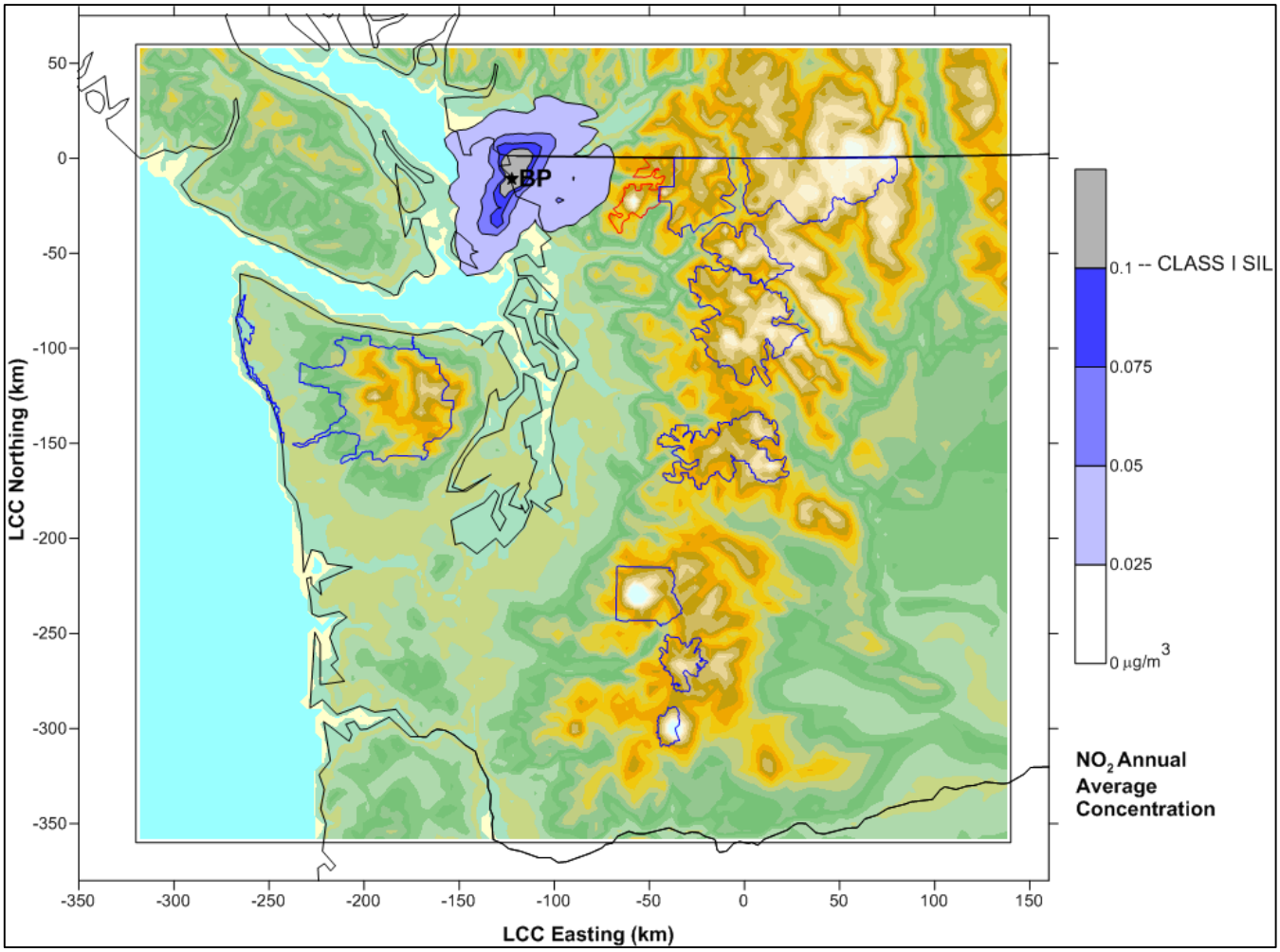



**Figure 6-3. Maximum Annual Average $NO_2$ Concentrations**

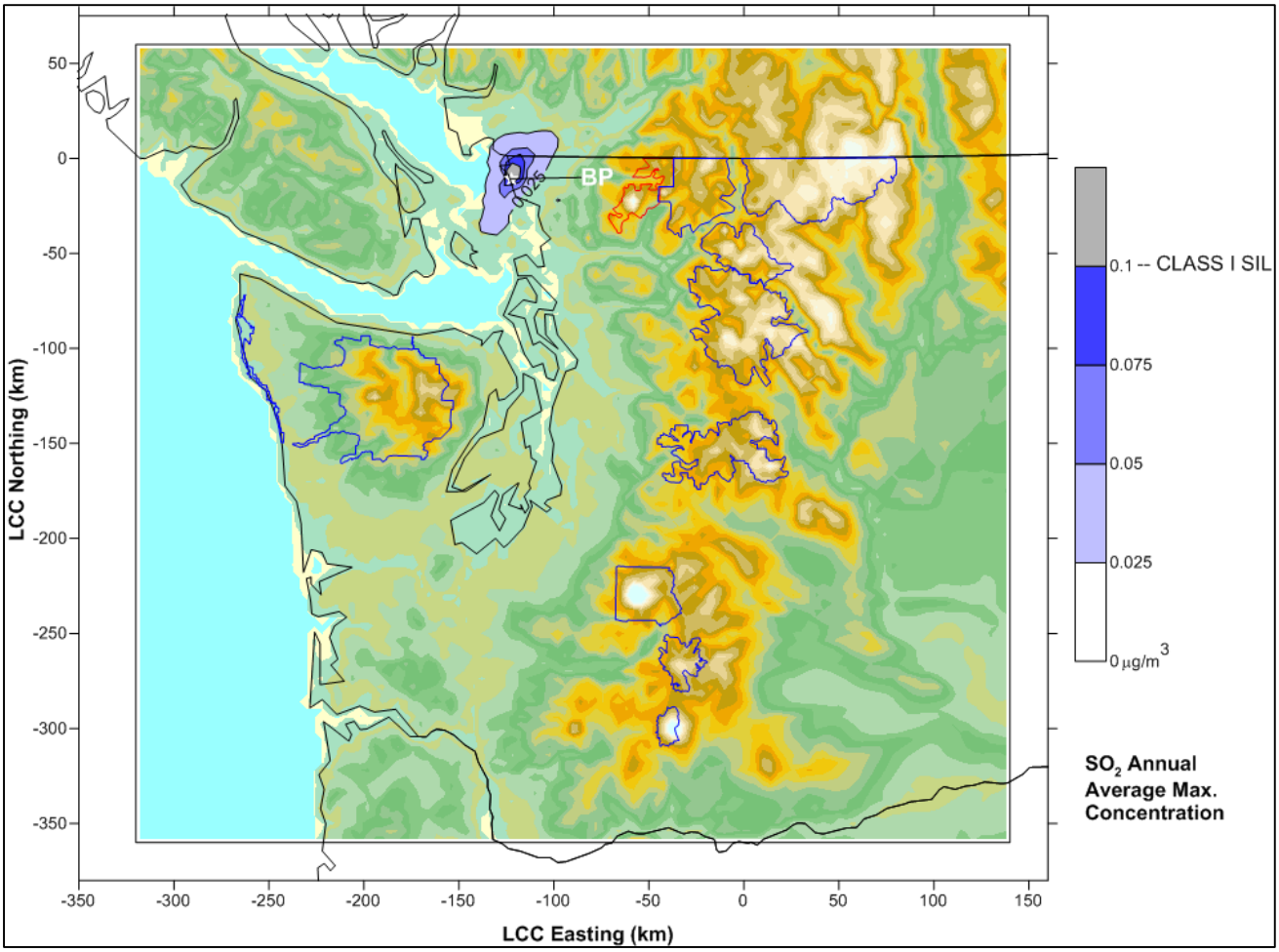



**Figure 6-4. Maximum Annual Average $SO_2$ Concentrations**

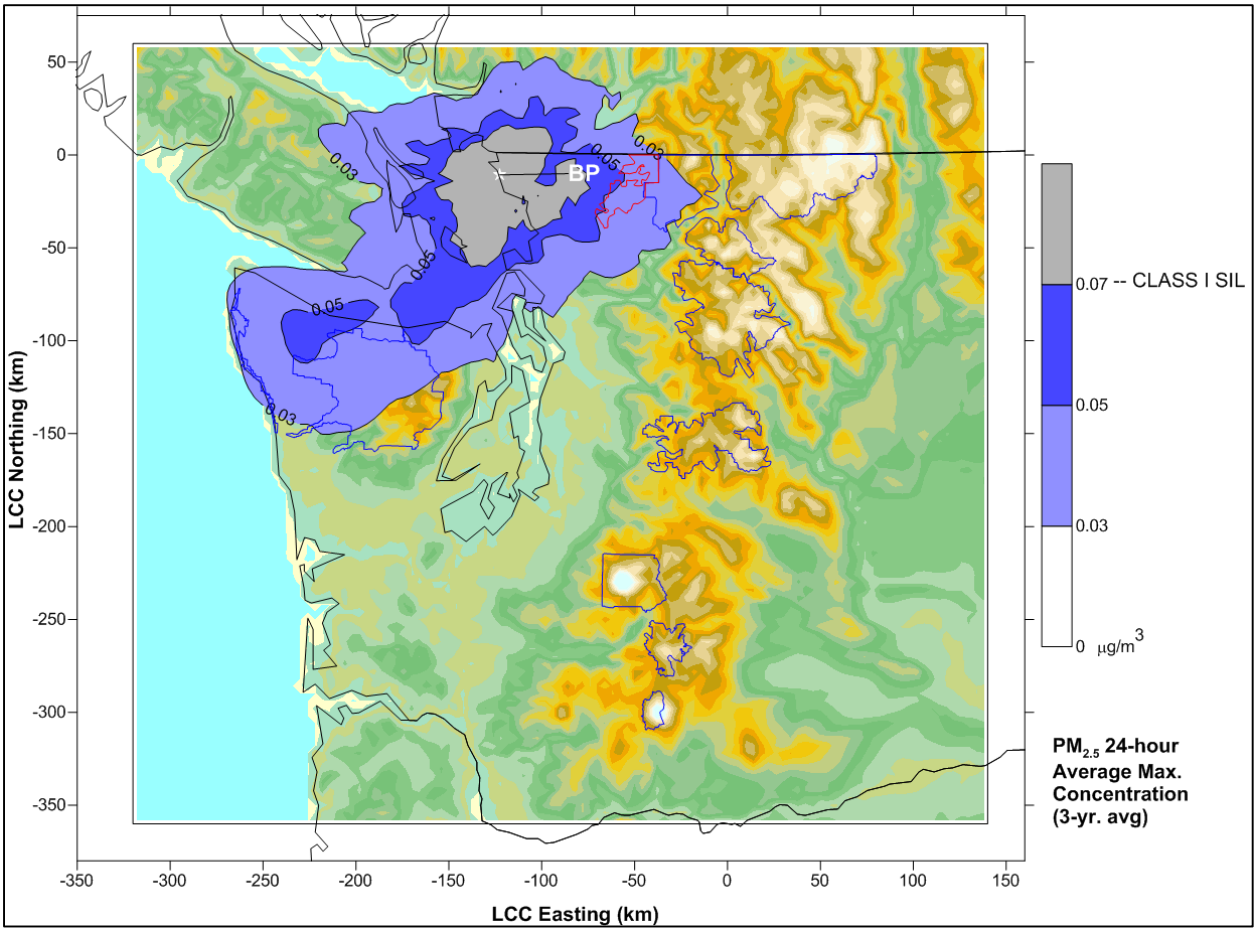



**Figure 6-5. Maximum 3yr Average 24-hour $PM_{2.5}$ Concentrations**

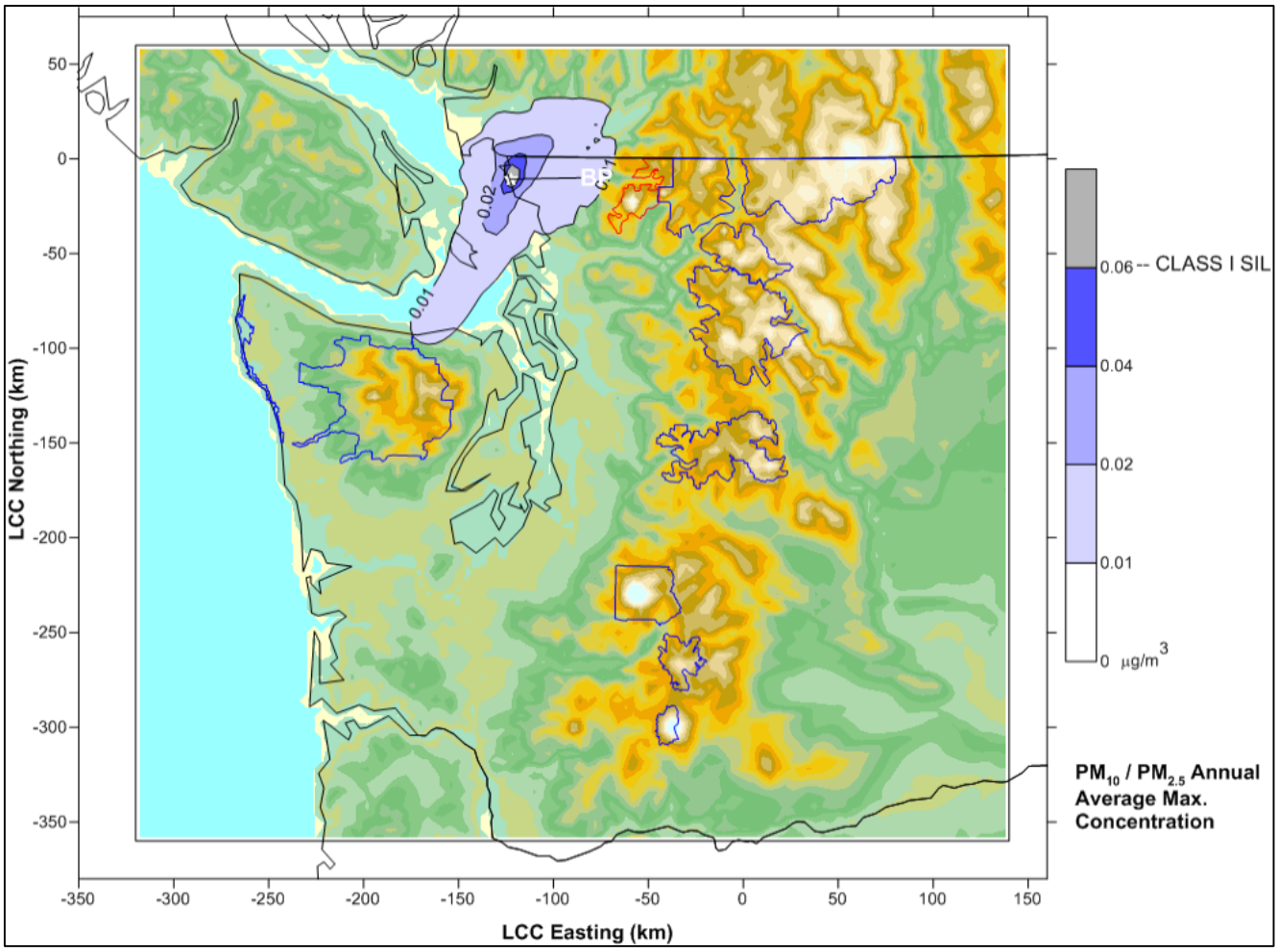



**Figure 6-6. Maximum $PM_{2.5}$ Annual Average Concentrations**

CALPUFF was also used to predict deposition of nitrogen and sulfur compounds emitted by the Project on soils and vegetation in regional Class I Areas. The deposition analysis results are shown in Table 6-5. There are no promulgated standards for characterizing deposition. However, the NPS has established Deposition Analysis Thresholds (DATs) for nitrogen and sulfur of 0.005 kg/ha/yr. These "thresholds" are based on natural background deposition estimates culled from various research efforts, a variability factor, and a safety factor that accounts for cumulative effects. The DATs are not adverse impact thresholds, but are intended as conservative screening criteria that allow the FLMs to identify potential deposition fluxes that require their consideration on a case-by-case basis.

Table 6-5 indicates CALPUFF-predicted maximum nitrogen and sulfur deposition fluxes do not exceed the DATs in any Class I Area. Figures 6-7 and 6-8 show the spatial variation of the predicted nitrogen and sulfur deposition fluxes, respectively, attributable to the Project over the entire simulation domain.

**Table 6-5: Predicted Class I Area Deposition Fluxes**

| Class I Area of Interest | Nitrogen Deposition (kg/ha/yr) | Sulfur Deposition (kg/ha/yr) |
|---|---|---|
| Alpine Lakes Wilderness Area | 0.0003 | 0.0006 |
| Glacier Peak Wilderness Area | 0.0013 | 0.0017 |
| Goat Rocks Wilderness Area | 0.0001 | 0.0001 |
| Mount Adams Wilderness Area | 0.0001 | 0.0001 |
| Mount Rainier National Park | 0.0001 | 0.0002 |
| N. Cascades National Park | 0.0029 | 0.0043 |
| Olympic National Park | 0.0019 | 0.0030 |
| Pasayten Wilderness Area | 0.0022 | 0.0033 |
| NPS DAT | 0.005 | 0.005 |
| Mount Baker Wilderness Area [a] | 0.0042 | 0.0059 |
| San Juan Island [a] | 0.0021 | 0.0046 |

Notes:

[a] Mount Baker Wilderness Area and San Juan Island are not Class I Areas, they are included in the analysis because FLMs have requested inclusion in previous permit applications.

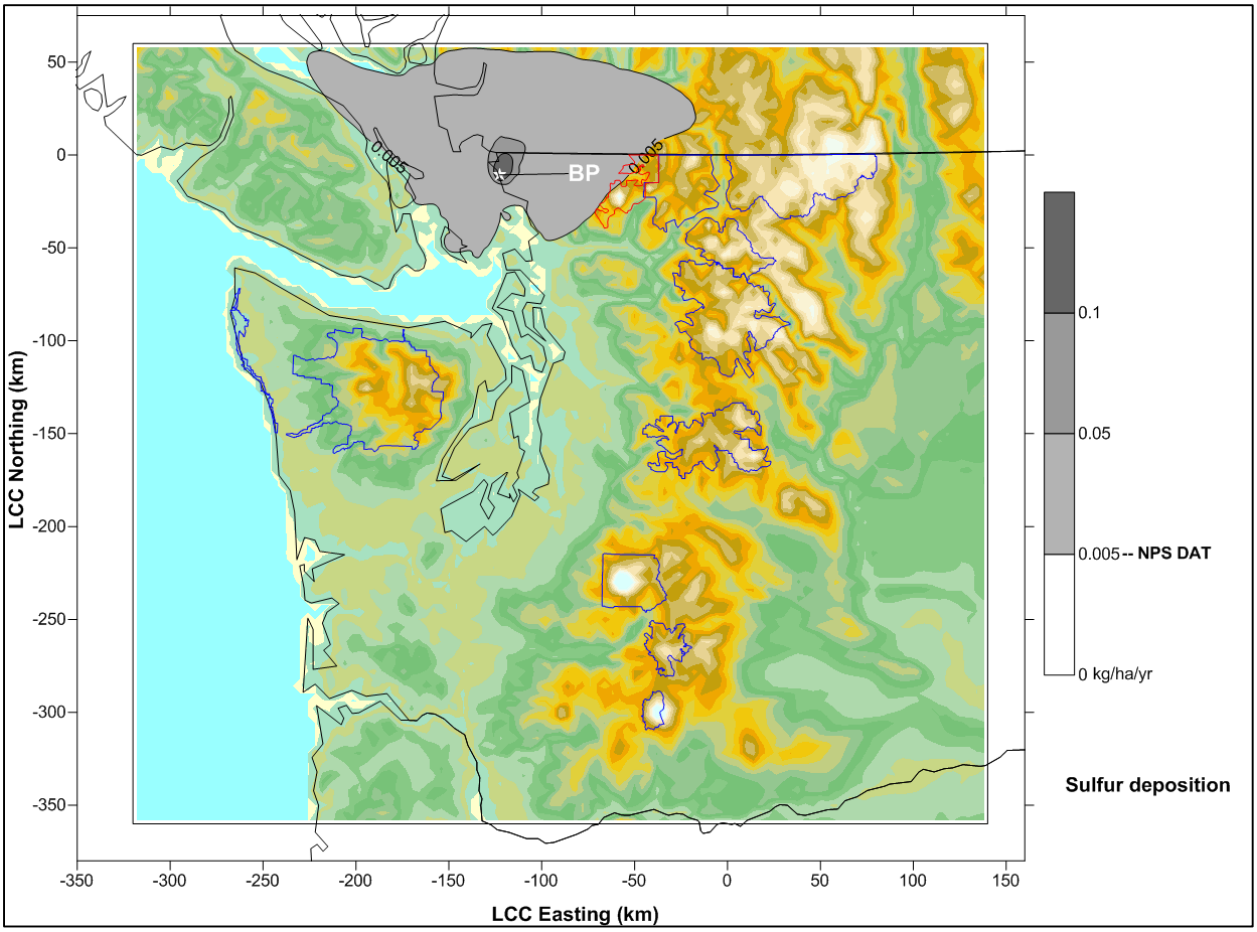



**Figure 6-7. Maximum Annual Sulfur Deposition Rate**

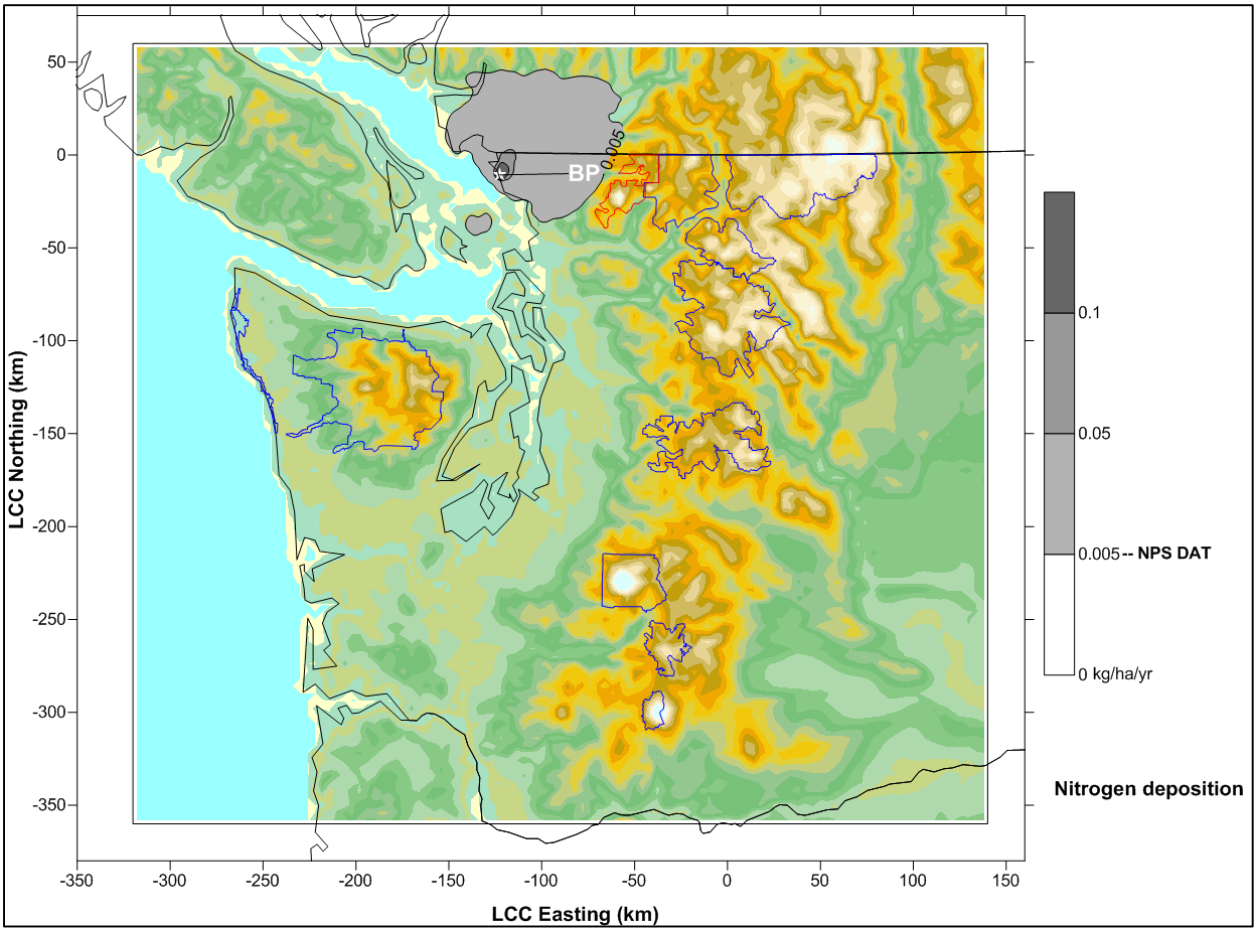



**Figure 6-8. Maximum Annual Nitrogen Deposition Rate**

Compliance with FLM-recommended criteria for regional visibility impacts was assessed by calculating the change in 24-hour extinction for each Class I receptor. The CALPUFF modeling system was used to predict both the extinction coefficient attributable to emissions from the Project as well as the background extinction coefficients for that day's meteorology. Table 6-6 summarizes the 98th percentile predicted change in extinction at each Class I Area as well as the Mt. Baker Wilderness Area and San Juan Island. Table 6-6 also summarises the number of days the change in visibility was above 5 percent and 10 percent for each area of interest.

**Table 6-6: Predicted Class I Area Visibility Results**

| Class I Area of Interest | 98th Percentile Change in Visibility | | | | # total days over 5% | # total days over 10% |
|---|---|---|---|---|---|---|
| | 2003 | 2004 | 2005 | 3 year | | |
| Alpine Lakes Wilderness | 0.24 | 0.28 | 0.24 | 0.26 | 0 | 0 |
| Glacier Peak Wilderness | 0.61 | 0.63 | 0.64 | 0.63 | 0 | 0 |
| Goat Rocks Wilderness | 0.07 | 0.06 | 0.09 | 0.08 | 0 | 0 |
| Mount Adams Wilderness | 0.05 | 0.05 | 0.06 | 0.06 | 0 | 0 |
| Mount Rainier National Park | 0.12 | 0.11 | 0.13 | 0.12 | 0 | 0 |
| N Cascades National Park | 0.95 | 0.94 | 0.88 | 0.94 | 0 | 0 |
| Olympic National Park | 1.83 | 1.49 | 1.82 | 1.76 | 1 | 0 |
| Pasayten Wilderness | 0.54 | 0.6 | 0.53 | 0.6 | 0 | 0 |
| Mount Baker Wilderness [a] | 1.19 | 1.28 | 1.35 | 1.32 | 0 | 0 |
| San Juan Islands [a] | 2.49 | 1.97 | 2.2 | 2.25 | 0 | 0 |

Notes:

a Mount Baker Wilderness Area and San Juan Islands are not Class I Areas, results are included in the analysis because FLMs have requested its inclusion in previous permit applications.

The FLMs recommend in the FLAG Phase I Report that a five percent change in extinction be used to indicate a "just perceptible" change to a landscape. As indicated in Table 6-6, the 98th percentile changes in extinction are less than the 5 percent threshold established by the FLMs.

The spatial distribution of the maximum change in visibility is shown in Figure 6-9.

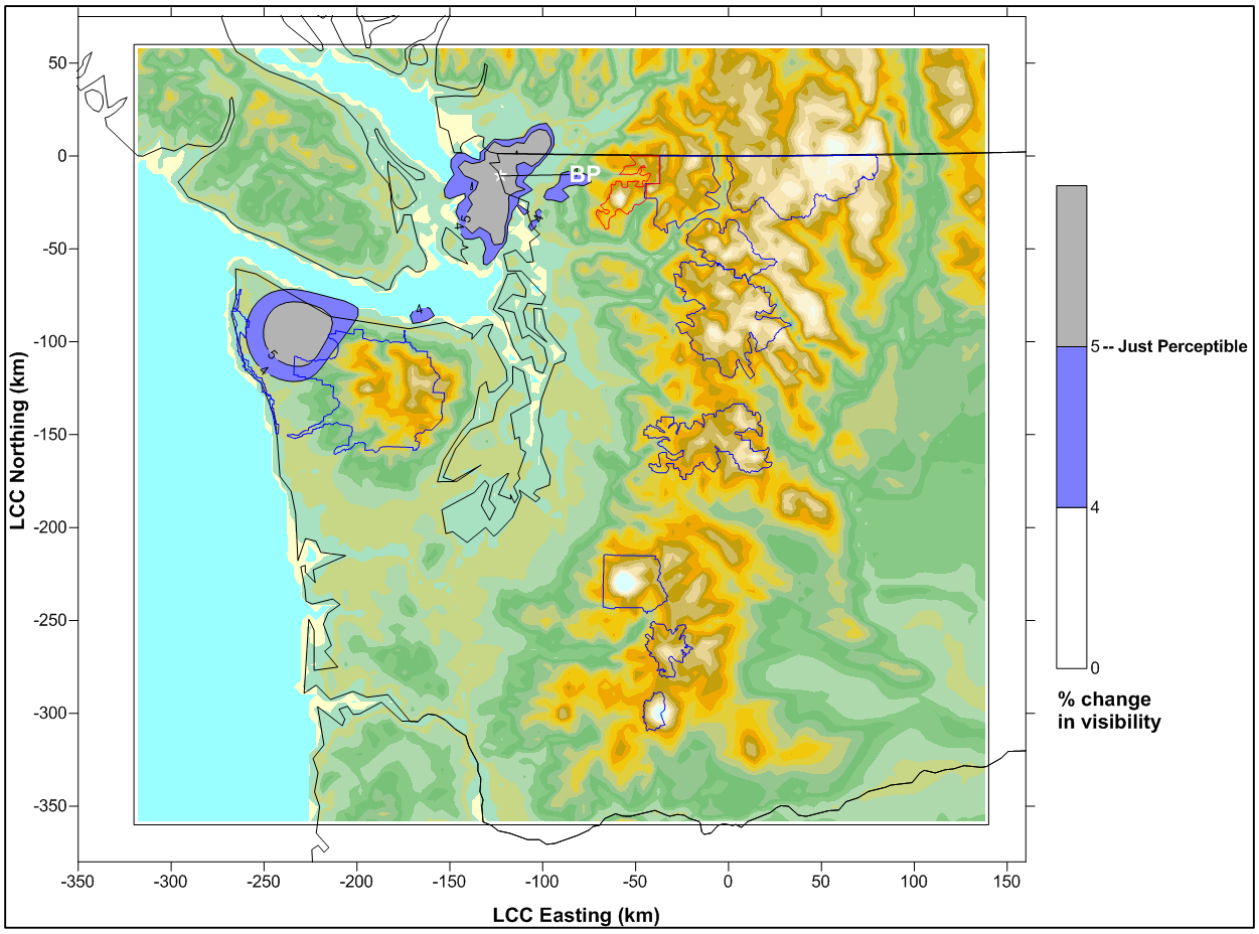



**Figure 6-9. Maximum Percent Change in Visibility Attributable to Project Emissions**

# 7 Additional Impact Analysis

## 7.1 Class II Area Growth

Construction of the Project will span approximately two years. During peak construction, there will be as many as 150 additional workers employed at the site. Laydown and worker parking areas are located on BP property. The temporary increases in vehicle miles traveled and vehicular emissions will be insignificant. During construction, local demand for skilled crafts people will increase. However, this demand will be temporary (less than two years). Once operational, BP does not anticipate employing additional workers.

BP does not expect the Project to cause significant population growth in the area nor significant secondary air quality impacts as a result of that growth.

## 7.2 Class II Visibility

On a large spatial scale, visibility is typically evaluated as “regional haze” and is addressed as part of the Class I air quality related values (Section 6.4). On a local scale, “visibility” is usually evaluated by considering perceptibility of a plume from a stack or cooling tower.

The replacement coker heaters and the projected increases in emissions from other combustion units (i.e. Hydrocracker heaters) will be the largest sources of emissions associated with the Project. Although state and local regulations restrict visible emissions to a 20 percent opacity limit, emissions from gas-fired combustion units are typically less than 5 percent and are rarely visible.

As a result of the project, BP projects a slight increase in annual #1 and #2 Cooling Tower circulation water usage. The cooling towers produce visible water vapor clouds that vary in size depending on meteorology and operational factors. Cooling tower plumes are most visible when the ambient air is nearly saturated with water and when visibility is already poor. The slight increase in cooling tower recirculation water will not result in any noticeable changes to visible water vapor clouds that are created by the cooling tower.

## 7.3 Soils and Vegetation

Air quality permitting regulations require proponents of major modifications to existing major sources to provide an evaluation of potential impacts to air quality related values. These include impacts to visibility, soils and vegetation. In virtually all cases, the impact analysis for soils and vegetation has focused on impacts to Class I Areas. The focus on Class I Areas occurs because these areas often include sensitive environments, such as alpine lakes and streams, high-elevation vegetation, and sensitive habitat for threatened or endangered species. Section 6.4 addresses impacts to soils and vegetation in Class I Areas. Such impacts were judged to be insignificant based on impact criteria established by Federal Land Managers.

For Class II Areas, the concern for soil and vegetation impacts is different from Class I Areas. Generally a sensitive habitat is not of concern, but rather the economic well-being of the soils and vegetation for the area. Impacts to agriculture or forestry are the major concerns. There have been instances elsewhere in the U.S. where high levels of sulfur emissions from coal fired power plants, or smelters have caused localized impacts to vegetation and soils near the facility.

In fact, the NAAQS were established to protect the public health and welfare, and secondary standards were identified specifically to protect ecological properties such as soils and vegetation.

The Class II Air Quality Assessment results (Section 5) indicate that the maximum ambient impacts due to the proposed Project will be less than the applicable Significant Impact Levels (SILs) for both $NO_X$ and $SO_2$. Because ambient concentrations attributable to the Project will be so low, deposition of nitrogen and sulfur compounds will also be very low.

During the Clean Fuels Project, RE discussed deposition concerns with the director of the Washington State University Extension Service.[29] The director indicated that if a farmer wanted to acidify his land, a minimum of three tons of sulfur would be added per acre; in other words, it takes a lot of sulfur to have a significant effect on the pH of the soil.

Based on the CALPUFF modeling described in Chapter 6, deposition of sulfur and nitrogen in the vicinity of the refinery will each be less than 0.8 lb/acre/yr and 0.5 lb/acre/year, respectively. These very low deposition rates supports for the Project are similar to those predicted as part of the Clean Fuels Project. It was the Director's personal opinion that impacts to commercial farms will be insignificant from the Clean Fuels Project, and it would be reasonable to state the same conclusion for impacts from the coker heater replacement project.

[29] Telephone communication between Eric Hansen of RE and Craig McConnell, Director of WSU Extension Service for Whatcom County. January 11, 2010.

# Appendix A

## NOC and PSD Forms

northwest Clean Air agency
1600 South Second Street
Mount Vernon, WA 98273-5202
ph 360.428.1617
fax 360.428.1620
www.nwcleanair.org

# Notice of Construction and Application for Approval

## To Construct, Install, Establish, or Alter an Air Contaminant Source and/or Control Facility

Name of Facility: BP Cherry Point Refinery
Location of Facility: 4519 Grandview Road
City: Blaine State: WA Zip Code: 98230

Name of Owner: BP West Coast Products, LLC Owner's Agent: ENVIRON International Corp.
Owner's Address: 4519 Grandview Road
City: Blaine State: WA Zip Code: 98230
Billing Address (if different):
City: State: Zip Code:
Phone: 360-371-1530 Fax: 360-671-1402 E-mail Address: Scott.Inloes@bp.com

Name of Operator: BP West Coast Products, LLC Operator's Agent: ENVIRON International Corp.
Mailing Address: 4519 Grandview Road
City: Blaine State: WA Zip Code: 98230
Phone: 360-371-1530 Fax: 360-671-1402 E-mail Address: Scott.Inloes@bp.com

Type of Process/Equipment:

Replacement of two existing coker heaters.

Estimated Start of Construction: Q4 2015 Facility NAICS Code: 324110
Estimated Completion Date: Q1 2017

**A filing fee & new source review fees must accompany this application.** Once you have saved this document, click here for fee schedule.

Robert Allendorfer
Applicant Name (Must be owner or operator)

Business Unit Leader
Title

Signature

29SEP14
Date

**NWCAA Office Use Only** *(version 08/31/2011 MEA)*

N.O.C. #: Inspection: Fee Received:
Tech Staff Assigned: Cert. of Approval: Date Received:
SEPA Checklist Date: Added to Database: Receipt #:
Public Notice Given: Letter of Completion:
Order of Approval:

Notes:

Print Form

# Application for Prevention of Significant Deterioration

**INSTRUCTIONS**

Use this form for all projects in Washington that are subject to the Prevention of Significant Deterioration (PSD) Program. If you want Ecology to determine whether your project is subject to the PSD Program, submit a Request for a PSD Program Applicability Determination form (ECY 070-413).

Fill out the front and back of this form. Attach a check for the initial fee and mail the form and your application to:

**Department of Ecology**
**Cashiering Unit**
**P.O. Box 47611**
**Olympia, WA 98504-7611**

*For Fiscal Office Use Only:*
001-NSR-216-0299-000404

**Check the box to indicate what you are submitting for review.**

| **New project** | **Initial Fee** |
|---|---|
| ☒ New project application. The initial fee covers 158 hours of review. | $15,000 |
| ☐ New PSD permit application that is limited to greenhouse gases. The initial fee covers 79 hours of review. | $7,500 |
| **Revise an existing PSD permit** | |
| ☐ Administrative permit revision. The initial fee covers 20 hours of review. | $1,900 |
| ☐ All other permit revisions. The initial fee covers 79 hours of review. | $7,500 |
| ☐ Major modification. The initial fee covers 158 hours of review. | $15,000 |
| **Other actions** | |
| ☐ Permit extension. This is a flat fee. | $500 |
| ☐ Plant-wide applicability emission limit: establish limit. The initial fee covers 158 hours of review. [See note] | $15,000 |
| ☐ Plant-wide applicability emission limit: all other requests. Other requests may include increasing a limit; renewing a limit; or processing an expired limit. The initial fee covers 79 hours of review. [See note] | $7,500 |
| Note. An additional fee does not apply when a request to establish a plant-wide applicability limit is part of an application covered by the new project, all other permit revisions, or major modification fees on this form. | |

| **For more information** | |
|---|---|
| Air Quality Program<br>Science and Engineering Section<br>Ecology Headquarters Office | Marc Crooks<br>Phone: (360) 407-6800<br>E-mail: marc.crooks@ecy.wa.gov |



If you need this document in a format for the visually impaired, call the Air Quality Program at 360-407-6800. Persons with hearing loss can call 711 for Washington Relay Service. Persons with a speech disability can call 877-833-6341.

# Application for Prevention of Significant Deterioration

**Read each statement, then check the box next to it to acknowledge what you have read.**

| | |
|---|---|
| ☒ | The initial fee you submit may not cover the cost of processing your application. Ecology will track the number of hours spent on your project. If the number of hours exceeds the number of hours included in your initial fee, Ecology will send you a bill for that extra time. |
| ☒ | Ecology will bill you $95 per hour for each hour worked beyond the initial hours. |
| ☒ | You must pay the bill before we will issue your permit or finalize an action or decision. |

**Applicant Information**
The applicant is the business requesting services from Ecology and is responsible for paying the costs Ecology incurs.

Name of business: BP Cherry Point Refinery

Physical location of project (city): Blaine, Washington 98230

Name of project: **Two Coker Heaters – Replacement**

**Project Manager Information**

Ecology will send this person all official correspondence.

Name, Title: Bob Allendorfer

Mailing address 4519 Grandview Rd.,

City, State, Zip Blaine, WA 98230

Phone, Fax, E-mail: 360-371-1747, fax N/A Robert.allendorfer@bp.com

**Project Billing Contact Information**
Ecology will send the Project Manager the bills if there are any.
☐ If the Project Billing Contact is different from the Project Manager, check this box and provide the required information.

Name, Title: Scott Inloes

Mailing address 4519 Grandview Rd.,

City, State, Zip Blaine, WA 98230

Phone, Fax, E-mail 360-371-1530; fax 360-371-1697; Scott.Inloes@bp.com

**Project Consultant Information**
☒ If you hired a consultant to prepare the application (or materials), check this box and provide the required information.

Consultant Name, Title: Kyle Heitkamp

Organization: Environ Intl Corp.

Mailing address 19020 33rd Ave W, Ste 310

City, State, Zip Lynnwood, WA 98036

Phone, Fax, E-mail 425-412-1803; 425-412-1840, kheitkamp@environcorp.com

# Application for
# Prevention of Significant Deterioration

**Responsible Official Signature Block**

I certify, based on information and belief formed after reasonable inquiry, the statements and information in this application are true, accurate, and complete.

Printed Name Robert K. Allendorfer Title Business Unit Leader

Signature [signature] Date 29JUL14

# Appendix B

## BACT Analysis

# Best Available Control Technology
# Coker Heater Replacement Project
Blaine, Washington

Prepared for:
**BP Cherry Point Refinery**
**Blaine, Washington**

Prepared by:
**Ramboll Environ**
**Lynnwood, Washington**

Date:
**June 2016**

Project Number:
**29-30623E**

RAMBOLL ENVIRON

# Contents

**Page**

**1 Introduction ..... 1**
1.1 Project Description ..... 2
1.2 BACT Review Process ..... 2

**2 Coker Heaters ..... 5**
2.1 Identify Commercially-Available Emission Reduction Alternatives ..... 5
2.2 Eliminate Technically Infeasible Alternatives ..... 9
2.3 $NO_X$ BACT ..... 12
2.4 CO and VOC BACT ..... 15
2.5 PM, $PM_{10}$, $PM_{2.5}$ BACT ..... 16
2.6 $SO_2$ and $H_2SO_4$ BACT ..... 18
2.7 GHG BACT ..... 21
2.8 Toxic Air Pollutant BACT (tBACT) ..... 30
2.9 BACT During Startup, Shutdown, and Standby ..... 31

**3 Component Leaks ..... 32**
3.1 Identify Commercially-Available Emission Reduction Alternatives ..... 32
3.2 Eliminate Technically Infeasible Alternatives ..... 33
3.3 Ranking of Remaining Alternatives ..... 33
3.4 Consideration of Energy, Environmental and Cost Factors ..... 34
3.5 Proposed BACT Limits and Control Option ..... 34

Attachment 1. SCR Cost Effectiveness Calculations
Attachment 2. Oxidation Catalyst Cost Effectiveness Calculations
Attachment 3. New Coker Off Gas Compressor Cost Effectiveness Calculations
Attachment 4. Spray Tower Cost Effectiveness Calculations
Attachment 5. Merox Cost Effectiveness Calculations
Attachment 6. LDAR Regulation Comparison
Attachment 7. BP SCR, Oxidation Catalyst, and Merox Cost Estimates

# 1 Introduction

BP West Coast Products, LLC (BP), which owns and operates the Cherry Point Refinery (hereafter referred to as "the Facility") located at 4519 Grandview Road, near the community of Birch Bay in Whatcom County, Washington, proposes to replace the two existing coker heaters with two new coker heaters. The cokers are used to convert residual oil from the Crude Unit to low-molecular-weight hydrocarbon gases, naphtha, light and heavy gas oils, and petroleum coke. The coking process thermally "cracks" the long chain hydrocarbon molecules in the residual oil feed to create shorter chain molecules, leaving behind excess carbon in the form of green coke.

The Coker Unit at the Facility employs two heaters which provide the heat required for the thermal cracking reaction, and these heaters fire the low molecular weight hydrocarbon gases generated by the reaction process. The rated capacity of each heater is 190 million British thermal units per hour (MMBtu/hr). The existing heaters are over 40 years old and BP evaluated whether to conduct significant repairs to multiple portions of the existing heaters or replace the heaters with new state of the art coker heaters.

BP proposes to replace the existing Coker Unit heaters with new heaters. The replacement heaters will have burners rated up to 303 MMBtu/hr. Each coker will also have online cleaning capability (spalling) to reduce the time for periodic offline heater cleaning. BP also proposes install a lean oil absorption system with a compressor in the coker off gas system to recover C3 (i.e. propanes) and C4 (i.e. butanes) hydrocarbons. The recovered intermediates will be processed in the light ends unit for saleable product.

As part of the Project, BP will also install additional bypasses on existing heat exchangers in the Crude Unit preheat system. The new bypasses will allow for online cleaning of existing heat exchangers without having to shutdown the crude unit. No new heat exchangers are planned as part of this Project.

Whatcom County is within the jurisdiction of the Northwest Clean Air Agency (NWCAA), and, therefore, the proposed project must comply with regulations adopted by that agency, as applicable. Because the proposed project is a modification to an existing stationary source of air pollutants, a Notice of Construction (NOC) and/or Prevention of Significant Deterioration (PSD) permit application must be filed with NWCAA or Washington Department of Ecology (Ecology), and construction of the facility cannot commence until NWCAA issues an Order of Approval (OA).[1] Before NWCAA issues an OA, or Ecology issues a PSD permit, the proposed project must comply with the requirements of WAC 173-400-113 for modification of stationary sources located in attainment or unclassifiable areas.[2]

Among the requirements for modification of stationary sources in attainment or unclassifiable areas, is the requirement that new or modified emission units will employ Best Available Control

[1] NWCAA Regulations, Section 300.1
[2] Whatcom County is in attainment of or unclassifiable for all state and federal ambient air quality standards.

Technology (BACT) for all pollutants not previously emitted, or that would increase as a result of the project.

BP has retained Ramboll Environ (RE) to prepare this BACT analysis in support of the combined NOC/PSD application developed for the proposed coker heater replacement project.

## 1.1 Project Description

Changes associated with the coker heater replacement project with the potential to increase air pollutant emissions are:

- Construction of two new coker heaters, which will each be fired with coker off gas fuel.
- Permanent removal of the two existing coker heaters.
- Increased utilization of other process units at the refinery.
- Possible additional components in crude preheat system.

## 1.2 BACT Review Process

BACT, as it applies to regulated pollutants not subject to major new source review, is defined in WAC 173-400-030 as:

> "…an emission limitation based on the maximum degree of reduction for each air pollutant subject to regulation under chapter 70.94 RCW emitted from or which results from any new or modified stationary source, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. "

In a December 1, 1987 memorandum from the U.S. Environmental Protection Agency (USEPA) Assistant Administrator for Air and Radiation, the agency provided guidance on the "top-down" methodology for determining BACT. The "top-down" process involves the identification of all applicable control technologies according to control effectiveness. Evaluation begins with the "top," or most stringent, control alternative. If the most stringent option is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration and then the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts. The top control alternative that is not eliminated in this process becomes the proposed BACT basis.

This top-down BACT analysis process can be considered to contain five basic steps:

- Step 1: Identify all available emission reduction alternatives with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
- Step 2: Eliminate all technically infeasible alternatives;
- Step 3: Rank remaining alternatives by effectiveness;
- Step 4: Evaluate the economic, energy, and environmental impacts starting with the most effective alternative; and
- Step 5: Select BACT, which will be the most effective practical alternative not rejected in the previous steps.

Formal use of these steps is not always necessary. However, both USEPA and the Ecology have consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which USEPA believes must be met by any BACT determination, regardless of whether it is conducted in a “top-down” manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that provide the “maximum degree of emissions reduction.” Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of “energy, environmental, and economic impacts” contained in the record of the permit decisions.

Additionally, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate no less stringent than the applicable New Source Performance Standard (NSPS) emission rate, if any NSPS standard for that pollutant is applicable to the source.

This BACT analysis was conducted in a manner consistent with this stepwise approach. Control options for potential reductions in criteria pollution emissions were identified for each emission unit. These options were identified by researching the EPA database known as the RACT/BACT/LAER Clearinghouse (RBLC), drawing upon previous environmental permitting experience for similar units and surveying available literature. Available controls that are judged to be technically feasible are further evaluated based on an analysis of economic, environmental, and energy impacts.

Assessing the technical feasibility of emission control alternatives is discussed in EPA's draft "New Source Review Workshop Manual." Using terminology from this manual, if a control technology has been "demonstrated" successfully for the type of emission unit under review, then it would normally be considered technically feasible. For an undemonstrated technology, “availability” and “applicability” determine technical feasibility. An available technology is one that is commercially available; meaning that it has advanced through the following steps:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and

- Commercial sales.

Suitability for consideration as a BACT measure involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission unit), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit, depending on differences in the gas streams' physical and chemical characteristics.

Control technology cost effectiveness evaluations in Step 4 require a capital recovery factor to annualize total capital investments over the equipment life. An interest rate of seven percent was incorporated into the capital recovery factor based on guidance from the Office of management and Budget (OMB).[3] The same interest rate is referenced in EPA's 2002 Air Pollution Control Cost Manual and confirmed in EPA 2015 refinery sector rulemaking cost effectiveness evaluations.[4]

[3] Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs. OMB, Circular A-94, October 29, 1992.

[4] Economic Impact Analysis, Petroleum Refinery Final Amendments to NESHAPs and NSPS. EPA Docket Number: EPA-HQ-OAR-2010-0682, September 2015.

# 2 Coker Heaters

The two existing coker heaters will be replaced with two new balanced draft design heaters, each with burners rated at 303 MMBtu/hr. The new heaters will primarily operate in balanced draft mode (forced draft and induced draft fans); however, they will have the option to operate in natural draft mode (i.e. without the air preheater) under certain operating conditions. BP will typically operate in balanced draft mode in order to utilize the air preheater and maximize the heater efficiency.

The existing heaters combust the hydrocarbon gases volatilized in the coke drums ("coker off gas"). The replacement coker heaters will also combust coker off gas. BP is currently planning to install a lean oil absorption system with compressor to recover C3 (i.e. propanes) and C4 (i.e. butanes) hydrocarbons from the coker off gas prior to combustion in the replacement heaters. These hydrocarbons will be processed by the light ends unit to become a saleable product. The lean oil absorption system is designed to process approximately 44 percent of the coker off gas generated, which is enough to fire the replacement coker heaters at the maximum burner capacity. A benefit of the lean oil absorption system is additional sulfur removal (up to 39 percent annual average) from the coker off gas that will be used as fuel in the new coker heaters.

Pollutant emissions from the heaters are expected to include oxides of nitrogen ($NO_X$), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter (PM), including the fractions less than ten microns ($PM_{10}$) and 2.5 microns ($PM_{2.5}$), sulfur dioxide ($SO_2$), sulfuric acid ($H_2SO_4$), and toxic air pollutants (TAPs).

## 2.1 Identify Commercially-Available Emission Reduction Alternatives

Review of the federal RBLC database, recent petroleum refinery BACT determinations, and other emission reduction information sources indicate that the following emission reduction alternatives are available for refinery heaters:

- Good Combustion Practices (GCPs),
- Oxidation Temperature Minimization,
- Low-$NO_X$ Burners (LNBs),
- Selective Non-Catalytic Reduction (SNCR),
- Selective Catalytic Reduction (SCR),
- Non-Selective Catalytic Reduction (NSCR),
- Oxidation Catalysts,
- EMx,
- Low-Sulfur Fuel,
- Cyclone Separator,
- Electrostatic Precipitator (ESP),
- Wet Electrostatic Precipitator (WESP),

- Fabric Filter,
- Wet Scrubber, and
- Flue Gas Desulfurization (FGD).

### 2.1.1 Combustion Controls

Techniques that seek to influence the combustion process and, thereby, prevent the formation of a given pollutant, are referred to as "combustion controls."

#### 2.1.1.1 Good Combustion Practices

GCPs include combustor design elements and operational strategies intended to control the amount and distribution of excess air in the combustion zone to ensure that enough oxygen is present for complete combustion.

#### 2.1.1.2 Oxidation Temperature Minimization

Techniques intended to reduce $NO_X$ emissions by reducing oxidation temperatures in the combustion zone include flue gas recirculation (FGR), staged combustion, overfire air injection (OFA), and water/steam injection. All of these practices seek to limit the creation of $NO_X$ by limiting peak combustion temperatures and/or controlling the mixture of oxygen and fuel. FGR employs both mechanisms, because introducing cooled flue gas into the combustion zone reduces the temperature of the combustion zone by absorbing heat, and the relatively oxygen-poor flue gas also reduces the oxygen content in the combustion zone. Staged combustion and OFA injection are similar techniques that both restrict the amount of oxygen available at the start of the combustion process by providing too little combustion air, and then introducing additional air later. By limiting the availability of oxygen to the fuel, combustion temperatures and $NO_X$ creation are both reduced. Water or steam injected into the combustion zone absorbs heat, which reduces the flame temperature, and, therefore, $NO_X$ creation. Because CO and VOC emissions are minimized by high temperatures and oxygen/fuel interaction, these techniques tend to increase CO and VOC emissions.

#### 2.1.1.3 Low-$NO_X$ Burners

LNBs are similar to the oxidation temperature minimization techniques described above, but the staged combustion of fuel that controls $NO_X$ formation is accomplished through burner design rather than manipulating combustion in the furnace. The design controls both the stoichiometry and temperature of combustion by tuning the fuel and air locally within each individual burner's flame envelope. Burner design includes features that regulate the aerodynamic distribution and mixing of the fuel and air. A lean, pre-mixed burner design mixes the fuel and air prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher $NO_X$ emissions. A lean fuel-to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower the combustion temperature, which in turn lowers thermal $NO_X$ formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment. LNBs that feature an FGR system integrated into the burner design, which further minimizes flame temperatures and oxygen availability, are often referred to as ultra-low $NO_X$ burners (ULNBs).

#### 2.1.1.4 Low-Sulfur Fuel

This technique seeks to limit the quantity of sulfur introduced to the combustion system. Unlike the formation of $NO_X$, which can be mitigated through combustion controls, the potential for $SO_2$ emissions is entirely dependent upon the quantity of sulfur present in the fuel. Sulfur compounds in fuel readily oxidize at combustion temperatures to form $SO_2$ (as well as some $SO_3$). Minimizing the sulfur content of the fuel combusted, either by selecting a fuel that naturally contains little sulfur, or one that has been processed to remove sulfur, is a popular method for reducing $SO_2$ emissions. In addition, sulfur in fuel has been shown to contribute to fine particulate emissions. Therefore, controlling or minimizing the sulfur content of the fuel will also minimize PM emissions.

### 2.1.2 Add-On Controls

Control alternatives that involve adding equipment designed to remove or transform a given pollutant after it has been created are referred to as “add-on controls.”

#### 2.1.2.1 Selective Non-Catalytic Reduction

In the SNCR process, ammonia is mixed with the exhaust from the combustion device and the $NO_X$ in the exhaust reacts with the introduced ammonia to form nitrogen ($N_2$) and water ($H_2O$). The reagent, which can be anhydrous ammonia ($NH_3$), aqueous ammonia, or urea dissolved in water, is typically injected at the exit of the furnace to mix with the hot flue gases. The success of this process in reducing $NO_X$ emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas. This must occur within a zone of the exhaust stream where the flue gas temperature is within a range, typically from 1,600°F to 2,200°F. In order to achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 second. The consequences of operating outside the optimum temperature range are severe. Within the temperature range, the reagent will be converted to $NO_X$. At temperatures less than that range, the reagent will not react with the $NO_X$ and significant quantities of will $NH_3$ discharge from the stack (known as “ammonia slip”).

#### 2.1.2.2 Selective Catalytic Reduction

The SCR process is similar to SNCR, in that a reagent (usually $NH_3$) reacts with $NO_X$ to form $N_2$ and $H_2O$, but a catalyst matrix is used to allow the reduction reaction to take place at lower temperatures (600 to 700ºF for SCR, as opposed to 1,600 to 2,200ºF for SNCR).

#### 2.1.2.3 Non-Selective Catalytic Reduction

NSCR uses a catalyst to reduce $NO_X$, CO, and hydrocarbons (HCs) to $N_2$, $CO_2$, and $H_2O$. Because the CO and HCs will more readily react with $O_2$ than $NO_X$, there must be little $O_2$ in the exhaust (between 0.5 and 4 percent, depending upon the system). Excess oxygen is removed by the catalyst or, in some designs, an afterburner, which necessitates injecting additional hydrocarbons (i.e., coker off gas or RFG) to act as the reducing agent.

#### 2.1.2.4 Oxidation Catalysts

Catalytic oxidation does not rely on the introduction of additional chemical reagents to promote the desired reactions. The activation energy required for the oxidation reaction between $O_2$,

CO, and VOCs to proceed is reduced in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. The catalyst oxidizes CO to $CO_2$, and VOCs to $CO_2$ and $H_2O$, but it also can promote other, less desirable, oxidation reactions such as $NH_3$ to $NO_X$ and $SO_2$ to $SO_3$. Consequently, the presence of an oxidation catalyst can cause emissions of other pollutants to increase, and therefore its design needs to be carefully considered.

#### 2.1.2.5 EMx

The EMx (formerly SCONOx) system is an add-on control device that reduces emissions of multiple pollutants. EMx control technology is provided by Emerachem, LLC (formerly Goal Line Environmental Technologies). EMx utilizes a single catalyst for the reduction of CO, VOC and $NO_X$, which are converted to $CO_2$, $H_2O$ and $N_2$. The system does not use $NH_3$, and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of EMx requires natural gas, water, steam, electricity and ambient air, and no special reagent chemicals or processes are necessary. Steam is used periodically to regenerate the catalyst bed and is an integral part of the process.

#### 2.1.2.6 Cyclone Separator

A cyclone separator, also called simply a “cyclone,” employs centrifugal force generated by spinning a gas stream in a cylindrical chamber. Because cyclone operating costs and collection efficiency of fine PM are low, they are often used to remove larger particulate matter before the exhaust reaches the primary control device (e.g., ESP, fabric filter).

#### 2.1.2.7 Electrostatic Precipitator

ESPs remove PM from an exhaust stream by imposing an electrical charge on the particles and then attracting them to an oppositely charged plate. The dust collected on the charged plates is periodically removed by vibrating or rapping of the plates.

#### 2.1.2.8 Wet Electrostatic Precipitator

Wet ESPs remove PM from an exhaust stream using the same principals as dry ESPs (discussed above), except the collection surfaces are intermittently/continuously washed by a spray of liquid. The liquid effluent is collected and treated.

#### 2.1.2.9 Fabric Filter

Also referred to as “baghouses,” fabric filters use various types of materials (generally fabrics) to trap PM while the gas passes through the voids in the material. The dust that becomes caked on the fabric bags is removed periodically by shaking, by blowing jets of air, or by using sonic horns.

#### 2.1.2.10 Wet Collector

Wet collectors use a liquid, typically water, to capture PM or to increase the size of aerosol to facilitate capture in another control device. Configurations include spray chambers (with or without impingement baffles), wet cyclones, and venturi scrubbers. They tend to complicate disposal of the collected PM by introducing liquids that create sludge, though, in some cases, a sludge is easier to handle than dry dust.

#### 2.1.2.11 Flue Gas Desulfurization

The FGD or $SO_2$ scrubbing process typically uses a calcium- or sodium-based alkaline reagent. The reagent is injected in the flue gas in a spray tower or directly into the exhaust duct. The $SO_2$ is absorbed, neutralized and/or oxidized by the alkaline reagent into a solid compound, either calcium or sodium sulfate. The solid is removed from the waste gas stream using downstream equipment.

FGDs are classified as “once-through” or “regenerable”, based on how the solids generated by the process are handled. Once-through systems either dispose of the spent sorbent as a waste or utilize it as a byproduct. Regenerable systems recycle the sorbent back into the system. Regenerable process systems typically have higher costs than once-through systems; however, regenerable processes might be chosen if space or disposal options are limited and markets for the byproduct (i.e., gypsum) are available.

## 2.2 Eliminate Technically Infeasible Alternatives

In this section, the technical feasibility of each of the emission reduction alternatives identified in the previous section is considered. In the following sections, alternatives determined to be technically feasible, as well as combinations of feasible alternatives, will be ranked and evaluated for each pollutant for which BACT is required.

### 2.2.1 Good Combustion Practices

GCPs are a technically feasible method of controlling CO, VOC, and, to some extent, PM emissions from the proposed replacement coker heaters, and are considered a baseline control alternative.

### 2.2.2 Oxidation Temperature Minimization

The coker heaters will heat a stream of residual oil to greater than 900 °F as it is delivered to the coke drums to begin the coking process. Control alternatives that result in cooler flame temperatures compromise the ability of the heater to quickly heat the residual oil to the temperature at which long-chain hydrocarbon molecules become unstable and begin breaking apart (i.e., the coking process begins). Effective and timely heating to the required temperature ensures that the residual oil will be delivered to the coke drum before the coking reactions begin, which reduces the need for cleaning operations. As a result, oxidation temperature minimization techniques are considered technically infeasible for reducing $NO_X$ emissions from the replacement coker heaters.

### 2.2.3 Low-$NO_X$ Burners

LNBs and ULNBs are commonly employed to reduce $NO_X$ emissions attributable to process heaters at petroleum refineries, including coker heaters, and are considered technically feasible.

### 2.2.4 Low-Sulfur Fuels

To reduce sulfur compound emissions, refineries typically use natural gas or treated refinery fuel gas. BP has evaluated the potential of several systems that remove sulfur from refinery fuel gas or coker off gas. BP identified four technologies:

- Caustic treatment without regeneration

- Caustic treatment with regeneration (i.e. gas-phase Merox)
- Cryogenic recovery of liquids
- PraxAir catalytic conversion

Caustic treatment without regeneration is not technically feasible because it would require significant upgrades to the wastewater treatment plant in order to treat the new caustic treatment stream that would be generated by this type of treatment. Caustic treatment without regeneration would also produce unrecoverable hydrogen gas as a byproduct. The PraxAir catalytic conversion technology is only available at the laboratory scale and has not been proven on a full scale setup. Both gas-phase Merox and cryogenic recovery are technically feasible.

### 2.2.5 Selective Non-Catalytic Reduction

Exhaust gas temperatures in coker heaters can vary during normal operations. The coker unit is a semi-batch process and coker off gas composition fluctuates with each batch processed. $NO_X$ emissions actually increase if exhaust gas temperatures drop below the required SNCR operating range (1,600 – 2,200 degrees F). A review of the RBLC found no evidence of SNCR being installed on a coker heater. SNCR is not technically feasible for reducing $NO_X$ emissions from the proposed replacement coker heaters.

### 2.2.6 Selective Catalytic Reduction

Although the catalyst is susceptible to poisoning by sulfur, SCR is technically feasible for reducing $NO_X$ emissions from most gaseous combustion operations, including the proposed replacement coker heaters.

### 2.2.7 Non-Selective Catalytic Reduction

Exhaust from the proposed replacement coker heaters will not be the low-oxygen, fuel-rich exhaust stream that an NSCR system requires. In addition, there is no evidence that such a system has ever been employed to reduce emissions from an external gaseous combustion device. At one time, the technology was used to reduce process (not combustion) $NO_X$ emissions from adipic and nitric acid plants, but it has fallen out of favor for economic reasons. NSCR is currently used in some cases to reduce $NO_X$ emissions from reciprocating internal combustion engines, which can run under stoichiometric or fuel-rich conditions. NSCR is not technically feasible for the proposed replacement coker heaters.

### 2.2.8 Oxidation Catalysts

Catalytic oxidation is technically feasible for reducing CO and VOC emissions from the proposed replacement coker heaters.

### 2.2.9 EMx

There are currently several EMx units in commercial installations worldwide, although all are applied to small combustion turbines. The original application of EMx was at the Federal Plant in Vernon, California, owned by Sunlaw Cogeneration. This installation was on a GE LM2500, an approximately 34 megawatt (MW) combined-cycle system, and has been in operation since December 1996. The system has undergone many changes over the years.

The second commissioning of an EMx system was at the Genetics Institute in Massachusetts on a 5 MW Solar Turbine Taurus 50 Model. This facility has reported problems with meeting permitted $NO_X$ levels of 2.5 ppm, and subsequently received a permit modification extending the EMx demonstration period. Three other units were installed in recent years, two on 13 MW Solar Titan combustion turbines at the University of California, San Diego, and one on an 8 MW Allison combustion turbine at Los Angeles International Airport.

EMx was considered at some larger applications including a 250 MW unit at the La Paloma plant near Bakersfield and a 510 MW plant in Otay Mesa. However, the La Paloma and Otay Mesa projects have installed SCR systems instead.

The EMx technology has not been demonstrated for a large refinery process heater that combusts coker off gas or RFG. The technical differences between the few emission units to which EMx has been demonstrated in practice, and the proposed replacement coker heaters result in a determination that EMx is technically infeasible for reducing emissions from the proposed replacement coker heaters, and is removed from consideration as BACT.

### 2.2.10 Cyclone Separator

Combustion processes produce PM as unburned solid carbon (soot), unburned vapors or gases that subsequently condense, and the unburnable portion of the fuel (ash). Because gaseous fuels contain little or no ash, and a burner operated with GCPs combusting gaseous fuels typically does not generate much soot, the majority of the PM resulting from combusting gaseous fuel is condensed unburnt fuel or combustion products. Past BP source tests indicates the filterable and condensable portions of particulate in RFG-fired heaters and boilers are 25 percent and 75 percent, respectively. A cyclone would only be capable of capturing the filterable portion. Typically filterable particulate in gaseous combustion source exhaust is less than one micron in size.[5] A cyclone separator would be ineffective at removing PM generated by the replacement coker heaters, and is therefore considered technically infeasible and is removed from consideration as BACT.

### 2.2.11 Dry/Wet Electrostatic Precipitators

In an ESP and wet ESP, the flue gas is introduced into an electric field that imparts a charge on the suspended particles. The charged particles then migrate to the charged plates where they are collected. The low particulate concentration from gaseous fuel combustion would not allow significant charge buildup on the particles, resulting in poor migration to the collecting plates. In addition, 75 percent of the particulate emissions from gaseous fuel combustion is in vapor form (condensable) at stack conditions and ESP are generally not designed to collect vapors. Based on these issues, dry ESPs and wet ESPs are considered technically infeasible and removed from consideration as BACT.

### 2.2.12 Fabric Filter

In a fabric filter, or baghouse, the flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to be collected on the fabric and the resulting collected particulate

[5] US EPA AP-42 Section 1.4 – Emission Factors for Natural Gas Combustion (http://www.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf)

(called cake) by sieving and other mechanisms. Most of the particle collection is performed by the filter cake itself. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group.

Past BP source tests indicates the filterable and condensable portions of particulate in RFG-fired heaters and boilers are 25 percent and 75 percent, respectively. The majority of the PM will not be collected by a fabric filter. Also, due to the low particulate concentration, a cake will be slow to form (assuming one forms at all), resulting in poor collection efficiency.

To capture the compounds that will become condensable PM, the gas stream would need to be cooled before reaching the baghouse. However, cooling would result in condensation of acids, and subsequent corrosion of the filter media and baghouse structure. The low collection efficiency for gas-fired units, the requirement for cooling of gas streams to capture the condensable component, and the small particle size all make implementing a baghouse to control PM generated by the proposed replacement coker heaters technically infeasible, and this technology is removed from consideration as BACT.

### 2.2.13 Wet Collector

Wet collection depends on the inertia of the PM in the flue gas to impact the scrubbing liquid and be collected. However, the fine particulate generated by gaseous fuel combustion (less than one micron in size) has little inertia, so the particles follow the gas stream without impacting the scrubbing liquid and being collected. Therefore, wet scrubbers are not a suitable control technology for application to the coker heaters, and are eliminated from consideration as BACT based on technical infeasibility.

### 2.2.14 Flue Gas Desulfurization

There are no instances of FGD, or any other add-on control technology, being used to reduce $SO_2$ in exhaust from any refinery process heater. While this technology has been proven effective on large coal-fired boilers, it has never been demonstrated on gas-fired coker heaters such as those proposed by BP. As a result, this technology is considered technically feasible for the proposed coker heaters.

## 2.3 $NO_X$ BACT

Several of the identified alternatives are commercially available combustion and post-combustion control technologies which are capable of reducing $NO_X$ emission from a forced-draft coker heater. As shown in Table 1, these controls include GCPs, LNBs, and SCR.

Table 1. $NO_X$ and CO BACT for Coker Heaters

| Facility | State | $NO_X$ Limit (lb/MMBtu) | Control[1] | CO Limit (lb/MMBtu) | Control[1] |
|---|---|---|---|---|---|
| Tesoro – Martinez [3] | CA | 7 ppmvd @ 3% $O_2$ | ULNB& SCR | 35 ppmvd @ 3% $O_2$ | GCP |
| Shell – Martinez [3] | CA | 10 ppmvd @ 3% $O_2$ | SCR | 50 ppmvd @ 3% $O_2$ | GCP |
| Total Refining – Port Arthur [3] | TX | 0.01 | SCR | 0.07 | GCP |
| Marathon Garyville Refinery | LA | 0.0125[2] | ULNB & SCR[4] | 0.04 | GCP |
| ConocoPhillips Borger Refinery | TX | 0.035 | GCP[5] | None | GCP |
| United Refinery Co.[6] | PA | 0.035 | LNB | 0.07 | GCP |
| Valero Corpus Christi Refinery East Plant | TX | 0.06 | None | None | GCP |
| Exxon Mobil Baytown Refinery | TX | 0.06 | ULNB | None | None |
| Basis Petroleum | TX | 0.06 | LNB | None | None |
| Citgo Corpus Christi Refinery - West Plant | TX | 0.180 | None | 0.082 | None |
| ConocoPhillips – Wood River | IL | None[7] | ULNB | 0.02 | GCP |
| Flint Hills Resources – Pine Bend | MN | 0.06/0.01[8] | ULNB& SCR | None | None |

Notes:
1 GCP = Good Combustion Practices, LNB = Low $NO_X$ Burner, None = No Control Specified, SCR = Selective Catalytic Reduction, ULNB = Ultra-Low $NO_X$ Burner
2 Annual average
3 Tesoro and Shell Martinez refineries are located in 8-hour ozone non-attainment area, requiring lowest achievable emission rate (LAER) and pollutant offsets. Total Refining – Port Arthur project netted out of Non-Attainment for $NO_X$.
4 SCR was deemed to not be BACT by Louisiana DEQ, but the facility has installed SCR
5 Coker heater is natural draft design
6 Permit was issued, but new coker heater was never installed
7 Project netted out of federal NSR for $NO_X$, and, while the permit specifies a control device (ULNB), it imposes no numeric limit
8 Hourly average (same as NSPS Subpart Ja Limit with no SCR)/annual average (with SCR to limit annual $NO_X$ emissions below PSD permitting thresholds).

### 2.3.1 Ranking of Remaining Alternatives

In top-down order of decreasing stringency, the feasible $NO_X$ controls are listed with the approximate emission factor achieved by each technology:

- ULNBs with GCPs and SCR – 0.01 lb/MMBtu
- ULNBs with GCPs – 0.035 to 0.06 lb/MMBtu
- Conventional Burners with GCPs – 0.10 lb/MMBtu

The facilities listed in Table 1 that installed SCR to control NOx are located in non-attainment areas and required to install Lowest Achievable Emissions Rate (LAER), or are facilities that proposed to install SCR in order to avoid non-attainment or PSD permitting. A conventional

burner operated with GCPs is considered the baseline control alternative for $NO_X$. The emission factors ranked above are assumed to be based on an average of three one-hour tests.

NSPS Subpart Ja, which would apply to the proposed heaters, limits $NO_X$ emissions from forced/balanced draft process heaters at refineries to 60 ppmvd at 0% $O_2$ (0.06 lb/MMBtu) on a 30-day rolling average. Natural draft process heaters at refineries are limited to 40 ppmvd at 0% $O_2$ (0.04 lb/MMBtu) on a 30-day rolling average. The proposed coker heaters will be capable of operating in both modes. However, BP plans to primarily operate in balanced draft mode to use the preheater system allows the new coker heaters to have higher thermal efficiency compared to a natural draft system without air preheat.

Higher $NO_X$ concentrations are generated in balanced draft mode because the air preheater raises temperature of the incoming combustion air and results in higher thermal $NO_X$ generation when compared to a natural draft system with no air preheat. The benefit to incorporating air preheat is that the replacement coker heaters will operate at a thermal efficiency near 90 percent and burn less coker off gas than a natural draft system.

Vendors have provided BP with a range of $NO_X$ guarantees for ULNBs (50 ppmvd to 60 ppmvd at 0% $O_2$). The $NO_X$ guarantees cover a range of coker heater operating conditions that includes coker heater tubes after spalling (50 ppmvd) to expected NOx emissions prior to spalling (60 ppmvd). The coker heater tubes need to be maintained at temperatures below metallurgy limits. The temperature of the heater tubes begins to rise as coke accumulates on the heater tubes. The combustion air needs to be cooled slightly to reduce the heater tube temperatures. Two options of cooling the combustion air are 1) increasing excess oxygen in the heater, and 2) reducing combustion air that goes through the air preheater. Increasing excess oxygen is the preferred option because the air preheater is needed to maintain heater efficiency. As combustion air through the preheater is reduced, the heater efficiency decreases and additional fuel must be combusted to continue processing the same amount of coker feed.

### 2.3.2 Consideration of Energy, Environmental and Cost Factors

#### 2.3.2.1 ULNBs and SCR

The most effective control alternative is to use ULNBs and SCR to reduce $NO_X$ emissions. Installing an SCR system is estimated to cost approximately $10 million, annual ammonia costs would be approximately $1.4 million per year, and the catalyst would have to be replaced every 6 years, at a cost of $0.2 million. Amortized over twenty years, an SCR system would cost approximately $2,600,000 per year (including capital, operation, and maintenance costs). As detailed in Attachment 1, SCR would reduce $NO_X$ emissions from NSPS Ja emission limits by approximately 66.4 tons per year, which corresponds to more than $39,000 per ton $NO_X$ removed. An SCR system would therefore not be cost effective.

Continuing the practice of the existing coker heaters, the proposed replacement coker heaters would combust coker off gas, which contains sulfur. Because the catalysts employed by SCR systems are deactivated by sulfur, some level of sulfur removal would be warranted. The cost and effectiveness of the sulfur removal system would have to be balanced with the cost savings realized by extending the life of the catalyst.

#### 2.3.2.2 ULNBs

There are energy and environmental considerations for operating the replacement coker heaters in balanced draft and natural draft modes. Operating in balanced draft mode with the air preheater results in higher energy efficiency (less coker off gas burned) and higher $NO_X$ emissions compared to a natural draft heater. To process the same amount of coker feed, a natural draft coker heater without air preheat would need to burn approximately 10 percent more fuel than a balanced draft design. The environmental considerations for a natural draft heater are a 25 percent reduction in $NO_X$ emissions but a 12.5 percent increase in combustion emissions of all other pollutants.[6] The proposed heater design is based on balanced draft with air preheat, which results in a heater with 90 percent thermal efficiency. Thermal efficiency is based on absorbed duty divided by fired duty.

The proposed heaters have the capability of operating in both balanced draft and natural draft modes. However, the heater design is based on balanced draft with air preheat. Operating in natural draft mode lowers the heater efficiency and constrains coker unit throughput. The throughput capacity of the proposed coker heaters will be reduced when operating in natural draft mode because the size of the firebox and the heat input capacity of the burners limit the amount of heat that would be transferred to the coker feed. BP does not plan to operate the heaters in natural draft mode during normal operations, but BP also recognizes the need for operational flexibility if an air preheater (balanced draft) needs to be taken offline.

### 2.3.3 Proposed BACT Limits and Control Option

BP proposes BACT for $NO_X$ emissions from a coker heater is ULNB with GCP achieving 60 ppmvd at 0% $O_2$, 30-day average (forced/balanced draft mode) and 40 ppmvd at 0% $O_2$, 30-day average (natural draft mode), respectively. BP proposes to achieve this limit using ULNBs with GCPs.

As stated above, the proposed replacement coker heaters will be of a balanced-draft design. Forced-draft heaters tend to have greater $NO_X$ emissions but are more efficient because they consume less fuel. BP proposes to operate the coker heaters in balanced-draft mode but also requires flexibility to operate in natural draft mode during some circumstances.

## 2.4 CO and VOC BACT

Based on a review of permitted coker heaters, CO BACT emission limits for recently permitted natural coker heaters ranges from 0.035 lb/MMBtu to 0.08 lb/MMBtu, and for VOCs, from 0.0015 lb/MMBtu to 0.0054 lb/MMBtu. The lower range VOC emission limit is based on a source test of a refinery fuel gas-fired coker heater at the Marathon Garyville Refinery, whereas the proposed coker heaters will be fired on coker off gas. Vendors have provided BP with preliminary CO emission guarantees for burners at 33 ppmvd at 0% $O_2$. BACT for CO and VOCs on most reviewed units is GCP.

[6] $NO_X$ emissions from the coker heaters would decrease by 25 percent going from balanced draft design (301 MMBtu/hr *0.06 lb $NO_X$/MMBtu) to natural draft design (331 MMBtu/hr * 0.04 lb $NO_X$/MMBtu). However, all other combustion emissions from a natural draft design would increase by approximately 10 percent because of the reduced heater efficiency and resulting additional fuel burned.

### 2.4.1 Ranking of Remaining Alternatives

GCP and oxidation catalyst, are considered technically feasible for coker heaters. In top-down order of decreasing stringency, the feasible CO and VOC controls are listed with the approximate level of control that could be achieved:

- Oxidation Catalyst and GCP – CO 0.002 lb/MMBtu (90 percent control), VOC 0.0027 lb/MMBtu (50 percent control)
- GCP – CO - 33 ppmvd at 0% $O_2$ (0.02 lb/MMBtu), VOC - 0.054 lb/MMBtu

### 2.4.2 Consideration of Energy, Environmental and Cost Factors

With respect to energy considerations, post-combustion controls on burners of the capacity range proposed will noticeably reduce the thermal efficiency of the unit. Catalyst modules increase the back-pressure downstream of the combustion chamber between 0.05 and 0.5 inches of $H_2O$ per inch of catalyst bed depth, depending upon design.[7] Secondary environmental impact issues associated with spent catalyst module disposal are common among installations that employ post-combustion catalytic systems. While landfill disposal fees for spent catalyst are not expensive, the potential liability associated with disposal is difficult to assess from a monetary perspective. Catalyst recycling options are not fully developed, and have their own specific liabilities associated with transport, processing, and disposal of by-products.[8]

As demonstrated in Attachment 2, add-on CO and VOC control technology for the proposed coker heaters would be cost-prohibitive in terms of cost per ton abated. Assuming an oxidation catalyst could provide 90 percent reduction of CO and 50 percent reduction of VOCs, implementation of a catalytic oxidizer has an estimated annualized cost of over $1,800,000, and provides a combined CO and VOC reduction of 27.5 tons per year, compared with GCP. From these results, the cost effectiveness of the catalytic oxidizer option is conservatively estimated to be $68,000 per ton reduced. Catalytic oxidation is eliminated as a BACT alternative because it is not cost effective.

### 2.4.3 Proposed BACT Limits and Control Option

BP proposes that BACT for CO and VOC emissions from the proposed replacement coker heaters is 33 ppmvd at 0% $O_2$ for CO (30-day rolling average), and 0.0054 lb/MMBtu for VOC, both achieved by employing GCP.

## 2.5 PM, $PM_{10}$, $PM_{2.5}$ BACT

The BACT analysis assumes that all $PM_{10}$ emissions from the proposed replacement coker heaters are $PM_{2.5}$, and that the $PM_{10}$ and $PM_{2.5}$ emission rates are all equivalent. PM is typically evaluated only as the filterable portion.

[7] Cooper, C.D. and F.C. Alley, "Air Pollution Control: A Design Approach," Waveland Press, 1994. Page 359.
[8] Electric Power Research Institute (EPRI), "Recycling and Disposal of Spent Selective Catalytic Reduction Catalyst," Report No. 1004888, October 2003.

### 2.5.1 Ranking of Remaining Alternatives

The only remaining alternatives are good combustion practices and fuel selection:

- Coker Off Gas Fuel – $PM_{10}/PM_{2.5}$ 0.01 lb/MMBtu; PM (filterable) 0.0025 lb/MMBtu
- Natural Gas Fuel - $PM_{10}/PM_{2.5}$ 0.0075 lb/MMBtu; PM (filterable) 0.002 lb/MMBtu

### 2.5.2 Consideration of Energy, Environmental and Cost Factors

BP's design of the replacement coker heaters is based on combusting coker off gas. If natural gas was imported and burned in the coker heaters instead of the coker off gas, the quantity of coker off gas sent to the RFG mix drum would increase significantly. The result would be a "fuel gas long" scenario (i.e., more fuel gas available than could be burned in refinery heaters), which would require flaring of RFG. Flaring RFG rather than combusting it in process heaters instead of natural gas, is inefficient from an energy conservation standpoint.

### 2.5.3 Proposed BACT Limits and Control Option

BP submits that BACT for PM, $PM_{10}$, and $PM_{2.5}$ emissions from the replacement coker heaters is good combustion practices and fuel selection (including using low sulfur fuels – see the $SO_2$ section below). All of the emission limits in the RBLC are consistent with the AP-42 emission factor of 0.0075 lb/MMBtu of $PM_{10}$ (filterable and condensable) for natural gas combustion (AP-42 Table 1.4-2). The AP-42 emission factor is based on the source test results from multiple emission units across the United States.

However, BP's source testing of similar RFG-fired heaters (#2 DHDS and #3 DHDS Charge Heaters) firing refinery fuel gas supports a site specific emission rate of 0.01 lb/MMBtu of $PM_{10}$ and $PM_{2.5}$ (filterable and condensable) and a filterable component emission rate of 0.0025 lb/MMBtu of PM. The source test data used to calculate emissions for the coker heaters are summarized in Table 2.

Table 2 - Particulate Emissions Test Summary

| | | | | | |
|---|---|---|---|---|---|
| #2 DHDS Charge Heater | Refinery Fuel Gas | | | | |
| EPA Method 5/OTM28 | ULNB | | | | |
| | Test Date | 9/10/2009 | 9/11/2009 | 9/11/2009 | |
| | Run # | Run 1 | Run 2 | Run 3 | Average |
| Daily Average Firing Rate | mmBtu/hour HHV | 24.65 | 24.65 | 24.65 | 24.65 |
| Filterable PM | lb/mmBtu | 0.002 | 0.003 | 0.002 | 0.002 |
| Condensable PM | lb/mmBtu | 0.007 | 0.006 | 0.008 | 0.007 |
| Total PM | lb/mmBtu | 0.009 | 0.008 | 0.011 | 0.009 |
| #3 DHDS Charge Heater | Refinery Fuel Gas | | | | |
| EPA Methods 5/202 | ULNB | | | | |
| | Test Date | 8/13/2013 | 8/13/2013 | 8/13/2013 | |
| | Run # | Run 1 | Run 2 | Run 3 | Average |
| Daily Average Firing Rate | mmBtu/hour HHV | 27.54 | 26.44 | 26.67 | 26.88 |
| Filterable PM | lb/mmBtu | 0.002 | 0.002 | 0.002 | 0.002 |
| Condensable PM | lb/mmBtu | 0.007 | 0.004 | 0.006 | 0.006 |
| Total PM | lb/mmBtu | 0.009 | 0.006 | 0.008 | 0.008 |

The data include filterable and condensable particulate matter collected using EPA test methods on stacks combusting refinery fuel gas. BACT for $PM_{10}$ and $PM_{2.5}$ (0.01 lb/MMBtu) is based on RFG combustion with a slight margin of safety over the test results of 0.008 and 0.009 lb/MMBtu. Individual source test runs were as high as 0.01 lb/MMBtu.

## 2.6 $SO_2$ and $H_2SO_4$ BACT

Sulfur dioxide ($SO_2$) and sulfuric acid ($H_2SO_4$) emissions are entirely dependent upon the amount of sulfur present in the fuel. Sulfur contained in the fuel combines with oxygen at combustion temperatures to form $SO_2$ and a fraction of the sulfur converts to $H_2SO_4$.

### 2.6.1 Ranking of Remaining Alternatives

Limiting the sulfur in gaseous fuel is the only method in use to control $SO_2$ emissions from combustion units fired on coker off gas or RFG. Although not a proven technology for refinery heaters, flue gas desulfurization is capable of reducing $SO_2$ emissions from the proposed coker heaters. A review of the RBLC reveals a range of sulfur limits that have been deemed BACT:

- Limit $H_2S$: 25 to 35 ppmv $H_2S$
- $SO_2$ Limits: 0.023 lb/MMBtu to 0.034 lb/MMBtu

The only RBLC listing for $H_2SO_4$ was to limit $H_2S$ concentrations in the fuel gas to 160 ppmv.

### 2.6.2 Consideration of Energy, Environmental and Cost Factors

#### 2.6.2.1 Fuel Selection

Refineries can use natural gas or treated RFG to reduce $SO_2$ emissions. Other refineries route coker off gas directly to the RFG mix drum and then back to the coker heaters, which effectively spreads the sulfur in the coker off gas to heaters and boilers across the entire refinery. Burning only natural gas in the replacement coker heaters would result in lower $SO_2$ emissions from the coker heaters, but increased $SO_2$ emissions from other heaters and boilers at the refinery (all coker off gas sent to RFG system).

Using natural gas to fuel the replacement coker heaters would result in additional greenhouse gas emissions from the refinery because the coker off gas would be burned as RFG in other process heaters or boilers. There would be additional costs associated with buying additional natural gas.

#### 2.6.2.2 Lean Oil Absorption

The lean oil absorption system is designed to process approximately 44 percent of the coker off gas stream. The system will recover C3 (i.e. propanes) and C4 (i.e. butanes) hydrocarbons and process the hydrocarbons in the light ends unit to generate saleable products. One additional benefit of the lean oil absorption system is sulfur removal from the processed coker off gas because mercaptans will be removed with the light hydrocarbons.

BP anticipates the lean oil absorption system will reduce annual average sulfur concentrations in the coker off gas 39 percent (from 600 ppm S down to 366 ppm S). This will also reduce $SO_2$

emissions from the replacement coker heaters by 39 percent. With the lean oil absorption system, the replacement coker heaters are expected to achieve an annual average $SO_2$ emission rate of 36 ppmvd at 0% $O_2$ (0.050 lb/MMBtu). $H_2SO_4$ emissions are expected to be 0.0040 lb/MMBtu, assuming, based on refinery fuel gas-fired heater source test results, 2.63 percent of coker off gas sulfur is converted to $H_2SO_4$.

#### 2.6.2.3 Lean Oil Absorption with Additional Compression

BP will install a new compressor prior to the lean oil absorption system. The compressed coker off gas results in additional C3 (propanes) and C4 (butanes) hydrocarbons recovered in the lean oil system and processed in the light ends unit for saleable product. Recovering additional C3 and C4 hydrocarbons also reduce the sulfur in the coker off gas by up to 65 percent (removal of mercaptans in C3 and C4 hydrocarbons) compared to expected annual sulfur concentrations. Total capital investment for a 1,000 horsepower compressor to treat the coker off gas stream would be approximately $13.6 million. Assuming only the installation cost and annual electricity costs to operate the new compressor, the annualized cost is conservatively $1.7 million. This cost estimate is conservatively low because it does not include an estimate for annual maintenance, taxes, administration, and administration costs. The combined $SO_2$ and $H_2SO_4$ reduction of 93 tons per year for installing a new compressor equates to a cost effectiveness of $18,300 per ton reduced, which is not cost effective. Although additional compression does not meet BACT cost effectiveness criteria, BP has decided to install the compressor as part of the final Project design.

#### 2.6.2.4 Flue Gas Desulfurization

A spray tower would provide a 95 percent reduction in $SO_2$ and $H_2SO_4$ emissions from a coker heater. The annualized cost of installing and operating one spray tower is approximately $1 million per heater based capital cost estimates from 2008 Jacobs Engineering, but the control costs do not include required upgrades to wastewater treatment in order to handle additional flows from the spray towers. In addition, there are siting issues for locating spray towers near the coker heaters within the constrained coker unit footprint.

Regardless of siting concerns, a spray tower would reduce combined $SO_2$ and $H_2SO_4$ emissions from one coker heater by 67.7 tons per year, which corresponds to more than $20,000 per ton $SO_2$ and $H_2SO_4$ reduced (see Attachment 4). Flue gas desulfurization is eliminated as a BACT alternative because it is not a cost effective control.

#### 2.6.2.5 Cryogenic Fuel Gas Treatment

BP estimates that the capital cost for installing a cryogenic system would be approximately $104 million dollars, which, amortized over twenty years, would cost approximately $9.8 million per year. Even a 100 percent reduction in $SO_2$ and $H_2SO_4$ from the two coker heaters (143 tons per year), would result in a cost effectiveness of $68,500 per ton of $SO_2$ removed, which is not cost effective.

#### 2.6.2.6 Gas Phase Merox Treatment

As demonstrated in Attachment 5, add-on gas phase merox control technology for the proposed coker heaters would be cost-prohibitive in terms of cost per ton abated. Assuming the gas phase merox system could provide 90 percent reduction of $SO_2$ and $H_2SO_4$, implementation of

the fuel gas treatment system has an estimated annualized cost of over $3.4 million, and provides a combined $SO_2$ and $H_2SO_4$ reduction of 128.3 tons per year, compared with expected emissions. From these results, the cost effectiveness of the gas phase merox system option is conservatively estimated to be $26,600 per ton reduced. Gas phase merox is eliminated as a BACT alternative because it is not a cost effective control.

### 2.6.3 Proposed BACT Limits and Control Option

The applicable NSPS Subpart Ja requirements would limit $H_2S$ content in the coker off gas to 0.1 gr/dscf (162 ppmv) on a 3-hour rolling average basis and to 60 ppmv on a 365 consecutive operating day average. However, a limit on the total $SO_2$ emissions is more stringent than a limit just on $H_2S$ because other sulfur species (e.g., carbon disulfide, mercaptan, etc.) remain uncontrolled and may comprise a significant source of sulfur in refinery fuel gas streams.

Based on the coker off gas total sulfur content after the new lean oil absorption system (366 ppm S), the proposed $SO_2$ BACT emission limit is 36 ppm $SO_2$ at 0% $O_2$ on an annual average. To accommodate for short-term fluctuations in coker off gas sulfur content, BP is proposing a short-term $SO_2$ BACT emission limit of 40 lb/hr (calendar day average) combined for the two coker heaters based on a predicted sulfur concentration in the coker off gas (0.066 lb $SO_2$/MMBtu) and the maximum burner capacity of each replacement coker heater (303 MMBtu/hr). $H_2SO_4$ emissions are based on 2.63 percent sulfur conversion to $H_2SO_4$ and corresponds to a short-term limit of 3.2 lb/hr (calendar day average) combined for the two coker heaters.

BP proposes that BACT for $SO_2$ and $H_2SO_4$ emissions from the replacement coker heaters is the use of coker off gas and good operating practices.

BP recognizes that BACT limits are often expressed in ppm or lb/MMBtu values, but variability in the coker off gas sulfur concentrations make it difficult to determine a single sulfur concentration in the coker off gas used as fuel in the replacement coker heaters. For this reason, BP proposes only a mass emissions limit for the short-term $SO_2$ BACT limit.

Sulfur concentrations in the coker off gas are dependent on the characteristics of the residual material processed by the coker unit, heater temperatures, residence time in coke drums, and the new lean oil absorption system operating conditions. The lean oil absorption system will recover additional gases (including mercaptans) from the coker off gas, but there will be instances when regular maintenance of a downstream unit (i.e. naphtha unit handling recovered gas from lean oil absorption system) will result in higher sulfur concentrations in the coker off gas fuel to the coker heaters. When the sulfur concentration in the coker off gas is above 0.066 lb $SO_2$/MMBtu, BP could reduce coker heater firing rates/throughput or operate on a single coker heater (two coke drum operation) to reduce combined $SO_2$ emissions from coker heaters. The proposed combined mass emission limit is designed to provide the facility with operational flexibility while accounting for the variable sulfur concentrations in coker off gas and operation of the lean oil absorption system. Ecology used a similar approach to determine $NO_X$ and CO BACT emission limits for Boiler #5 (PSD-02-04) due to variability in boiler operating conditions and refinery fuel gas composition.

Short-term $SO_2$ mass emissions of 20 lb/hr per heater were used to evaluate compliance with the applicable 1-hour $SO_2$ significant impact levels (see Section 5 of the PSD/NOC application).

## 2.7 GHG BACT

While EPA's recommended process for GHG BACT is similar to that recommended for criteria pollutants, there are enough differences that it is helpful to review the background and procedures associated with the GHG BACT analysis before launching into the details.

On May 13, 2010, USEPA issued the final "Tailoring Rule" with the stated intent of establishing a "common sense approach" to addressing GHG emissions from stationary sources, by "tailoring" the major source applicability thresholds under the Prevention of Significant Deterioration (PSD) and Title V air operating permit programs and providing a phased implementation for GHG permitting requirements. Under the Tailoring Rule, GHG emissions thresholds were established to determine which new sources or modifications of existing major sources would be subject to PSD review for GHGs. Because there are no ambient standards or increments for GHGs, the only PSD requirement that could potentially apply to GHGs is that BACT must be employed to reduce GHG emissions from the proposed project.

On June 23, 2014, the Supreme Court ruled, in Utility Air Regulatory Group v. EPA, that EPA could not establish regulatory thresholds different from those required under statute, as it had done in the Tailoring Rule. As a result, new sources or modifications with potential criteria pollutant emission rate increases that are less than the PSD threshold are not subject to the requirements of the PSD program, regardless of the GHG emission rate increase associated with the project. However, in the same decision, the Supreme Court ruled that a new project or modification that triggers PSD review as a result of a criteria pollutant emission increase can be required to implement BACT for GHGs. As indicated in Section 3 of the application, the proposed Project is subject to PSD review as a result of $NO_X$, CO, $SO_2$, PM, $PM_{10}$, $PM_{2.5}$, VOC, and $H_2SO_4$ emission increases, and, therefore, must implement BACT for GHG emission increases.

GHG emissions may be divided into two categories: fugitive GHGs, and "stack" GHGs. Stack GHGs may be further divided between those resulting from fuel combustion, and those resulting from an industrial process that does not directly involve combustion.

Fugitive GHG emissions are typically the result of leaks associated with stored or transported GHGs. Coker off gas contains methane, which is considered a GHG. Components associated with transferring coker off gas may generate fugitive GHG emissions. BACT for fugitive leaks from components are discussed in Section 3 of the BACT analysis. The proposed replacement coker heaters, which will combust coker off gas, will increase only the three combustion GHGs (i.e., $CO_2$, $CH_4$, and $N_2O$) and component leaks ($CH_4$).

This GHG BACT analysis will follow the evaluation process recommended by EPA in a guidance document issued in March 2011.

### 2.7.1 Identify Available Control Alternatives

The first step in the top-down procedure is to identify all available control technologies and emission reduction options for the emissions unit and pollutant undergoing the BACT analysis. Available control technologies are those with a practical potential for application to the particular pollutant and emissions unit under review, which have been demonstrated in practice on full scale operations and are commercially available. Pollutant emission reduction options can be grouped into two categories:

- Inherently lower-emitting processes, practices or designs; and,
- Add-on control technologies.

Also, emission reduction options can sometimes be used in combination.

#### 2.7.1.1 Inherently Lower-Emitting Processes, Practices or Design

An inherently lower-emitting production process is one that maximizes product yield and thermal efficiency while minimizing pollutant emissions. This is typically achieved by utilizing state-of-the-art equipment design that maximizes feedstock conversion and energy recovery, minimizes fuel and energy use, and uses clean fuels. For GHGs, “clean fuels” and “low-carbon” fuels are those that combust most efficiently, thereby emitting fewer GHGs per unit of heat input.

The following inherently lower-emitting processes, practices and design options are included as “available” control options for the consideration of BACT in this analysis, and all can be considered in combination.

- Use of lower-emitting, or low-carbon, fuels;
- Energy efficient design, and;
- Use of good combustion practices.

#### 2.7.1.2 Add-On Control Technologies

The only potential add-on control technology for removing $CO_2$ (which will constitute more than 99 percent of the GHG emission increase associated with the project) from a gas stream is typically referred to as “carbon capture and sequestration/storage” (CCS). CCS technology includes three stages: (1) removing or segregating $CO_2$ from the gas stream, (2) compressing and transporting the $CO_2$, and (3) permanently storing the $CO_2$ (i.e., in a permitted Class VI well) or using it in some beneficial way (i.e., enhanced oil recovery or other industrial use).

CCS is a developing technology that has not been demonstrated in practice on full-scale operations over the long term, although there are demonstration projects currently under way. According to the Global CCS Institute, which maintains a database of large-scale integrated CCS projects, as of July, 2014, there are 19 CCS projects in the U.S.: 7 operational, 2 under construction, 6 in the planning stage, and 4 under evaluation.[9] None of the projects involve a petroleum refinery. The facilities with operational CCS projects involve natural gas processing,

[9] http://www.globalccsinstitute.com/data/status-ccs-project-database

and creating fertilizer or $H_2$ from natural gas. The two projects under-construction are a coal-fired ethanol plant[10] and an IGCC facility that will use lignite as an energy source. All of the planned or proposed projects feature coal, lignite, petcoke, or natural gas as the energy source.

The March 2011 guidance states that EPA classifies CCS as an "available" add-on $CO_2$ control technology for "large $CO_2$-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity $CO_2$ streams (e.g. hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)." This document further states that "available" means the control alternative has the potential for practical application to the emission unit and the regulated pollutant under evaluation," and that EPA supports the recommendations of the Interagency Task Force on Carbon Capture and Storage, which concluded that current $CO_2$ capture technologies, while available for fossil-fueled power plants, "are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application." The Task Force's conclusion went on to say that "[s]ince the $CO_2$ capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."

Neither the existing nor the replacement coker heaters emit $CO_2$ in amounts comparable to a large fossil fuel-fired power plant. $CO_2$ emissions from the highest-emitting one hundred power plants in the US ranged from approximately 7.5 to 25.3 million tons per year (MMtpy) each,[11] whereas the maximum potential $CO_2$ emissions increase attributable to the coker heater replacement project is approximately 0.7 MMtpy. Further, $CO_2$ emissions at the refinery do not occur in high-purity streams; rather, $CO_2$ is emitted primarily as a product of combustion from the replacement coker heaters. Also, petroleum refining is not one of the industry types specifically listed in the March 2011 Guidance for which USEPA classifies CCS as "available." Thus, BP does not consider CCS an "available" technology in the context of USEPA's March 2011 Guidance.

Nonetheless, in the interest of providing a complete and thorough permitting record, the technical, logistical and cost considerations of the application of CCS are discussed further below. As documented herein, even if CCS were considered an "available" control technology for potential application as BACT for GHG emissions attributable to the project, it would not be considered cost effective.

Add-on technologies to remove $CH_4$ and $N_2O$ exist (e.g., thermal and catalytic oxidation, non-selective catalytic reduction), but none have been employed to remove these GHG compounds from process heaters at refineries or from combustion sources in general. Furthermore, $CH_4$ and $N_2O$ emissions comprise only approximately 0.1 percent of the total projected GHG emissions increase attributable to the project; thus, application of add-on technology to reduce these pollutants would not have a practical effect on the overall GHG emission rate, even if such

[10] The captured $CO_2$ is a by-product of ethanol production from corn, not from the coal combustion used to heat the process.
[11] http://www.sciencedaily.com/releases/2007/11/071114163448.htm

controls were found to be technically feasible. Therefore, no add-on technologies for removal of $CH_4$ or $N_2O$ will be considered in the BACT analysis.

### 2.7.2 Eliminate Technically Infeasible Alternatives

In the second step of a top-down BACT analysis, the available pollutant reduction options listed in Step 1 are considered, and, if found to be technically infeasible for the specific emission unit or units under review, eliminated.

#### 2.7.2.1 Low-Carbon Fuels

A review of the $CO_2$ emission factors prescribed for calculating GHG emissions for the federal GHG mandatory reporting rule program indicates that natural gas is the fuel available at the refinery that emits the least $CO_2$ per unit of heat input.[12] Other fuels available at the refinery include RFG, which is a mixture of light (C1 to C4) hydrocarbons and other gases that are not condensed in the various distillation processes at the refinery, among them the cokers, which produce coker off gas. Carbon content of RFG and coker off gas varies with the type of crude processed at the refinery; combustion of refinery process gases typically results in greater $CO_2$ emissions per unit of heat input than natural gas (composed of primarily methane). Nevertheless, RFG and coker off gas are considered low carbon fuels when compared to other common fuels.[13]

Combusting low-carbon fuels such as natural gas, RFG, and coker off gas in the proposed replacement coker heaters is considered technically feasible. In addition, the lean oil absorption system will remove C3 and C4 hydrocarbons from the coker off gas prior to combustion in the coker heaters.

#### 2.7.2.2 Energy-Efficient Design and Good Combustion Practices

The following measures are considered technically feasible for maximizing the efficient operation of the proposed replacement coker heaters:

- Preheating combustion air with flue gases
- Heat recovery to produce 25,000 lb of 140 pound-per-square-inch (psi) steam per hour per heater
- Using burners with the most efficient design available
- Excess air monitoring and control (balanced-draft design)
- Maintaining and operating burners as recommended by the manufacturer

#### 2.7.2.3 CCS

There are three basic approaches to $CO_2$ capture associated with combustion:

[12] 40 CFR Part 98 (Mandatory Greenhouse Gas Reporting), Subpart C (General Stationary Fuel Combustion Sources), Table C-1

[13] From 40 CFR Part 98, Subpart C, Table C-1 (all expressed in kg $CO_2$/MMBtu): Natural Gas – 53.06, Fuel Gas – 59.00, Propane Gas – 61.46, No. 2 Fuel Oil – 73.96, Bituminous Coal – 93.28

- Post-combustion capture – the fuel is combusted in air and the $CO_2$ generated is removed from the exhaust using a solvent scrubbing system, physical filter, cryogenic condensation system, or membrane separation system.
- Pre-combustion capture – the fuel is converted to a syngas composed largely of $CO_2$ and hydrogen ($H_2$); the $CO_2$ is removed from the syngas, and the remaining $H_2$ is combusted in air, which produces exhaust gases composed almost completely of water ($H_2O$); and
- Oxy-fuel combustion – the fuel is combusted with high-purity oxygen ($O_2$) instead of air, which produces a concentrated $CO_2$ exhaust that allows for a smaller-scale $CO_2$ removal system.

Following capture, the $CO_2$ is compressed and transported via pipeline to a storage or industrial use location.

There is broad consensus that the technology for the safe and effective capture, transport, and storage or use of $CO_2$ currently exists, but not all components that comprise an effective CCS program are currently commercially available. Oxy-fuel combustion is currently in the research phase, primarily for application to coal combustion, and is not commercially available. For purposes of this BACT analysis, CCS incorporating post-combustion or pre-combustion capture technology is considered a technically feasible control alternative for $CO_2$ generated by refinery fuel gas combusted in process heaters.

### 2.7.3 Rank Technically Feasible Alternatives

In Step 3, the remaining alternatives that have not been removed from consideration due to technical infeasibility are ranked, starting with the most effective. Typically, 90 percent of the $CO_2$ in an exhaust stream can be recovered using current capture technology. Losses associated with compression, transport, and storage or use of the $CO_2$ is negligible. However, the energy required to capture, compress, and transport the $CO_2$ is significant, and accounting for the additional $CO_2$ generated to produce additional energy results in a net "$CO_2$ avoided" of approximately 85 percent.

Use of low carbon fuels, energy efficient design, and good combustion practices are considered baseline alternatives for reducing GHGs.

### 2.7.4 Evaluate Economic, Energy, and Environmental Impacts

EPA's March 2011 Guidance suggests that, instead of the more traditional approach where emission reduction alternatives are considered and either eliminated or adopted in decreasing order of effectiveness, the economic, energy, and environmental impacts of all options are considered. In light of this guidance, each technically feasible option was evaluated, regardless of the Step 3 ranking.

#### 2.7.4.1 Low-Carbon Fuels

Coker off gas is comprised of the gases volatilized in the coke drums during the coking process. Firing coker off gas in process heaters such as the proposed replacement coker heaters reduces the quantity of natural gas the refinery purchases and combusts, which is both economically beneficial and makes efficient use of energy resources. Natural gas is considered

a lower-carbon fuel than coker off gas or RFG, but the economic, energy, and environmental considerations outlined above make coker off gas and RFG the most desirable fuels for the replacement coker heaters, and BP proposes to continue with the practice.

#### 2.7.4.2 Energy Efficient Design

BP proposes to replace the existing coker heaters with new technology heaters that incorporate a more energy-efficient design and equipment. Operating the replacement heaters will have a positive energy and environmental impact compared to the existing coker heaters. The replacement coker heaters will be operated and maintained as recommended by the manufacturer.

#### 2.7.4.3 Carbon Capture and Storage

As discussed in Step 3, CCS systems require additional energy to remove $CO_2$ from an exhaust stream, as well as to compress it for transport and storage. The coker heater exhaust gases would contain between 10 and 20 percent $CO_2$ by weight; a strong solvent would be required to capture the $CO_2$, and regenerating the solvent would require a considerable amount of energy. The captured $CO_2$ would be compressed to approximately 2,200 pounds per square inch gauge (psig) for transport. The additional energy demand would be satisfied either by purchasing additional power, or establishing electrical generation at the facility. Either scenario would have a negative economic impact on the refinery, increase criteria pollutant emissions, and reduce the net GHG reduction associated with the CCS system. The economic impacts of the additional energy requirements for capture, compression, and transport would be in addition to the capital and operating costs associated with equipping and maintaining a CCS system.

Captured and compressed $CO_2$ must be transported to a storage facility or end use. Ecology's 2007 white paper on $CO_2$ sequestration lists saline aquifers, depleted oil and gas fields, deep coal beds, and basalt deposits as potential $CO_2$ storage options. However, the report indicates that little is known about the structure of deep coal beds, and storage in saline aquifers in Washington is not ideal because of increased risk of earthquakes, extensive faulting and fracturing, and proximity to volcanoes. Very little oil and gas exploration has occurred in the state and little is known about the geologic structure of oil and gas fields in the state. There has been extensive drilling of basalts in the Hanford, Washington area, but a systematic and quantitative evaluation of the potential for geologic sequestration of $CO_2$ has not been developed.[14] Because $CO_2$ storage facilities are currently not available the only real alternative for sequestering captured $CO_2$ is enhanced oil recovery (EOR). The nearest EOR operations are in Wyoming, more than 700 miles from BPCP.

Most cost information related to CCS technology focuses on fossil fuel (particularly coal) combustion for power generation, natural gas processing, and syngas production operations. U.S. Department of Energy analyses indicate that application of post-combustion $CO_2$ capture technology to a new 550 MWe net output coal-fired power plant would cost approximately $86 per ton of $CO_2$ avoided. A study by the Global CCS Institute estimates that cost of avoided

[14] Washington Department of Ecology. "Feasibility of Using Geologic Formations to Sequester Carbon Dioxide ($CO_2$)." August 2007.

$CO_2$ emitted by a pulverized coal power plant with a first-of-its-kind CCS system would range between $62 and $81 per tonne.[15] Based on the less expensive of these costs ($62 per tonne of $CO_2$ avoided) and the calculated annual $CO_2$ emission rate attributable to the proposed new and modified combustion sources, the CCS system for the replacement coker heaters would cost approximately $18,600,000. Amortized over 20 years, this is equivalent to an annualized cost of approximately $1,753,000.

The NETL 2010 report provided estimated operating costs for a natural gas-fired combined-cycle combustion turbine with and without a $CO_2$ capture system. The difference in operating costs between the two scenarios was approximately $11,300,000 per year, for a facility that would combust approximately 90,600 MMBtu per day. Scaling the operating cost increase using a maximum replacement coker heater heat input of approximately 14,544 MMBtu per day yields a $CO_2$ capture system operating cost of approximately $1,811,000 per year. A new compressor would be required for the captured $CO_2$ and would add additional capital and annual operating costs to CCS.

While an EOR operation in Wyoming is the nearest currently available destination for captured $CO_2$ at BPCP, the Big Sky Carbon Sequestration Partnership's Kevin Dome $CO_2$ Storage Demonstration Project is currently being developed near Sunburst, Montana, which is approximately 500 miles from BPCP. The capital and operating costs of a hypothetical pipeline used to deliver approximately 300,000 tons per year of $CO_2$ were calculated using formulas provided in a DOE/NETL document,[16] and the diameter of the pipe used to construct the pipeline was assumed to be 6 inches.[17] Pipeline costs are broken down into three categories, as follows:

- Pipeline/Transport Cost – includes pipeline materials, direct labor, indirect costs, and right of way acquisition as a function of pipeline length and diameter;
- Related Capital Expenditures – includes a $CO_2$ surge tank and pipeline control system; and
- O&M Costs – based on a cost per mile of pipeline per year operated.

Table 3 is a summary of the estimated $307 million capital cost to construct the hypothetical $CO_2$ pipeline described above. Table 4 is a summary of the total annualized cost of the pipeline (operating costs plus capital costs amortized over 20 years), which would be almost $29 million per year.

[15] For comparison, the cost of naturally-sourced $CO_2$ used for EOR is between $10 and $15 per tonne.
[16] "Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs in NETL Studies", DOE/NETL-2013/1614, March 2013 – http://www.netl.doe.gov/energy-analyses/pubs/QGESS_CO2T%26S_Rev2_20130408.pdf
[17] Diameter estimated from Massachusetts Institute of Technology $CO_2$ Pipeline Transport Cost Estimation, June 2009, Figure 2.1 and Table 1 – http://e40-hjh-server1.mit.edu/energylab/wikka.php?wakka=MIT

Table 3. Capital $CO_2$ Pipeline Cost

| Cost Type | Inputs & Units[1] | Cost | |
|---|---|---|---|
| **Pipeline Capital Costs** | | | |
| *Materials* | *Diameter (inches), Length (miles)* | $70,350 + $2.01 x L x (330.5 x $D^2$ + 686.7 x D + 26,960) | $43,263,441 |
| *Labor* | *Diameter (inches), Length (miles)* | $371,850 + $2.01 x L x (343.2 x $D^2$ + 2,074 x D + 170,013) | $196,158,111 |
| *Miscellaneous* | *Diameter (inches), Length (miles)* | $147,250 + $1.55 x L x (8,417 x D + 7,234) | $44,892,650 |
| *Right of Way* | *Diameter (inches), Length (miles)* | $51,200 + $1.28 x L x (577 x D + 29,788) | $21,331,200 |
| **Other Capital Costs** | | | |
| *$CO_2$ Surge Tank* | *$* | | $ 1,244,724 |
| *Pipeline Control System* | *$* | | $ 111,907 |
| **Total Capital Cost** | | | |
| $ 307,002,033 | | | |

Notes:

1 Pipeline diameter was assumed to be 6 inches based on estimation from Massachusetts Institute of Technology $CO_2$ Pipeline Transport Cost Estimation, June 2009, Figure 2.1 and Table 1 – http://e40-hjh-server1.mit.edu/energylab/wikka.php?wakka=MIT; pipeline length was assumed to be 500 miles, based on distance between the refinery and the approximate location of the Kevin Dome $CO_2$ Storage Demonstration Project near Sunburst, Montana.

Table 4. Annual $CO_2$ Pipeline Cost

| Cost Type | Inputs & Units[1] | Cost | |
|---|---|---|---|
| **Annualized Capital Cost** | | | |
| *Total Capital Cost* | *Total Capital Cost (TCC, $), Interest Rate (i) Period (n)* | TCC x $(1+i)^n$ | $28,978,820 |
| **Annual O&M Cost** | | | |
| *Fixed O&M* | *Length (miles)* | $8,632 x L | $ 4,316,000 |
| **Total Annualized Cost** | | | |
| | | | $33,294,820 |

Notes:

1 Total capital costs were annualized based on an assumed equipment life of 20 years, and a 7% interest rate; pipeline length was assumed to be 500 miles, based on distance between the refinery and the approximate location of the Kevin Dome $CO_2$ Storage Demonstration Project near Sunburst, Montana.

The total annual cost of a $CO_2$ capture system and pipeline to transport the captured $CO_2$ to a potential storage location would be approximately $33,295,000 per year. For comparison, the capital cost of the replacement coker heaters is approximately $185 million ($18 million annualized over 20 years). The estimated annual cost to operate a CCS system would be almost twice the cost of the two replacement heaters.

The considerable monetary and energy requirements of a CCS system suggest unacceptable economic and energy impacts. Also, the increased energy requirements would result in additional emissions of all pollutants other than $CO_2$, and, therefore, use of a CCS system to mitigate GHG emissions would have an unacceptable collateral environmental impact as well. As a result, CCS systems are removed from consideration as BACT for GHGs emitted by the replacement coker heaters.

### 2.7.5 Select BACT

Based on the BACT analysis information presented here, BP proposes that BACT for GHG emissions from the proposed replacement coker heater is the use of low-carbon fuels (i.e., coker off gas and/or RFG), energy efficient design, and good combustion practices. BP proposes to limit GHG emissions from the proposed replacement coker heaters to 121 lb $CO_2e$/MMBtu (36,631 $CO_2e$/hr for each heater) on an annual average.

BP has conducted analyses on the coker off gas to determine the carbon content and assumes that all carbon will be emitted as $CO_2$ (120.2 lb $CO_2$/MMBtu). $CH_4$ and $N_2O$ emission factors

were obtained from AP-42 Section 1.4 (natural gas combustion) and global warming potential (GWP) values for each greenhouse gas were used to calculate $CO_2e$.[18]

In past correspondence, Ecology specifically requested a list of coker heater modifications that were considered but rejected as part of the GHG BACT analysis. Over the past couple of years, the BP project team has considered hundreds of factors when evaluating options for the coker heaters. The two most favorable options were 1) repair the existing heaters; and 2) replace the existing heaters. Repairing the existing heaters is a smaller capital investment than replacing the heaters, but the purpose of this Project is to replace the existing heaters with the latest technology heater.

A primary design consideration the replacement heaters was energy efficiency. Natural draft heaters have lower thermal efficiencies compared to balanced draft heaters with air preheat systems. BP's project team selected the more energy efficient balanced draft heater design. The higher thermal efficiency in the heater requires a lower temperature residual feed from the vacuum unit. At current residual feed temperatures there would be a higher potential of coking the replacement heater tubes because more heat would be transferred to the residual feed (more energy efficient) than the existing coker heaters.

Several options were evaluated to cool the incoming residual feed from the vacuum unit. Examples include installing heat exchangers to transfer heat from the residual material to the crude preheat system or vacuum preheat system; and generating steam. These options proved to be uneconomical for the quantity of heat transferred or steam generated. The Project will use an existing cooling box to transfer heat from the residual oil to the refinery cooling towers.

BP has the option of using pipeline natural gas as fuel for the replacement heaters. The BP project team decided it was more efficient use of energy resources to continue using coker off gas as fuel for the coker heaters instead of purchasing additional natural gas.

The existing coker heaters do not have online cleaning capabilities and the project team considered not including online cleaning for the replacement heaters. However, the benefits from reducing the frequency and time required for offline cleaning of the heaters resulted in the Project team's decision to include online cleaning capabilities in the replacement heaters.

Overall, the Project team designed for very efficient replacement heaters that incorporate use of existing low-carbon fuels and online cleaning capabilities.

## 2.8 Toxic Air Pollutant BACT (tBACT)

Toxic air pollutant (TAP) compounds emitted by a coker heater are, in general, either volatiles (VOCs) or particulate (PM). The proposed BACT for VOC and PM are also proposed to be tBACT for VOC and PM TAPs, respectively. tBACT for TAPs that contain chlorine (e.g., hydrogen chloride) and sulfur (e.g., sulfuric acid) is proposed to be the same as that proposed

[18] $CO_2e$ calculated based on global warming potential (GWP) for each Greenhouse gas: $CO_2$ = 1; $CH_4$ = 25; and $N_2O$ = 298 (40 CFR Part 98, Subpart A).

for $SO_2$. For nitrogen-containing compounds (e.g., nitric oxide), tBACT is proposed to be the same as that proposed for $NO_X$.

## 2.9 BACT During Startup, Shutdown, and Standby

During startup and shutdown, $NO_X$ and CO concentrations in the exhaust have the potential to exceed those experienced under normal operation for brief periods. This is a characteristic of all combustion devices because optimum combustion conditions are not achieved immediately after startup or shutdown commences.

During startup and shutdown it is not technologically feasible to meet CO concentration BACT limits that are specified on the basis of normal burner operation. BP proposes that, during startup and shutdown periods, BACT for CO is 75.0 lb/hr, respectively per heater. BACT would consist of limiting the frequency and the duration of startups and shutdowns through the implementation of best practices and training. BP proposes to comply with the same $NO_X$ concentration and mass emissions limits (calendar day average mass emission limits and 30-day rolling average concentration limits) during startup/shutdown and normal operations.

The coker heaters will operate in standby mode when residual oil is unavailable for processing. Standby model includes operating only one coker heater, limiting heater firing rate to less than 120 MMBtu/hr, and recycling hot residual oil through the coker fractionator column. In standby operations, the one coker heater at reduced firing rate would have higher $NO_X$ and CO concentrations in the coker heater exhaust compared to concentrations during normal operation. BP proposes standby $NO_X$ and CO mass emission limits of 8.0 lb/hr and 75.0 lb/hr per heater, respectively. BP estimates the coker unit would operate in standby mode two – four times during a six year period.

During the initial heater commissioning, BP will be required to slowly dry the heater refractory before the coker unit can startup and begin processing residual oil. This is a one-time event that will occur over approximately one week. Subsequent refractory drying may occur over a couple days after a turnaround/maintenance on the coker heaters, which is only planned to occur every 5 to 6 years. EPA has clarified that certain pre-startup activities are required to ready heaters for services and do not qualify as “startup” of an emission unit.[19] Pre-startup activities include curing refractory, general mechanical checkout of equipment, instrument system review, pressure testing, and purging equipment.

[19] Manual for Clarification of Startup in Source Categories Affected by New Source Performance Standards (EPA-68-01-4143) and EPA Applicability Determination Index (ADI) Control Number 0700030.

# 3 Component Leaks

The proposed project will include piping, valves, connectors, pumps, compressors, and other components to move VOCs through the new coker heaters, lean oil absorption system, cooling box, and new bypasses for heat exchangers. All components are subject to some level of leakage, and fugitive VOC, TAP, and GHG (as $CH_4$) emissions are expected to occur when components are in service.

## 3.1 Identify Commercially-Available Emission Reduction Alternatives

A broad review of permitted operations included in the federal RBLC database and other permitted sources indicates that fugitive emissions from leaking petroleum service components are reduced through a combination of proper equipment selection and a leak detection and repair (LDAR) program. Identified alternatives include:

- Use of components that incorporate leakless technology
- Implementation of an LDAR program

LDAR programs involve periodic monitoring of components with a hydrocarbon analyzer, identification of components that leak above the leak definition levels specified in the equipment leak standard, and subsequent repair of the leaking components. LDAR programs are frequently defined by regulations; those deemed to represent BACT for other facilities permitted in the past ten years that were found in the RBLC include:

- 40 CFR 63 Subpart H (National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks)
- 40 CFR 63 Subpart CC (National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries)
- 40 CFR 63 Subpart UU (National Emission Standards for Equipment Leaks—Control Level 2 Standards)
- 40 CFR 60 Subpart VVa (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006)
- 40 CFR 60 Subpart GGGa (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006)
- 40 CFR 61 Subpart V (National Emission Standard for Equipment Leaks (Fugitive Emission Sources))
- Louisiana Refinery MACT (Louisiana Administrative Code §2121, §2122, and Chapter 51)

The RBLC findings are summarized in Table 4.

**Table 4 Summary of BACT Determinations for Component Losses**

| Facility | State | Date Permitted | BACT Determination |
|---|---|---|---|
| Valero Refining - St. Charles Refinery | Louisiana | 11/17/2009 | LA Refinery MACT, 40 CFR 63 Subpart H, 40 CFR 61 Subpart V |
| Sunoco Toledo Refinery | Ohio | 2/23/2009 | 40 CFR 63 Subpart CC, 40 CFR 60 Subparts VV & GGG |
| Marathon Petroleum Garyville Refinery | Louisiana | 12/27/2006 | 40 CFR 63 Subpart CC, 40 CFR 60 Subpart GGG, LA Refinery MACT |
| ConocoPhillips Wood River Refinery | Illinois | 8/5/2008 | 40 CFR 63 Subpart H |
| Arizona Clean Fuels Yuma | Arizona | 4/14/2005 | 40 CFR 63 Subpart H[1] |

Notes:

1 In addition, the following leak definitions have been included: 100 ppmv for valves and connectors in gas/vapor and light liquid service and 500 ppmv for all other components. All pumps must be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. All compressors must be equipped with a seal system that includes a barrier fluid system that prevents leakage of process fluid to the atmosphere. Other requirements exist for other connector types and valves. The percent of leaking components cannot exceed the following: 1.0% for pumps in light liquid service and compressors on a source-wide basis, 1.0% for the total number of pressure relief devices on a source-wide basis, 0.3% for total number of connectors in gas/vapor service and connectors in light liquid service on a source-wide basis, 0.3% of the total number of valves in gas/vapor service and valves in light liquid service on a source-wide basis, and not more than 0.025% of valves in gas/vapor service and valves in light liquid service shall be leaking with a concentration in excess of 10,000 ppmv.

## 3.2 Eliminate Technically Infeasible Alternatives

Proper equipment selection and implementing an LDAR program based on any of the regulations identified in the previous section are considered technically feasible for reducing fugitive VOC, TAP and GHG emissions from component leaks.

## 3.3 Ranking of Remaining Alternatives

There are many LDAR programs available, some codified in regulations (e.g., NSPS, NESHAP, etc.), some developed by state agencies for consent decrees, and others developed by industry groups. Some of the non-regulatory alternatives include:

- Remote sensing technology
- Enhanced LDAR standards
- Audio/visual/olfactory methods

The effectiveness of these alternative programs has not been quantified, but none are thought to be any more effective than a regulatory LDAR program which includes implementation of EPA Method 21 (Determination of Volatile Organic Compound Leaks). All of the regulations identified in the previous section that require implementation of a formal LDAR program include Method 21.

A comparison of fugitive component emissions regulations compiled by the Louisiana Department of Environmental Quality (LDEQ) is provided in Attachment 6. Taken as a whole,

the requirements of 40 CFR 63 Subpart H are the most stringent. However, Subpart H requirements are specific to synthetic organic chemical manufacturing with streams in HAP service, which is not applicable to the proposed replacement coker heaters. Implementation of an LDAR program and proper equipment selection are considered baseline alternatives, so there is no ranking.

## 3.4 Consideration of Energy, Environmental and Cost Factors

Because BP proposes to use the most effective alternatives, no evaluation of energy, environmental, or cost was conducted.

## 3.5 Proposed BACT Limits and Control Option

BP proposes that implementation of an LDAR program that meets the applicable requirements of 40 CFR 60 Subpart GGGa and its referenced Subpart VVa. BP believes that emission rate limits are not appropriate for a fugitive source, and, therefore, does not propose any such limits as BACT.

**Project:** BP Cherry Point - Coker Heater Replacement Project
**Control Option:** Coker Heater equipped with SCR
**Date:** July 25, 2014
**Author:** Kyle Heitkamp

RAMBOLL ENVIRON



| | | |
|---|---|---|
| **DESIGN CONDITIONS** | | |
| **Economic Factors** | | |
| Equipment Life (n) | | 20 years |
| Annual Interest Rate (I) | OAQPS | 7 % |
| **TOTAL CAPITAL INVESTMENT** | | |
| **Direct Costs (DC)** | Total Equip + ST + Fr + Install + Electric | $5,013,000 |
| Total Purchased Equipment Cost (Total Equip) | Equip + F&S + Pipe + Insul + Paint | $3,495,000 |
| SCR Equipment Cost (Equip and Catalyst) | SCR Cost Estimate | $1,500,000 |
| Sales Tax (ST) | Conservatively assume no sales tax | $0 |
| Freight (Fr) | 0.05 * Total Equip | $174,750 |
| Foundations and Support (F&S) | 0.10 * Equip | $150,000 |
| Total Purchased Equipment Installation (Install) | 0.35 * Total Equip | $1,223,250 |
| Electrical (Electric) | 0.08 * Equip | $120,000 |
| Piping (Pipe) | Run ammonia pipe to coker heater location | $1,600,000 |
| Insulation for Ductwork (Insul) | BP estimate | $200,000 |
| Painting (Paint) | BP estimate | $45,000 |
| **Indirect Costs (IC)** | CE + E&S + Contract + SU | $3,638,050 |
| Construction Expenses (CE) | 0.08 * DC | $401,040 |
| Engineering and Supervision (E&S) | 0.08 * DC | $401,040 |
| Contractor Fees (Contract) | 0.05 * DC | $250,650 |
| Start-up (SU) | BP estimate | $2,585,320 |
| Project Contingency (PC) | 0.15 * (DC + IC) | $1,297,657 |
| Total Plant Cost (B) | DC + IC + PC | $9,948,707 |
| Total Capital Investment (TCI) | B | $9,948,707 |
| **TOTAL ANNUAL COSTS** | | |
| Annual Maintenance Cost (AMC) | 0.015 * TCI | $149,231 |
| Annual Reagent Cost (ARC) | | $1,400,000 |
| Catalyst Replace Cost (ACRC) | $200,000 every six years | $33,333 |
| Annual Electricity Cost (AEC) | additional fans | $100,000 |
| Direct Annual Costs (DAC) | AMC + ARC + ACRC + AEC + CEMS QAQC | $1,682,564 |
| Capital Recovery Factor (CRF) | (i * (1 + i)^n) / ((1 + i)^n - 1) | 0.09 |
| Fuel Penalty (FP) | assume zero for worst case | $0 |
| Taxes/Insurance/Admin (TIA) | | $0 |
| Indirect Annual Costs (IDAC) | (CRF * TCI) + FP + TIA | $939,088 |
| Total Annual Costs (TAC) | DAC + IDAC | $2,621,652 |
| **COST EFFECTIVENESS** | | |
| NSPS Ja NOx Emissions | 303 MMBtu/hr * 0.06 lb NOx/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 79.6 tpy |
| SCR NOx Emissions | 303 MMBtu/hr * 0.01 lb NOx/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 13.3 tpy |
| NOx Removal due to the Installation of SCR Unit | Difference between NSPS Ja limit and SCR | 66.4 tpy |
| **Cost Effectiveness of SCR Unit** | **TAC / NOx Removal** | **$39,508 $/ton** |

**Project:** BP Cherry Point - Coker Heater Replacement Project
**Control Option:** Coker Heater equipped with Oxidation Catalyst
**Date:** July 25, 2014
**Author:** Kyle Heitkamp

RAMBOLL ENVIRON



| | | |
|---|---|---|
| **DESIGN CONDITIONS** | | |
| **Economic Factors** | | |
| Equipment Life (n) | | 20 years |
| Annual Interest Rate (I) | OAQPS | 7 % |
| **TOTAL CAPITAL INVESTMENT** | | |
| **Direct Costs (DC)** | Total Equip + ST + Fr + Install + Electric | $1,599,944 |
| Total Purchased Equipment Cost (Total Equip) | Equip + F&S + Pipe + Insul + Paint | $1,099,843 |
| Equipment Cost (Equip and Catalyst) | Cost Estimate | $752,037 |
| Sales Tax (ST) | Conservatively assume no sales tax | $0 |
| Freight (Fr) | 0.05 * Total Equip | $54,992 |
| Foundations and Support (F&S) | 0.10 * Equip | $75,204 |
| Total Purchased Equipment Installation (Install) | 0.35 * Total Equip | $384,945 |
| Electrical (Electric) | 0.08 * Equip | $60,163 |
| Piping (Pipe) | BP estimated | $166,076 |
| Insulation for Ductwork (Insul) | BP estimate | $106,526 |
| Painting (Paint) | BP estimate | |
| **Indirect Costs (IC)** | CE + E&S + Contract + SU | $1,083,529 |
| Construction Expenses (CE) | 0.08 * DC | $127,995 |
| Engineering and Supervision (E&S) | 0.08 * DC | $127,995 |
| Contractor Fees (Contract) | 0.05 * DC | $79,997 |
| Start-up (SU) | BP estimate | $747,540 |
| Project Contingency (PC) | 0.15 * (DC + IC) | $402,521 |
| Total Plant Cost (B) | DC + IC + PC | $3,085,993 |
| Total Capital Investment (TCI) | B | $3,085,993 |
| **TOTAL ANNUAL COSTS** | | |
| Annual Maintenance Cost (AMC) | 0.015 * TCI | $46,290 |
| Annual Reagent Cost (ARC) | | $1,400,000 |
| Catalyst Replace Cost (ACRC) | $200,000 every six years | $33,333 |
| Annual Electricity Cost (AEC) | additional fans | $100,000 |
| Direct Annual Costs (DAC) | AMC + ARC + ACRC + AEC + CEMS QAQC | $1,579,623 |
| Capital Recovery Factor (CRF) | (i * (1 + i)^n) / ((1 + i)^n - 1) | 0.09 |
| Fuel Penalty (FP) | assume zero for worst case | $0 |
| Taxes/Insurance/Admin (TIA) | | $0 |
| Indirect Annual Costs (IDAC) | (CRF * TCI) + FP + TIA | $291,296 |
| Total Annual Costs (TAC) | DAC + IDAC | $1,870,919 |
| **COST EFFECTIVENESS** | | |
| Good Combustion CO Emissions | 303 MMBtu/hr * 0.02 lb CO/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 26.5 tpy |
| Oxidation Catalyst CO Emissions | 303 MMBtu/hr * 0.002 lb CO/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 2.7 tpy |
| Good Combustion VOC Emissions | 303 MMBtu/hr * 0.0054 lb VOC/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 7.2 tpy |
| Oxidation Catalyst CO Emissions | 303 MMBtu/hr * 0.0027 lb VOC/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 3.6 tpy |
| CO and VOC Removal due to the Installation of Oxidation Catalyst | Difference between Good Combustion and Oxidation Catalysts | 27.5 tpy |
| **Cost Effectiveness of Oxidation Catalyst** | **TAC / (CO + VOC Removal)** | **$68,103 $/ton** |

**Project:** BP Cherry Point - Coker Heater Replacement Project
**Control Option:** Coker Heater off gas pressurized with new compressor
**Date:** January 19, 2016
**Author:** Kyle Heitkamp

RAMBOLL ENVIRON



| | | |
|---|---|---|
| **DESIGN CONDITIONS** | | |
| **Economic Factors** | | |
| Equipment Life (n) | | 20 years |
| Annual Interest Rate (I) | OAQPS | 7 % |
| **TOTAL CAPITAL INVESTMENT** | | |
| **Direct Costs (DC)** | Total Equip + ST + Fr + Install + Electric | $9,742,873 |
| Total Purchased Equipment Cost (Total Equip) | Equip + F&S + Pipe + Insul + Paint | $6,366,061 |
| Equipment Cost (Equip and Instrumentation) | BP Estimate (attached) | $5,402,416 |
| Sales Tax (ST) | Conservatively assume no sales tax | $0 |
| Freight (Fr) | 0.05 * Total Equip | $318,303 |
| Foundations and Support (F&S) | BP Estimate (attached) | $284,933 |
| Total Purchased Equipment Installation (Install) | 0.35 * Total Equip | $2,228,121 |
| Electrical (Electric) | BP Estimate (attached) | $830,388 |
| Piping (Pipe) | BP Estimate (attached) | $463,238 |
| Insulation for Ductwork (Insul) | BP Estimate (attached) | $151,379 |
| Painting (Paint) | BP Estimate (attached) | $64,095 |
| **Indirect Costs (IC)** | CE + E&S + Contract | $2,046,003 |
| Construction Expenses (CE) | 0.08 * DC | $779,430 |
| Engineering and Supervision (E&S) | 0.08 * DC | $779,430 |
| Contractor Fees (Contract) | 0.05 * DC | $487,144 |
| Project Contingency (PC) | 0.15 * (DC + IC) | $1,768,331.46 |
| Total Plant Cost (B) | DC + IC + PC | $13,557,208 |
| Total Capital Investment (TCI) | B | $13,557,208 |
| **TOTAL ANNUAL COSTS** | | |
| Annual Maintenance Cost (AMC) | Conservatively assume no maintenance costs | $0 |
| Utility Costs (electricity) | BP Estimate (1000 hp at 0.06$/kW-hr) | $412,734 |
| Direct Annual Costs (DAC) | AMC + Electricity | $412,734 |
| Capital Recovery Factor (CRF) | (i * (1 + i)^n) / ((1 + i)^n - 1) | 0.09 |
| Taxes/Insurance/Admin (TIA) | Conservatively assume no taxes, insurance, admin. | $0 |
| Indirect Annual Costs (IDAC) | (CRF * TCI) + FP + TIA | $1,279,705 |
| Total Annual Costs (TAC) | DAC + IDAC | $1,692,439 |
| **COST EFFECTIVENESS (Both Heaters)** | | |
| Coker Off Gas SO2 Emissions | 2 * 303 MMBtu/hr * 0.050 lb SO2/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 131.9 tpy |
| High Pressure Lean Oil Absorption SO2 Emissions | 2 * 303 MMBtu/hr * 0.017 lb SO2/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 46.2 tpy |
| Coker Off Gas H2SO4 Emissions | 2 * 303 MMBtu/hr * 0.0040 lb H2SO4/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 10.6 tpy |
| High Pressure Lean Oil Absorption H2SO4 Emissions | 2 * 303 MMBtu/hr * 0.0014 lb H2SO4/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 3.7 tpy |
| SO2 and H2SO4 Removal due to the High Pressure Treatment | Difference between coker off gas and High Pressure treated coker off gas | 92.7 tpy |
| **Cost Effectiveness of installing a new Compressor** | **TAC / (SO2 and H2SO4 Removal)** | **$18,266 $/ton** |

BP Coker Heater Replacement Project
Spray Tower Cost Effectiveness Calculation - One Coker Heater
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $1,182,092 | Jacobs |
| b. Vessel Installed Cost | $3,618,517 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $1,819,856 | Jacobs |
| d. Duct Installed Cost | $792,437 | Jacobs |
| e. Cyclone Installed Cost | $66,536 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $7,479,438 | *Calculation* |
| f. CEMS Installation | | Jacobs |
| g. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | $0 | Jacobs |
| i. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $7,479,438 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $2,991,775 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $10,471,213 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $10,471,213 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$988,408** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for spray tower) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $157,068 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $127,385 | Jacobs |
| b. Sewer | $23,506 | Jacobs |
| O. Caustic costs | $58,765 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for spray tower) | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$366,724** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC ] (TACC+TDIAC)*** | **$1,355,133** | *Calculation* |
| Coker Off Gas SO2 Emissions = 303 MMBtu/hr * 0.050 lb SO2/MMBtu * 8760 hr/yr / 2000 lb/to | tons/year | 66.0 | *Calculation* |
| Spray Tower SO2 Emissions = Coker Off Gas Emissions * (1 - 0.95) | tons/year | 3.3 | *Calculation* |
| Coker Off Gas H2SO4 Emissions = 303 MMBtu/hr * 0.0040 lb H2SO4/MMBtu * 8760 hr/yr / 200 | tons/year | 5.3 | |
| Spray Tower H2SO4 Emissions = Coker Off Gas Emissions * (1 - 0.95) | tons/year | 0.3 | |
| Reduction from baseline Off Gas Emissions | Percent | 95.0 | Jacobs |
| Total SO2 & H2SO4 Emissions Reduction | tons/year | 67.7 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 20,016** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).

**Project:** BP Cherry Point - Coker Heater Replacement Project
**Control Option:** Coker Heater off gas treated with Gas Phase Merox
**Date:** January 19, 2016
**Author:** Kyle Heitkamp

RAMBOLL ENVIRON



| | | |
|---|---|---|
| **DESIGN CONDITIONS** | | |
| **Economic Factors** | | |
| Equipment Life (n) | | 20 years |
| Annual Interest Rate (I) | OAQPS (Sept. 2015) Economic Impact Analysis for Refinery Sector Rule Amendments. | 7 % |
| **TOTAL CAPITAL INVESTMENT** | | |
| **Direct Costs (DC)** | Total Equip + ST + Fr + Install + Electric | $17,011,500 |
| Total Purchased Equipment Cost (Total Equip) | Equip + F&S + Pipe + Insul + Paint | $11,810,000 |
| Equipment Cost (Equip and Instrumentation) | BP estimate for merox skid and columns (attached) | $9,150,000 |
| Sales Tax (ST) | Conservatively assume no sales tax | $0 |
| Freight (Fr) | 0.05 * Total Equip | $590,500 |
| Foundations and Support (F&S) | BP estimate (attached) | $1,228,000 |
| Total Purchased Equipment Installation (Install) | 0.35 * Total Equip | $4,133,500 |
| Electrical (Electric) | BP estimate (attached) | $477,500 |
| Piping (Pipe) | BP estimate (attached) | $957,500 |
| Insulation for Ductwork (Insul) | BP estimate (attached) | $363,000 |
| Painting (Paint) | BP estimate (attached) | $111,500 |
| **Indirect Costs (IC)** | CE + E&S + Contract | $3,572,415 |
| Construction Expenses (CE) | 0.08 * DC | $1,360,920 |
| Engineering and Supervision (E&S) | 0.08 * DC | $1,360,920 |
| Contractor Fees (Contract) | 0.05 * DC | $850,575 |
| Project Contingency (PC) | 0.15 * (DC + IC) | $3,087,587 |
| Total Plant Cost (B) | DC + IC + PC | $23,671,502 |
| Total Capital Investment (TCI) | B | $23,671,502 |
| **TOTAL ANNUAL COSTS** | | |
| Annual Operation and Maintenance Cost (AMC) | Jacobs Engineering estimate as part of Best Available Retrofit Technology (BART) analysis (5% of TCI) | $1,183,575 |
| Direct Annual Costs (DAC) | AMC | $1,183,575 |
| Capital Recovery Factor (CRF) | (i * (1 + i)^n) / ((1 + i)^n - 1) | 0.09 |
| Fuel Penalty (FP) | | $0 |
| Taxes/Insurance/Admin (TIA) | | $0 |
| Indirect Annual Costs (IDAC) | (CRF * TCI) + FP + TIA | $2,234,422 |
| Total Annual Costs (TAC) | DAC + IDAC | $3,417,997 |
| **COST EFFECTIVENESS (Both Heaters)** | | |
| Coker Off Gas SO2 Emissions | 2 * 303 MMBtu/hr * 0.050 lb SO2/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 131.9 tpy |
| Gas phase Merox SO2 Emissions | 2 * 303 MMBtu/hr * 0.0050 lb SO2/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 13.2 tpy |
| Coker Off Gas H2SO4 Emissions | 2 * 303 MMBtu/hr * 0.0040 lb H2SO4/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 10.6 tpy |
| Gas phase Merox H2SO4 Emissions | 2 * 303 MMBtu/hr * 0.00040 lb H2SO4/MMBtu * 8,760 hr/yr / 2,000 lb/ton | 1.1 tpy |
| SO2 and H2SO4 Removal due to the Merox treatment | Difference between coker off gas and Merox treated coker off gas | 128.3 tpy |
| **Cost Effectiveness of Gas Phase Merox** | **TAC / (SO2 and H2SO4 Removal)** | **$26,643 $/ton** |

## REGULATIONS COMPARISON TABLE

| Item of Comparison | 40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants) | 40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery) | 40 CFR 63 Subpart H - SOCMI HON MACT | 40 CFR 63 Subpart TT – Equipment Leaks Control Level 1 | 40 CFR 63 Subpart UU – Equipment Leaks Control Level 2 | 40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT | 40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT | LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements | 40 CFR 63 Subpart CC - Refinery MACT Modified HON Option | LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT | LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment | 40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT | RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB | LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III | 40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Stream Applicability** | > 10% VOC by weight | > 10% VOC by weight | > 5% VHAP by weight<br><br>In organic HAP service > 300 hrs | > 5% VHAP by weight or as defined in the referencing Subpart | > 5% VHAP by weight or as defined in the referencing Subpart | Elastomer Product Process Units | > 5% VHAP by weight<br><br>In organic HAP service > 300 hrs | 5% wt of the sum of Class I and II organics TAPs<br>or<br>>10% wt of the sum of Class I, II and III organic TAPs | > 5% VHAP by weight<br><br>In organic HAP service > 300 hrs | 5% wt of the sum of Class I and II organics TAPs<br>or<br>>10% wt of the sum of Class I, II and III organic TAPs | >10% VOC by weight<br><br>For sources in non-attainment areas for ozone | >10% wt VTAP (vinyl chloride or benzene) | > 10% by weight | >10% VOC by volume (2121) | "In Gasoline Service" (R) or "In Hydrogen Fluoride Service", as defined |
| **Leak Definition** | **Valves-Gas/LL:**<br>10,000<br>**HL:**<br>No visual/10,000<br>**Pumps-LL:**<br>10,000<br>**HL:**<br>No visual/10,000<br>**Compressors:**<br>Seal system failure<br>**CVS:** 500<br>**PRVs-Gas:** 500<br>**Liquid:** No visual/ 10,000<br>**Connectors:**<br>No visual/10,000<br>**Agitators:**<br>No visual leak<br>**Process Drains:**<br>No visual leak<br>**Sampling Points:**<br>No visual leak | **Valves-Gas/LL:**<br>500<br>**HL:**<br>No visual/10,000<br>**Pumps-LL:**<br>5,000 – monomer<br>2,000 – other<br>**HL:**<br>No visual/10,000<br>**Compressors:**<br>Seal system failure<br>**CVS:** 500<br>**PRVs-Gas:** 500<br>**Liquid:** No visual/ 10,000<br>**Connectors-Gas/ LL:** 500<br>**HL:**<br>No visual/10,000<br>**Agitators:**<br>No visual leak<br>**Process Drains:**<br>No visual leak<br>**Sampling Points:**<br>No visual leak | **Valves-Gas/LL:**<br>500<br>**HL:**<br>No visual/500<br>**Pumps-LL:**<br>1,000<br>**HL:**<br>No visual/2,000<br>**Compressors:**<br>500<br>**CVS:** 500<br>**PRVs-Gas:** 500<br>**Liquid:** No visual/ 500<br>**Connectors:** 500<br>**Agitators:** 10,000<br>**Process Drains:**<br>No visual leak<br>**Sampling Points:**<br>No visual leak | **Valves-Gas/LL:**<br>10,000<br>**HL:**<br>No visual/10,000<br>**Pumps-LL:**<br>10,000<br>**Pumps-HL:**<br>No visual/10,000<br>**Compressors:**<br>Seal system failure<br>**CVS:** 500<br>**PRVs-Gas:** 500<br>**Liquid:** No visual/ 10,000<br>**Connectors:**<br>No visual/10,000<br>**Agitators:**<br>No visual leak/10,000<br>**Process Drains:**<br>No visual leak<br>**Sampling Points:**<br>No visual leak | **Valves-Gas/LL:**<br>500<br>**HL:**<br>No visual/500<br>**Pumps-LL:**<br>5,000 – polymers<br>2,000 – food/med<br>1,000 – other<br>**HL:**<br>5,000 – polymers<br>2,000 – food/med<br>2,000 – other<br>**Compressors:** 500<br>**CVS:** 500<br>**PRVs-Gas:** 500<br>**Liquid:** 500<br>**Connectors:**500<br>**Agitators:** 10,000<br>**Process Drains:**<br>No visual leak<br>**Sampling Points:**<br>No visual leak | **Valves-Gas/LL:**<br>500<br>**HL:**<br>No visual/500<br>**Pumps-LL:**<br>1,000<br>**HL:**<br>No visual/2,000<br>**Compressors:**<br>500<br>**CVS:** 500<br>**PRVs-Gas:**500<br>**Liquid:** 500<br>**Connectors:** 500<br>**Agitators:**<br>No visual leak<br>**Process Drains:**<br>No visual leak<br>**Sampling Points:**<br>No visual leak | **Valves-Gas/LL:**<br>500<br>**HL:**<br>No visual/500<br>**Pumps-LL:**<br>No visual/2,000<br>**HL:**<br>No visual/2,000<br>**Compressors:**<br>500<br>**CVS:** 500<br>**PRVs-Gas:**500<br>**Liquid:** No visual/ 500<br>**Connectors:** 500<br>**Agitators:**<br>No visual/10,000<br>**Process Drains:**<br>No visual leak<br>**Sampling Points:**<br>No visual leak | **Valves-Gas/LL:**<br>200 / 500<br>**HL:**<br>No visual/1,000<br>**Pumps-LL:**<br>2,000<br>**HL:**<br>No visual/2,000<br>**Compressors:** 5,000<br>**CVS:** 500<br>**PRVs-Gas:** 500<br>**Liquid:** No visual/ 1,000<br>**Connectors:** 1,000<br>**Agitators-HL:**<br>10,000<br>**Process Drains:**<br>No visual leak<br>**Sampling Points:**<br>No visual leak | **Valves-Gas/LL:**<br>1,000<br>**HL:**<br>No visual/1,000<br>**Pumps-LL:**<br>2,000<br>**HL:**<br>Reciprocating pumps exempt<br>**Compressors:** 500<br>**CVS:** 500<br>**PRVs-Gas:** 500<br>**Liquid:** No visual/ 500<br>**Connectors:** 1,000<br>**Agitators:** 10,000<br>**Process Drains:**<br>No visual leak<br>**Sampling Points:**<br>No visual leak | **Valves-Gas/LL:**<br>1,000<br>**HL:**<br>No visual/1,000<br>**Pumps-LL:**<br>2,000<br>**HL:**<br>No visual/2,000<br>**Compressors:** 5,000<br>**CVS:** 500<br>**PRVs-Gas:** 500<br>**Liquid:** No visual/ 1,000<br>**Connectors:** 1,000<br>**Agitators-HL:**<br>10,000<br>**Process Drains:**<br>No visual leak<br>**Sampling Points:**<br>No visual leak | **Valves-Gas/LL:**<br>1,000<br>**HL:**<br>No visual/1,000<br>**Pumps-LL:**<br>5,000<br>**HL:**<br>No visual/5,000<br>**Compressors:**<br>5,000<br>**CVS:** No visual<br>**PRVs-Gas:** 1,000<br>**Liquid:** No visual/ 1,000<br>**Connectors:**<br>No visual /1,000<br>**Agitators:**<br>10,000<br>**Process Drains:**<br>1,000<br>**Sampling Points:**<br>No visual leak | **Valves-Gas/LL:**<br>10,000<br>**HL:**<br>No visual /10,000<br>**Pumps-LL:**<br>10,000<br>**HL:**<br>No visual /10,000<br>**Compressors:**<br>No visual leak<br>**CVS:** 500<br>**PRVs-Gas:**500<br>**Liquid**: 10,000<br>**(HH)All:** 10,000<br>**Connectors:**<br>No visual leak<br>**Agitators:**<br>No visual leak<br>**Process Drains:**<br>No visual leak<br>**Sampling Points:**<br>No visual leak | **Valves-Gas/LL:**<br>10,000<br>**HL:**<br>No visual/10,000<br>**Pumps-LL:**<br>10,000<br>**HL:**<br>No visual/10,000<br>**Compressors:**<br>10,000<br>**CVS:** 10,000<br>**PRVs-Gas:** 10,000<br>**Liquid:** 10,000<br>**Connectors:**<br>Visual<br>**Agitators:**<br>No visual leak<br>**Process Drains:**<br>No visual leak<br>**Sampling Points:**<br>No visual leak | **All equipment:**<br>10,000<br><br>Subpart III –annually or after reinstallation | **All equipment:**<br>Evidence of potential leak detected by visual, audible, or olfactory means. |
| **Leak Definition** | **SurgeCtrlVessel:**<br>No visual leak<br>**Instrument Systems:**<br>No visual leak | **SurgeCtrlVessel:**<br>No visual leak<br>**Instrument Systems:**<br>No visual leak | **SurgeCtrlVessel:**<br>No visual leak<br>**Instrument Systems:**<br>No visual/500 | **SurgeCtrlVessel:**<br>No visual leak<br>**Instrument Systems:**<br>No visual leak | **SurgeCtrlVessel:**<br>No visual leak<br>**Instrument Systems:**<br>No visual/500 | **SurgeCtrlVessel:**<br>No visual leak<br>**Instrument Systems:**<br>500 | **SurgeCtrlVessel:**<br>No visual leak<br>**Instrument Systems:**<br>No visual/500 | **SurgeCtrlVessel:**<br>No visual leak<br>**Instrument Systems:**<br>No visual/1,000 | **SurgeCtrlVessel:**<br>No visual leak<br>**Instrument Systems:**<br>No visual/1,000 | **SurgeCtrlVessel:**<br>No visual leak<br>**Instrument Systems:**<br>No visual/1,000 | **SurgeCtrlVessel:**<br>No visual leak<br>**Instrument Systems:**<br>No visual leak | **SurgeCtrlVessel:**<br>No visual leak<br>**Instrument Systems:**<br>No visual leak | **SurgeCtrlVessel:**<br>No visual leak<br>**Instrument Systems:**<br>No visual leak | **All equipment:**<br>10,000 | |

| Item of Comparison | 40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants) | 40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery) | 40 CFR 63 Subpart H - SOCMI HON MACT | 40 CFR 63 Subpart TT – Equipment Leaks Control Level 1 | 40 CFR 63 Subpart UU – Equipment Leaks Control Level 2 | 40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT | 40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT | LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements | 40 CFR 63 Subpart CC - Refinery MACT Modified HON Option | LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT | LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment | 40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT | RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB | LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III | 40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Open-ended lines:**<br>No visual leak | **Open-ended lines:**<br>No visual leak | **Open-ended lines:**<br>No visual leak | **Open-ended lines:**<br>No visual leak | **Open-ended lines:**<br>No visual leak | **Open-ended lines:**<br>No visual leak | **Open-ended lines:**<br>No visual leak | **Open-ended lines:**<br>1,000 | **Open-ended lines:**<br>No visual leak | **Open-ended lines:**<br>1,000 | **Open-ended lines:**<br>No visual leak | **Open-ended lines:**<br>No visual leak | **Open-ended lines:**<br>No visual leak | | |
| **Monitoring Frequency:**<br>**Light Liquid valves** | Monthly<br>If ND leak for 2 successive months = quarterly | Monthly<br>If ND leak for 2 successive months = quarterly | Monthly if >2% leaking<br>Quarterly if <2% leaking<br>Every 2 qtrs if < 1% leaking<br>Every 4 qtrs if <0.5% leaking | Monthly<br>If ND leak for 2 successive months = quarterly | Monthly if >2% leaking<br>Quarterly if <2% leaking<br>Every 2 qtrs if < 1% leaking<br>Every 4 qtrs if <0.5% leaking | Monthly if >2% leaking<br>Quarterly if <2% leaking<br>Every 2 qtrs if < 1% leaking<br>Every 4 qtrs if <0.5% leaking | Monthly if >2% leaking<br>Quarterly if <2% leaking<br>Every 2 qtrs if < 1% leaking<br>Every 4 qtrs if <0.5% leaking<br>Every 2 years if <0.25% | Monthly if > 4%<br>Quarterly if < 4% | **Monthly:**<br>->5% (with connectors)<br>->4%(without )<br>**Quarterly:**<br>- <5% (with connectors)<br>- <4% (without)<br>**Semiannual:**<br>- <4% (with)<br>- <3% (without)<br>**Annual:**<br>- <3% (with)<br>- <2% (without) | Monthly if > 4%<br>Quarterly if < 4% | Quarterly | Monthly | Monthly<br>If ND leak for 2 successive months = quarterly | Quarterly<br>Annually (pipeline valves) | Monthly (63 R)<br>-or-<br>Once per shift (63 YY) |
| **Monitoring Frequency:**<br>**Gas Valves** | Monthly<br>If ND leak for 2 successive months = quarterly | Monthly<br>If ND leak for 2 successive months = quarterly | Monthly if >2% leaking<br>Quarterly if <2% leaking<br>Every 2 qtrs if < 1% leaking<br>Every 4 qtrs if <0.5% leaking | Monthly<br>If ND leak for 2 successive months = quarterly | Monthly if >2% leaking<br>Quarterly if <2% leaking<br>Every 2 qtrs if < 1% leaking<br>Every 4 qtrs if <0.5% leaking | Monthly if >2% leaking<br>Quarterly if <2% leaking<br>Every 2 qtrs if < 1% leaking<br>Every 4 qtrs if <0.5% leaking | Monthly if >2% leaking<br>Quarterly if <2% leaking<br>Every 2 qtrs if < 1% leaking<br>Every 4 qtrs if <0.5% leaking<br>Every 2 years if <0.25% | Monthly if > 4%<br>Quarterly if < 4% | **Monthly:**<br>->5% (with connectors)<br>->4%(without )<br>**Quarterly:**<br>- <5% (with connectors)<br>- <4% (without)<br>**Semiannual:**<br>- <4% (with)<br>- <3% (without)<br>**Annual:**<br>- <3% (with)<br>- <2% (without) | Monthly if > 4%<br>Quarterly if < 4% | Quarterly | Monthly | Monthly<br>If ND leak for 2 successive months = quarterly | Quarterly | Monthly (63 R)<br>-or-<br>Once per shift (63 YY) |
| **Monitoring Frequency:**<br>**Gas Pressure Relief Valves** | Monitor within 5 days of release | Monitor within 5 days of release | Monitor within 5 days of a release | Monitor within 5 days of release | Monitor within 5 days of a release | Monitor within 5 days of a release | Monitor within 5 days of a release | Monitor within 5 days of a release | Monitor within 5 days of a release | Monitor within 5 days of a release | Quarterly and within 24 hours of an atmospheric release | Monitor within 5 days of release | Monitor within 5 days of release | Quarterly and within 24 hours of an atmospheric release | Monitor within 5 days of detection by sight, sound, or smell |
| **Monitoring Frequency:**<br>**Liquid Pressure Relief Valves** | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of a release or detection by sight, smell, or sound | Monitor within 5 days of a release or detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 24 hours of an atmospheric release | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 24 hours of an atmospheric release | Monitor within 5 days of detection by sight, smell, or sound |
| **Monitoring Frequency:**<br>**Light Liquid Pumps** | Monthly monitor & weekly visual | Monthly monitor & weekly visual | Monthly monitor & weekly visual | Monthly monitor & weekly visual | Monthly monitor & weekly visual | Monthly monitor & weekly visual | Monthly monitor & weekly visual | Monthly monitor & weekly visual | Quarterly if <3% leaking<br>Monthly if <10% or 3 leaking, whichever is greater | Quarterly monitor & weekly visual | Quarterly monitor & weekly visual (seals) | Monthly monitor & weekly visual | Monthly monitor & weekly visual | Quarterly monitor & weekly visual | Monthly (63 R) |

| Item of Comparison | 40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants) | 40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery) | 40 CFR 63 Subpart H - SOCMI HON MACT | 40 CFR 63 Subpart TT – Equipment Leaks Control Level 1 | 40 CFR 63 Subpart UU – Equipment Leaks Control Level 2 | 40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT | 40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT | LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements | 40 CFR 63 Subpart CC - Refinery MACT Modified HON Option | LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT | LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment | 40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT | RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB | LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III | 40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Pump repair not required unless leak > 2000 ppm | | | | | | | | | | | Pump seals (annually) | -or-<br><br>Once per shift (63 YY) |
| **Monitoring Frequency:**<br><br>**Compressors** | Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere<br><br>Check sensor daily | Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere<br><br>Check sensor daily | Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere<br><br>Check sensor daily | Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere<br><br>Check sensor daily | Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere<br><br>Check sensor daily | Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere<br><br>Check sensor daily | Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere<br><br>Check sensor daily | Quarterly<br><br>Or<br><br>Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere<br><br>Check sensor daily | Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere<br><br>Check sensor daily | Quarterly<br><br>Or<br><br>Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere<br><br>Check sensor daily | Quarterly monitor (seals) | Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere<br><br>Check sensor daily | Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere<br><br>Check sensor daily | Quarterly monitor & weekly visual (seals) | Monthly (63 R)<br><br>-or-<br><br>Once per shift (63 YY) |
| **Monitoring Frequency:**<br><br>**Flanges/ Connectors** | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Initial monitor<br><br>Monitor annually if >0.5% leaking<br><br>Monitor biennially if <0.5% leaking<br><br>Monitor every 4 years if <0.5% leaking for 2 years<br><br>HL connectors:<br><br>Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Initial monitor<br><br>Monitor annually if >0.5% leaking<br><br>Monitor every 4 years if <0.5% and >0.25%<br><br>Monitor at least 50% of connectors within four years if <0.25%<br><br>HL connectors:<br><br>Monitor within 5 days of detection by sight, smell, or sound | Monitor annually if >0.5% leaking<br><br>Monitor biennially if <0.5% leaking<br><br>Monitor every 4 years if <0.5% leaking for 2 years | Initial monitor<br><br>Monitor annually if >0.5% leaking<br><br>Monitor biennially if <0.5% leaking<br><br>Monitor every 4 years if <0.5% leaking for 2 years<br><br>HL connectors:<br><br>Monitor within 5 days of detection by sight, smell, or sound | Annually (random 200 or 10% by unit)<br><br>If <2% leaking = annually<br><br>If >2% leaking = quarterly until <2% obtained for 4 qrts otherwise monitor all connectors<br><br>Monitor within 90 days after welding (xray, etc.) or breaking the seal (OVA) | **2 Options**(if monitoring connectors):<br><br>**Random 200**<br>- monitor within 1st 12months after Phs III date<br><br>- every 6 mos. if >2%<br><br>- annual if <2% and >1%<br><br>- biannaul if <1% and >.5%<br><br>- every 4 years if <0.5%<br><br>**Inspection Alternative**<br>- monitor all gas/ vapor connctors within 12 months after Phs III date<br><br>- inspect all light liquid connectors (> 3 drops/minute)<br><br>- annual if >2% leaking<br>- biannual if ,2% and >1% leaking<br>- every 4 years if <1% leaking | Annually (random 200 or 10% by unit)<br><br>If <2% leaking = annually<br><br>If >2% leaking = quarterly until <2% obtained for 4 qrts otherwise monitor all connectors<br><br>Monitor within 90 days after welding (xray, etc.) or breaking the seal (OVA) | Weekly visual<br><br>(no records)<br><br>Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monthly (63 R)<br><br>-or-<br><br>Once per shift (63 YY) |
| **Monitoring Frequency: Process Drains** | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | Annually monitor | NA | NA | Annually monitor | NA |

| Item of Comparison | 40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants) | 40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery) | 40 CFR 63 Subpart H - SOCMI HON MACT | 40 CFR 63 Subpart TT – Equipment Leaks Control Level 1 | 40 CFR 63 Subpart UU – Equipment Leaks Control Level 2 | 40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT | 40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT | LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements | 40 CFR 63 Subpart CC - Refinery MACT Modified HON Option | LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT | LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment | 40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT | RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB | LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III | 40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Monitoring Frequency:**<br><br>**Heavy Liquid Equipment** | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound. Repaired systems do not require monitoring | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound. Repaired systems do not require monitoring | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound. Repaired systems do not require monitoring | Monitor within 5 days of detection by sight, smell, or sound | Monitor if leak suspected by sight, smell, or sound | NA | Monitor within 5 days of detection by sight, smell, or sound | Monitor if leak suspected by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound |
| **Monitoring Frequency:**<br><br>**Closed Vent Systems** | Hard piping:<br><br>Initial monitoring<br><br>Annual visual<br><br>Duct work:<br><br>Annual monitor | Hard piping:<br><br>Initial monitoring<br><br>Annual visual<br><br>Duct work:<br><br>Annual monitor | Hard piping:<br><br>Initial monitoring<br>Annual visual<br><br>Duct Work:<br><br>Annual monitor | Hard piping:<br><br>Initial monitoring<br><br>Annual visual<br><br>Duct work:<br><br>Annual monitor | Hard piping:<br><br>Initial monitoring<br>Annual visual<br><br>Duct Work:<br><br>Annual monitor | Hard Piping:<br><br>Annual visual<br><br>Duct Work:<br><br>Annual monitor | Hard piping:<br><br>Initial monitoring<br>Annual visual<br><br>Duct Work:<br><br>Annual monitor | Annually monitor | Hard piping:<br><br>Initial monitoring<br>Annual visual<br><br>Duct Work:<br><br>Annual monitor | Annually monitor | NA | Annually monitor | Hard piping:<br><br>Initial monitoring<br><br>Annual visual | Monitor if leak suspected by sight, smell, or sound | Hard piping:<br><br>Initial monitoring<br>Annual visual<br><br>Duct Work:<br><br>Annual monitor |
| **Monitoring Frequency:**<br><br>**Open-ended valves/lines** | Requires cap, plug, blind flange, or 2nd valve | Requires cap, plug, blind flange, or 2nd valve | Requires cap, plug, blind flange, or 2nd valve | Requires cap, plug, blind flange, or 2nd valve | Requires cap, plug, blind flange, or 2nd valve | Requires cap, plug, blind flange, or 2nd valve | Requires cap, plug, blind flange, or 2nd valve | Requires cap, plug, blind flange, or 2nd valve | Requires cap, plug, blind flange, or 2nd valve | Requires cap, plug, blind flange, or 2nd valve | Requires cap, plug, blind flange, or 2nd valve<br><br>Monitor annually | Requires cap, plug, blind flange, or 2nd valve | Requires cap, plug, blind flange, or 2nd valve | Requires cap, plug, blind flange, or 2nd valve<br><br>Monitor if leak suspected by sight, smell, or sound | Requires cap, plug, blind flange, or 2nd valve |
| **Monitoring Frequency:**<br><br>**Sampling Points/ Connections** | Requires closed purge system, or closed vent system<br><br>Return or recycle purge | Requires closed purge system, or closed vent system<br><br>Return or recycle purge | Requires closed purge, closed loop, or closed vent system<br><br>Return or recycle purge | Requires closed purge system, or closed vent system<br><br>Return or recycle purge | Requires closed purge, closed loop, or closed vent system<br><br>Return or recycle purge | Requires closed purge or closed loop system | Requires closed purge, closed loop, or closed vent system<br><br>Return or recycle purge | Requires closed purge, or closed vent system<br><br>Return or recycle purge<br><br>Zero emissions to atm | Requires closed purge, closed loop, or closed vent system<br><br>Return or recycle purge | Requires closed purge, or closed vent system<br><br>Return or recycle purge<br><br>Zero emissions to atm | NA | Requires closed purge, closed vent system<br><br>Return or recycle purge<br><br>Zero purge to atm | Requires closed purge system, or closed vent system<br><br>Return or recycle purge | Monitor within 5 days of detection by sight, smell, or sound | Requires closed purge, closed loop, or closed vent system<br><br>Return or recycle purge |
| **Monitoring Frequency:**<br><br>**Agitators** | NA | NA | Monthly monitor & weekly visual | Monthly monitor & weekly visual | Monthly monitor & weekly visual | Monthly monitor & weekly visual | Monthly monitor & weekly visual | Within 5 days of detection by sight, smell, or sound | Monthly monitor & weekly visual | Within 5 days of detection by sight, smell, or sound | NA | NA | NA | Monitor within 5 days of detection by sight, smell, or sound | Monthly monitor & weekly visual |
| **Monitoring Frequency:**<br><br>**Surge Control Vessels and Bottoms Receivers** | NA | NA | Requires closed vent system | NA | NA | Requires closed vent system<br><br>Exempt from requirements if contains a latex and located downstream of stripping operation. | Requires closed vent system | Requires closed vent system | Requires closed vent system | Requires closed vent system | NA | Requires closed vent system | NA | Monitor within 5 days of detection by sight, smell, or sound | Requires closed vent system |
| **Monitoring Frequency:**<br><br>**Visual Leaks** | | | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | | Monitor within 5 days of detection by sight, smell, or sound | | Monitor immediately any component leaking based on sight, smell, or sound | | NA | Monitor immediately any component leaking based on sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound |
| **Monitoring Frequency:**<br><br>**Instrument-ation Systems** | NA | NA | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound | NA | NA | NA | Monitor within 5 days of detection by sight, smell, or sound | Monitor within 5 days of detection by sight, smell, or sound |

| Item of Comparison | 40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants) | 40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery) | 40 CFR 63 Subpart H - SOCMI HON MACT | 40 CFR 63 Subpart TT – Equipment Leaks Control Level 1 | 40 CFR 63 Subpart UU – Equipment Leaks Control Level 2 | 40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT | 40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT | LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements | 40 CFR 63 Subpart CC - Refinery MACT Modified HON Option | LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT | LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment | 40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT | RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB | LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III | 40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Skip periods** | **Valves only:**<br>2 consecutive quarters <2% = skip 1 quarter<br>5 consecutive quarters <2% = skip 3 quarters | **Valves only:**<br>2 consecutive quarters <2% = skip 1 quarter<br>5 consecutive quarters <2% = skip 3 quarters | **Valves only:**<br>Initial performance of 2% leaks = quarterly<br>Initial performance of 1% leaks = semi-annually<br>**Pumps only:**<br>No skip period only avoid QIP requirements<br>Batch process monitoring<br>Historical performance acceptable without prior approval | **Valves only:**<br>2 consecutive quarters <2% = skip 1 quarter<br>5 consecutive quarters <2% = skip 3 quarters<br>Monthly if >2% | **Valves only:**<br>Monthly if >2%<br>Quarterly if <2%<br>Semiannually if <1%<br>Annually if <0.5%<br>Biennally if <0.25%<br>**Pumps only:**<br>No skip period only avoid QIP requirements | **Valves only:**<br>Initial performance of 2% leaks = quarterly<br>Initial performance of 1% leaks = semi-annually<br>**Pumps only:**<br>No skip period only avoid QIP requirements<br>Batch process monitoring | **Valves only:**<br>Initial performance of 2% leaks = quarterly<br>Initial performance of 1% leaks = semi-annually<br>**Pumps only:**<br>No skip period only avoid QIP requirements<br>Batch process monitoring<br>Historical performance acceptable without prior approval | **Valves only:**<br>Not Allowed | **Valves (with connectors):**<br>Initial performance of 5% leaks = quarterly<br>Initial performance of 4% leaks = semi-annually<br>**Valves (without connectors):**<br>Initial performance of 4% leaks = quarterly<br>Initial performance of 3% leaks = semi-annually<br>**Pumps only:**<br>No skip period only avoid QIP requirements<br>Historical performance acceptable without prior approval | **Valves only:**<br>2 consecutive quarters <2% = semi-annual<br>2 consecutive semi-annual < 2% = annual<br>>2% leaking = increase monitoring<br>Historical performance acceptable without prior approval | **Valves only:**<br>2 consecutive quarters < 2% = skip 1 quarter<br>5 consecutive quarters < 2% = skip 3 quarters<br>Total leaking FECs cannot be > 4%<br>Historical performance acceptable without prior approval | **Valves only:**<br>2 successive months ND = first month of every qtr until leak detected<br>2 consecutive qtrs < 2% = skip 1 qtr<br>5 consecutive qtrs < 2% = skip 3 qtrs<br>Vinyl Chloride NESHAP allows 200 or 90% valves if <2% | **Valves only:**<br>2 consecutive quarters <2% = skip 1 quarter<br>5 consecutive quarters <2% = skip 3 quarters | **Valves only:**<br>2 consecutive quarters <2% = skip 1 qtr for valves and pumps (LL)<br>5 consecutive quarters <2% = skip 3 qtrs | None for 63 R |
| **Light/heavy liquid definition and exemptions** | Light liquid has VP > 0.3 kPa @ 20 degC & is 20%w of total process stream | Light liquid has VP > 0.3 kPa @ 20 degC & is 20%w of total process stream | Light liquid has VP > 0.3 kPa @ 20 degC | Light liquid has VP > 0.3 kPa @ 20 degC | Light liquid has VP > 0.3 kPa @ 20 degC | Light liquid has VP > 0.2 kPa @ 20 degC | Light liquid has VP > 0.3 kPa @ 20 degC & is 20%w of total process stream | Light liquid has VP > 0.3 kPa @ 20 degC or a 10% evaporation point > 150 degC using ASTM D-86 | Light liquid has VP > 0.3 kPa @ 20 degC or a 10% evaporation point > 150 degC using ASTM D-86 | Light liquid has VP > 0.3 kPa @ 20 degC or a 10% evaporation point > 150 degC using ASTM D-86 | | Light liquid has VP >0.3 kPa @ 20 degC or a 10% evaporation point > 150 degC using ASTM D-86 | Light liquid has VP > 0.3 kPa @ 20 degC | NA | |
| **Liquid dripping definition** | | | | | | | | | | | | Visible leakage including spraying, misting, clouding and ice formation | | Per HON | |
| **Materials included in VOC definition** | TOC excluding methane, ethane, 1-1-1-TCE, methylene chloride, and various CFCs | TOC excluding methane, ethane, 1-1-1-TCE, methylene chloride, and various CFCs | | | | | | Consistent with LAC 33:III.2117 | | Consistent with LAC 33:III.2117 | | | Consistent with LAC 33:III.2117 | | |
| **Monitoring Method** | Method 21 | Method 21 | Method 21 | 40 CFR 264.1063 (b) | Method 21 | Method 21 | Method 21 | LAC 33:III.6077 | LAC 33:III Chapter 60, 61 or 63 | LAC 33:III.6077 | Method 21 | Method 21 | Method 21 | Visual, audible, or olfactory | |

| Item of Comparison | 40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants) | 40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery) | 40 CFR 63 Subpart H - SOCMI HON MACT | 40 CFR 63 Subpart TT – Equipment Leaks Control Level 1 | 40 CFR 63 Subpart UU – Equipment Leaks Control Level 2 | 40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT | 40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT | LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements | 40 CFR 63 Subpart CC - Refinery MACT Modified HON Option | LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT | LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment | 40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT | RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB | LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III | 40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Calibrate within 2000 ppm | | Calibrate within 2000 ppm | | Calibrate within 2000 ppm | | | | | | | | |
| **Monitoring Distance** | Consistent with EPA protocol | Consistent with EPA protocol | Consistent with EPA protocol | Consistent with EPA protocol | Consistent with EPA protocol | Consistent with EPA protocol | Consistent with EPA protocol | Not specified | Consistent with EPA protocol | Not specified | Consistent with EPA protocol | Consistent with EPA protocol | Not specified | NA | |
| **Comments** | | | | | | Comply with Subpart H of SOCMI HON<br><br>This table outlines HON requirements for Elastomer MACT | Comply with HON except for specific deviations<br><br>These two regulations are carbon copies of each other | | | | | | | | |
| **Post repair inspection** | Not specified, but assumed to be required immediately after repair to confirm a repair was successful | Not specified, but assumed to be required immediately after repair to confirm a repair was successful | Valves, after repair, monitored at least once within 3 months<br><br>Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check | Valves, after repair, monitored at least once within 3 months | Valves, after repair, monitored at least once within 3 months<br><br>Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check | Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check | Valves, after repair, monitored at least once within 3 months<br><br>Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check | Not specified, but assumed to be required immediately after repair to confirm a repair was successful | Valves, after repair, monitored at least once within 3 months<br><br>If monitoring connectors, monitor repaired connector within 2st 3 months after repair.<br><br>Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check | Not specified, but assumed to be required immediately after repair to confirm a repair was successful | Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check | Not specified, but assumed to be required immediately after repair to confirm a repair was successful | Not specified, but assumed to be required immediately after repair to confirm a repair was successful | Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check | No visible leak or holds a test pressure |
| **Repair periods (1st/Final Attempt)** | 5 days/15 days | 5 days/15 days | 5 day/15 days | 5 days/15 days | 5 day/15 days | 5 days/15 days | 5 days/15 days | 5 days*/15 days<br>*Includes monitoring | 5 day/15 days | 5 days/15 days | 15 days | 5 days/15 days | 5 days/15 days | 15 days | 5 days/15 days |
| **Calibration gas** | Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm | Zero air, methane or n-hexane and air at a concentration no more than 2,000 ppm above leak definition and highest scale with a calibration gas of approximately 10,000 ppm | Zero air, and mixtures dependent on phase monitored | Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm | Zero air, methane or n-hexane and air at a concentration of approximately 2,000 ppm | Zero air, air mixtures dependent of phase monitored | Zero air, methane or n-hexane and air at a concentration of approximately 2,000 ppm | Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm | Zero air, and mixtures dependent on phase monitored | Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm | Not specified in rule | Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm | Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm | Not specified in rule | NA |
| **Calibration Frequency** | Before use on each day | Before use on each day | Before use on each day | Before use on each day | Before use on each day | Before use on each day | Before use on each day | Before use on each day | Before use on each day | Before use on each day | Not specified in rule | Before use each day | Before use on each day | Not specified in rule | NA |
| **Criteria for unsafe to monitor exemption** | **Valves:**<br><br>Immediate danger Follow written plan to monitor when safe | **Valves:**<br><br>Immediate danger Follow written plan to monitor when safe | **Valves & connectors:**<br><br>Immediate danger Follow written plan to monitor when safe | **Valves & connectors:** Immediate danger Follow written plan to monitor when safe | **Valves & connectors:**<br><br>Immediate danger Follow written plan to monitor when safe | **Valves & connectors:**<br><br>Immediate danger<br><br>Follow written plan to monitor when safe | **Valves & connectors:**<br><br>Immediate danger Follow written plan to monitor when safe | **Valves, connectors & CVS:** Immediate danger Follow written plan to monitor when safe | **Valves & connectors:**<br><br>Immediate danger Follow written plan to monitor when safe | **Valves, connectors & CVS:** Immediate danger Follow written plan to monitor when safe | No criteria, but monitor when safe | **Valves:**<br><br>Immediate danger Follows written plan to monitor when safe | **Valves:**<br><br>Immediate danger Follow written plan to monitor when safe | No criteria, but monitor when safe | **Valves & connectors:**<br><br>Immediate danger Follow written plan to monitor when safe |

| Item of Comparison | 40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants) | 40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery) | 40 CFR 63 Subpart H - SOCMI HON MACT | 40 CFR 63 Subpart TT – Equipment Leaks Control Level 1 | 40 CFR 63 Subpart UU – Equipment Leaks Control Level 2 | 40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT | 40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT | LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements | 40 CFR 63 Subpart CC - Refinery MACT Modified HON Option | LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT | LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment | 40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT | RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB | LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III | 40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Criteria for inaccessible components exemption** | | **Connector:**<br>Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible ) | **Connector:**<br>Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible ) | **Connector:**<br>Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible ) | **Connector:**<br>Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible ) | **Connector:**<br>Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible ) | **Connector:**<br>Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible ) | **Connector:**<br>Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible ) | **Random 200 option** - only accessible connectors<br>**Inspection Alternative** - only accessible connectors | **Connector:**<br>Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible ) | | | | | **Connector:**<br>Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible ) |
| **Criteria for difficult to monitor** | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor | Cannot monitor without elevating >2m above support surface<br>Follow written plan to annually monitor |
| **Exemptions** | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals with barrier fluid and alarm<br>Closed vent system<br>No detectable emissions<br>Difficult to monitor | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals with barrier fluid and alarm<br>Closed vent system<br>No detectable emissions<br>Difficult to monitor | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals with barrier fluid and alarm<br>Closed vent system<br>No detectable emissions<br>Difficult to monitor<br><.75" FECs in instrumentation systems<br>PRVs equipped with rupture disk | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals with barrier fluid and alarm<br>Closed vent system<br>No detectable emissions<br>Difficult to monitor<br>Equipment in service <300 hours per year | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals with barrier fluid and alarm<br>Closed vent system<br>No detectable emissions<br>Difficult to monitor<br>Equipment in service <300 hours per year | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals with barrier fluid and alarm<br>Closed vent system<br>No detectable emissions<br>Difficult to monitor<br>Equipment in service <300 hours per year | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals with barrier fluid and alarm<br>Closed vent system<br>No detectable emissions<br>Difficult to monitor<br>Equipment in service <300 hours per year | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals with barrier fluid and alarm<br>Closed vent system<br>No detectable emissions<br>Difficult to monitor<br>Equipment in service <300 hours per year | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals with barrier fluid and alarm<br>Closed vent system<br>No detectable emissions<br>Difficult to monitor<br><.75" FECs in instrumentation systems<br>PRVs equipped with rupture disk | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals with barrier fluid and alarm<br>Closed vent system<br>No detectable emissions<br>Difficult to monitor<br>Equipment in service <300 hours per year | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals<br>Vapor pressure <0.0435 psia<br>R&D facilities (< 100 FEC)<br>Insulated components | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals with barrier fluid and alarm<br>Closed vent system<br>No detectable emissions<br>Difficult to monitor | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals with barrier fluid and alarm<br>Closed vent system<br>No detectable emissions<br>Difficult to monitor | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals<br>Vapor pressure <0.0435 psia<br>R&D facilities (< 100 FEC)<br>Check valves | Vacuum service<br>Unsafe to monitor<br>Dual Mechanical seals with barrier fluid and alarm<br>Closed vent system<br>Difficult to monitor<br>Open ended lines for emergency<br>PRVs equipped with rupture disk |
| **Exemptions (Continued)** | | | Unmanned sites:<br>Monthly visual inspections allowed<br>Compressors operated <300 hrs or tied to CVS or VRU | | Open ended lines for emergency<br>PRVs equipped with rupture disk | Open ended lines for emergency<br>PRVs equipped with rupture disk | Open ended lines for emergency<br>PRVs equipped with rupture disk | Open ended lines for emergency<br>PRVs equipped with rupture disk | Unmanned sites:<br>Monthly visual inspections allowed<br>Compressors operated <300 hrs or tied to CVS or VRU | Open ended lines for emergency<br>PRVs equipped with rupture disk | Components of shutdown repair list | | | | Unmanned sites:<br>Monthly visual inspections allowed<br>Compressors operated <300 hrs or tied to CVS or VRU |
| **Delay of repair** | **All equipment:**<br>Technically infeasible w/o PU shutdown;<br>Isolated and out of VOC service | **All equipment:**<br>Technically infeasible w/o PU shutdown;<br>Isolated and out of VOC service | **All equipment:**<br>Technically infeasible w/o PU shutdown;<br>Isolated and out of HAP service | **All equipment:**<br>Technically infeasible w/o PU shutdown;<br>Isolated and out of HAP service | **All equipment:**<br>Technically infeasible w/o PU shutdown;<br>Isolated and out of HAP service | **All equipment:**<br>Technically infeasible w/o PU shutdown;<br>Isolated and out of HAP service | **All equipment:**<br>Technically infeasible w/o PU shutdown;<br>Isolated and out of HAP service | **All equipment:**<br>Technically infeasible w/o PU shutdown;<br>Isolated and out of VOTAP service | **All equipment:**<br>Technically infeasible w/o PU shutdown;<br>Isolated and out of HAP service | **All equipment:**<br>Technically infeasible w/o PU shutdown;<br>Isolated and out of VOTAP service | **All equipment:**<br>Requires a PU shutdown | **All equipment:**<br>Technically infeasible w/o PU shutdown;<br>Isolated and out of VHAP service | **All equipment:**<br>Technically infeasible w/o PU shutdown;<br>Isolated and out of VOC service | **All equipment:**<br>Requires a PU shutdown | **All equipment:**<br>Technically infeasible w/o PU shutdown;<br>Isolated and out of HAP service |

| Item of Comparison | 40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants) | 40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery) | 40 CFR 63 Subpart H - SOCMI HON MACT | 40 CFR 63 Subpart TT – Equipment Leaks Control Level 1 | 40 CFR 63 Subpart UU – Equipment Leaks Control Level 2 | 40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT | 40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT | LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements | 40 CFR 63 Subpart CC - Refinery MACT Modified HON Option | LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT | LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment | 40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT | RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB | LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III | 40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Valves:**<br>Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device<br>**Pumps:**<br>Replacing with DMS (within 6 months) | **Valves:**<br>Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device<br>**Pumps:**<br>Replacing with DMS (within 6 months) | **Valves, Connectors, Agitators:**<br>Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device<br>**Pumps:**<br>Replacing with DMS (within 6 months) | **Valves, Connectors, Agitators:**<br>Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device<br>**Pumps:**<br>Replacing with DMS (within 6 months) | **Valves, Connectors, Agitators:**<br>Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device<br>**Pumps:**<br>Replacing with DMS (within 6 months) | **Valves, Connector, Agitators:**<br>Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device<br>**Pumps:**<br>Replacing with DMS (within 6 months) | **Valves, Connectors, Agitators:**<br>Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device<br>**Pumps:**<br>Replacing with DMS (within 6 months) | **Valves, connectors & agitators:**<br>Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device<br>Drill and tap required on non-control valves, if feasible, before placing on delay of repair<br>All components on delay of repair must be monitored per routine monitoring<br>**Pumps:**<br>Replacing with DMS (within 6 months) | **Valves, Connectors, Agitators:**<br>Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device<br>**Pumps:**<br>Replacing with DMS (within 6 months) | **Valves, connectors & agitators:**<br>Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device<br>**Pumps:**<br>Replacing with DMS (within 6 months) | Isolated or bypassed to reduce leakage<br>Shutdown would create more emissions than repair would eliminate | **Valves:**<br>Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device<br>**Pumps:**<br>Replacing with DMS (within 6 months) | **Valves:**<br>Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device<br>**Pumps:**<br>Replacing with DMS (within 6 months) | Isolated or bypassed to reduce leakage<br>Shutdown would create more emissions than repair would eliminate | **Valves, Connectors, Agitators:**<br>Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device<br>**Pumps:**<br>Replacing with DMS (within 6 months) |
| **Delay of repair beyond PU shutdown** | **Valves:**<br>Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion | **Valves:**<br>Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion | **Valves:**<br>Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion. | **Valves:**<br>Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion | **Valves:**<br>Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion. | **Valves:**<br>Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion. | **Valves:**<br>Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion. | **Valves:**<br>Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion | **Valves:**<br>Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion. | **Valves:**<br>Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion | | **Valves:**<br>Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion. | **Valves:**<br>Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion | | **Valves:**<br>Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion. |
| **Tagging** | Leaking components | Leaking components | Leaking components | Leaking components | Leaking components | Leaking components | Leaking components | Leaking components | Leaking components | Leaking components | Leaking components | Leaking components and affected components | Physical tag required | Leaking components | None |
| **Use of background concentration data** | Subtract for determining compliance | Subtract for determining compliance | Subtract for determining compliance | Subtract for determining compliance | Subtract for determining compliance | Subtract for determining compliance | Subtract for determining compliance | Subtract for determining compliance | Subtract for determining compliance | Subtract for determining compliance | Not specified in rule | Subtract for determining compliance | | Not specified in rule | NA |
| **Recordkeeping** | Leak and repair records<br>Component Inventory<br>CVS design and operation records<br>Valve records<br>Exemption data | Leak and repair records<br>Component Inventory<br>CVS design and operation records<br>Valve records<br>Exemption data | Leak and repair records<br>Component Inventory<br>Connector monitoring schedule<br>DMS records<br>Valves records | Leak and repair records<br>Component Inventory<br>CVS design and operation records<br>Valve records<br>Exemption data | Leak and repair records<br>Component Inventory<br>Connector monitoring schedule<br>DMS records<br>Valves records | Leak and repair records<br>Component Inventory<br>Connector monitoring schedule<br>DMS records<br>Valves records | Leak and repair records<br>Component Inventory<br>Connector monitoring schedule<br>DMS records<br>Valves records | Leak and repair records<br>Component Inventory<br>Connector monitoring schedule<br>Valves records<br>Exemption data | Leak and repair records<br>Component Inventory<br>Connector monitoring schedule<br>DMS records<br>Valves records | Leak and repair records<br>Component Inventory<br>Connector monitoring schedule<br>Valves records<br>Exemption data | Leak and repair records<br>Component inventory<br>Calibration records | Leak and repair records<br>CVS design and operation records<br>Component Inventory<br>Valve records<br>Exemption data | Leak and repair records<br>Component Inventory<br>CVS design and operation records<br>Valve records<br>Exemption data | Leak and repair records<br>Component inventory<br>Calibration records | Maintain log book of inspections, and leaking components, with summary descriptions. |

| Item of Comparison | 40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants) | 40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery) | 40 CFR 63 Subpart H - SOCMI HON MACT | 40 CFR 63 Subpart TT – Equipment Leaks Control Level 1 | 40 CFR 63 Subpart UU – Equipment Leaks Control Level 2 | 40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT | 40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT | LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements | 40 CFR 63 Subpart CC - Refinery MACT Modified HON Option | LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT | LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment | 40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT | RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB | LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III | 40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Exemption data<br>Batch Process Monitoring<br>HL determinations<br>Visual inspection dates<br>Compliance tests<br>CVS system design and operation<br>QIP | | Exemption data<br>Batch Process Monitoring<br>HL determinations<br>Visual inspection dates<br>Compliance tests<br>CVS system design and operation<br>QIP | Exemption data<br>Batch Process Monitoring<br>HL determinations<br>Visual inspection dates<br>Compliance tests<br>CVS system design and operation<br>QIP | Exemption data<br>Batch Process Monitoring<br>HL determinations<br>Visual inspection dates<br>Compliance tests<br>CVS system design and operation<br>QIP | CVS system design and operation<br>DORs must be signed within 30 days of leak identifcation | Exemption data<br>HL determinations<br>Visual inspection dates<br>Compliance tests<br>CVS system design and operation<br>QIP | CVS system design and operation | | | Compliance Test Results | | |
| **Recordkeeping Period** | 2 years | 2 years | 2 years | Per referencing Subpart (5 years) | Per referencing Subpart | 2 years | 5 years | 5 years | 2 years | 5 years | 2 years | 2 years | 2 years | 2 years | 5 years |
| **Reporting** | Initial report<br>LDAR Performance<br>reports semi-annually | Initial report<br>LDAR Performance<br>reports semi-annually | LDAR Performance<br>reports semi-annually after Not. of Comp.<br>Initial Notification<br>Initial Notification of Compliance | Per referencing Subpart | LDAR Performance<br>reports semi-annually after Not. of Comp.<br>Initial Notification<br>Initial Notification of Compliance | LDAR performance report semi-annually after Not. of Comp.<br>Initial Notification<br>Initial Notification of Compliance | LDAR Performance<br>reports semi-annually after Not. of Comp.<br>Initial Notification<br>Initial Notification of Compliance | Initial notification<br>Quarterly LDAR Performance reports 3 months after initial report | LDAR Performance<br>reports semi-annually after Not. of Comp.<br>Initial Notification<br>Initial Notification of Compliance | Initial notification<br>Quarterly LDAR Performance reports 3 months after initial report | Quarterly LDAR Performance reports, including repair data | Initial report<br>Semi-annual reports starting 6 months after initial | LDAR Performance<br>reports semi-annually | Quarterly LDAR Performance reports, including repair data | 63 Subpart R: Quarterly<br>63 Subpart YY: Records only |
| **Effective dates** | 5-Jan-81 | Nov. 16, 2007 | Group I<br>24-Oct-94<br>24-Oct-95<br>24-Apr-97<br>Group II<br>23-Jan-95<br>23-Jan-96<br>23-Jul-97<br>Group III<br>24-Apr-95<br>24-Apr-96<br>24-Oct-97<br>Group IV<br>24-Jul-95<br>24-Jul-96<br>24-Dec-97 | | | One year after promulgation<br>for compressors<br>6 months after promulgation for other equipment | | Jan 1, 1995, unlessotherwise specified in Air Toxics Compliance Plan, but no later than Dec 20, 1996 | New Sources - upon startup<br>Existing Sources - Phase I- Aug 18, 1998<br>Phase II - Aug 18, 1999<br>Phase III - 18-Feb-01 | Jan 1, 1995, unlessotherwise specified in Air Toxics Compliance Plan, but no later than Dec 20, 1996 | 1-Jan-96 | 6-Jun-84<br>Vinyl Chloride NESHAP Oct 21, 1976 | As required by permit | | |

| Item of Comparison | 40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants) | 40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery) | 40 CFR 63 Subpart H - SOCMI HON MACT | 40 CFR 63 Subpart TT – Equipment Leaks Control Level 1 | 40 CFR 63 Subpart UU – Equipment Leaks Control Level 2 | 40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT | 40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT | LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements | 40 CFR 63 Subpart CC - Refinery MACT Modified HON Option | LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT | LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment | 40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT | RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB | LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III | 40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Group V<br>23-Oct-95<br>23-Oct-96<br>23-Apr-97 | | | | | | | | | | | | |

**Note:** For this table –

CVS = closed vent systems; DMS = dual mechanic: Gas = in gas/vapor serv HL = in heavy liquid se Liquid = in liquid service;
LL = in light liquid service; ND = no leak is detecte PRVs = pressure relief PU = process unit; QIP = quality improve program;
SurgeCtrlVessel = surge control vessel; TOC = total volatil org VRU = vapor recovery unit.

# Cherry Point Refinery

## Coker Heater: Ammonia & SCR Analysis Project

# ESTIMATE BASIS

**END OF APPRAISE STAGE**

**Rev: 0**

**Project ID: 601**
**AMR:**

**9/17/2014**

**By: R. Stamulis**

## 5.2.1.2 - Standard TIC Estimate Summary

Cherry Point

# BPCP - ESTIMATE SUMMARY

BP Project ID: 601

Project Title: Coker Heater: Ammonia & SCR Analysis

Project Stage: Appraise

BP Project Manager: C. Kope

Contractor Project Manager:

Estimator: R. Stamulis

Date: 09/17/2014

Rev: 0

| Description | Key Qty | UoM | HRS | Rate | Labor | S/C | Bulk Materials | Engineered Equipment | Total |
|---|---|---|---|---|---|---|---|---|---|
| Demolition | | LT | | - | | | | | |
| Site Work and Civil | 217 | CY | 1,254 | 66.75 | 83,700 | | 100,944 | | 184,643 |
| Concrete | 257 | CY | 4,121 | 65.76 | 271,034 | | 71,822 | | 342,857 |
| Structural Steel | 22 | TN | 1,143 | 74.02 | 84,613 | | 115,378 | | 199,991 |
| Buildings | | SF | | - | | | | | |
| Major Equipment | 17 | EA | 1,312 | 77.70 | 101,935 | | 61,054 | 1,131,080 | 1,294,069 |
| Piping | 6,017 | LF | 10,893 | 78.80 | 858,314 | | 728,337 | | 1,586,650 |
| Electrical | 10,339 | LF | 5,528 | 70.70 | 390,826 | | 86,182 | 23,085 | 500,093 |
| Instrumentation | 127 | EA | 4,593 | 77.63 | 356,559 | | 231,800 | 241,307 | 829,665 |
| Paint | 362 | SF | 85 | 51.63 | 4,368 | | 278 | | 4,646 |
| Insulation | 1,008 | ELF | 2,556 | 61.93 | 158,311 | | 65,072 | | 223,383 |
| Specialized Concrete/Coatings | | CF | 256 | 61.41 | 15,698 | | 29,307 | | 45,005 |
| Fire / Safety Watch | 10% | PL | 1,089 | 78.80 | 85,831 | | | | 85,831 |
| Scaffold | 15% | FL | 4,924 | 73.45 | 361,678 | | | | 361,678 |
| | | **Direct Cost** | **37,754** | **73.45** | **$2,772,868** | | **$1,490,173** | **$1,395,472** | **$5,658,514** |
| Contractor Mob / Demob | 4% | % of DFH | 1,510 | 73.45 | 110,915 | | | | 110,915 |
| Craft Support Labor | 15% | % of DFH | 5,663 | 73.45 | 415,930 | | | | 415,930 |
| Contractor Field Staff | 20% | % of DFH | 7,551 | 73.45 | 554,574 | | | | 554,574 |
| Construction Equipment | $10.00 | X DFH | | | | 377,540 | | | 377,540 |
| Temporary Facilities | $1.50 | X DFH | | | | 56,631 | | | 56,631 |
| Per Diem | | X DFH | | | | - | | | - |
| | | | | | | - | | | - |
| TAR Event Allocation (TEA) | - | TAR hrs | 200 | 17.00 | 3,400 | - | | | 3,400 |
| **All-in Rate** | **$113.68** | **X DFH** | | | | | | | |
| Heavy Haul / Crane | | | | | | 150,000 | | | 150,000 |
| | | **Indirect Cost** | **14,924** | **72.69** | **$1,084,819** | **$584,171** | | | **$1,668,990** |
| **TOTAL FIELD COST (TFC)** | | | **52,678** | | **$3,857,687** | **$584,171** | **$1,490,173** | **$1,395,472** | **$7,327,504** |
| Taxes | | | | | | | | | |
| Catalyst | | | | | | | | 200,000 | 200,000 |
| Contaminated Soil Removal | | | | | | | | 58,000 | 58,000 |
| | | | | | | | | | - |
| | | | | | | | | | - |
| | | **Special Cost** | | | | | | | **$258,000** |
| Startup Costs | | | | | | | | | - |
| | | | | | | | | | - |
| | | **Startup Costs** | | | | | | | |
| Owner Services | 8% | of Base Est. | 7,736 | 105.00 | 812,253 | - | | | 812,253 |
| | | | | | | | | | |
| | | | | | | | | | - |
| Project Services | 17% | of Base Est. | - | 100.00 | - | - | | | 1,773,067 |
| | | | | | - | - | | | - |
| | | **Office Cost** | **7,736** | | **$812,253** | | | | **$2,585,320** |
| **TOTAL BASE ESTIMATE** | | | **60,414** | | **$4,669,940** | **$584,171** | **$1,490,173** | **$1,395,472** | **$10,170,823** |

| | | |
|---|---|---|
| **Escalation:** | **9%** | **$915,374** |
| **Contingency:** | **30%** | **$3,326,000** |
| **Expected TIC:** | | **$15,000,000** |
| **High Range (+50%)** | | **$22,500,000** |
| **Low Range (-30%)** | | **$10,500,000** |

**Basis for Contingency:** **Qualitative**

**Previous Stage $TIC Value:**

Print Date: 9/17/2014

# Cherry Point Refinery

## Coker Heater: CO Combustion Project

# ESTIMATE BASIS

**END OF APPRAISE STAGE**

**Rev: 0**

**Project ID: 601**
**AMR:**

**7/10/2014**

**By: R. Stamulis**

# 1.0 General Overview

## 1.1 Project Scope

The objective of this project is to reduce CO from the flue gas of the Coker Heater.

If this project is required it will be integrated with the Coker Heater Replacement Project.

## 1.2 Purpose and Type of Estimate

Appraise Stage estimate for initial project feasibility.

## 1.3 Major Schedule Milestones

- Issue for Construction - 2Q2016
- Mid-Point of Construction – 4Q2016
- Mechanical Completion - 2Q2017

## 1.4 Estimating Tools/Methodology

- Estimate was generated using ACCE (Aspen Capital Cost Estimator) V8.2. Quantities and design data were inputted and direct material and field construction manhours were estimated and exported to the standard Cherry Point Estimate Summary.
- Estimate was generated using forced detailed takeoff from conceptual modeling.

## 1.5 Quantities/Equipment Basis

- Process – Process Design Basis is conceptual
- Structural and Civil MTOs based on conceptual modeling
- Piping MTOs based on a typical P&ID for a Box Heater
- Electrical MTOs based on conceptual modeling
- Instrument MTOs based on conceptual modeling and a typical P&ID for a Box Heater.

## 1.6 Design Completion/MTO Allowance

10% MTO allowance is included in all field accounts to cover anticipated development of material and technical requirements during design. Does not address potential changes to scope.

## 1.7 Allowances

The following allowances have been included for scope items that are required but not well defined:

- None

## 1.8 General Assumptions/Exclusions

- The new CO heater will be installed in the Unit 12 area within 100' from the Coker Heater.
- It is assumed that most work can be done outside of a turnaround window with the exception of tie-ins.
- It is assumed that there will be adequate temperature for the CO system. No allowance has been included for heaters.

## 1.9 Discipline Assumptions

### 1.9.1 Major Equipment

- The estimate includes a plug number of $100M for each CO catalyst.
- The CO catalyst is assumed to be a bolt on type option.

### 1.9.2 Site Work/Civil

- All excavated soils are assumed to be contaminated and disposed of at $100/CY.
- All fill will be 100% imported

### 1.9.3 Concrete

- No assumptions / exclusions

### 1.9.4 Structural

- (4) Piles are included for each Box Heater.

### 1.9.5 Buildings

- N/A

### 1.9.6 Piping

- N/A

### 1.9.7 Electrical

- An allowance is included for equipment grounding. All grounding grids and lighting in the Coker area are assumed to be covered under a separate estimate.

### 1.9.8 Instrumentation

- The distance from the source component to the FTB in the Coker area is 30'. The estimate assumes the homerun from the FTB or CEMS is assumed to be included in the full Coker Heater Replacement estimate.
- An allowance is included in the estimate for I/O cards and controllers.
- All instrument tubing is Incoloy 825
- CEMS is excluded

## 2.0 Direct Cost

### 2.1 Labor

- Labor composition: All labor is outside union contractor.
- Direct labor rate includes the following: Base, fringes, payroll burdens, overhead and profit, small tools and consumables, and spot overtime.
- Source or basis for labor units: ACCE (Kbase)/In-house
- Labor productivity adjustments: Estimate includes standard site productivity adjustments for all direct field hours. 10% increase to labor units for non-TA, 50% increase for TA.
- Workweek: All field work is based on 40 hour, single shift workweek. All work is assumed to be during the TA and is based on a 60 hour, double shift work week.

### 2.2 Equipment & Materials

- Equipment pricing sources: In-house
- Material pricing source: In-house
- Field vs shop fabrication assumptions: Piping and structural steel will be remote shop fabricated to the optimal extent and field installed.
- Freight/material handling costs: Includes 4% of equipment, piping, steel, instrument, and electrical material pricing and labor hours.

### 2.3 Misc/Other

The following have been factored based on historical costs with an assessment of this project's particular requirements:

- Scaffold: 15% of direct labor hours
- Safety Watch (Fire, confined space, hole watch, traffic, etc.): 10% of piping and structural hours
- Heavy Haul/Crane/Equipment Logistics and Staging: A $150,000 allowance has been included for a 100 TON carne to install the SCR units.

## 3.0 Indirect Costs

### 3.1 Construction Labor Indirects

Calculated as a percentage of direct labor (based on historical Cherry Point averages):

- Contractor Field Staff – 20% of FL
- Craft Support Labor – 15% of FL
- Contractor Mob/Demob – 4% of FL

### 3.2 Construction Non-Labor Indirects

Calculated as a percentage of direct labor (based on historical Cherry Point averages):

- Temporary Facilities - $1.50/DFH
- Construction Equipment Rental - $10/DFH
- Turnaround Event Allocation (TEA) – $17 per direct field hour has been included to cover TA specific indirect charges.

## 4.0 Office Costs

### 4.1 Contract Project Services

Based on spent to date costs, plus a detail estimate by discipline. This includes the following costs for both IBL and OBL engineering:

- Post option selection Select Stage engineering – Actual costs
- Define Stage engineering – Forecast costs
- Execute Stage engineering – Detail estimate by discipline group.
- Construction Field support by engineering team – Detail estimate by group.
- Project Management Services including Project Managers, Project Engineers, Project Controls, Procurement, Document Control, administrative services, etc.
- Estimated Project Services labor rate is based on historical data.

### 4.2 Owner's Services

Based on historical percentage, which is 8% of the base estimate.

This includes the following: BP Project Management, BP Project Engineering, BP Procurement, BP Field Coordination/Construction Management, BP Discipline Engineering, BP Inspection, BP Project Controls, BP Safety Representative, Contractor Constructability, Permits/Fees, Trip expenses, Vendor support, Safety Incentives and Recognition, Operations support (if project requires dedicated support), As-Builts, IPA fees, Program support allocation, Geotech services (potholing), VIP/Hazop/PHSSER Facilitators, Start-up.

## 5.0 Other

### 5.1 Escalation

Based on cash flow and schedule requirements. Calculated at 3% per annum, to the midpoint of spend. The estimate includes 9% escalation.

### 5.2 Special

Includes contaminated soil disposal and special chemicals/initial catalyst load.

### 5.3 Sales Tax

Calculated at 8.5% of total field costs if the project is not manufacture-exempt. Sales tax is not required if project is manufacture-exempt, except must always be applied to construction equipment, heavy crane, and scaffold rental.

### 5.4 UAP (Contingency) and Confidence Range

30% of base estimate based on subjective assessment of project risk. Expected confidence range is plus or minus -50%/+100%.

## 5.2.1.2 - Standard TIC Estimate Summary

Cherry Point

# BPCP - ESTIMATE SUMMARY

BP Project ID: 601

Project Title: Coker Heater: CO Combustion

Project Stage: Appraise

BP Project Manager: C. Kope

Contractor Project Manager:

Estimator: R. Stamulis

Date: 07/10/2014

Rev: 0

| Description | Key Qty | UoM | HRS | Rate | Labor | S/C | Bulk Materials | Engineered Equipment | Total |
|---|---|---|---|---|---|---|---|---|---|
| Demolition | | LT | | - | | | | | |
| Site Work and Civil | | CY | 397 | 69.91 | 27,752 | | 46,279 | | 74,031 |
| Concrete | 59 | CY | 999 | 65.42 | 65,333 | | 21,138 | | 86,470 |
| Structural Steel | 3 | TN | 189 | 74.80 | 14,122 | | 27,575 | | 41,698 |
| Buildings | | SF | | - | | | | | |
| Major Equipment | 2 | EA | 358 | 78.94 | 28,287 | | | 523,750 | 552,037 |
| Piping | 92 | LF | 594 | 79.33 | 47,155 | | 118,921 | | 166,076 |
| Electrical | 720 | LF | 496 | 70.77 | 35,132 | | 5,489 | | 40,621 |
| Instrumentation | 30 | EA | 1,896 | 78.01 | 147,914 | | 68,886 | 121,841 | 338,642 |
| Paint | | SF | | - | | | | | |
| Insulation | | ELF | 1,291 | 62.10 | 80,166 | | 26,360 | | 106,526 |
| Specialized Concrete/Coatings | | CF | 129 | 61.41 | 7,928 | | 2,636 | | 10,564 |
| Fire / Safety Watch | 10% | PL | 59 | 79.33 | 4,716 | | | | 4,716 |
| Scaffold | 15% | FL | 961 | 71.54 | 68,776 | | | | 68,776 |
| | | **Direct Cost** | **7,371** | **71.54** | **$527,282** | | **$317,284** | **$645,591** | **$1,490,157** |
| Contractor Mob / Demob | 4% | % of DFH | 295 | 71.54 | 21,091 | | | | 21,091 |
| Craft Support Labor | 15% | % of DFH | 1,106 | 71.54 | 79,092 | | | | 79,092 |
| Contractor Field Staff | 20% | % of DFH | 1,474 | 71.54 | 105,456 | | | | 105,456 |
| Construction Equipment | $10.00 | X DFH | | | | 73,706 | | | 73,706 |
| Temporary Facilities | $1.50 | X DFH | | | | 11,056 | | | 11,056 |
| Per Diem | | X DFH | | | | - | | | - |
| | | | | | | - | | | - |
| TAR Event Allocation (TEA) | - | TAR hrs | | | | - | | | - |
| **All-in Rate** | **$110.94** | **X DFH** | | | | | | | |
| Heavy Haul / Crane | | | | | | 150,000 | | | 150,000 |
| | | **Indirect Cost** | **2,875** | **71.54** | **$205,640** | **$234,762** | | | **$440,402** |
| **TOTAL FIELD COST (TFC)** | | | **10,245** | | **$732,922** | **$234,762** | **$317,284** | **$645,591** | **$1,930,559** |
| Taxes | | | | | | | | | |
| CO Catalyst | | | | | | | | 200,000 | 200,000 |
| Contaminated Soil Removal | | | | | | | | 30,300 | 30,300 |
| | | | | | | | | | - |
| | | | | | | | | | - |
| | | **Special Cost** | | | | | | | **$230,300** |
| Startup Costs | | | | | | | | | - |
| | | | | | | | | | - |
| | | **Startup Costs** | | | | | | | |
| Owner Services | 8% | of Base Est. | 2,213 | 105.00 | 232,341 | - | | | 232,341 |
| | | | | | | | | | |
| | | | | | | | | | - |
| Project Services | 18% | of Base Est. | - | 100.00 | - | - | | | 515,200 |
| | | | | | - | - | | | - |
| | | **Office Cost** | **2,213** | | **$232,341** | | | | **$747,540** |
| **TOTAL BASE ESTIMATE** | | | **12,458** | | **$965,263** | **$234,762** | **$317,284** | **$645,591** | **$2,908,400** |

| | | |
|---|---|---|
| **Escalation:** | **9%** | **$261,756** |
| **Contingency:** | **30%** | **$951,000** |
| **Expected TIC:** | | **$4,121,000** |
| **High Range (+100%)** | | **$8,242,000** |
| **Low Range (-50%)** | | **$2,061,000** |

**Basis for Contingency:** **Qualitative**

**Previous Stage $TIC Value:**

Print Date: 9/17/2014

Cherry Point Refinery

# Coker Fuel Gas: Compressor Only Project

## ESTIMATE COVER SHEET

**END OF SELECT STAGE**

**Rev: 0**

**Project ID: 601.1**
**AMR:**

**1/4/2016**

**By: R. Stamulis**

## 5.2.1.2 - Standard TIC Estimate Summary

Cherry Point

### BPCP Summary

BP Project ID: 601.1
Project Title: Coker Fuel Gas
Project Stage: Select
BP Project Manager: N. El-Badawi

Contractor Project Manager:
Estimator: R. Stamulis
Date: 01/04/2016
Rev: 0

| Description | Key Qty | UoM | HRS | Rate | Labor | S/C | Bulk Materials | Engineered Equipment | Total |
|---|---|---|---|---|---|---|---|---|---|
| Demolition | 1 | LT | 4 | 89.71 | 353 | | - | | 353 |
| Site Work and Civil | 604 | CY | 1,259 | 74.52 | 93,841 | | 190,406 | | 284,247 |
| Concrete | 101 | CY | 2,054 | 67.22 | 138,078 | | 25,691 | | 163,769 |
| Structural Steel | 12 | TN | 611 | 79.01 | 48,250 | | 72,914 | | 121,163 |
| Buildings | | SF | | - | | | | | |
| Major Equipment | 3 | EA | 2,354 | 75.26 | 177,162 | | | 4,623,000 | 4,800,162 |
| Piping | 1,664 | LF | 3,298 | 81.37 | 268,335 | | 194,903 | | 463,238 |
| Electrical | 13,521 | LF | 6,310 | 72.94 | 460,241 | | 151,961 | 218,186 | 830,388 |
| Instrumentation | 27 | EA | 1,692 | 76.98 | 130,260 | | 99,829 | 372,166 | 602,255 |
| Paint | 1,750 | SF | 390 | 53.49 | 20,869 | | 911 | | 21,781 |
| Insulation | 3,718 | ELF | 1,604 | 65.37 | 104,886 | | 46,493 | | 151,379 |
| Specialized Concrete/Coatings | 94 | CF | 534 | 69.60 | 37,135 | | 5,179 | | 42,314 |
| Fire / Safety Watch | 10% | PL | 330 | 81.37 | 26,834 | | | | 26,834 |
| Scaffold | 20% | FL | 4,088 | 73.69 | 301,249 | | | | 301,249 |
| | | **Direct Cost** | **24,527** | **73.69** | **$1,807,492** | | **$788,287** | **$5,213,352** | **$7,809,132** |
| Contractor Mob / Demob | 2% | % of DFH | 491 | 73.69 | 36,150 | | | | 36,150 |
| Craft Support Labor | 5% | % of DFH | 1,226 | 73.69 | 90,375 | | | | 90,375 |
| Contractor Field Staff | 25% | % of DFH | 6,135 | 73.69 | 452,100 | | | | 452,100 |
| Construction Equipment | $8.00 | X DFH | | | | 196,216 | | | 196,216 |
| Temporary Facilities | | X DFH | | | | - | | | - |
| Per Diem | | X DFH | | | - | - | | | - |
| | | | | | | - | | | - |
| TAR Event Allocation (TEA) | - | TAR hrs | 39.17 | 17.00 | 666 | - | | | 666 |
| **All-in Rate** | **$105.31** | **X DFH** | | | | | | | |
| Heavy Haul / Crane | | | | | | 100,000 | | | 100,000 |
| | | **Indirect Cost** | **7,891** | **73.41** | **$579,290** | **$296,216** | | | **$875,506** |
| **TOTAL FIELD COST (TFC)** | | | **32,418** | | **$2,386,782** | **$296,216** | **$788,287** | **$5,213,352** | **$8,684,638** |
| Equipment Spares | | | | | | - | | 750,000 | 750,000 |
| Catalyst & Other Initial Fills | | | | | | | | | - |
| Uninstalled Spare Parts | | | | | | | | | - |
| Demolition and Removals | | | | | | | | | - |
| Other Special Costs (interest, etc.) | | | | | | | | | - |
| | | **Special Cost** | | | | | | | **$750,000** |
| Startup Costs | | | | | | | | | - |
| | | | | | | | | | - |
| | | **Startup Costs** | | | | | | | |
| Owner Services | 15% | of Base Est. | 19,856 | 105.00 | 2,084,903 | | | | 2,084,903 |
| | | | | | | | | | |
| | | | | | | | | | - |
| Project Services | 17% | of Base Est. | - | 100.00 | | | | | 2,358,174 |
| | | | | | | | | | - |
| | | **Office Cost** | **19,856** | | **$2,084,903** | | | | **$4,443,076** |
| **TOTAL BASE ESTIMATE** | | | **52,274** | | **$4,471,685** | **$296,216** | **$788,287** | **$5,213,352** | **$13,877,714** |

| | | |
|---|---|---|
| **Escalation:** | **6%** | **$763,274** |
| **Contingency:** | **16%** | **$2,343,000** |
| **Expected TIC:** | | **$16,984,000** |

**Basis for Contingency:** **Qualitative**

**Previous Stage $TIC Value:**

Print Date: 1/20/2016

Project Title: BPCP Coker Heater - CFGas Merox Treating

Estimator: T. Vekved
Date: 1/12/2016
Rev: 0

**CONCEPTUAL ESTIMATE - COST FACTORING MATRIX**
**COMPONENTS OF TOTAL BATTERY LIMIT INSTALLATION COST**
**EXPRESSED AS PERCENTAGE OF EQUIPMENT COST**

| | | COLUMNS SHELLS | MEROX SKID |
|---|---|---|---|
| COST OF EQUIP, EX WORKS | | 100% | 100% |
| OTHER MATERIAL: | | | |
| 100% FOUNDATIONS, PAVING | | 15% | 8% |
| 100% PLATFORMS, SUPPORTS | | 10% | 4% |
| 100% BUILDINGS | | 0% | 0% |
| 100% PIPING | | 55% | 5% |
| 100% INSULATION, FIRE PROOFING | | 20% | 2% |
| 100% ELECTRICAL | | 7% | 5% |
| 100% INSTRUMENTATION | | 30% | 4% |
| 100% PAINT,CLEAN,TEST, MISC. | | 3% | 1% |
| SUBTOTAL, OTHER MAT'L | | 140% | 29% |
| | | | |
| TOTAL, EQUIP. & OTHER | | 240% | 129% |
| FIELD LABOR: | | | |
| 0% HANDLE AND SET EQUIP. | | 15% | 10% |
| 0% OTHER CONSTRUCTION | | 80% | 15% |
| SUBTOTAL, FIELD LABOR | | 95% | 25% |
| 0% RETROFIT LABOR FACTOR ADJ. | | 0% | 0% |
| TOTAL DIRECT COST | | 335% | 154% |
| INDIRECT COST: | | | |
| 50% | | 48% | 13% |
| INDIRECT LABOR ADJUSTMENT | | 5% | 5% |
| TOTAL INSTALLATION | | 388% | 172% |
| APPROXIMATE RATIO: TOTAL INSTALLATION / EQUIPMENT COST | | 3.9 | 1.7 |

| | CONSTR. HOURS | COLUMNS SHELLS | MEROX SKID | TOTAL |
|---|---|---|---|---|
| COST OF EQUIP, EX WORKS | | $ 1,000,000 | $ 8,150,000 | $9,150,000 |
| 5% FREIGHT | | $ 50,000 | $ 407,500 | $457,500 |
| OTHER MATERIAL: | | | | $9,607,500 |
| FOUNDATIONS, PAVING | | $ 150,000 | $ 652,000 | $802,000 |
| PLATFORMS, SUPPORTS | | $ 100,000 | $ 326,000 | $426,000 |
| BUILDINGS | | $ - | $ - | $0 |
| PIPING | | $ 550,000 | $ 407,500 | $957,500 |
| INSULATION, FIRE PROOFING | | $ 200,000 | $ 163,000 | $363,000 |
| ELECTRICAL | | $ 70,000 | $ 407,500 | $477,500 |
| INSTRUMENTATION | | $ 300,000 | $ 326,000 | $626,000 |
| PAINT,CLEAN,TEST, MISC. | | $ 30,000 | $ 81,500 | $111,500 |
| SUBTOTAL, OTHER MAT'L | | $ 1,400,000 | $ 2,363,500 | $3,763,500 |
| | | | | $0 |
| TOTAL, EQUIP. & OTHER | | $ 2,450,000 | $ 10,921,000 | $13,371,000 |
| FIELD LABOR: | | | | $0 |
| HANDLE AND SET EQUIP. | 11,768 | $ 150,000 | $ 815,000 | $965,000 |
| OTHER CONSTRUCTION | 24,665 | $ 800,000 | $ 1,222,500 | $2,022,500 |
| SUBTOTAL, DIRECT FIELD LABOR | 36,433 | $ 950,000 | $ 2,037,500 | $2,987,500 |
| | | | | $0 |
| TOTAL DIRECT COST | | $ 3,400,000 | $ 12,958,500 | $16,358,500 |
| INDIRECT COST (B): | | | | $0 |
| | | $ 525,000 | $ 1,426,250 | $1,951,250 |
| TOTAL FIELD COST | | $ 3,925,000 | $ 14,384,750 | $18,309,750 |
| Contractor Project Services | 13% | $ 1,059,750 | $ 2,157,713 | $3,217,463 |
| Owner cost and Services | 6% | $ 392,500 | $ 1,150,780 | $1,543,280 |
| Escalation | 5% | $ 483,953 | $ 1,592,392 | $2,076,344 |

# Appendix C

## Emissions Calculations

BP - Cherry Point

# Coker Heater Replacement Project - Coker Heater Combustion Emissions

## This spreadsheet identifies total emissions of criteria pollutants attributable to the Coker Heaters

| | | |
|---|---|---|
| Maximum Heater Burner Capacity | 303.00 MMBtu/hr | per heater |
| Annual Hours of Operation | 8,760 hours/year | |
| Annual hours in startup/shutdown or standby | 504 hours/year | estimated three weeks per heater |
| **Stack Exhaust Flow Information** | | |
| F Factor (Refinery Fuel Gas) | 8,381 dscf/MMBtu | Source: Coker Heater Design Case |
| Exhaust gas volume flow | 42,323 dscfm @ 0%O2 | |

PVM=mRuT --> V=mRuT/PM --> m=PVM/RuT
Ideal Gas Law

| | | |
|---|---|---|
| T = | 293.15 | K |
| P = | 1 | atm |
| Ru= | 1.314 | atm-ft^3/lbmol-K |

### Criteria and PSD Pollutant Emissions

| | | New Coker Heaters | | | | | |
|---|---|---|---|---|---|---|---|
| | | Emission Factor | | Emission Rate [k] (1 Heater) | | Emission Rate (2 Heaters) | |
| CAS | Pollutant | (ppmvd) | (lb/mmBtu) | (lb/hr) | (tpy) | (lb/hr) | (tpy) |
| 10102-44-0 | NOx (balanced draft) [a] | 60 ppmdv (0% O2) | 0.06 | 18.2 | 79.6 | 36.4 | 159.3 |
| | NOx (natural draft) [a] | 40 ppmdv (0% O2) | 0.04 | 12.1 | 53.1 | 24.2 | 106.2 |
| 630-08-0 | CO (normal operation)[a] | 33 ppmdv (0% O2) | 0.020 | 6.1 | 26.5 | 12.1 | 53.1 |
| | CO (Startup/Shutdown or Standby) | -- | -- | 75.0 | 18.9 | 150.0 | 37.8 |
| 7446-09-05 | SO2 (1-hr) [c] | -- | -- | 20.0 | -- | 40.0 | -- |
| -- | SO2 (24-hr) [c] | -- | -- | 20.0 | -- | 40.0 | -- |
| -- | SO2 (Annual) [c] | 36 ppmdv (0% O2) | 0.050 | -- | 66.0 | -- | 132 |
| -- | PM (Filt.) [d] | -- | 0.0025 | 0.76 | 3.3 | 1.5 | 6.6 |
| -- | PM10 (Filt. & Cond.) [d] | -- | 0.0100 | 3.0 | 13.3 | 6.1 | 26.5 |
| -- | PM2.5 (Filt. & Cond.) [d] | -- | 0.0100 | 3.0 | 13.3 | 6.1 | 26.5 |
| -- | VOC [e] | -- | 0.0054 | 1.6 | 7.2 | 3.3 | 14.3 |
| 7439-92-1 | Lead [e] | -- | 4.9E-07 | 1.5E-04 | 6.5E-04 | 3.0E-04 | 1.3E-03 |
| 7664-93-9 | H2SO4 [f] | -- | 0.0053 / 0.0040 | 1.6 | 5.3 | 3.2 | 10.6 |
| 7783-06-4 | H2S [g] | -- | -- | 0.005 | 0.016 | 0.010 | 0.033 |
| -- | CO2 [h] | -- | 120.2 | 36,419 | 159,514 | 72,837 | 319,028 |
| -- | CH4 [i] | -- | 0.0023 | 0.68 | 3.0 | 1.4 | 6.0 |
| -- | N2O [i] | -- | 0.0022 | 0.65 | 2.9 | 1.3 | 5.7 |
| -- | CO2e [j] | -- | 120.9 | 36,631 | 160,442 | 73,261 | 320,883 |

notes:

a - NOx and CO emissions based on proposed BACT.

b - CO startup/shutdown/standby emissions based on 75 lb/hr and conservative estimate of 504 hours of operation in startup/shutdown/standby modes per year.

c - SO2 emission factors based on short-term and long-term sulfur concentration in coker off gas.

d - PM10 and PM2.5 emission factor based on 2009 & 2013 refinery source test data with a safety factor. PM emission factor based on 25 percent of PM10 emission factor (average from #2 DHDS Charge Heater and #3 DHDS Charge Heater source tests, fraction of filterable particulate in total particulate).

e - VOC and Lead emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf).

f - H2SO4 emission factors based on 2.63 percent of sulfur in fuel converting to H2SO4 (Source Test for #1 Reformer firing RFG).

g - H2S emissions based on 0.0002 ratio of H2S emissions to SO2 emissions (based on average from 2012 & 2013 data for existing coker heaters).

h - CO2 emission factor based on coker off gas fuel analysis and 100% conversion of carbon in fuel to CO2.

i - CH4 and N20 emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf)

j - CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).

k - Hourly and annual emission rates based on 303 mmBtu/hr and 8,760 hours per year of operation.

## Toxic Air Pollutant Emissions

| CAS | Compound | Emission Factor [a] lb/mmscf | Emission Factor [a] lb/mmBtu | Emission Rate [d] (2 Heaters) lb/hr | Emission Rate [d] (2 Heaters) lb/day | Emission Rate [d] (2 Heaters) tpy |
|---|---|---|---|---|---|---|
| 75-07-0 | Acetaldehyde [e] | 1.2E-02 | 1.2E-05 | 7.3E-03 | 1.7E-01 | 3.2E-02 |
| 107-02-8 | Acrolein [e] | 1.7E-02 | 1.7E-05 | 1.0E-02 | 2.5E-01 | 4.5E-02 |
| 7440-38-2 | Arsenic | 2.0E-04 | 2.0E-07 | 1.2E-04 | 2.9E-03 | 5.2E-04 |
| 71-43-2 | Benzene | 2.1E-03 | 2.1E-06 | 1.2E-03 | 3.0E-02 | 5.5E-03 |
| 7440-41-7 | Beryllium [e] | 1.3E-04 | 1.3E-07 | 7.9E-05 | 1.9E-03 | 3.5E-04 |
| 7440-43-9 | Cadmium | 1.1E-03 | 1.1E-06 | 6.5E-04 | 1.6E-02 | 2.9E-03 |
| 630-08-0 | CO [b] | -- | -- | 150 | 3600 | 90.89 |
| 18540-29-9 | Chromium VI [c] | 5.6E-05 | 5.5E-08 | 3.3E-05 | 8.0E-04 | 1.5E-04 |
| 7440-48-4 | Cobalt | 8.4E-05 | 8.2E-08 | 5.0E-05 | 1.2E-03 | 2.2E-04 |
| 7440-50-8 | Copper | 8.5E-04 | 8.3E-07 | 5.1E-04 | 0.012 | 2.2E-03 |
| 106-46-7 | Dichlorobenzene | 1.2E-03 | 1.2E-06 | 7.1E-04 | 0.017 | 3.1E-03 |
| 100-41-4 | Ethylbenzene [e] | 1.6E-02 | 1.6E-05 | 9.7E-03 | 2.3E-01 | 4.2E-02 |
| 50-00-0 | Formaldehyde | 7.5E-02 | 7.4E-05 | 0.045 | 1.07 | 0.195 |
| 110-54-3 | Hexane | 1.8 | 1.8E-03 | 1.07 | 25.67 | 4.68 |
| 7783-06-4 | H2S [b] | -- | -- | 0.01 | 0.24 | 0.04 |
| 7664-93-9 | H2SO4 [b] | -- | 5.3E-03 | 3.22 | 77.32 | 10.63 |
| 7439-92-1 | Lead [b] | -- | 4.9E-07 | 3.0E-04 | 7.1E-03 | 1.3E-03 |
| 7439-96-5 | Manganese | 3.8E-04 | 3.7E-07 | 2.3E-04 | 5.4E-03 | 9.9E-04 |
| 7439-97-6 | Mercury | 2.6E-04 | 2.5E-07 | 1.5E-04 | 3.7E-03 | 6.8E-04 |
| 91-20-3 | Naphthalene | 6.1E-04 | 6.0E-07 | 3.6E-04 | 8.7E-03 | 1.6E-03 |
| 7440-02-0 | Nickel | 2.1E-03 | 2.1E-06 | 1.2E-03 | 0.030 | 5.5E-03 |
| 10102-44-0 | NOx [b] | -- | 6.0E-02 | 36.36 | 872.64 | 159.26 |
| 108-95-2 | Phenol [e] | 4.1E-03 | 4.0E-06 | 2.4E-03 | 5.8E-02 | 1.1E-02 |
| 115-07-1 | Propylene [e] | 1.5E-01 | 1.5E-04 | 9.1E-02 | 2.2E+00 | 4.0E-01 |
| 7782-49-2 | Selenium [e] | 9.0E-04 | 8.8E-07 | 5.3E-04 | 1.3E-02 | 2.3E-03 |
| 7446-09-05 | SO2 [b] | -- | -- | 40.00 | 960.00 | 131.92 |
| 108-88-3 | Toluene | 3.4E-03 | 3.3E-06 | 2.0E-03 | 0.04848 | 8.8E-03 |
| 7440-62-2 | Vanadium | 2.3E-03 | 2.3E-06 | 1.4E-03 | 0.033 | 6.0E-03 |
| 56-55-3 | Benz(a)anthracene [e] | 2.2E-05 | 2.2E-08 | 1.3E-05 | 3.2E-04 | 5.8E-05 |
| 50-32-8 | Benzo(a)pyrene [e] | 5.8E-05 | 5.7E-08 | 3.5E-05 | 8.3E-04 | 1.5E-04 |
| 205-99-2 | Benzo(b)fluoranthene [e] | 2.8E-05 | 2.7E-08 | 1.6E-05 | 3.9E-04 | 7.2E-05 |
| 207-08-9 | Benzo(k)fluoranthene [e] | 1.7E-05 | 1.7E-08 | 1.0E-05 | 2.5E-04 | 4.5E-05 |
| 218-01-9 | Chrysene [e] | 1.6E-06 | 1.6E-09 | 9.7E-07 | 2.3E-05 | 4.2E-06 |
| 53-70-3 | Dibenzo(a,h)anthrancene | 1.2E-06 | 1.2E-09 | 7.1E-07 | 1.7E-05 | 3.1E-06 |
| 193-39-5 | Indeno(1,2,3-cd)pyrene [e] | 7.2E-05 | 7.1E-08 | 4.3E-05 | 1.0E-03 | 1.9E-04 |
| 56-49-5 | 3-Methylcholanthrene | 1.8E-06 | 1.8E-09 | 1.1E-06 | 2.6E-05 | 4.7E-06 |
| 57-97-6 | 7,12-Dimethylbenz[a]anthracene | 1.6E-05 | 1.6E-08 | 9.5E-06 | 2.3E-04 | 4.2E-05 |
| POM | Polycyclic Organic Matter | 8.8E-05 | 8.6E-08 | 5.2E-05 | 1.3E-03 | 2.3E-04 |

notes:

a - HAP and TAP emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf), unless souce is otherwise noted. The use of AP-42 data is supported by EPA's Emissions Estimation Protocol for Petroleum Refineries as of August 2014.

b - NOx, CO, SO2, H2S, H2SO4, and lead emissions based on 'Criteria and PSD Calculations' presented above. CO short-term emissions based on startup/shutdown/standby operations.

c - AP-42 provides a chromium emission factor for natural gas fired external combustion, but does not include guidance for partitioning emissions between the carcinogenic chromium VI (hexavalent chromium) and the chromium III (trivalent chromium). EPA's 2002 National-Scale Air Toxics Assessment (NATA) released June 2009 includes a chromium speciation profile for gas-fired process heaters, which indicates 4 percent of total chromium is chromium VI and 96 percent is chromium III. ENVIRON assumed 4 percent of total chromium emissions were emitted as chromium VI.

d - Potential TAP emissions based on two heaters (303 MMBtu/hr per heater) and continuous operation (24 hrs/day and 8,760 hrs/yr).

e - Emission factors from Hansell and England, 1998 (EPA's Emissions Estimation Protocol for Petroleum Refineries, August 2014).

BP - Cherry Point

## Coker Heater Replacement Project - Coker Component Fugitive Emissions

Based on leak data for existing coker unit.

**Increase in Total Criteria Pollutant Emission Increases Attributable to Project**

**TOTAL Fugitive VOC EMISSIONS:**

| | | |
|---|---|---|
| Coker Heaters Fug. VOCs = | 0.99 tpy | |
| Other new compoenents (Lean Oil & Heat Exchangers) = | 0.10 tpy | Basis (10% of New Heaters and Heat Exchangers) |
| **Total Fug. VOCs =** | **1.09 tpy** | |

### New Coker Heaters Fugitive VOC Emission Rate Calculations

**Project Estimated Fugitive Emissions**

| Service | Component Type | Total Components [a] | Tons VOC/yr per component [b] | Tons VOC/yr |
|---|---|---|---|---|
| Gas | Connector | 2,210 | 2.35E-04 | 0.52 |
| Gas | PSV | 3 | 2.67E-04 | 8.0E-04 |
| Gas | Valve | 530 | 4.18E-04 | 0.22 |
| Gas | Instrumentation | 53 | 5.89E-04 | 3.1E-02 |
| Gas | Control Valve | 12 | 4.99E-05 | 6.0E-04 |
| Light Liquid | Connector | 42 | 1.86E-04 | 7.8E-03 |
| Light Liquid | Instrumentation | 8 | 2.17E-04 | 1.6E-03 |
| Light Liquid | Valve | 35 | 1.04E-04 | 3.6E-03 |
| Light Liquid | Control Valve | 2 | 4.15E-05 | 6.2E-05 |
| Heavy Liquid | Total | 945 | 2.17E-04 | 0.21 |
| **Total** | | **3,837** | | **0.99** |

a - Component counts for new coker heaters based on existing coker heater component counts with a conservative 50 percent increase in components.

b - Emission factors based upon historical data from existing coker heaters (2012 – 2013 average, Heavy Liquid service leak rates conservatively based on the highest Light Liquid leak rate).

### Coker Heater Fugitive GHG Emission Rate Calculations

- Based off 40 CFR Part 98, Subpart Y, Equation Y-21 for Equipment Leaks (based on 1 delayed coking unit).

Fugitive CH4 emissions = 0.2 tons CH4/yr

Converted to CO2e = 5.51 tons CO2e/yr basis: GWP for CH4 is 25

**New Coker Heaters Fugitive TAP Emission Rate Calculations**

| | | Gas [a] | Light Liquid [b] | Heavy Liquid [c] | Emission Rate [d] | | |
|---|---|---|---|---|---|---|---|
| | Number of Components [e] = | 3,087 | 94 | 1,040 | | | |
| **CAS** | **TAP** | **(lb/yr)** | **(lb/yr)** | **(lb/yr)** | **(lb/hr)** | **(lb/day)** | **(lb/yr)** |
| 106-99-0 | 1,3-Butadiene | 0.20 | - | - | 2.3E-05 | 5.5E-04 | 0.20 |
| 71-43-2 | Benzene | - | 0.40 | 0.0E+00 | 4.6E-05 | 1.1E-03 | 0.40 |
| 98-82-8 | Cumene | - | 0.02 | 0.60 | 7.1E-05 | 1.7E-03 | 0.62 |
| 110-82-7 | Cyclohexane | - | 0.81 | 0.91 | 2.0E-04 | 4.7E-03 | 1.72 |
| 111-42-2 | Diethanolamine | - | - | 0.44 | 5.0E-05 | 1.2E-03 | 0.44 |
| 100-41-4 | Ethylbenzene | - | 0.17 | 0.91 | 1.2E-04 | 3.0E-03 | 1.08 |
| 110-54-3 | Hexane | - | 1.33 | - | 1.5E-04 | 3.6E-03 | 1.33 |
| 7783-06-4 | Hydrogen Sulfide [f] | - | - | - | 2.5E-02 | 6.0E-01 | 218.1 |
| 91-20-3 | Naphthalene | - | 0.00 | 5.14 | 5.9E-04 | 1.4E-02 | 5.14 |
| 115-07-1 | Propylene | 17.20 | - | - | 2.0E-03 | 4.7E-02 | 17.20 |
| 108-88-3 | Toluene | - | 0.97 | 1.51 | 2.8E-04 | 6.8E-03 | 2.48 |
| 106-42-3 | Xylenes | - | 0.79 | 3.63 | 5.0E-04 | 1.2E-02 | 4.41 |

notes:

a - TAP emissions based on fuel gas emission factors from historical data - average when more than one.

b - TAP emissions based on nahptha emissions factors from historical data.

c - TAP emissions based on diesel and DEA emissions factors from historical data.

d - Total Emissions include the sum of Gas, Light Liquid, and Heavy Liquid Services. Short-term emission rates assume continuous operation (8,760 hours/yr).

e - New components based on VOC calculation above with a 10% increase to account for additional components.

f - Fugitive Hydrogen Sulfide emission rates based on VOC leak rate calculation and multiplied by an estimated 10% H2S concentration in fugitive streams.

## Old Coker Heaters Fugitive VOC Emission Rate Calculations

**Estimated Fugitive Emissions for Coker Heaters that will be removed**

| Service | Component Type | Total Components [a] | Tons VOC/yr per component [b] | Tons VOC/yr |
|---|---|---|---|---|
| Gas | Connector | 1,473 | 2.35E-04 | 0.35 |
| Gas | PSV | 2 | 2.67E-04 | 5.3E-04 |
| Gas | Valve | 353 | 4.18E-04 | 0.15 |
| Gas | Instrumentation | 35 | 5.89E-04 | 2.1E-02 |
| Gas | Control Valve | 8 | 4.99E-05 | 4.0E-04 |
| Light Liquid | Connector | 28 | 1.86E-04 | 5.2E-03 |
| Light Liquid | Instrumentation | 5 | 2.17E-04 | 1.1E-03 |
| Light Liquid | Valve | 23 | 1.04E-04 | 2.4E-03 |
| Light Liquid | Control Valve | 1 | 4.15E-05 | 4.1E-05 |
| Heavy Liquid | Total | 630 | 2.17E-04 | 0.14 |
| **Total** | | **2,558** | | **0.66** |

a - Component counts for existing coker heater component counts.
b - Emission factors based upon historical data from existing coker heaters (2012 – 2013 average), Heavy Liquid service leak rates conservatively based on the highest Light Liquid leak rate.

## Coker Heater Fugitive GHG Emission Rate Calculations

- Based off 40 CFR Part 98, Subpart Y, Equation Y-21 for Equipment Leaks (based on 1 delayed coking unit).

Fugitive CH4 emissions = 0.2 tons CH4/yr

Converted to CO2e = 5.51 tons CO2e/yr basis: GWP for CH4 is 25

**Existing Coker Heaters Fugitive TAP Emission Rate Calculations**

| | | **Gas [a]** | **Light Liquid [b]** | **Heavy Liquid [c]** | | | |
|---|---|---|---|---|---|---|---|
| | Number of Components= | 1,871 | 57 | 630 | **Emission Rate [d]** | | |
| **CAS** | **TAP** | **(lb/yr)** | **(lb/yr)** | **(lb/yr)** | **(lb/hr)** | **(lb/day)** | **(lb/yr)** |
| 106-99-0 | 1,3-Butadiene | 0.12 | - | - | 1.4E-05 | 3.3E-04 | 0.12 |
| 71-43-2 | Benzene | - | 0.24 | 0.0E+00 | 2.8E-05 | 6.7E-04 | 0.24 |
| 98-82-8 | Cumene | - | 0.01 | 0.37 | 4.3E-05 | 1.0E-03 | 0.38 |
| 110-82-7 | Cyclohexane | - | 0.49 | 0.55 | 1.2E-04 | 2.9E-03 | 1.04 |
| 111-42-2 | Diethanolamine | - | - | 0.27 | 3.0E-05 | 7.3E-04 | 0.27 |
| 100-41-4 | Ethylbenzene | - | 0.10 | 0.55 | 7.5E-05 | 1.8E-03 | 0.65 |
| 110-54-3 | Hexane | - | 0.81 | - | 9.2E-05 | 2.2E-03 | 0.81 |
| 7783-06-4 | Hydrogen Sulfide [e] | - | - | - | 1.5E-02 | 3.6E-01 | 132.2 |
| 91-20-3 | Naphthalene | - | 0.00 | 3.11 | 3.6E-04 | 8.5E-03 | 3.11 |
| 115-07-1 | Propylene | 10.42 | - | - | 1.2E-03 | 2.9E-02 | 10.42 |
| 108-88-3 | Toluene | - | 0.59 | 0.92 | 1.7E-04 | 4.1E-03 | 1.50 |
| 106-42-3 | Xylenes | - | 0.48 | 2.20 | 3.1E-04 | 7.3E-03 | 2.67 |

notes:
a - TAP emissions based on fuel gas emission factors from historical data - average when more than one.
b - TAP emissions based on nahptha emissions factors from historical data.
c - TAP emissions based on emissions factors from historical data for components in heavy liquid service.
d - Total Emissions include the sum of Gas, Light Liquid, and Heavy Liquid Services. Short-term emission rates assume continuous operation (8,760 hours/yr).
e - Fugitive Hydrogen Sulfide emission rates based on VOC leak rate calculation and multiplied by an estimated 10% H2S concentration in fugitive streams.

**BP Cherry Point Toxic Contributions by Stream - Historical Data (2003)**

| Speciation Class | Corresponding Service[a] | VOC (TPY) | % by weight | lb/year | Component Count | lb/component/ year |
|---|---|---|---|---|---|---|
| Total VOC | | | | 8,180 | | |
| Total VOC | | 4.09 | 100 | 8,180 | 3,671 | 2.2 |
| 1,2,4-TRIMETHYLBENZENE | | | | 16.7 | | |
| DIESEL | HL | 3.79 | 0.22 | 16.7 | 2,609 | 6.40E-03 |
| NAPH | LL | 0.02 | 0.12 | 0.05 | 211 | 2.54E-04 |
| 1,3-BUTADIENE | | | | 0.1 | | |
| AVERAGE FUELGAS + F | Gas | | | | | 3.24E-05 |
| FUELGAS | | 0.06 | 0.05 | 0.1 | 851 | 6.48E-05 |
| LPFLARE | | 0.00 | 0 | 0.0 | 851 | 0.00E+00 |
| 2,2,4-TRIMETHYLPENTANE | | | | 0.8 | | |
| DIESEL | HL | 3.79 | 0.01 | 0.8 | 2,609 | 2.91E-04 |
| NAPH | LL | 0.02 | 0.09 | 0.0 | 211 | 1.91E-04 |
| BENZENE | | | | 0.9 | | |
| DIESEL | HL | 0.65 | 0 | 0.0 | 2,609 | 0.00E+00 |
| NAPH | LL | 0.02 | 2.01 | 0.9 | 211 | 4.26E-03 |
| CRESOL (ALL ISOMERS) | | | | 3.8 | | |
| DIESEL | HL | 3.79 | 0.05 | 3.8 | 2,609 | 1.45E-03 |
| CUMENE | | | | 1.6 | | |
| DIESEL | HL | 3.79 | 0.02 | 1.5 | 2,609 | 5.81E-04 |
| NAPH | LL | 0.02 | 0.08 | 0.0 | 211 | 1.70E-04 |
| CYCLOHEXANE | | | | 4.1 | | |
| DIESEL | HL | 3.79 | 0.03 | 2.3 | 2,609 | 8.72E-04 |
| NAPH | LL | 0.02 | 4.07 | 1.8 | 211 | 8.62E-03 |
| DIETHANOLAMINE | | | | 1.1 | | |
| DEA | HL | 0.00 | 100 | 1.1 | 2,609 | 4.23E-04 |
| ETHYLBENZENE | | | | 2.7 | | |
| DIESEL | HL | 3.79 | 0.03 | 2.3 | 2,609 | 8.72E-04 |
| NAPH | LL | 0.02 | 0.86 | 0.4 | 211 | 1.82E-03 |
| ETHYLENE | | | | 1.0 | | |
| AVERAGE FUELGAS + F | Gas | | | | | 3.98E-04 |
| FUELGAS | | 0.06 | 0.9 | 1.0 | 851 | 1.17E-03 |
| HPFLARE | | 0.00 | 0.14 | 0.0 | 851 | 1.12E-05 |
| LPFLARE | | 0.00 | 0.37 | 0.0 | 851 | 1.63E-05 |
| HEXANE | | | | 3.0 | | |
| NAPH | LL | 0.02 | 6.68 | 3.0 | 211 | 1.42E-02 |
| HYDROGEN SULFIDE | | | | 0.1 | | |
| AVERAGE FLARES | Gas | | | | | 7.25E-05 |
| HPFLARE | | 0.00 | 0.93 | 0.1 | 851 | 7.43E-05 |
| LPFLARE | | 0.00 | 1.61 | 0.1 | 851 | 7.07E-05 |
| NAPHTHALENE | | | | 12.9 | | |
| DIESEL | HL | 3.79 | 0.17 | 12.9 | 2,609 | 4.94E-03 |
| NAPH | LL | 0.02 | 0 | 0.0 | 211 | 0.00E+00 |
| PROPYLENE (PROPENE) | | | | 4.8 | | |
| AVERAGE FUELGAS + F | Gas | | | | | 1.90E-03 |
| FUELGAS | | 0.06 | 4.3 | 4.7 | 851 | 5.57E-03 |
| HPFLARE | | 0.00 | 0.57 | 0.0 | 851 | 4.55E-05 |
| LPFLARE | | 0.00 | 1.65 | 0.1 | 851 | 7.25E-05 |
| TOLUENE | | | | 6.0 | | |
| DIESEL | HL | 3.79 | 0.05 | 3.8 | 2,609 | 1.45E-03 |
| NAPH | LL | 0.02 | 4.87 | 2.2 | 211 | 1.03E-02 |
| XYLENES | | | | 10.9 | | |
| DIESEL | HL | 3.79 | 0.12 | 9.1 | 2,609 | 3.49E-03 |
| NAPH | LL | 0.02 | 3.95 | 1.8 | 211 | 8.37E-03 |

**Notes:**
[a] Service types limited to gas, light liquid (LL) and heavy liquid (HL).

BP - Cherry Point

## Coker Heater Replacement Project - Coke Drum Venting, Cutting, and Water Handling Emissions

### This spreadsheet identifies the increase in coke drum venting emissions

| | | |
|---|---|---|
| Current Average Coker Feed Rate | 50.6 kbpd | BP historical records for coker unit |
| Projected Coker Feed Rate | 61.9 kbpd | BP projection |
| | 22% | Increase |

### Criteria and PSD Pollutant Emissions

| Year | CO [a] (tpy) | PM/PM10/PM2.5 [a] (tpy) | VOC [a] (tpy) | CH4 [a] (tpy) | CO2e [b] (tpy) | H2S [a] (tpy) |
|---|---|---|---|---|---|---|
| 2003 | 1.1 | 5.6 | 16.3 | 77 | 1,917 | 11.3 |
| 2004 | 1.0 | 5.2 | 15.0 | 71 | 1,770 | 10.4 |
| 2005 | 1.0 | 5.2 | 14.9 | 70 | 1,756 | 10.3 |
| 2006 | 1.0 | 5.0 | 14.4 | 68 | 1,695 | 10.0 |
| 2007 | 1.0 | 5.0 | 14.3 | 68 | 1,688 | 9.9 |
| 2008 | 1.0 | 5.2 | 14.9 | 70 | 1,755 | 10.3 |
| 2009 | 1.0 | 5.7 | 14.9 | 71 | 1,771 | 10.4 |
| 2010 | 1.7 | 4.2 | 12.0 | 72 | 1,789 | 10.5 |
| 2011 | 0.4 | 2.2 | 12.6 | 66 | 1,659 | 9.8 |
| 2012 | 0.0 | 2.0 | 12.0 | 61 | 1,523 | 9.0 |
| 2013 | 0.5 | 2.7 | 16.1 | 68 | 1,698 | 6.6 |
| 2014 | 0.4 | 2.4 | 14.0 | 59 | 1,483 | 5.9 |
| Baseline Actual Emission | 1.0 | 3.2 | 14.1 | -- | 1,724 | 7.8 |
| Baseline Period | 2010-2011 | 2010-2011 | 2012-2013 | -- | 2010-2011 | 2012-2013 |
| Excludable Emissions [c] | 0.0 | 2.6 | 0.9 | -- | 46.4 | 2.6 |
| BAE + Excludable | 1.0 | 5.7 | 14.9 | -- | 1,771 | 10.4 |
| Projected Emissions [d] | 2.1 | 10.6 | 29.1 | 146.3 | 3,664 | 14.4 |
| Emission Increase | 1.1 | 4.9 | 14.2 | -- | 1,893 | 4.0 |

a - Annual emissions are based on BP's annual actual emission reporting and updated based on latest coke drum venting emission information.

b - CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).

c - Excludable emissions are calculated based on maximum baseline year with highest green coke production (2009) minus baseline actual emissions. No excludeable emissions for H2S because baseline already includes excludable period.

d - Projected actual emissions are based on BP calculations for coker blowdown emissions at less than 5 psig pressure release.

BP - Cherry Point

## Coker Heater Replacement Project - Coke Handling Emissions

**This spreadsheet identifies total increase in emissions of criteria pollutants attributable to increased green coke production.**

### Criteria and PSD Pollutant Emissions

**Baseline Information for Coke Handling**

| Year | Calciner 1 & 2 (tons/yr) Green coke | Calciner 3 (tons/yr) Green coke | |
|---|---|---|---|
| 2003 | 743,175 | 658,267 | |
| 2004 | 741,530 | 670,430 | |
| 2005 | 763,564 | 694,529 | |
| 2006 | 763,148 | 583,980 | |
| 2007 | 758,288 | 545,043 | |
| 2008 | 745,193 | 692,378 | |
| 2009 | 775,555 | 562,255 | |
| 2010 | 748,759 | 543,949 | |
| 2011 | 658,142 | 457,352 | |
| 2012 | 418,765 | 296,860 | |
| 2013 | 678,250 | 493,482 | |
| 2014 | 575,781 | 410,675 | |
| Projected Actual | 948,752 | 849,631 | 1,798,383 Total |

| Year | Baseline Annual Emissions (tpy PM | PM10 | PM2.5 |
|---|---|---|---|
| 2005 | 18.0 | 17.9 | 17.9 |
| 2006 | 18.0 | 17.9 | 17.9 |
| 2007 | 20.9 | 19.0 | 18.1 |
| 2008 | 20.9 | 19.0 | 18.1 |
| 2009 | 20.7 | 18.9 | 18.1 |
| 2010 | 21.0 | 19.0 | 18.1 |
| 2011 | 20.7 | 18.9 | 18.1 |
| 2012 | 19.0 | 18.3 | 18.0 |
| 2013 | 21.0 | 19.0 | 18.1 |
| 2014 | 21.0 | 19.0 | 18.1 |
| Baseline Actual Emissions (tpy) | 18.0 | 17.9 | 17.9 |
| Projected Actual Emissions (tpy) | 21.5 | 19.2 | 18.1 |
| Emission Increase (tpy) | 3.5 | 1.2 | 0.2 |

Notes:
Green Coke Handling based on AP-42 13.2.4, Equation 1 (11/06) for transfer of green coke.
Calcined Coke Handling = 17.9 tons/yr (potential emissions from baghouses)
Projected actual green coke handling based on highest throughput rate (2003 - 2014) plus a 22% increase.
Projected Actual Emissions based on 17.9 tpy (PTE for coke handling baghouses) + projected green coke production multiplied by PM, PM10, or PM2.5 drop equation emission factors and two material transfer points.

BP - Cherry Point
**Coker Heater Replacement Project - Calciner Emissions**

**This spreadsheet identifies total increase in emissions of criteria pollutants attributable to increased utilization of the calciner**

## Criteria and PSD Pollutant Emissions

**Baseline Heat Input for Calciners**

| | Calciner 1 & 2 | | | Calciner 3 (tons/yr) | | |
|---|---|---|---|---|---|---|
| | Fuel Usage (MMBtu/yr) | Green Coke (tons/yr) | Calcined Coke (tons/yr) | Fuel Usage (MMBtu/yr) | Green Coke (tons/yr) | Calcined Coke (tons/yr) |
| 2005 | 0 | 763,564 | 534,495 | 0 | 694,529 | 486,127 |
| 2006 | 0 | 763,148 | 534,204 | 0 | 583,980 | 408,749 |
| 2007 | 0 | 758,288 | 530,802 | 0 | 545,043 | 381,496 |
| 2008 | 58,398 | 745,193 | 521,635 | 21,706 | 692,378 | 484,621 |
| 2009 | 67,137 | 775,555 | 542,889 | 53,895 | 562,255 | 393,543 |
| 2010 | 40,810 | 748,759 | 524,132 | 115,324 | 543,949 | 380,730 |
| 2011 | 84,058 | 658,142 | 460,700 | 84,422 | 457,352 | 320,117 |
| 2012 | 436,807 | 418,765 | 296,860 | 88,507 | 488,636 | 346,391 |
| 2013 | 51,969 | 678,250 | 493,482 | 139,390 | 463,336 | 337,377 |
| 2014 | 58,244 | 575,781 | 410,675 | 110,624 | 521,690 | 373,468 |
| Projected Actual (Calciner Capacity) | | 951,084 | 665,760 | | 813,503 | 569,400 |

| **Capable of Accomodating Coke Production Rates** | **Calciner 1 & 2** | **Calciner 3** |
|---|---|---|
| Highest two-month average calciner production rate (tons/day) | 1,516 | 1,471 |
| Time period for highest two-month average | Aug. 2006 - Sept. 2006 | Nov. 2005 - Dec. 2005 |
| Two-month average calculated for year (tons/yr) | 553,362 | 537,025 |

**Baseline Emissions and Projected Actual Emissions for Calciners**

| **NOx Emission Increase** | **Calciner 1 & 2 [a]** | **Calciner 3 [a]** | **Total** | |
|---|---|---|---|---|
| 2005 Emissions (tpy) | 333.0 | 207.0 | 540.0 | |
| 2006 Emissions (tpy) | 338.0 | 219.0 | 557.0 | |
| 2007 Emissions (tpy) | 328.7 | 185.2 | 514.0 | |
| 2008 Emissions (tpy) | 299.8 | 320.4 | 620.2 | |
| 2009 Emissions (tpy) | 293.8 | 193.5 | 487.3 | |
| 2010 Emissions (tpy) | 317.9 | 262.1 | 580.0 | |
| 2011 Emissions (tpy) | 359.8 | 182.0 | 541.8 | |
| 2012 Emissions (tpy) | 253.0 | 272.0 | 525.0 | |
| 2013 Emissions (tpy) | 313.0 | 198.0 | 511.0 | |
| 2014 Emissions (tpy) | 265.0 | 236.0 | 501.0 | |
| Baseline Actual Emissions (tpy) [b] | 306.4 | 227.0 | 567.1 | baseline period 2011-2012 |
| BAE Average Calcined Coke (tpy) [b] | 378,780 | 333,254 | -- | |
| COA Calcined Coke (tpy) [c] | 553,362 | 537,025 | -- | |
| Excludable Emissions (tpy) [d] | 141.2 | 138.8 | -- | |
| BAE + Excludable (tpy) | 447.6 | 365.8 | -- | |
| Projected Calcined Coke (tpy) [e] | 665,760 | 569,400 | -- | |
| NOx EF (lb/ton calcined coke) [e] | -- | 1.57 | -- | |
| Projected Emissions (tpy) [e] | 509.0 | 447.1 | -- | |
| NOx Emission Increase (tpy) [f] | 61.4 | 81.4 | 142.7 | |

a - NOx emissions for Calciner 1, 2, and 3 are based on annual actual emission reporting.
b - Baseline actual emissions (BAE) is the annual average emissions from 2011-2012. Annual average calcined coke production during baseline period.

c - Calciners are capable of accomodating (COA): 553,362 tons calcined coke/yr (Calciners 1 & 2) and 537,025 tons calcined coke/yr (Calciner 3) based on highest 2-month calciner production rates extrapolated to annual throughput rates. These COA rates are unrelated to the Coker Heater Project and could have been accomodated during the baselien period.

d - Excludable emissions are calculated by scaling the baseline actual emissions using the ratio of baseline COA coke production to BAE coke production. Example: 306.4 tpy BAE X (553,362 tpy COA / 378,780 tpy BAE) - 306.4 tpy BAE = 141.2 tpy excludable emissions.
e - Project actual emissions from Calciner 1 & 2 based on potential NOx emission limit (509 tpy) and Calciner 3 emissions are based on calciner capacity. Emission factor is based on the maximum emission factor (lb pollutant/ton calcined coke) from the 10-year lookback period.
f - Project emission increase is Projected Actual Emissiosn minus (Baseline Actual Emissions + Excludable Emissions).

| CO Emission Increase | Calciner 1 & 2 [a] | Calciner 3 [a] | Total | |
|---|---|---|---|---|
| 2005 Emissions (tpy) | 6.0 | 6.0 | 12.0 | |
| 2006 Emissions (tpy) | 7.0 | 5.0 | 12.0 | |
| 2007 Emissions (tpy) | 6.8 | 5.0 | 11.7 | |
| 2008 Emissions (tpy) | 6.3 | 6.7 | 13.0 | |
| 2009 Emissions (tpy) | 6.7 | 5.0 | 11.7 | |
| 2010 Emissions (tpy) | 6.6 | 5.3 | 11.9 | |
| 2011 Emissions (tpy) | 6.5 | 4.3 | 10.9 | |
| 2012 Emissions (tpy) | 4.2 | 4.9 | 9.1 | |
| 2013 Emissions (tpy) | 7.0 | 4.8 | 11.8 | |
| 2014 Emissions (tpy) | 5.8 | 5.3 | 11.1 | |
| Baseline Actual Emissions (tpy) [b] | 6.6 | 4.8 | 12.3 | baseline period 2010-2011 |
| BAE Average Calcined Coke (tpy) [b] | 492,416 | 350,424 | -- | |
| COA Calcined Coke (tpy) [c] | 553,362 | 537,025 | -- | |
| Excludable Emissions (tpy) [d] | 0.8 | 2.6 | -- | |
| BAE + Excludable (tpy) | 7.4 | 7.4 | -- | |
| Projected Calcined Coke (tpy) [e] | 665,760 | 569,400 | -- | |
| CO EF (lb/ton calcined coke) [e] | 0.0284 | 0.0284 | -- | |
| Projected Emissions (tpy) [e] | 9.4 | 8.1 | -- | |
| CO Emission Increase (tpy) [f] | 2.0 | 0.7 | 2.7 | |

a - COx emissions for Calciner 1, 2, and 3 are based on annual actual emission reporting.
b - Baseline actual emissions (BAE) is the annual average emissions from 2010-2011. Annual average calcined coke production during baseline period.
c - Calciners are capable of accomodating (COA): 553,362 tons calcined coke/yr (Calciners 1 & 2) and 537,025 tons calcined coke/yr (Calciner 3) based on highest 2-month calciner production rates extrapolated to annual throughput rates. These COA rates are unrelated to the Coker Heater Project and could have been accomodated during the baselien period.

d - Excludable emissions are calculated by scaling the baseline actual emissions using the ratio of baseline COA coke production to BAE coke production. Example: 6.6 tpy BAE X (553,362 tpy COA / 492,416 tpy BAE) - 6.6 tpy BAE = 0.8 tpy excludable emissions.
e - Project actual emissions based on calciner capacity. Emission factor is based on the average from November 2013 testing of Calciner 3.
f - Project emission increase is Projected Actual Emissiosn minus (Baseline Actual Emissions + Excludable Emissions).

| SO2 Emission Increase | Calciner 1 & 2 [a] | Calciner 3 [a] | Total | |
|---|---|---|---|---|
| 2005 Emissions (tpy) | 15.0 | 140.0 | 155.0 | |
| 2006 Emissions (tpy) | 11.0 | 81.0 | 92.0 | |
| 2007 Emissions (tpy) | 16.3 | 100.1 | 116.4 | |
| 2008 Emissions (tpy) | 15.9 | 223.7 | 239.6 | |
| 2009 Emissions (tpy) | 16.4 | 141.0 | 157.3 | |
| 2010 Emissions (tpy) | 15.8 | 182.2 | 198.0 | |
| 2011 Emissions (tpy) | 23.1 | 138.1 | 161.1 | |
| 2012 Emissions (tpy) | 14.4 | 153.4 | 167.8 | |
| 2013 Emissions (tpy) | 29.0 | 163.1 | 192.1 | |
| 2014 Emissions (tpy) | 23.7 | 222.8 | 246.5 | |
| Baseline Actual Emissions (tpy) [b] | 16.1 | 182.3 | 198.5 | baseline period 2008-2009 |
| BAE Average Calcined Coke (tpy) [b] | 532,262 | 439,082 | -- | |
| COA Calcined Coke (tpy) [c] | 553,362 | 537,025 | -- | |
| Excludable Emissions (tpy) [d] | 0.6 | 40.7 | -- | |
| BAE + Excludable (tpy) | 16.8 | 223.0 | -- | |
| Projected Calcined Coke (tpy) [e] | 665,760 | 569,400 | -- | |
| SO2 EF (lb/ton calcined coke) [e] | 0.12 | 1.12 | -- | |
| Projected Emissions (tpy) [e] | 39.1 | 320.0 | -- | |
| SO2 Emission Increase (tpy) [f] | 22.3 | 97.0 | 119.3 | |

a - SO2 emissions for Calciner 1, 2, and 3 are based on annual actual emission reporting.
b - Baseline actual emissions (BAE) is the annual average emissions from 2008-2009. Annual average calcined coke production during baseline period.
c - Calciners are capable of accomodating (COA): 553,362 tons calcined coke/yr (Calciners 1 & 2) and 537,025 tons calcined coke/yr (Calciner 3) based on highest 2-month calciner production rates extrapolated to annual throughput rates. These COA rates are unrelated to the Coker Heater Project and could have been accomodated during the baselien period.

d - Excludable emissions are calculated by scaling the baseline actual emissions using the ratio of baseline COA coke production to BAE coke production. Example: 16.1 tpy BAE X (553,362 tpy COA / 532,262 tpy BAE) - 16.1 tpy BAE = 0.6 tpy excludable emissions.
e - Project actual emissions based on calciner capacity. Emission factors are based on the maximum emission factor (lb pollutant/ton calcined coke) from the 10-year lookback period. Calciner 2 emission factor based on 1.12 lb SO2/ton calcined coke (conservative estimate for projected emissions).
f - Project emission increase is Projected Actual Emissiosn minus (Baseline Actual Emissions + Excludable Emissions).

| PM/PM10/PM2.5 Emission Increase | Calciner 1 & 2 [a] | Calciner 3 [a] | Total | |
|---|---|---|---|---|
| 2005 Emissions (tpy) | 4.0 | 8.0 | 12.0 | |
| 2006 Emissions (tpy) | 4.0 | 8.0 | 12.0 | |
| 2007 Emissions (tpy) | 3.8 | 7.2 | 11.0 | |
| 2008 Emissions (tpy) | 3.5 | 6.1 | 9.6 | |
| 2009 Emissions (tpy) | 3.8 | 9.3 | 13.1 | |
| 2010 Emissions (tpy) | 3.7 | 13.7 | 17.5 | |
| 2011 Emissions (tpy) | 3.7 | 9.5 | 13.2 | |
| 2012 Emissions (tpy) | 2.4 | 7.3 | 9.7 | |
| 2013 Emissions (tpy) | 3.9 | 6.6 | 10.5 | |
| 2014 Emissions (tpy) | 3.3 | 10.8 | 14.1 | |
| Baseline Actual Emissions (tpy) [b] | 3.7 | 11.6 | 12.0 | baseline period 2010-2011 |
| BAE Average Calcined Coke (tpy) [b] | 492,416 | 350,424 | -- | |
| COA Calcined Coke (tpy) [c] | 553,362 | 537,025 | -- | |
| Excludable Emissions (tpy) [d] | 0.5 | 6.2 | -- | |
| BAE + Excludable (tpy) | 4.2 | 17.8 | -- | |
| Projected Calcined Coke (tpy) [e] | 665,760 | 569,400 | -- | |
| Particulate EF (lb/ton calcined coke) | 0.02 | 0.07 | -- | |
| Projected Emissions (tpy) [e] | 5.4 | 20.5 | -- | |
| Particulate Emission Increase (tpy) [f] | 1.2 | 2.7 | 3.9 | |

a - Particulate emissions for Calciner 1, 2, and 3 are based on annual actual emission reporting.
b - Baseline actual emissions (BAE) is the annual average emissions from 2010-2011. Annual average calcined coke production during baseline period.
c - Calciners are capable of accomodating (COA): 553,362 tons calcined coke/yr (Calciners 1 & 2) and 537,025 tons calcined coke/yr (Calciner 3) based on highest 2-month calciner production rates extrapolated to annual throughput rates. These COA rates are unrelated to the Coker Heater Project and could have been accomodated during the baselien period.

d - Excludable emissions are calculated by scaling the baseline actual emissions using the ratio of baseline COA coke production to BAE coke production. Example: 3.7 tpy BAE X (553,362 tpy COA / 492,416 tpy BAE) - 3.7 tpy BAE = 0.5 tpy excludable emissions.
e - Project actual emissions based on calciner capacity. Emission factor is based on the maximum emission factor (lb pollutant/ton calcined coke) from the 10-year lookback period.
f - Project emission increase is Projected Actual Emissiosn minus (Baseline Actual Emissions + Excludable Emissions).

| VOC Emission Increase | Calciner 1 & 2 [a] | Calciner 3 [a] | Total | |
|---|---|---|---|---|
| 2005 Emissions (tpy) | 0.7 | 0.6 | 1.3 | |
| 2006 Emissions (tpy) | 0.7 | 0.6 | 1.3 | |
| 2007 Emissions (tpy) | 0.7 | 0.5 | 1.3 | |
| 2008 Emissions (tpy) | 0.7 | 0.7 | 1.4 | |
| 2009 Emissions (tpy) | 0.7 | 0.5 | 1.3 | |
| 2010 Emissions (tpy) | 0.7 | 0.6 | 1.3 | |
| 2011 Emissions (tpy) | 0.7 | 0.5 | 1.1 | |
| 2012 Emissions (tpy) | 0.4 | 0.5 | 1.0 | |
| 2013 Emissions (tpy) | 0.7 | 0.5 | 1.2 | |
| 2014 Emissions (tpy) | 0.6 | 0.6 | 1.2 | |
| Baseline Actual Emissions (tpy) [b] | 0.6 | 0.5 | 1.3 | baseline period 2012-2013 |
| BAE Average Calcined Coke (tpy) [b] | 395,171 | 341,884 | -- | |
| COA Calcined Coke (tpy) [c] | 553,362 | 537,025 | -- | |
| Excludable Emissions (tpy) [d] | 0.2 | 0.3 | -- | |
| BAE + Excludable (tpy) | 0.8 | 0.8 | -- | |
| Projected Calcined Coke (tpy) [e] | 665,760 | 569,400 | -- | |
| VOC EF (lb/ton calcined coke) [e] | 0.003 | 0.003 | -- | |
| Projected Emissions (tpy) [e] | 1.0 | 0.9 | -- | |
| VOC Emission Increase (tpy) [f] | 0.2 | 0.1 | 0.2 | |

a - VOC emissions for Calciner 1, 2, and 3 are based on annual actual emission reporting.
b - Baseline actual emissions (BAE) is the annual average emissions from 2012-2013. Annual average calcined coke production during baseline period.
c - Calciners are capable of accomodating (COA): 553,362 tons calcined coke/yr (Calciners 1 & 2) and 537,025 tons calcined coke/yr (Calciner 3) based on highest 2-month calciner production rates extrapolated to annual throughput rates. These COA rates are unrelated to the Coker Heater Project and could have been accomodated during the baselien period.

d - Excludable emissions are calculated by scaling the baseline actual emissions using the ratio of baseline COA coke production to BAE coke production. Example: 0.6 tpy BAE X (553,362 tpy COA / 395,171 tpy BAE) - 0.6 tpy BAE = 0.2 tpy excludable emissions.
e - Project actual emissions based on calciner capacity. Emission factor is based on the maximum emission factor (lb pollutant/ton calcined coke) from the 10 year lookback period.
f - Project emission increase is Projected Actual Emissiosn minus (Baseline Actual Emissions + Excludable Emissions).

| Pb Emission Increase | Calciner 1 & 2 [a] | Calciner 3 [a] | Total | |
|---|---|---|---|---|
| 2005 Emissions (tpy) | 0.02 | 0.02 | 0.05 | |
| 2006 Emissions (tpy) | 0.02 | 0.02 | 0.04 | |
| 2007 Emissions (tpy) | 0.02 | 0.02 | 0.04 | |
| 2008 Emissions (tpy) | 0.02 | 0.02 | 0.04 | |
| 2009 Emissions (tpy) | 0.02 | 0.02 | 0.04 | |
| 2010 Emissions (tpy) | 0.02 | 0.02 | 0.04 | |
| 2011 Emissions (tpy) | 0.02 | 0.01 | 0.03 | |
| 2012 Emissions (tpy) | 0.01 | 0.02 | 0.03 | |
| 2013 Emissions (tpy) | 0.02 | 0.01 | 0.04 | |
| 2014 Emissions (tpy) | 0.02 | 0.02 | 0.03 | |
| Baseline Actual Emissions (tpy) [b] | 0.02 | 0.02 | 0.04 | baseline period 2010-2011 |
| Pb EF (lb/ton Green Coke) [a] | 6.2E-05 | 6.2E-05 | -- | |
| BAE Average Calcined Coke (tpy) [b] | 492,416 | 350,424 | -- | |
| COA Calcined Coke (tpy) [c] | 553,362 | 537,025 | -- | |
| Excludable Emissions (tpy) [d] | 2.7E-03 | 8.3E-03 | -- | |
| BAE + Excludable (tpy) | 2.5E-02 | 2.4E-02 | -- | |
| Projected Calcined Coke (tpy) [e] | 665,760 | 569,400 | -- | |
| Pb EF (lb/ton calcined coke) [e] | 8.9E-05 | 8.9E-05 | -- | |
| Projected Emissions (tpy) [e] | 2.9E-02 | 2.5E-02 | -- | |
| Pb Emission Increase (tpy) [f] | 5.0E-03 | 1.4E-03 | 6.4E-03 | |

a - Pb emissions for Calciner 1, 2, and 3 are based on annual fuel use records and lead emission factor based on emission factor from API WSPA August 1998.

b - Baseline actual emissions (BAE) is the annual average emissions from 2010-2011. Annual average calcined coke production during baseline period.

c - Calciners are capable of accomodating (COA): 553,362 tons calcined coke/yr (Calciners 1 & 2) and 537,025 tons calcined coke/yr (Calciner 3) based on highest 2-month calciner production rates extrapolated to annual throughput rates. These COA rates are unrelated to the Coker Heater Project and could have been accomodated during the baselien period.

d - Excludable emissions are calculated by scaling the baseline actual emissions using the ratio of baseline COA coke production to BAE coke production. Example: 0.022 tpy BAE X (553,362 tpy COA / 492,416 tpy BAE) - 0.022 tpy BAE = 0.003 tpy excludable emissions.

e - Project actual emissions based on calciner capacity. Emission factor is based on the maximum emission factor (lb pollutant/ton calcined coke) from the 10-year lookback period.

f - Project emission increase is Projected Actual Emissiosn minus (Baseline Actual Emissions + Excludable Emissions).

| H2SO4 Emission Increase | Calciner 1 & 2 [a] | Calciner 3 [a] | Total | |
|---|---|---|---|---|
| 2005 Emissions (tpy) | 8.6 | 10.8 | 19.4 | |
| 2006 Emissions (tpy) | 8.4 | 10.7 | 19.0 | |
| 2007 Emissions (tpy) | 8.4 | 10.2 | 18.6 | |
| 2008 Emissions (tpy) | 4.1 | 15.8 | 19.9 | |
| 2009 Emissions (tpy) | 9.4 | 8.9 | 18.3 | |
| 2010 Emissions (tpy) | 16.1 | 12.7 | 28.8 | |
| 2011 Emissions (tpy) | 11.5 | 21.5 | 33.0 | |
| 2012 Emissions (tpy) | 2.5 | 4.5 | 7.0 | |
| 2013 Emissions (tpy) | 4.2 | 13.5 | 17.7 | |
| 2014 Emissions (tpy) | 23.2 | 22.8 | 46.0 | |
| Baseline Actual Emissions (tpy) [b] | 13.7 | 18.1 | 19.2 | baseline period 2013-2014 |
| BAE Average Calcined Coke (tpy) [b] | 452,079 | 355,423 | -- | |
| COA Calcined Coke (tpy) [c] | 553,362 | 537,025 | -- | |
| Excludable Emissions (tpy) [d] | 3.1 | 9.3 | -- | |
| BAE + Excludable (tpy) | 16.8 | 27.4 | -- | |
| Projected Calcined Coke (tpy) [e] | 665,760 | 569,400 | -- | |
| H2SO4 EF (lb/ton calcined coke) [e] | 0.11 | 0.13 | -- | |
| Projected Emissions (tpy) [e] | 37.6 | 38.3 | -- | |
| H2SO4 Emission Increase (tpy) [f] | 20.8 | 10.9 | 31.8 | |

a - H2SO4 emissions based on source testing of calciner stacks.

b - Baseline actual emissions (BAE) is the annual average emissions from 2013-2014. Annual average calcined coke production during baseline period.

c - Calciners are capable of accomodating (COA): 553,362 tons calcined coke/yr (Calciners 1 & 2) and 537,025 tons calcined coke/yr (Calciner 3) based on highest 2-month calciner production rates extrapolated to annual throughput rates. These COA rates are unrelated to the Coker Heater Project and could have been accomodated during the baselien period.

d - Excludable emissions are calculated by scaling the baseline actual emissions using the ratio of baseline COA coke production to BAE coke production. Example: 13.7 tpy BAE X (553,362 tpy COA / 452,079 tpy BAE) - 13.7 tpy BAE = 3.1 tpy excludable emissions.

e - Project actual emissions based on calciner capacity. Emission factor is based on the maximum emission factor (lb pollutant/ton calcined coke) from the 10-year lookback period.

f - Project emission increase is Projected Actual Emissiosn minus (Baseline Actual Emissions + Excludable Emissions).

| GHG Emission Increase | Calciner 1 & 2 [a] | Calciner 3 [a] | Total | |
|---|---|---|---|---|
| 2005 CO2 Emissions (tpy) | 687,655 | 625,635 | 1,313,289 | |
| 2006 CO2 Emissions (tpy) | 687,279 | 526,054 | 1,213,333 | |
| 2007 CO2 Emissions (tpy) | 682,902 | 490,978 | 1,173,880 | |
| 2008 CO2 Emissions (tpy) | 671,111 | 623,699 | 1,294,810 | |
| 2009 CO2 Emissions (tpy) | 698,452 | 506,483 | 1,204,936 | |
| 2010 CO2 Emissions (tpy) | 674,320 | 489,993 | 1,164,313 | |
| 2011 CO2 Emissions (tpy) | 592,712 | 411,988 | 1,004,699 | |
| 2012 CO2 Emissions (tpy) | 364,091 | 424,840 | 788,931 | |
| 2013 CO2 Emissions (tpy) | 545,313 | 371,603 | 916,916 | |
| 2014 CO2 Emissions (tpy) | 491,827 | 440,814 | 932,640 | |
| Baseline Actual CO2 Emissions (tpy) | 633,516 | 450,990 | 1,263,311 | baseline period 2010-2011 |
| BAE Average Calcined Coke (tpy) [b] | 492,416 | 350,424 | -- | |
| COA Calcined Coke (tpy) [c] | 553,362 | 537,025 | -- | |
| Excludable CO2 Emissions (tpy) [d] | 78,409.2 | 240,153.9 | -- | |
| BAE + Excludable CO2 (tpy) | 711,925 | 691,144 | -- | |
| Projected Calcined Coke (tpy) [e] | 665,760 | 569,400 | -- | |
| Projected Green Coke (tpy) [e] | 951,084 | 813,503 | -- | |
| Projected CO2 Emissions (tpy) [e] | 854,987 | 731,493 | -- | |
| CO2 Emission Increase (tpy) [f] | 143,063 | 40,349 | 183,411 | |
| CO2e Emission Increase (tpy) [g] | 143,417 | 40,449 | 183,866 | |

a - GHG emissions based on mass balance of carbon in (green coke) minus carbon out (calcined coke and coke dust) assuming same average carbon contents from 2013 green coke and calcined coke testing. Assume 0.9% of green coke is captured as calcined dust. 40 CFR Part 98, Subpart Y, Equation Y-13

b - Baseline actual emissions (BAE) is the annual average emissions from 2010-2011. Annual average calcined coke production during baseline period.

c - Calciners are capable of accomodating (COA): 553,362 tons calcined coke/yr (Calciners 1 & 2) and 537,025 tons calcined coke/yr (Calciner 3) based on highest 2-month calciner production rates extrapolated to annual throughput rates. These COA rates are unrelated to the Coker Heater Project and could have been accomodated during the baselien period.

d - Excludable emissions are calculated by scaling the baseline actual emissions using the ratio of baseline COA coke production to BAE coke production. Example: 633515.6 tpy BAE X (553,362 tpy COA / 492,416 tpy BAE) - 633515.6 tpy BAE = 78409.2 tpy excludable emissions.

e - Project actual emissions based on calciner capacity. Emissions based on mass balance of carbon in (green coke) minus carbon out (calcined coke and coke dust) assuming same average carbon contents from 2013 green coke and calcined coke testing. Assume 0.95% of green coke is captured as calcined dust.

f - Project emission increase is Projected Actual Emissiosn minus (Baseline Actual Emissions + Excludable Emissions).

g - CH4 and N2O emissions based on 40 CFR Part 98, Subpart Y, Equations Y-9 and Y-10 with default EPA emission factors. CH4 and N2O converted to CO2e based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).

BP - Cherry Point

## Coker Heater Replacement Project - Increased Utilization of the hydrocracker

**This spreadsheet identifies total increase in emissions of criteria pollutants attributable to increased utilization of the hydrocracker.**

### Criteria and PSD Pollutant Emissions

**Baseline Heat Input for Hydrocracker**

| | R1 Heater | 1st Frac Reboiler | R4 Heater | 2nd Frac Reboiler | Total |
|---|---|---|---|---|---|
| 2005 Heat Input (MMBtu/yr) | 678,852 | 872,714 | 363,774 | 1,266,419 | 3,181,758 |
| 2006 Heat Input (MMBtu/yr) | 601,272 | 736,158 | 360,780 | 1,132,797 | 2,831,008 |
| 2007 Heat Input (MMBtu/yr) | 564,335 | 954,713 | 315,643 | 1,441,294 | 3,275,985 |
| 2008 Heat Input (MMBtu/yr) | 720,816 | 837,805 | 342,662 | 1,306,786 | 3,208,068 |
| 2009 Heat Input (MMBtu/yr) | 432,764 | 725,367 | 335,581 | 1,113,552 | 2,607,264 |
| 2010 Heat Input (MMBtu/yr) | 479,363 | 1,047,743 | 406,095 | 1,530,639 | 3,463,840 |
| 2011 Heat Input (MMBtu/yr) | 653,395 | 1,037,819 | 409,869 | 1,389,518 | 3,490,601 |
| 2012 Heat Input (MMBtu/yr) | 336,895 | 968,015 | 339,396 | 1,105,807 | 2,750,112 |
| 2013 Heat Input (MMBtu/yr) | 494,595 | 1,219,477 | 496,870 | 1,360,301 | 3,571,243 |
| 2014 Heat Input (MMBtu/yr) | 651,405 | 1,027,700 | 406,183 | 1,379,780 | 3,465,069 |
| Potential Heat Input (MMBtu/yr) | 1,059,084 | 1,732,728 | 525,600 | 1,606,584 | 4,923,996 |

**Baseline Emissions and Projected Actual Emissions for Hydrocracker Heaters**

| NOx Emission Increase | R1 Heater [a] | 1st Frac Reboiler [b] | R4 Heater [c] | 2nd Frac Reboiler [d] | Total |
|---|---|---|---|---|---|
| 2005 Emissions (tpy) | 15.8 | 21.8 | 25.5 | 41.2 | 104.2 |
| 2006 Emissions (tpy) | 6.0 | 18.4 | 25.3 | 36.8 | 86.5 |
| 2007 Emissions (tpy) | 9.0 | 23.9 | 22.1 | 42.6 | 97.5 |
| 2008 Emissions (tpy) | 10.9 | 20.9 | 24.0 | 41.3 | 97.2 |
| 2009 Emissions (tpy) | 6.2 | 18.1 | 23.5 | 39.2 | 87.1 |
| 2010 Emissions (tpy) | 5.7 | 26.2 | 28.4 | 45.5 | 105.8 |
| 2011 Emissions (tpy) | 8.3 | 25.9 | 28.7 | 40.1 | 103.0 |
| 2012 Emissions (tpy) | 4.0 | 16.9 | 23.8 | 33.0 | 77.7 |
| 2013 Emissions (tpy) | 6.4 | 19.3 | 34.8 | 45.2 | 105.6 |
| 2014 Emissions (tpy) | 8.7 | 16.1 | 34.8 | 44.4 | 104.0 |
| Baseline Average (tpy) | 6.1 | 21.4 | 26.2 | 36.6 | 90.3 |
| Baseline Ave Heat Input (MMBt | 495,145 | 1,002,917 | 374,632 | 1,247,663 | |
| COA Heat Input (MMBtu/yr) | 720,816 | 1,219,477 | 496,870 | 1,530,639 | |
| Excludable Emissions (tpy) | 4.5 | 5.4 | 8.6 | 9.2 | |
| BAE + Excludable (tpy) | 10.7 | 26.8 | 34.8 | 45.7 | |
| Baseline EF (lb/MMBtu) | 0.04 | 0.05 | 0.14 | 0.065 | -- |
| Future EF (lb/MMBtu) | -- | 0.04 | 0.14 | 0.07 | -- |
| Projected Emissions (tpy) | 21.5 | 34.7 | 36.8 | 56.2 | 153.0 |
| NOx Emission Increase (tpy) | 10.8 | 7.8 | 2.0 | 10.5 | 31.1 |

a - R1 Heater baseline 2007 - 2014 NOx emissions based on CEMS data, 2005 - 2006 emissions based on emission factor and RFG use (complying with OAC #966a emission limit of 3.6 lb NOx/hr). Potential emissions based on hourly NOx emission limit (4.9 lb/hr from OAC #966b) and continuous operation (8,760 hrs/yr).

b - 1st Frac Reboiler NOx emissions based on past actual fuel use and an emission limit 0.05 lb/MMBtu from OAC #1067a through February 2012. Baseline actual NOx emissions based on CEMS data for May 2012 through current. Projected actual Nox emissions based on projected actual heat input requirements and a NOx emission factor of 0.04 lb/MMBtu.

c - R4 Heater NOx baseline actual emissions based on past actual fuel use and engineering estimate emission factor. Potential emissions based on potential heat input rate and engineering estimate emission factor.

d - 2nd Frac Reboiler baseline emisisons based Monthly Nox emission reports (2007-2014), baseline emission factor, and RFG use (complying with OAC #847a NOx emission limit of 0.070 lb/MMBtu and 56.2 tpy). Potential emissions based on annual NOx emission limit.

| CO Emission Increase | R1 Heater [a] | 1st Frac Reboiler [b] | R4 Heater [c] | 2nd Frac Reboiler [d] | Total |
|---|---|---|---|---|---|
| 2005 Emissions (tpy) | 13.6 | 17.5 | 7.3 | 25.3 | 63.6 |
| 2006 Emissions (tpy) | 12.0 | 14.7 | 7.2 | 22.7 | 56.6 |
| 2007 Emissions (tpy) | 11.3 | 19.1 | 6.3 | 28.8 | 65.5 |
| 2008 Emissions (tpy) | 14.4 | 16.8 | 6.9 | 26.1 | 64.2 |
| 2009 Emissions (tpy) | 8.7 | 14.5 | 6.7 | 22.3 | 52.1 |
| 2010 Emissions (tpy) | 9.6 | 21.0 | 8.1 | 30.6 | 69.3 |
| 2011 Emissions (tpy) | 13.1 | 20.8 | 8.2 | 27.8 | 69.8 |
| 2012 Emissions (tpy) | 6.7 | 19.4 | 6.8 | 22.1 | 55.0 |
| 2013 Emissions (tpy) | 9.9 | 24.4 | 9.9 | 27.2 | 71.4 |
| 2014 Emissions (tpy) | 13.0 | 20.6 | 8.1 | 27.6 | 69.3 |
| Baseline Average (tpy) | 11.3 | 20.9 | 8.2 | 29.2 | 69.5 |
| Baseline Ave Heat Input (MMBt | 566,379 | 1,042,781 | 407,982 | 1,460,079 | |
| COA Heat Input (MMBtu/yr) | 720,816 | 872,714 | 496,870 | 1,530,639 | |
| Excludable Emissions (tpy) | 3.1 | -3.4 | 1.8 | 1.4 | |
| BAE + Excludable (tpy) | 14.4 | 17.5 | 9.9 | 30.6 | |
| Baseline EF (lb/MMBtu) | 0.04 | 0.040 | 0.040 | 0.040 | -- |
| Future EF (lb/MMBtu) | -- | 0.040 | 0.040 | 0.040 | -- |
| Projected Emissions (tpy) | 23.7 | 34.7 | 10.5 | 32.1 | 101.0 |
| CO Emission Increase (tpy) | 9.2 | 17.2 | 0.6 | 1.5 | 28.5 |

a - R1 Heater baseline CO emissions based on 50 ppm CO emission rate (0.040 lb/MMBtu) and past actual fuel usage (complying with OAC #966a emission CO emission limit of 5.4 lb/hr). Future potential emissions based on hourly CO emission limit and continuous operation (8,760 hrs/yr). Numerous source test have been conducted on the hydrocracker heaters and almost all runs have been less than the CO analyzer detection level; therefore BP has elected to use a conservative 50 ppm CO emission factor (0.040 lb/MMbtu) to calculate baseline actual and projected actual emission rates. The AP-42 Section 1.4 default CO emission factor converts to roughly 100 ppm CO.

b - 1st Frac Reboiler CO emissions based on past actual fuel use, projected actual heat input requirements, and 0.040 lb CO/MMBtu emission limit (OAC 1067a).

c - R4 Heater CO emissions based on past actual fuel use, projected actual heat input requirements, and 50 ppm CO emission rate (0.040 lb/MMBtu).

d - 2nd Frac Reboiler CO emissions based on past actual fuel use, projected actual heat input requirements, and 50 ppm CO emission rate (0.040 lb/MMBtu).

| SO2 Emission Increase | R1 Heater [a] | 1st Frac Reboiler [a] | R4 Heater [a] | 2nd Frac Reboiler [a] | Total |
|---|---|---|---|---|---|
| 2005 Emissions (tpy) | 12.2 | 15.7 | 6.6 | 22.8 | 57.4 |
| 2006 Emissions (tpy) | 11.0 | 13.0 | 7.0 | 20.0 | 51.0 |
| 2007 Emissions (tpy) | 11.9 | 19.4 | 6.6 | 29.5 | 67.4 |
| 2008 Emissions (tpy) | 15.2 | 17.8 | 7.4 | 27.9 | 68.3 |
| 2009 Emissions (tpy) | 8.6 | 12.9 | 6.3 | 20.7 | 48.5 |
| 2010 Emissions (tpy) | 6.9 | 15.3 | 5.9 | 22.3 | 50.4 |
| 2011 Emissions (tpy) | 8.9 | 14.1 | 5.5 | 18.9 | 47.5 |
| 2012 Emissions (tpy) | 3.0 | 9.0 | 3.0 | 11.0 | 26.0 |
| 2013 Emissions (tpy) | 5.2 | 12.4 | 5.0 | 13.9 | 36.5 |
| 2014 Emissions (tpy) | 13.0 | 20.6 | 8.1 | 27.6 | 69.4 |
| Baseline Average (tpy) | 11.9 | 15.4 | 6.8 | 24.3 | 58.4 |
| Baseline Ave Heat Input (MMBt | 576,790 | 781,586 | 339,122 | 1,210,169 | -- |
| COA Heat Input (MMBtu/yr) | 720,816 | 1,219,477 | 496,870 | 1,530,639 | -- |
| Excludable Emissions (tpy) | 2.9 | 8.8 | 3.2 | 6.4 | -- |
| BAE + Excludable (tpy) | 14.8 | 24.1 | 10.0 | 30.7 | -- |
| Baseline EF | 0.040 | 0.040 | 0.040 | 0.040 | -- |
| Projected EF (lb/MMBtu) | 0.0317 | 0.0317 | 0.0317 | 0.0317 | -- |
| Projected Emissions (tpy) | 16.8 | 27.4 | 8.3 | 25.4 | 78.0 |
| SO2 Emission Increase (tpy) | 2.0 | 3.3 | 0.0 | 0.0 | 5.3 |

a - SO2 emissions based past actual fuel use, potential heat input requirements, and annual RFG SO2 emission factor. Increase limited to zero if projected actual emissions are lower than baseline actual.

| PM Emission Increase | R1 Heater [a] | 1st Frac Reboiler [a] | R4 Heater [a] | 2nd Frac Reboiler [a] | Total |
|---|---|---|---|---|---|
| 2005 Emissions (tpy) | 0.7 | 0.9 | 0.4 | 1.3 | 3.4 |
| 2006 Emissions (tpy) | 0.6 | 0.8 | 0.4 | 1.2 | 3.0 |
| 2007 Emissions (tpy) | 0.6 | 1.0 | 0.3 | 1.5 | 3.5 |
| 2008 Emissions (tpy) | 0.8 | 0.9 | 0.4 | 1.4 | 3.4 |
| 2009 Emissions (tpy) | 0.5 | 0.8 | 0.4 | 1.2 | 2.8 |
| 2010 Emissions (tpy) | 0.5 | 1.1 | 0.4 | 1.6 | 3.7 |
| 2011 Emissions (tpy) | 0.7 | 1.1 | 0.4 | 1.5 | 3.7 |
| 2012 Emissions (tpy) | 0.4 | 1.0 | 0.4 | 1.2 | 2.9 |
| 2013 Emissions (tpy) | 0.5 | 1.3 | 0.5 | 1.4 | 3.8 |
| 2014 Emissions (tpy) | 0.7 | 1.1 | 0.4 | 1.5 | 3.7 |
| Baseline Average (tpy) | 0.6 | 1.1 | 0.4 | 1.6 | 3.7 |
| Baseline Ave Heat Input (MMBt | 566,379 | 1,042,781 | 407,982 | 1,460,079 | |
| COA Heat Input (MMBtu/yr) | 720,816 | 1,219,477 | 496,870 | 1,530,639 | |
| Excludable Emissions (tpy) | 0.2 | 0.2 | 0.1 | 0.1 | |
| BAE + Excludable (tpy) | 0.8 | 1.3 | 0.5 | 1.6 | |
| Emission Factor (lb/MMBtu) | 0.0021 | 0.0021 | 0.0021 | 0.0021 | -- |
| Projected Emissions (tpy) | 1.1 | 1.8 | 0.6 | 1.7 | 5.2 |
| PM Emission Increase (tpy) | 0.4 | 0.5 | 0.0 | 0.1 | 1.0 |

a - PM emissions based past actual fuel use, potential heat input requirements, and an emission factor based on source test results (25 percent of total particulate is filterable).

| PM10 Emission Increase | R1 Heater [a] | 1st Frac Reboiler [a] | R4 Heater [a] | 2nd Frac Reboiler [a] | Total |
|---|---|---|---|---|---|
| 2005 Emissions (tpy) | 2.9 | 3.7 | 1.5 | 5.4 | 13.5 |
| 2006 Emissions (tpy) | 2.6 | 3.1 | 1.5 | 4.8 | 12.0 |
| 2007 Emissions (tpy) | 2.4 | 4.1 | 1.3 | 6.1 | 13.9 |
| 2008 Emissions (tpy) | 3.1 | 3.6 | 1.5 | 5.6 | 13.6 |
| 2009 Emissions (tpy) | 1.8 | 3.1 | 1.4 | 4.7 | 11.1 |
| 2010 Emissions (tpy) | 2.0 | 4.5 | 1.7 | 6.5 | 14.7 |
| 2011 Emissions (tpy) | 2.8 | 4.4 | 1.7 | 5.9 | 14.8 |
| 2012 Emissions (tpy) | 1.4 | 4.1 | 1.4 | 4.7 | 11.7 |
| 2013 Emissions (tpy) | 2.1 | 5.2 | 2.1 | 5.8 | 15.2 |
| 2014 Emissions (tpy) | 2.8 | 4.4 | 1.7 | 5.9 | 14.7 |
| Baseline Average (tpy) | 2.4 | 4.4 | 1.7 | 6.2 | 14.8 |
| Baseline Ave Heat Input (MMBt | 566,379 | 1,042,781 | 407,982 | 1,460,079 | |
| COA Heat Input (MMBtu/yr) | 720,816 | 1,219,477 | 496,870 | 1,530,639 | |
| Excludable Emissions (tpy) | 0.7 | 0.8 | 0.4 | 0.3 | |
| BAE + Excludable (tpy) | 3.1 | 5.2 | 2.1 | 6.5 | |
| Emission Factor (lb/MMBtu) | 0.0085 | 0.0085 | 0.0085 | 0.0085 | -- |
| Projected Emissions (tpy) | 4.5 | 7.4 | 2.2 | 6.8 | 20.9 |
| PM10 Emission Increase (tpy) | 1.4 | 2.2 | 0.1 | 0.3 | 4.1 |

a - PM10 emissions based past actual fuel use, potential heat input requirements, and a PM10 emission factor based on 2009 & 2013 refinery source test data (average from #2 DHDS Charge Heater and #3 DHDS Charge Heater source tests).

| PM2.5 Emission Increase | R1 Heater [a] | 1st Frac Reboiler [a] | R4 Heater [a] | 2nd Frac Reboiler [a] | Total |
|---|---|---|---|---|---|
| 2005 Emissions (tpy) | 2.9 | 3.7 | 1.5 | 5.4 | 13.5 |
| 2006 Emissions (tpy) | 2.6 | 3.1 | 1.5 | 4.8 | 12.0 |
| 2007 Emissions (tpy) | 2.4 | 4.1 | 1.3 | 6.1 | 13.9 |
| 2008 Emissions (tpy) | 3.1 | 3.6 | 1.5 | 5.6 | 13.6 |
| 2009 Emissions (tpy) | 1.8 | 3.1 | 1.4 | 4.7 | 11.1 |
| 2010 Emissions (tpy) | 2.0 | 4.5 | 1.7 | 6.5 | 14.7 |
| 2011 Emissions (tpy) | 2.8 | 4.4 | 1.7 | 5.9 | 14.8 |
| 2012 Emissions (tpy) | 1.4 | 4.1 | 1.4 | 4.7 | 11.7 |
| 2013 Emissions (tpy) | 2.1 | 5.2 | 2.1 | 5.8 | 15.2 |
| 2014 Emissions (tpy) | 2.8 | 4.4 | 1.7 | 5.9 | 14.7 |
| Baseline Average (tpy) | 2.4 | 4.4 | 1.7 | 6.2 | 14.8 |
| Baseline Ave Heat Input (MMBt | 566,379 | 1,042,781 | 407,982 | 1,460,079 | |
| COA Heat Input (MMBtu/yr) | 720,816 | 1,219,477 | 496,870 | 1,530,639 | |
| Excludable Emissions (tpy) | 0.7 | 0.8 | 0.4 | 0.3 | |
| BAE + Excludable (tpy) | 3.1 | 5.2 | 2.1 | 6.5 | |
| Emission Factor (lb/MMBtu) | 0.0085 | 0.0085 | 0.0085 | 0.0085 | -- |
| Projected Emissions (tpy) | 4.5 | 7.4 | 2.2 | 6.8 | 20.9 |
| PM2.5 Emission Increase (tpy) | 1.4 | 2.2 | 0.1 | 0.3 | 4.1 |

a - PM2.5 emissions based past actual fuel use, potential heat input requirements, and PM10 emission factor.

| VOC Emission Increase | R1 Heater [a] | 1st Frac Reboiler [a] | R4 Heater [a] | 2nd Frac Reboiler [a] | Total |
|---|---|---|---|---|---|
| 2005 Emissions (tpy) | 1.8 | 2.4 | 1.0 | 3.4 | 8.6 |
| 2006 Emissions (tpy) | 1.6 | 2.0 | 1.0 | 3.1 | 7.6 |
| 2007 Emissions (tpy) | 1.5 | 2.6 | 0.9 | 3.9 | 8.8 |
| 2008 Emissions (tpy) | 1.9 | 2.3 | 0.9 | 3.5 | 8.6 |
| 2009 Emissions (tpy) | 1.2 | 2.0 | 0.9 | 3.0 | 7.0 |
| 2010 Emissions (tpy) | 1.3 | 2.8 | 1.1 | 4.1 | 9.3 |
| 2011 Emissions (tpy) | 1.8 | 2.8 | 1.1 | 3.7 | 9.4 |
| 2012 Emissions (tpy) | 0.9 | 2.6 | 0.9 | 3.0 | 7.4 |
| 2013 Emissions (tpy) | 1.3 | 3.3 | 1.3 | 3.7 | 9.6 |
| 2014 Emissions (tpy) | 1.8 | 2.8 | 1.1 | 3.7 | 9.3 |
| Baseline Average (tpy) | 1.1 | 2.9 | 1.1 | 3.3 | 8.5 |
| Baseline Ave Heat Input (MMBt | 415,745 | 1,093,746 | 418,133 | 1,233,054 | |
| COA Heat Input (MMBtu/yr) | 720,816 | 1,219,477 | 496,870 | 1,530,639 | |
| Excludable Emissions (tpy) | 0.8 | 0.3 | 0.2 | 0.8 | |
| BAE + Excludable (tpy) | 1.9 | 3.3 | 1.3 | 4.1 | |
| Emission Factor (lb/MMBtu) | 0.0054 | 0.0054 | 0.0054 | 0.0054 | -- |
| Projected Emissions (tpy) | 2.9 | 4.7 | 1.4 | 4.3 | 13.3 |
| VOC Emission Increase (tpy) | 0.9 | 1.4 | 0.1 | 0.2 | 2.6 |

a - VOC emissions based on past actual fuel use, potential heat input requirements, and AP-42 Section 1.4 VOC emission factor converted to lb/MMBtu.

| Pb Emission Increase | R1 Heater [a] | 1st Frac Reboiler [a] | R4 Heater [a] | 2nd Frac Reboiler [a] | Total |
|---|---|---|---|---|---|
| 2005 Emissions (tpy) | 1.7E-04 | 2.1E-04 | 8.9E-05 | 3.1E-04 | 7.8E-04 |
| 2006 Emissions (tpy) | 1.5E-04 | 1.8E-04 | 8.8E-05 | 2.8E-04 | 6.9E-04 |
| 2007 Emissions (tpy) | 1.4E-04 | 2.3E-04 | 7.7E-05 | 3.5E-04 | 8.0E-04 |
| 2008 Emissions (tpy) | 1.8E-04 | 2.1E-04 | 8.4E-05 | 3.2E-04 | 7.9E-04 |
| 2009 Emissions (tpy) | 1.1E-04 | 1.8E-04 | 8.2E-05 | 2.7E-04 | 6.4E-04 |
| 2010 Emissions (tpy) | 1.2E-04 | 2.6E-04 | 1.0E-04 | 3.8E-04 | 8.5E-04 |
| 2011 Emissions (tpy) | 1.6E-04 | 2.5E-04 | 1.0E-04 | 3.4E-04 | 8.6E-04 |
| 2012 Emissions (tpy) | 8.3E-05 | 2.4E-04 | 8.3E-05 | 2.7E-04 | 6.7E-04 |
| 2013 Emissions (tpy) | 1.2E-04 | 3.0E-04 | 1.2E-04 | 3.3E-04 | 8.8E-04 |
| 2014 Emissions (tpy) | 1.6E-04 | 2.5E-04 | 1.0E-04 | 3.4E-04 | 8.5E-04 |
| Baseline Average (tpy) | 1.4E-04 | 2.6E-04 | 1.0E-04 | 3.6E-04 | 8.5E-04 |
| Baseline Ave Heat Input (MMB | 566,379 | 1,042,781 | 407,982 | 1,460,079 | |
| COA Heat Input (MMBtu/yr) | 720,816 | 1,219,477 | 496,870 | 1,530,639 | |
| Excludable Emissions (tpy) | 3.8E-05 | 4.3E-05 | 2.2E-05 | 1.7E-05 | |
| BAE + Excludable (tpy) | 1.8E-04 | 3.0E-04 | 1.2E-04 | 3.8E-04 | |
| Emission Factor (lb/MMBtu) | 4.9E-07 | 4.9E-07 | 4.9E-07 | 4.9E-07 | -- |
| Projected Emissions (tpy) | 2.6E-04 | 4.2E-04 | 1.3E-04 | 3.9E-04 | 1.2E-03 |
| Pb Emission Increase (tpy) | 8.3E-05 | 1.3E-04 | 7.0E-06 | 1.9E-05 | 3.5E-04 |

a - Lead emissions based on past actual fuel use, potential heat input requirements, and AP-42 Section 1.4 lead emission factor converted to lb/MMBtu.

| H2SO4 Emission Increase | R1 Heater [a] | 1st Frac Reboiler [a] | R4 Heater [a] | 2nd Frac Reboiler [a] | Total |
|---|---|---|---|---|---|
| 2005 Emissions (tpy) | 0.4 | 0.6 | 0.2 | 0.8 | 2.1 |
| 2006 Emissions (tpy) | 0.4 | 0.5 | 0.2 | 0.7 | 1.9 |
| 2007 Emissions (tpy) | 0.4 | 0.6 | 0.2 | 0.9 | 2.1 |
| 2008 Emissions (tpy) | 0.5 | 0.5 | 0.2 | 0.9 | 2.1 |
| 2009 Emissions (tpy) | 0.3 | 0.5 | 0.2 | 0.7 | 1.7 |
| 2010 Emissions (tpy) | 0.3 | 0.7 | 0.3 | 1.0 | 2.3 |
| 2011 Emissions (tpy) | 0.4 | 0.7 | 0.3 | 0.9 | 2.3 |
| 2012 Emissions (tpy) | 0.2 | 0.6 | 0.2 | 0.7 | 1.8 |
| 2013 Emissions (tpy) | 0.3 | 0.8 | 0.3 | 0.9 | 2.3 |
| 2014 Emissions (tpy) | 0.4 | 0.7 | 0.3 | 0.9 | 2.3 |
| Baseline Average (tpy) | 0.4 | 0.7 | 0.3 | 0.9 | 2.3 |
| Baseline Ave Heat Input (MMB | 573,000 | 1,123,589 | 451,527 | 1,370,041 | |
| COA Heat Input (MMBtu/yr) | 720,816 | 1,219,477 | 496,870 | 1,530,639 | |
| Excludable Emissions (tpy) | 0.10 | 0.06 | 0.03 | 0.11 | |
| BAE + Excludable (tpy) | 0.47 | 0.80 | 0.33 | 1.00 | |
| Emission Factor (lb/MMBtu) | 0.0013 | 0.0013 | 0.0013 | 0.0013 | -- |
| Projected Emissions (tpy) | 0.7 | 1.1 | 0.3 | 1.1 | 3.2 |
| H2SO4 Emission Increase (tpy | 0.22 | 0.34 | 0.02 | 0.05 | 0.9 |

a - H2SO4 emissions based on past actual fuel use, potential heat input requirements, and 2.63 percent of SO2 converting to H2SO4 (Source Test of #1 Reformer firing RFG).

| H2S Emission Increase | R1 Heater [a] | 1st Frac Reboiler [a] | R4 Heater [a] | 2nd Frac Reboiler [a] | Total |
|---|---|---|---|---|---|
| 2012 Emissions (tpy) | 0.001 | 0.002 | 0.001 | 0.002 | 0.006 |
| 2013 Emissions (tpy) | 0.003 | 0.007 | 0.003 | 0.007 | 0.019 |
| 2014 Emissions (tpy) | 0.001 | 0.002 | 0.001 | 0.002 | 0.006 |
| Baseline Average (tpy) | 0.002 | 0.004 | 0.002 | 0.005 | 0.013 |
| Baseline Ave Heat Input (MMBt | 415,745 | 1,093,746 | 418,133 | 1,233,054 | |
| COA Heat Input (MMBtu/yr) | 720,816 | 1,219,477 | 496,870 | 1,530,639 | |
| Excludable Emissions (tpy) | 0.002 | 0.001 | 0.000 | 0.002 | |
| BAE + Excludable (tpy) | 0.004 | 0.005 | 0.002 | 0.007 | |
| Emission Factor (lb/MMBtu) | 1.2E-05 | 1.2E-05 | 1.2E-05 | 1.2E-05 | -- |
| Projected Emissions (tpy) | 0.006 | 0.010 | 0.003 | 0.009 | 0.03 |
| H2SO4 Emission Increase (tpy) | 0.003 | 0.005 | 0.0011 | 0.0029 | 0.02 |

a - H2S emissions based on past actual fuel use, potential heat input requirements, and a baseline H2S to SO2 ratio of 0.00038. Projected emissions based on H2S to SO2 ratio and projected SO2 emission factor (0.0317 lb/MMBtu).

| CO2e Emission Increase | R1 Heater [a] | 1st Frac Reboiler [a] | R4 Heater [a] | 2nd Frac Reboiler [a] | Total |
|---|---|---|---|---|---|
| 2005 Emissions (tpy) | 40,961 | 52,658 | 21,950 | 76,414 | 191,983 |
| 2006 Emissions (tpy) | 36,280 | 44,419 | 21,769 | 68,351 | 170,819 |
| 2007 Emissions (tpy) | 34,051 | 57,606 | 19,045 | 86,966 | 197,668 |
| 2008 Emissions (tpy) | 43,493 | 50,552 | 20,676 | 78,850 | 193,570 |
| 2009 Emissions (tpy) | 26,112 | 43,768 | 20,248 | 67,190 | 157,319 |
| 2010 Emissions (tpy) | 28,924 | 63,219 | 24,503 | 92,357 | 209,003 |
| 2011 Emissions (tpy) | 39,425 | 62,620 | 24,731 | 83,842 | 210,618 |
| 2012 Emissions (tpy) | 20,328 | 58,409 | 20,479 | 66,723 | 165,938 |
| 2013 Emissions (tpy) | 29,843 | 73,581 | 29,980 | 82,079 | 215,484 |
| 2014 Emissions (tpy) | 39,305 | 62,010 | 24,509 | 83,254 | 209,077 |
| Baseline Average (tpy) | 34,174 | 62,920 | 24,617 | 88,099 | 209,810 |
| Baseline Ave Heat Input (MMBt | 566,379 | 1,042,781 | 407,982 | 1,460,079 | |
| COA Heat Input (MMBtu/yr) | 720,816 | 1,219,477 | 496,870 | 1,530,639 | |
| Excludable Emissions (tpy) | 9,319 | 10,662 | 5,363 | 4,258 | |
| BAE + Excludable (tpy) | 43,493 | 73,581 | 29,980 | 92,357 | |
| Emission Factor (lb/MMBtu) | 121 | 121 | 121 | 121 | -- |
| Projected Emissions (tpy) | 63,904 | 104,550 | 31,714 | 96,939 | 297,107 |
| CO2e Emission Increase (tpy) | 20,411 | 30,969 | 1,734 | 4,582 | 87,296 |

a - CO2 emission factor based on refinery fuel gas analysis and 100% conversion of carbon in fuel to CO2.

## Greenhouse Gas Emissions

| Greenhouse Gas | Hydrocracker Heaters Emission Factor [b] lb/MMBtu |
|---|---|
| CO2 [a] | 120 |
| CH4 | 0.0023 |
| N2O | 0.0022 |
| CO2e [c] | 120.7 |

notes:

a - CO2 emission factor based on refinery fuel gas analysis and 100% conversion of carbon in fuel to CO2.

b - CH4 and N20 emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas

BP - Cherry Point
**Coker Heater Replacement Project - Sulfur Plant Emissions Increase**

**Increase in Regulated Pollutant Emission Increases Attributable to Project**

**Fuel Characteristics**

| | | |
|---|---|---|
| Energy value of natural gas | 1,036 GBtu/scf | Source: 'Natural Gas Analysis' worksheet |
| Energy value of tail gas | 15.6 GBtu/scf | Source: 'Tail Gas Analysis' worksheet |
| Energy value of hydrogen gas | 345.7 GBtu/scf | Source: 'Hydrogen Gas Analysis' worksheet |
| Energy value of clean acid gas gas | 610 GBtu/scf | Source: BP 2012 testing |
| SRU Incinerator Exhaust Flow | 5.54 mscfh/(lt/day S) | Source: BP 2014 testing |

**Sulfur Production**

| | | |
|---|---|---|
| Projected Sulfur Production | 270 lt/day | Source: BP, assume fill sulfur plant to 270 lt/day |

**Baseline Heat Input for Sulfur Plant**

| Year | SRU Incinerator (MMBtu/yr) | TGU #2 (MMBtu/yr) | Total (MMBtu/yr) | Baseline Period | 2yr Ave Heat Input (MMBtu/yr) | 2yr Ave S Prod (lt/yr) | 2yr Ave S Prod (lt/day) | 2yr Ave #2 TGU Acid Gas (mmscf/yr) |
|---|---|---|---|---|---|---|---|---|
| 2003 | 209,360 | -- | 209,360 | -- | -- | -- | -- | -- |
| 2004 | 188,373 | -- | 188,373 | 2003-2004 | 198,867 | 61,876 | 169.3 | -- |
| 2005 | 190,359 | -- | 190,359 | 2004-2005 | 189,366 | 57,982 | 158.6 | -- |
| 2006 | 258,869 | 2,072 | 260,941 | 2005-2006 | 225,650 | 60,183 | 164.9 | 2 |
| 2007 | 337,582 | 3,108 | 340,690 | 2006-2007 | 300,816 | 64,800 | 177.5 | 3 |
| 2008 | 341,487 | 20,720 | 362,207 | 2007-2008 | 351,449 | 71,266 | 195.0 | 12 |
| 2009 | 305,465 | 85,349 | 390,814 | 2008-2009 | 376,511 | 70,726 | 193.5 | 35 |
| 2010 | 299,199 | 194,615 | 493,814 | 2009-2010 | 442,314 | 72,968 | 199.9 | 73 |
| 2011 | 285,095 | 189,677 | 474,772 | 2010-2011 | 484,293 | 74,488 | 204.1 | 95 |
| 2012 | 247,575 | 164,019 | 411,595 | 2011-2012 | 443,183 | 71,803 | 196.4 | 82 |
| 2013 | 317,712 | 173,315 | 491,027 | 2012-2013 | 451,311 | 78,119 | 214.0 | 58 |
| 2014 | 135,539 | 74,591 | 210,130 | 2013-2014 | 350,579 | 81,103 | 222.4 | 59 |

**Baseline Sulfur Plant Emissions**

| | S Prod. | SRU Incinerator (tons/year) | | | #2 TGU (tons/year) | | |
|---|---|---|---|---|---|---|---|
| Year | (lt/yr) | NOx | CO | SO2 | NOx | CO | SO2 |
| 2003 | 67,017 | 8.3 | 141.9 | 37.9 | -- | -- | -- |
| 2004 | 56,736 | 8.2 | 139.5 | 105.3 | -- | -- | -- |
| 2005 | 59,228 | 8.3 | 141.9 | 26.9 | -- | -- | -- |
| 2006 | 61,138 | 8.2 | 139.9 | 37.9 | 3.4 | 3.3 | 11.5 |
| 2007 | 68,463 | 8.3 | 141.9 | 49.5 | 0.4 | 0.4 | 1.3 |
| 2008 | 74,070 | 8.3 | 142.3 | 55.2 | 1.9 | 2.4 | 13.0 |
| 2009 | 67,382 | 12.9 | 146.9 | 60.6 | 0.2 | 0 | 5.2 |
| 2010 | 78,553 | 16.9 | 152.6 | 61.0 | 0.7 | 0 | 6.2 |
| 2011 | 70,423 | 16.9 | 152.5 | 52.7 | 0 | 0 | 0 |
| 2012 | 73,183 | 15.0 | 132.0 | 96.00 | | | |
| 2013 | 83,055 | 18 | 154 | 77.00 | | | |
| 2014 | 79,151 | 8.3 | 141.9 | 47.6 | 8.5 | 10.6 | 14.9 |

- In 2012 and 2013, SRU and TGU emissions combined and presented in SRU Incinerator columns.

**Criteria and PSD Pollutant Emission Increases**

| Pollutant | Sulfur Plant Emission Factors<br>SRU Incinerator<br>Max. Emission Factor | TGU #2<br>Emission Factor | Sum/Maximum<br>Emission Factor | Projected Emissions<br>(tpy) | Baseline Emissions<br>(tpy) | Emission Increase<br>(tpy) | Baseline Period<br>(24-month period) |
|---|---|---|---|---|---|---|---|
| NOx [a] | 1.9 lb/hr | 2.3 lb/hr | 4.2 lb/hr | 25.0 | 15.9 | 9.0 | 2011-2012 |
| CO [a] | 32.4 lb/hr | 2.80 lb/hr | 35.2 lb/hr | 204.0 | 152.5 | 51.4 | 2010-2011 |
| SO2 [b] | -- | -- | -- | 99.0 | 67.0 | 32.0 | 2008-2009 |
| PM (Filt.) [c] | 0.0021 lb/MMBtu | 0.0021 lb/MMBtu | 0.0021 lb/MMBtu | 0.7 | 0.5 | 0.17 | 2010-2011 |
| PM10 (Total) [c] | 0.0085 lb/MMBtu | 0.0085 lb/MMBtu | 0.0085 lb/MMBtu | 2.7 | 2.1 | 0.66 | 2010-2011 |
| PM2.5 (Total) [c] | 0.0085 lb/MMBtu | 0.0085 lb/MMBtu | 0.0085 lb/MMBtu | 2.7 | 2.1 | 0.66 | 2010-2011 |
| VOC [d] | 0.0054 lb/MMBtu | 0.0054 lb/MMBtu | 0.0054 lb/MMBtu | 1.5 | 1.2 | 0.32 | 2012-2013 |
| Lead [d] | 4.9E-07 lb/MMBtu | 4.9E-07 lb/MMBtu | 4.9E-07 lb/MMBtu | 1.6E-04 | 1.2E-04 | 3.8E-05 | 2010-2011 |
| H2SO4 [e] | 2.63% of sulfur | 0.22 lb/hr | 2.63% of sulfur | 4.0 | 2.7 | 1.29 | 2013-2014 |
| H2S [f] | -- | -- | -- | 0.6 | 0.5 | 0.12 | 2012-2013 |
| CO2e - other GHGs [g] | 0.7 lb/MMBtu | 0.7 lb/MMBtu | 0.7 lb/MMBtu | 224 | 169 | 55 | 2010-2011 |
| CO2 - Tail Gas [h] | 3,152 lb/mmscf Exhaust | 01.19 lb/scf Clean Acid Gas | -- | 94,879 | 71,714 | 23,165 | |
| | | | | | CO2e Total | 23,220 | |

notes:

a - NOx and CO emission rates (lb/hr) based on source tests (SRU - 3/13/2008 and TGU - 8/26/2006 & 10/14/2008), projected emissions based on sum of incinerator and #2 TGU emission rates scaled up by increase in sulfur production up to 270 lt/day compared to daily average sulfur production during baseline and assume continuous future operation of 8,760 hours/year.

b - Baseline annual SO2 emissions based on 2008-2009 actuals. Projected emissions based on 99 tpy emission limit (OAC 890c).

c - PM10 emission factor based on 2009 & 2013 refinery source test data. PM emission factor based on 25 percent of PM10 emission factor (average from #2 DHDS Charge Heater and #3 DHDS Charge Heater source tests, fraction of filterable particulate in total particulate). Baseline emissions from baseline heat input rate and emission factor, and projected emissions based on scaling up baseline heat input by increasing sulfur production up to 270 lt/day compared to daily average sulfur production during baseline and assume continuous future operation of 8,760 hours/year.

d - VOC and Lead emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf). Baseline emissions from baseline heat input rate and emission factor, and projected emissions based on scaling up baseline heat input by increasing sulfur production up to 270 lt/day compared to daily average sulfur production during baseline and assume continuous future operation of 8,760 hours/year.

e - SRU H2SO4 emission factor based on 2.63 percent of sulfur converting to H2SO4 (Source Test of #1 Reformer firing RFG) and 8,760 hours/year. TGU #2 emission rate (lb/hr) based on average from source tests (8/24/2006 & 10/14/2008). Baseline and projected emission rates based on SO2 emissions.

f - Baseline H2S emissions from Incinerator and #2 TGU based on TRI reporting. Projected actual H2S based on scalling up baseline emissions by the ratio of projected sulfur production (98,550) to baseline sulfur production (78,119 ltpy).

g - Other GHG emissions (CH4 and N2O) from combustion based on CH4 and N2O emission factors from AP-42 Section 1.4, converted to lb/MMBtu. CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).

h - CO2 emission factor for SRU Incinerator based on average of 2014 engineering tests (CO2 per exhaust flow rate) and #2 TGU CO2 emission factor (lb CO2/cf clean acid gas) based on 2012 and 2013 source test results. Basline emisisons calculated as total from SRU Incinerator and #2 TGU. Incinerator baseline emissions calculated from estimated incinerator flow rate during baseline period using average exhaust flow rate per long ton sulfur produced, and #2 TGU baseline emission calculated from average clean acid gas processed during baseline period. Projected emissions based on SRU incinerator exhaust flow and clean acid gas processed during baseline scaled up to sulfur production rate of 270 lt/day over entire year compared to average sulfur production during baseline period.

**Greenhouse Gas Emissions**

| Greenhouse Gas | NG Emission Factors<br>TGU #2<br>Emission Factor |
|---|---|
| CO2 [a] | 114 lb/MMBtu |
| CH4 [b] | 0.0023 lb/MMBtu |
| N2O [b] | 0.0022 lb/MMBtu |

notes:

a - CO2 emission factor based on natural gas fuel analysis and 100% conversion of carbon in fuel to CO2.

b - CH3 and N20 emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf)

BP - Cherry Point

**Coker Heater Replacement Project - Increased Utilization of the #1 DHDS**

**This spreadsheet identifies the increases in emissions of PSD pollutants attributable to increased utilization of the #1 DHDS unit.**

## Criteria and PSD Pollutant Emissions

**Baseline Heat Input for #1 DHDS Stab. Reboiler**

| | Reboiler | Total | Basis |
|---|---|---|---|
| 2005 Heat Input (MMBtu/yr) | 362,386 | 362,386 | Fuel Use Records and Gas Heat Content |
| 2006 Heat Input (MMBtu/yr) | 337,221 | 337,221 | Fuel Use Records and Gas Heat Content |
| 2007 Heat Input (MMBtu/yr) | 344,782 | 344,782 | Fuel Use Records and Gas Heat Content |
| 2008 Heat Input (MMBtu/yr) | 337,337 | 337,337 | Fuel Use Records and Gas Heat Content |
| 2009 Heat Input (MMBtu/yr) | 317,099 | 317,099 | Fuel Use Records and Gas Heat Content |
| 2010 Heat Input (MMBtu/yr) | 351,867 | 351,867 | Fuel Use Records and Gas Heat Content |
| 2011 Heat Input (MMBtu/yr) | 347,193 | 347,193 | Fuel Use Records and Gas Heat Content |
| 2012 Heat Input (MMBtu/yr) | 283,365 | 283,365 | Fuel Use Records and Gas Heat Content |
| 2013 Heat Input (MMBtu/yr) | 331,534 | 331,534 | Fuel Use Records and Gas Heat Content |
| 2014 Heat Input (MMBtu/yr) | 331,462 | 331,462 | Fuel Use Records and Gas Heat Content |
| Future Actual (MMBtu/yr) | | 443,314 | Maximum Past Actual Firing Rate (2005) + 22% percent increase (projected increase in coker unit utilization). |

**Baseline Emissions and Projected Actual Emissions for #1 DHDS Stab. Reboiler**

| Year | NOx [a] (tpy) | CO [a] (tpy) | SO2 [b] (tpy) | PM [c] (tpy) | PM10/PM2.5 [c] (tpy) | VOC [d] (tpy) | Lead [d] (tpy) | H2SO4 [e] (tpy) | H2S [g] (tpy) | CO2e [f] (tpy) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 5.0 | 0.3 | 6.5 | 0.4 | 1.5 | 1.0 | 8.9E-05 | 0.2 | -- | 21,866 |
| 2006 | 4.7 | 0.3 | 6.0 | 0.4 | 1.4 | 0.9 | 8.3E-05 | 0.2 | -- | 20,347 |
| 2007 | 4.8 | 0.3 | 7.1 | 0.4 | 1.5 | 0.9 | 8.5E-05 | 0.2 | -- | 20,804 |
| 2008 | 4.7 | 0.3 | 7.5 | 0.4 | 1.4 | 0.9 | 8.3E-05 | 0.2 | -- | 20,354 |
| 2009 | 4.4 | 0.3 | 5.6 | 0.3 | 1.3 | 0.9 | 7.8E-05 | 0.2 | -- | 19,133 |
| 2010 | 4.9 | 0.3 | 5.1 | 0.4 | 1.5 | 0.9 | 8.6E-05 | 0.2 | -- | 21,231 |
| 2011 | 4.8 | 0.3 | 4.7 | 0.4 | 1.5 | 0.9 | 8.5E-05 | 0.2 | -- | 20,949 |
| 2012 | 3.9 | 0.2 | 3.0 | 0.3 | 1.2 | 0.8 | 6.9E-05 | 0.2 | 0.001 | 17,098 |
| 2013 | 4.6 | 0.3 | 3.4 | 0.4 | 1.4 | 0.9 | 8.1E-05 | 0.2 | 0.002 | 20,004 |
| 2014 | 4.1 | 0.3 | 5.0 | 0.4 | 1.4 | 0.9 | 8.1E-05 | 0.2 | 0.001 | 20,000 |
| Baseline Average (tpy) | 4.4 | 0.3 | 6.6 | 0.4 | 1.5 | 0.8 | 8.6E-05 | 0.2 | 0.001 | 21,090 |
| Baseline Period | 2011-2012 | 2010-2011 | 2008-2009 | 2010-2011 | 2010-2011 | 2012-2013 | 2010-2011 | 2013-2014 | 2012-2013 | 2010-2011 |
| Baseline Ave Heat Input (MMBt | 315,279 | 349,530 | 327,218 | 349,530 | 349,530 | 307,450 | 349,530 | 331,498 | 307,450 | 349,530 |
| COA Heat Input (MMBtu/yr) | 362,386 | 362,386 | 362,386 | 362,386 | 362,386 | 362,386 | 362,386 | 362,386 | 362,386 | 362,386 |
| Excludable Emissions (tpy) | 0.7 | 0.01 | 0.7 | 0.0 | 0.1 | 0.1 | 3.2E-06 | 0.02 | 2.1E-04 | 776 |
| BAE + Excludable (tpy) | 5.0 | 0.3 | 7.3 | 0.4 | 1.5 | 1.0 | 8.9E-05 | 0.2 | 0.0014 | 21,866 |
| Baseline EF (lb/MMBtu) | 0.028 | 0.002 | 0.040 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 7.6E-06 | 120.7 |
| Future EF (lb/MMBtu) | 0.028 | 0.002 | 0.032 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 8.7E-06 | 120.7 |
| Projected Act. Emissions (tpy) | 6.1 | 0.4 | 7.0 | 0.5 | 1.9 | 1.2 | 1.1E-04 | 0.3 | 0.002 | 26,749 |
| Emission Increase (tpy) | 1.1 | 0.065 | -0.2 | 0.086 | 0.34 | 0.22 | 2.0E-05 | 4.9E-02 | 5.2E-04 | 4,883 |

Notes:

a - NOx and CO emission factors from 7/17/2006 and 9/11/2009, respectively. CO source testing results based on CO analyzer detection limit. 2014 NOx emissions based on CEMS data.

b - Baseline SO2 emissions from the heater based on BP's monthly emission summaries. Future SO2 emissions based on a current 200 ppm Sulfur concentration in RFG with a 15% percent increase due to additional coker offgas generation.

c - PM10 emission factor based on 2009 & 2013 refinery source test data. PM emission factor based on 25 percent of PM10 emission factor (average from #2 DHDS Charge Heater and #3 DHDS Charge Heater source tests, fraction of filterable particulate in total particulate).

d - VOC and lead emission factor from AP-42 Section 1.4, converted to lb/MMBtu.

e - H2SO4 emission factor based on #1 Reformer Heater Source Test (6/26/07).

f - GHG emissions based on carbon in RFG for CO2 and CH4 and N2O emission factors from AP-42 Section 1.4, converted to lb/MMBtu. CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).

g - Baseline H2S emissions from the BP TRI Reporting. Future H2S emissions based on baseline average H2S emission factor with a 15% percent increase due to additional coker offgas generation.

## Greenhouse Gas Emission Factors

| Greenhouse Gas | Emission Factor [b] lb/MMBtu |
|---|---|
| CO2 [a] | 120 |
| CH4 [b] | 0.0023 |
| N2O [b] | 0.0022 |
| CO2e [c] | 120.7 |

notes:

a - CO2 emission factor based on refinery fuel gas analysis and 100% conversion of carbon in fuel to CO2.

b - CH4 and N20 emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf)

BP - Cherry Point

**Coker Heater Replacement Project - Increased Utilization of the Naphtha Unit Heaters**

**This spreadsheet identifies the increases in emissions of PSD pollutants attributable to increased utilization of the naphtha unit.**

## Criteria and PSD Pollutant Emissions

**Baseline Heat Input for Naphtha Heaters**

| | Charge Heater | Stripper Reboiler | Total | Basis |
|---|---|---|---|---|
| 2005 Heat Input (MMBtu/yr) | 374,689 | 382,996 | 757,685 | Fuel Use Records and Gas Heat Content |
| 2006 Heat Input (MMBtu/yr) | 358,668 | 444,088 | 802,756 | Fuel Use Records and Gas Heat Content |
| 2007 Heat Input (MMBtu/yr) | 376,617 | 403,428 | 780,045 | Fuel Use Records and Gas Heat Content |
| 2008 Heat Input (MMBtu/yr) | 319,466 | 396,658 | 716,123 | Fuel Use Records and Gas Heat Content |
| 2009 Heat Input (MMBtu/yr) | 362,332 | 361,108 | 723,441 | Fuel Use Records and Gas Heat Content |
| 2010 Heat Input (MMBtu/yr) | 410,888 | 382,860 | 793,748 | Fuel Use Records and Gas Heat Content |
| 2011 Heat Input (MMBtu/yr) | 279,289 | 363,556 | 642,845 | Fuel Use Records and Gas Heat Content |
| 2012 Heat Input (MMBtu/yr) | 307,514 | 327,079 | 634,592 | Fuel Use Records and Gas Heat Content |
| 2013 Heat Input (MMBtu/yr) | 424,866 | 425,325 | 850,191 | Fuel Use Records and Gas Heat Content |
| 2014 Heat Input (MMBtu/yr) | 502,432 | 428,703 | 931,136 | Fuel Use Records and Gas Heat Content |
| Future Actual (MMBtu/yr) | | | 1,139,077 | Maximum Past Actual Firing Rate (2014) + 22% percent increase (projected increase in coker unit utilization). |

**Baseline Emissions and Projected Actual Emissions for Naphtha Heaters**

| Year | NOx [a] (tpy) | CO [a] (tpy) | SO2 [b] (tpy) | PM [c] (tpy) | PM10/PM2.5 [c] (tpy) | VOC [a] (tpy) | Lead [a] (tpy) | H2SO4 [d] (tpy) | H2S [f] (tpy) | CO2e [e] (tpy) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 37.1 | 31.2 | 13.7 | 0.8 | 3.2 | 2.0 | 1.9E-04 | 0.5 | -- | 45,718 |
| 2006 | 39.4 | 33.1 | 14.0 | 0.9 | 3.4 | 2.2 | 2.0E-04 | 0.5 | -- | 48,437 |
| 2007 | 38.2 | 32.1 | 15.9 | 0.8 | 3.3 | 2.1 | 1.9E-04 | 0.5 | -- | 47,067 |
| 2008 | 35.1 | 29.5 | 14.8 | 0.8 | 3.0 | 1.9 | 1.8E-04 | 0.4 | -- | 43,210 |
| 2009 | 35.5 | 29.8 | 13.0 | 0.8 | 3.1 | 2.0 | 1.8E-04 | 0.4 | -- | 43,651 |
| 2010 | 38.9 | 32.7 | 11.5 | 0.8 | 3.4 | 2.1 | 1.9E-04 | 0.5 | -- | 47,894 |
| 2011 | 31.5 | 26.5 | 8.7 | 0.7 | 2.7 | 1.7 | 1.6E-04 | 0.4 | -- | 38,788 |
| 2012 | 31.1 | 26.1 | 6.0 | 0.7 | 2.7 | 1.7 | 1.6E-04 | 0.4 | 0.001 | 38,290 |
| 2013 | 41.7 | 35.0 | 8.6 | 0.9 | 3.6 | 2.3 | 2.1E-04 | 0.5 | 0.005 | 51,299 |
| 2014 | 45.6 | 38.3 | 14.3 | 1.0 | 4.0 | 2.5 | 2.3E-04 | 0.6 | 0.002 | 56,183 |
| Baseline Average (tpy) | 31.3 | 29.6 | 13.9 | 0.8 | 3.1 | 2.0 | 1.8E-04 | 0.5 | 0.003 | 43,341 |
| Baseline Period | 2011-2012 | 2010-2011 | 2008-2009 | 2010-2011 | 2010-2011 | 2012-2013 | 2010-2011 | 2013-2014 | 2012-2013 | 2010-2011 |
| Baseline Ave Heat Input (MMB | 638,719 | 718,297 | 719,782 | 718,297 | 718,297 | 742,391 | 718,297 | 890,663 | 742,391 | 718,297 |
| COA Heat Input (MMBtu/yr) | 931,136 | 931,136 | 931,136 | 931,136 | 931,136 | 931,136 | 931,136 | 931,136 | 931,136 | 931,136 |
| Excludable Emissions (tpy) | 14.3 | 8.76 | 4.1 | 0.2 | 0.9 | 0.5 | 5.2E-05 | 0.02 | 7.1E-04 | 12,842 |
| BAE + Excludable (tpy) | 45.6 | 38.3 | 18.0 | 1.0 | 4.0 | 2.5 | 2.3E-04 | 0.6 | 0.0037 | 56,183 |
| Baseline EF (lb/MMBtu) | 0.098 | 0.082 | 0.039 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 7.6E-06 | 120.7 |
| Future EF (lb/MMBtu) | 0.098 | 0.082 | 0.032 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 8.7E-06 | 120.7 |
| Projected Act. Emissions (tpy) | 55.8 | 46.9 | 18.0 | 1.2 | 4.8 | 3.1 | 2.8E-04 | 0.7 | 0.005 | 68,730 |
| Emission Increase (tpy) | 10.2 | 8.56 | 0.0 | 0.2 | 0.9 | 0.6 | 5.1E-05 | 0.12 | 0.001 | 12,547 |

Notes:

a - NOx, CO, VOC, and lead emission factor from AP-42 Section 1.4, converted to lb/MMBtu.

b - Baseline SO2 emissions from the heater based on BP's monthly emission summaries. Future SO2 emissions based on a current 200 ppm Sulfur concentration in RFG with a 15% percent increase due to additional coker offgas generation.

c - PM10 emission factor based on 2009 & 2013 refinery source test data. PM emission factor based on 25 percent of PM10 emission factor (average from #2 DHDS Charge Heater and #3 DHDS Charge Heater source tests, fraction of filterable particulate in total particulate).

d - H2SO4 emission factor based on #1 Reformer Heater Source Test (6/26/07).

e - GHG emissions based on carbon in RFG for CO2 and CH4 and N2O emission factors from AP-42 Section 1.4, converted to lb/MMBtu. CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).

f - Baseline H2S emissions from the BP TRI Reporting. Future H2S emissions based on baseline average H2S emission factor with a 15% percent increase due to additional coker offgas generation.

## Greenhouse Gas Emission Factors

| Greenhouse Gas | Emission Factor [b] lb/MMBtu |
|---|---|
| CO2 [a] | 120 |
| CH4 [b] | 0.0023 |
| N2O [b] | 0.0022 |
| CO2e [c] | 120.7 |

notes:

a - CO2 emission factor based on refinery fuel gas analysis and 100% conversion of carbon in fuel to CO2.

b - CH4 and N20 emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf)

BP - Cherry Point

**Coker Heater Replacement Project - Increased Utilization of the ISOM Heater**

**This spreadsheet identifies the increases in emissions of PSD pollutants attributable to increased utilization of the ISOM Unit.**

## Criteria and PSD Pollutant Emissions

**Baseline Heat Input for the ISOM Heater**

| | IHT Heater | Total | Basis |
|---|---|---|---|
| 2005 Heat Input (MMBtu/yr) | 12,372 | 12,372 | Fuel Use Records and Gas Heat Content |
| 2006 Heat Input (MMBtu/yr) | 17,316 | 17,316 | Fuel Use Records and Gas Heat Content |
| 2007 Heat Input (MMBtu/yr) | 18,060 | 18,060 | Fuel Use Records and Gas Heat Content |
| 2008 Heat Input (MMBtu/yr) | 20,808 | 20,808 | Fuel Use Records and Gas Heat Content |
| 2009 Heat Input (MMBtu/yr) | 21,633 | 21,633 | Fuel Use Records and Gas Heat Content |
| 2010 Heat Input (MMBtu/yr) | 22,542 | 22,542 | Fuel Use Records and Gas Heat Content |
| 2011 Heat Input (MMBtu/yr) | 17,965 | 17,965 | Fuel Use Records and Gas Heat Content |
| 2012 Heat Input (MMBtu/yr) | 13,719 | 13,719 | Fuel Use Records and Gas Heat Content |
| 2013 Heat Input (MMBtu/yr) | 29,142 | 29,142 | Fuel Use Records and Gas Heat Content |
| 2014 Heat Input (MMBtu/yr) | 31,075 | 31,075 | Fuel Use Records and Gas Heat Content |
| Future Actual (MMBtu/yr) | | 38,014 | Maximum Past Actual Firing Rate (2014) + 22% percent increase (projected increase in coker unit utilization). |

**Baseline Emissions and Projected Actual Emissions for the ISOM Heater**

| Year | NOx [a] (tpy) | CO [a] (tpy) | SO2 [b] (tpy) | PM [c] (tpy) | PM10/PM2.5 [c] (tpy) | VOC [d] (tpy) | Lead [d] (tpy) | H2SO4 [e] (tpy) | H2S [g] (tpy) | CO2e [f] (tpy) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 0.1 | 0.1 | 0.2 | 0.01 | 0.1 | 0.03 | 3.0E-06 | 0.01 | -- | 746 |
| 2006 | 0.2 | 0.1 | 0.3 | 0.02 | 0.1 | 0.05 | 4.2E-06 | 0.01 | -- | 1,045 |
| 2007 | 0.2 | 0.1 | 0.3 | 0.02 | 0.1 | 0.05 | 4.4E-06 | 0.01 | -- | 1,090 |
| 2008 | 0.2 | 0.1 | 0.4 | 0.02 | 0.1 | 0.1 | 5.1E-06 | 0.01 | -- | 1,256 |
| 2009 | 0.2 | 0.1 | 0.4 | 0.02 | 0.1 | 0.1 | 5.3E-06 | 0.01 | -- | 1,305 |
| 2010 | 0.3 | 0.1 | 0.3 | 0.02 | 0.1 | 0.1 | 5.5E-06 | 0.01 | -- | 1,360 |
| 2011 | 0.2 | 0.1 | 0.2 | 0.02 | 0.1 | 0.05 | 4.4E-06 | 0.01 | -- | 1,084 |
| 2012 | 0.2 | 0.1 | 0.1 | 0.01 | 0.1 | 0.04 | 3.4E-06 | 0.01 | 3.0E-05 | 828 |
| 2013 | 0.3 | 0.2 | 0.4 | 0.03 | 0.1 | 0.08 | 7.1E-06 | 0.02 | 1.6E-04 | 1,758 |
| 2014 | 0.4 | 0.2 | 0.5 | 0.03 | 0.1 | 0.1 | 7.6E-06 | 0.02 | 5.5E-05 | 1,875 |
| Baseline Average (tpy) | 0.2 | 0.1 | 0.4 | 0.02 | 0.1 | 0.1 | 5.0E-06 | 0.02 | 9.3E-05 | 1,222 |
| Baseline Period | 2011-2012 | 2010-2011 | 2008-2009 | 2010-2011 | 2010-2011 | 2012-2013 | 2010-2011 | 2013-2014 | 2012-2013 | 2010-2011 |
| Baseline Ave Heat Input (MMBt | 15,842 | 20,253 | 21,220 | 20,253 | 20,253 | 21,431 | 20,253 | 30,108 | 21,431 | 20,253 |
| COA Heat Input (MMBtu/yr) | 31,075 | 31,075 | 31,075 | 31,075 | 31,075 | 31,075 | 31,075 | 31,075 | 31,075 | 31,075 |
| Excludable Emissions (tpy) | 0.2 | 0.06 | 0.2 | 0.01 | 0.05 | 0.03 | 2.7E-06 | 0.00 | 3.6E-05 | 653 |
| BAE + Excludable (tpy) | 0.4 | 0.2 | 0.6 | 0.03 | 0.1 | 0.1 | 7.6E-06 | 0.02 | 1.3E-04 | 1,875 |
| Baseline EF (lb/MMBtu) | 0.023 | 0.011 | 0.038 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 7.5E-06 | 120.7 |
| Future EF (lb/MMBtu) | 0.033 | 0.011 | 0.032 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 8.6E-06 | 120.7 |
| Projected Act. Emissions (tpy) | 0.6 | 0.2 | 0.6 | 0.04 | 0.2 | 0.1 | 9.3E-06 | 0.02 | 1.6E-04 | 2,294 |
| Emission Increase (tpy) | 0.27 | 0.039 | 0.02 | 7.4E-03 | 2.9E-02 | 1.9E-02 | 1.7E-06 | 4.2E-03 | 3.5E-05 | 419 |

Notes:

a - Baseline NOx and CO emission factors from 9/26/2013 source test. Projected actual NOx and CO emissions based on October 2014 and September 2013 source tests, respectively.

b - Baseline SO2 emissions from the heater based on BP's monthly emission summaries. Future SO2 emissions based on average SO2 emission factor with a 22% percent increase due to additional coker offgas and projected fuel gas usage

c - PM10 emission factor based on 2009 & 2013 refinery source test data. PM emission factor based on 25 percent of PM10 emission factor (average from #2 DHDS Charge Heater and #3 DHDS Charge Heater source tests, fraction of filterable particulate in total particulate).

d - VOC and lead emission factor from AP-42 Section 1.4, converted to lb/MMBtu.

e - H2SO4 emission factor based on #1 Reformer Heater Source Test (6/26/07).

f - GHG emissions based on carbon in RFG for CO2 and CH4 and N2O emission factors from AP-42 Section 1.4, converted to lb/MMBtu. CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).

g - Baseline H2S emissions from the BP TRI Reporting. Future H2S emissions based on baseline average H2S emission factor with a 15% percent increase due to additional coker offgas generation.

## Greenhouse Gas Emission Factors

| Greenhouse Gas | Emission Factor [b] lb/MMBtu |
|---|---|
| CO2 [a] | 120 |
| CH4 [b] | 0.0023 |
| N2O [b] | 0.0022 |
| CO2e [c] | 120.7 |

notes:

a - CO2 emission factor based on refinery fuel gas analysis and 100% conversion of carbon in fuel to CO2.

b - CH4 and N20 emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf)

BP - Cherry Point

**Coker Heater Replacement Project - Increased Utilization of the Crude Unit**

**This spreadsheet identifies the increases in emissions of PSD pollutants attributable to increased utilization of the crude unit.**

## Criteria and PSD Pollutant Emissions

**Baseline Heat Input for Crude Heater**

| | Crude Heater | Basis |
|---|---|---|
| 2005 Heat Input (MMBtu/yr) | 4,322,855 | Fuel Use Records and Gas Heat Content |
| 2006 Heat Input (MMBtu/yr) | 4,710,108 | Fuel Use Records and Gas Heat Content |
| 2007 Heat Input (MMBtu/yr) | 4,802,340 | Fuel Use Records and Gas Heat Content |
| 2008 Heat Input (MMBtu/yr) | 4,701,229 | Fuel Use Records and Gas Heat Content |
| 2009 Heat Input (MMBtu/yr) | 4,776,974 | Fuel Use Records and Gas Heat Content |
| 2010 Heat Input (MMBtu/yr) | 5,090,501 | Fuel Use Records and Gas Heat Content |
| 2011 Heat Input (MMBtu/yr) | 4,196,534 | Fuel Use Records and Gas Heat Content |
| 2012 Heat Input (MMBtu/yr) | 3,712,418 | Fuel Use Records and Gas Heat Content |
| 2013 Heat Input (MMBtu/yr) | 4,839,545 | Fuel Use Records and Gas Heat Content |
| 2014 Heat Input (MMBtu/yr) | 4,796,744 | Fuel Use Records and Gas Heat Content |
| Future Actual (MMBtu/yr) | 5,282,377 | Crude Unit Maximum Past Actual Firing Rate (2010) + 4 percent increase (fewer decokes expected for coker unit and new crude heat exchangers). |

**Baseline Emissions and Projected Actual Emissions for Crude Heater**

| Year | NOx [a] (tpy) | CO [a] (tpy) | SO2 [b] (tpy) | PM [c] (tpy) | PM10/PM2.5 [c] (tpy) | VOC [d] (tpy) | Lead [d] (tpy) | H2SO4 [e] (tpy) | H2S [g] (tpy) | CO2e [f] (tpy) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 399.2 | 31.3 | 72.8 | 4.6 | 18.4 | 11.7 | 1.1E-03 | 2.6 | -- | 261,050 |
| 2006 | 435.0 | 34.1 | 79.0 | 5.0 | 20.0 | 12.7 | 1.2E-03 | 2.8 | -- | 284,436 |
| 2007 | 443.5 | 34.8 | 105.4 | 5.1 | 20.4 | 12.9 | 1.2E-03 | 2.9 | -- | 290,006 |
| 2008 | 434.2 | 34.1 | 174.8 | 5.0 | 20.0 | 12.7 | 1.2E-03 | 2.8 | -- | 283,900 |
| 2009 | 441.2 | 34.6 | 170.1 | 5.1 | 20.3 | 12.9 | 1.2E-03 | 2.9 | -- | 288,474 |
| 2010 | 470.1 | 36.9 | 172.0 | 5.4 | 21.6 | 13.7 | 1.2E-03 | 3.1 | -- | 307,407 |
| 2011 | 387.5 | 30.4 | 147.0 | 4.5 | 17.8 | 11.3 | 1.0E-03 | 2.5 | -- | 253,422 |
| 2012 | 342.8 | 26.9 | 108.0 | 3.9 | 15.8 | 10.0 | 9.1E-04 | 2.2 | 3.7E-03 | 224,187 |
| 2013 | 446.9 | 35.1 | 137.4 | 5.1 | 20.6 | 13.0 | 1.2E-03 | 2.9 | 2.7E-02 | 292,252 |
| 2014 | 443.0 | 34.8 | 159.1 | 5.1 | 20.4 | 12.9 | 1.2E-03 | 2.9 | 8.7E-03 | 289,668 |
| Baseline Average (tpy) | 365.2 | 33.7 | 172.5 | 4.9 | 19.7 | 11.5 | 1.1E-03 | 2.9 | 1.5E-02 | 280,415 |
| Baseline Period | 2011-2012 | 2010-2011 | 2008-2009 | 2010-2011 | 2010-2011 | 2012-2013 | 2010-2011 | 2013-2014 | 2012-2013 | 2010-2011 |
| Baseline Ave Heat Input (MMBt | 3,954,476 | 4,643,518 | 4,739,101 | 4,643,518 | 4,643,518 | 4,275,982 | 4,643,518 | 4,818,144 | 4,275,982 | 4,643,518 |
| COA Heat Input (MMBtu/yr) | 5,090,501 | 5,090,501 | 5,090,501 | 5,090,501 | 5,090,501 | 5,090,501 | 5,090,501 | 5,090,501 | 5,090,501 | 5,090,501 |
| Excludable Emissions (tpy) | 104.9 | 3.2 | 12.8 | 0.5 | 1.9 | 2.2 | 1.1E-04 | 0.2 | 2.7E-03 | 26,993 |
| BAE + Excludable (tpy) | 470.1 | 36.9 | 185.3 | 5.4 | 21.6 | 13.7 | 1.2E-03 | 3.1 | 1.8E-02 | 307,407 |
| Baseline EF (lb/MMBtu) | 0.1847 | 0.0145 | 0.0728 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 6.6E-06 | 120.8 |
| Future EF (lb/MMBtu) | 0.1847 | 0.0145 | 0.0728 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 7.6E-06 | 120.8 |
| Projected Act. Emissions (tpy) | 487.8 | 38.3 | 192.3 | 5.6 | 22.5 | 14.2 | 1.3E-03 | 3.2 | 2.0E-02 | 318,994 |
| Emission Increase (tpy) | 17.7 | 1.4 | 7.0 | 0.2 | 0.8 | 0.5 | 4.7E-05 | 0.12 | 1.9E-03 | 11,587 |

Notes:

a - NOx and CO emission factors are the average source test value from 6/11/2002 and 8/22/2002.

b - Baseline SO2 emissions from the crude unit based on BP's monthly emission summaries. SO2 emission factor based on highest annual average historical SO2 emission factor.

c - PM10 emission factor based on 2009 & 2013 refinery source test data. PM emission factor based on 25 percent of PM10 emission factor (average from #2 DHDS Charge Heater and #3 DHDS Charge Heater source tests, fraction of filterable particulate in total particulate).

d - VOC and lead emission factor from AP-42 Section 1.4, converted to lb/MMBtu.

e - H2SO4 emission factor based on #1 Reformer Heater Source Test (6/26/07).

f - GHG emissions based on carbon in RFG for CO2 and CH4 and N2O emission factors from AP-42 Section 1.4, converted to lb/MMBtu. CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).

g - Baseline H2S emissions from the BP TRI Reporting. Future H2S emissions based on baseline average H2S emission factor with a 15% percent increase due to additional coker offgas generation.

## Greenhouse Gas Emission Factors

| Greenhouse Gas | Emission Factor [b] lb/MMBtu |
|---|---|
| CO2 [a] | 120 |
| CH4 [b] | 0.0023 |
| N2O [b] | 0.0022 |
| CO2e [c] | 120.8 |

notes:

a - CO2 emission factor based on analyses completed for refinery fuel gas (97% of annual fuel-fired in crude unit) and vacuum tail gas (3% of annual fuel-fired in crude unit). Assume 100% conversion of carbon in fuel to CO2.

b - CH4 and N20 emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf)

BP - Cherry Point

**Coker Heater Replacement Project - Increased Utilization of the North Vacuum Heater**

**This spreadsheet identifies the increases in emissions of PSD pollutants attributable to increased utilization of the crude unit.**

## Criteria and PSD Pollutant Emissions

**Baseline Heat Input for N. Vacuum Heater**

| | N. Vac. Heater | Basis |
|---|---|---|
| 2005 Heat Input (MMBtu/yr) | 517,410 | Fuel Use Records and Gas Heat Content |
| 2006 Heat Input (MMBtu/yr) | 526,741 | Fuel Use Records and Gas Heat Content |
| 2007 Heat Input (MMBtu/yr) | 530,748 | Fuel Use Records and Gas Heat Content |
| 2008 Heat Input (MMBtu/yr) | 592,535 | Fuel Use Records and Gas Heat Content |
| 2009 Heat Input (MMBtu/yr) | 549,992 | Fuel Use Records and Gas Heat Content |
| 2010 Heat Input (MMBtu/yr) | 629,492 | Fuel Use Records and Gas Heat Content |
| 2011 Heat Input (MMBtu/yr) | 476,997 | Fuel Use Records and Gas Heat Content |
| 2012 Heat Input (MMBtu/yr) | 428,554 | Fuel Use Records and Gas Heat Content |
| 2013 Heat Input (MMBtu/yr) | 508,071 | Fuel Use Records and Gas Heat Content |
| 2014 Heat Input (MMBtu/yr) | 532,755 | Fuel Use Records and Gas Heat Content |
| Future Actual (MMBtu/yr) | 653,219 | Maximum Past Actual Firing Rate (2010) + 4 percent increase (fewer decokes expected for coker unit and new crude heat exchangers). |

**Baseline Emissions and Projected Actual Emissions for North Vacuum Heater**

| Year | NOx [a] (tpy) | CO [d] (tpy) | SO2 [b] (tpy) | PM [c] (tpy) | PM10/PM2.5 [c] (tpy) | VOC [d] (tpy) | Lead [d] (tpy) | H2SO4 [e] (tpy) | H2S [g] (tpy) | CO2e [f] (tpy) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 40.8 | 21.3 | 9.3 | 0.5 | 2.2 | 1.4 | 1.3E-04 | 0.3 | -- | 31,220 |
| 2006 | 41.5 | 21.7 | 10.0 | 0.6 | 2.2 | 1.4 | 1.3E-04 | 0.3 | -- | 31,783 |
| 2007 | 41.8 | 21.9 | 11.0 | 0.6 | 2.3 | 1.4 | 1.3E-04 | 0.3 | -- | 32,025 |
| 2008 | 46.7 | 24.4 | 12.9 | 0.6 | 2.5 | 1.6 | 1.5E-04 | 0.4 | -- | 35,753 |
| 2009 | 43.3 | 22.6 | 9.8 | 0.6 | 2.3 | 1.5 | 1.3E-04 | 0.3 | -- | 33,186 |
| 2010 | 49.6 | 25.9 | 9.2 | 0.7 | 2.7 | 1.7 | 1.5E-04 | 0.4 | -- | 37,983 |
| 2011 | 37.6 | 19.6 | 6.5 | 0.5 | 2.0 | 1.3 | 1.2E-04 | 0.3 | -- | 28,781 |
| 2012 | 33.8 | 17.6 | 4.0 | 0.5 | 1.8 | 1.2 | 1.1E-04 | 0.3 | 9.6E-04 | 25,858 |
| 2013 | 40.0 | 20.9 | 5.2 | 0.5 | 2.2 | 1.4 | 1.2E-04 | 0.3 | 2.7E-03 | 30,656 |
| 2014 | 44.4 | 21.9 | 8.2 | 0.6 | 2.3 | 1.4 | 1.3E-04 | 0.3 | 9.6E-04 | 32,146 |
| Baseline Average (tpy) | 35.7 | 22.8 | 11.3 | 0.6 | 2.4 | 1.3 | 1.4E-04 | 0.3 | 1.8E-03 | 33,382 |
| Baseline Period | 2011-2012 | 2010-2011 | 2008-2009 | 2010-2011 | 2010-2011 | 2012-2013 | 2010-2011 | 2013-2014 | 2012-2013 | 2010-2011 |
| Baseline Ave Heat Input (MMBt | 452,776 | 553,244 | 571,263 | 553,244 | 553,244 | 468,313 | 553,244 | 520,413 | 468,313 | 553,244 |
| COA Heat Input (MMBtu/yr) | 629,492 | 629,492 | 629,492 | 629,492 | 629,492 | 629,492 | 629,492 | 629,492 | 629,492 | 629,492 |
| Excludable Emissions (tpy) | 13.9 | 3.1 | 1.1 | 0.1 | 0.3 | 0.4 | 1.9E-05 | 0.07 | 6.1E-04 | 4,601 |
| BAE + Excludable (tpy) | 49.6 | 25.9 | 12.5 | 0.7 | 2.7 | 1.7 | 1.5E-04 | 0.4 | 2.4E-03 | 37,983 |
| Baseline EF (lb/MMBtu) | 0.158 | 0.082 | 0.039 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 7.6E-06 | 120.7 |
| Future EF (lb/MMBtu) | 0.167 | 0.082 | 0.032 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 8.7E-06 | 120.7 |
| Projected Act. Emissions (tpy) | 54.4 | 26.9 | 10.3 | 0.7 | 2.8 | 1.8 | 1.6E-04 | 0.4 | 2.8E-03 | 39,414 |
| Emission Increase (tpy) | 4.8 | 1.0 | -2.1 | 0.025 | 0.10 | 0.06 | 5.8E-06 | 0.014 | 4.0E-04 | 1,432 |

Notes:

a - Baseline NOx emission factor is the average source test value from 8/6/2013 and CEMS data. Projected actual NOx emissions based on max annual average NOx emission factor during baseline (annual CEMS data divided by fuel usage).

b - Baseline SO2 emissions from the vacuum heater based on BP's monthly emission summaries. Future SO2 emissions based on average SO2 emission factor with a 27% increase due to additional coker offgas and projected fuel gas usage.

c - PM10 emission factor based on 2009 & 2013 refinery source test data. PM emission factor based on 25 percent of PM10 emission factor (average from #2 DHDS Charge Heater and #3 DHDS Charge Heater source tests, fraction of filterable particulate in total particulate).

d - CO and VOC and lead emission factors from AP-42 Section 1.4, converted to lb/MMBtu.

e - H2SO4 emission factor based on #1 Reformer Heater Source Test (6/26/07).

f - GHG emissions based on carbon in RFG for CO2 and CH4 and N2O emission factors from AP-42 Section 1.4, converted to lb/MMBtu. CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).

g - Baseline H2S emissions from the BP TRI Reporting. Future H2S emissions based on baseline average H2S emission factor with a 15% percent increase due to additional coker offgas generation.

## Greenhouse Gas Emission Factors

| Greenhouse Gas | Emission Factor [b] lb/MMBtu |
|---|---|
| CO2 [a] | 120 |
| CH4 [b] | 0.0023 |
| N2O [b] | 0.0022 |
| CO2e [c] | 120.7 |

notes:

a - CO2 emission factor based on refinery fuel gas analysis and 100% conversion of carbon in fuel to CO2.

b - CH4 and N20 emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf)

BP - Cherry Point

**Coker Heater Replacement Project - Increased Utilization of the South Vacuum Heater**

**This spreadsheet identifies the increases in emissions of PSD pollutants attributable to increased utilization of the crude unit.**

## Criteria and PSD Pollutant Emissions

**Baseline Heat Input for S. Vacuum Heater**

| | S. Vac. Heater | Basis |
|---|---|---|
| 2005 Heat Input (MMBtu/yr) | 1,173,364 | Fuel Use Records and Gas Heat Content |
| 2006 Heat Input (MMBtu/yr) | 1,271,791 | Fuel Use Records and Gas Heat Content |
| 2007 Heat Input (MMBtu/yr) | 1,280,080 | Fuel Use Records and Gas Heat Content |
| 2008 Heat Input (MMBtu/yr) | 1,447,782 | Fuel Use Records and Gas Heat Content |
| 2009 Heat Input (MMBtu/yr) | 1,455,013 | Fuel Use Records and Gas Heat Content |
| 2010 Heat Input (MMBtu/yr) | 1,575,233 | Fuel Use Records and Gas Heat Content |
| 2011 Heat Input (MMBtu/yr) | 1,275,367 | Fuel Use Records and Gas Heat Content |
| 2012 Heat Input (MMBtu/yr) | 1,125,693 | Fuel Use Records and Gas Heat Content |
| 2013 Heat Input (MMBtu/yr) | 1,369,035 | Fuel Use Records and Gas Heat Content |
| 2014 Heat Input (MMBtu/yr) | 1,391,151 | Fuel Use Records and Gas Heat Content |
| Future Actual (MMBtu/yr) | 1,634,607 | Maximum Past Actual Firing Rate (2010) + 4 percent increase (fewer decokes expected for coker unit and new crude heat exchangers). |

**Baseline Emissions and Projected Actual Emissions for South Vacuum Heater**

| Year | NOx [a] (tpy) | CO [a] (tpy) | SO2 [b] (tpy) | PM [c] (tpy) | PM10/PM2.5 [c] (tpy) | VOC [d] (tpy) | Lead [d] (tpy) | H2SO4 [e] (tpy) | H2S [g] (tpy) | CO2e [f] (tpy) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 28.0 | 0.7 | 23.8 | 1.2 | 5.0 | 3.2 | 2.9E-04 | 0.7 | -- | 70,799 |
| 2006 | 25.0 | 0.8 | 26.0 | 1.4 | 5.4 | 3.4 | 3.1E-04 | 0.8 | -- | 76,738 |
| 2007 | 28.5 | 0.8 | 28.4 | 1.4 | 5.4 | 3.5 | 3.1E-04 | 0.8 | -- | 77,238 |
| 2008 | 36.2 | 0.9 | 30.9 | 1.5 | 6.2 | 3.9 | 3.5E-04 | 0.9 | -- | 87,357 |
| 2009 | 35.7 | 0.9 | 25.9 | 1.5 | 6.2 | 3.9 | 3.6E-04 | 0.9 | -- | 87,793 |
| 2010 | 39.7 | 1.0 | 23.0 | 1.7 | 6.7 | 4.2 | 3.9E-04 | 0.9 | -- | 95,047 |
| 2011 | 30.6 | 0.8 | 17.5 | 1.4 | 5.4 | 3.4 | 3.1E-04 | 0.8 | -- | 76,954 |
| 2012 | 28.0 | 0.7 | 11.0 | 1.2 | 4.8 | 3.0 | 2.8E-04 | 0.7 | 4.8E-02 | 67,923 |
| 2013 | 35.0 | 0.9 | 13.9 | 1.5 | 5.8 | 3.7 | 3.4E-04 | 0.8 | 7.3E-03 | 82,606 |
| 2014 | 37.7 | 0.9 | 20.9 | 1.5 | 5.9 | 3.8 | 3.4E-04 | 0.8 | 2.5E-03 | 83,940 |
| Baseline Average (tpy) | 29.3 | 0.9 | 28.4 | 1.5 | 6.1 | 3.4 | 3.5E-04 | 0.8 | 2.7E-02 | 86,001 |
| Baseline Period | 2011-2012 | 2010-2011 | 2008-2009 | 2010-2011 | 2010-2011 | 2012-2013 | 2010-2011 | 2013-2014 | 2012-2013 | 2010-2011 |
| Baseline Ave Heat Input (MMB | 1,200,530 | 1,425,300 | 1,451,398 | 1,425,300 | 1,425,300 | 1,247,364 | 1,425,300 | 1,380,093 | 1,247,364 | 1,425,300 |
| COA Heat Input (MMBtu/yr) | 1,575,233 | 1,575,233 | 1,575,233 | 1,575,233 | 1,575,233 | 1,575,233 | 1,575,233 | 1,575,233 | 1,575,233 | 1,575,233 |
| Excludable Emissions (tpy) | 4.4 | 0.1 | 2.4 | 0.2 | 0.6 | 0.9 | 3.7E-05 | 0.12 | 7.8E-03 | 9,047 |
| BAE + Excludable (tpy) | 33.7 | 1.0 | 30.8 | 1.7 | 6.7 | 4.2 | 3.9E-04 | 0.9 | 3.5E-02 | 95,047 |
| Baseline EF (lb/MMBtu) | 0.023 | 0.0013 | 0.039 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 4.8E-05 | 120.7 |
| Future EF (lb/MMBtu) | 0.054 | 0.0013 | 0.032 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 5.5E-05 | 120.7 |
| Projected Act. Emissions (tpy) | 44.3 | 1.0 | 25.9 | 1.7 | 6.9 | 4.4 | 4.0E-04 | 1.0 | 4.5E-02 | 98,630 |
| Emission Increase (tpy) | 10.6 | 0.038 | -4.9 | 0.063 | 0.25 | 0.16 | 1.5E-05 | 0.036 | 9.5E-03 | 3,583 |

Notes:

a - Baseline NOx emission factor based on CEMS data and fuel gas usage. CO emission factor based on the average source test value from 11/21/2003, 8/4/2005 and 6/14/2006. Projected actual NOx emissions based on max annual average NOx emission factor during baseline (annual CEMS data divided by fuel usage).

b - Baseline SO2 emissions from the vacuum heater based on BP's monthly emission summaries. Future SO2 emissions based on average SO2 emission factor with a 27% increase due to additional coker offgas and projected fuel gas usage.

c - PM10 emission factor based on 2009 & 2013 refinery source test data. PM emission factor based on 25 percent of PM10 emission factor (average from #2 DHDS Charge Heater and #3 DHDS Charge Heater source tests, fraction of filterable particulate in total particulate).

d - VOC and lead emission factor from AP-42 Section 1.4, converted to lb/MMBtu.

e - H2SO4 emission factor based on #1 Reformer Heater Source Test (6/26/07).

f - GHG emissions based on carbon in RFG for CO2 and CH4 and N2O emission factors from AP-42 Section 1.4, converted to lb/MMBtu. CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).

g - Baseline H2S emissions from the BP TRI Reporting. Future H2S emissions based on baseline average H2S emission factor with a 15% percent increase due to additional coker offgas generation.

## Greenhouse Gas Emission Factors

| Greenhouse Gas | Emission Factor [b] lb/MMBtu |
|---|---|
| CO2 [a] | 120 |
| CH4 [b] | 0.0023 |
| N2O [b] | 0.0022 |
| CO2e [c] | 120.7 |

notes:

a - CO2 emission factor based on refinery fuel gas analysis and 100% conversion of carbon in fuel to CO2.

b - CH4 and N20 emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf)

BP - Cherry Point

**Coker Heater Replacement Project - Increased Utilization of the No. 1 Reformer Heaters**

**This spreadsheet identifies the increases in emissions of PSD pollutants attributable to increased utilization of the reformer unit.**

## Criteria and PSD Pollutant Emissions

**Baseline Heat Input for No.1 Reformer**

| | No. 1 Reformer | Basis |
|---|---|---|
| 2005 Heat Input (MMBtu/yr) | 4,718,541 | Fuel Use Records and Gas Heat Content |
| 2006 Heat Input (MMBtu/yr) | 5,008,995 | Fuel Use Records and Gas Heat Content |
| 2007 Heat Input (MMBtu/yr) | 4,034,187 | Fuel Use Records and Gas Heat Content |
| 2008 Heat Input (MMBtu/yr) | 4,876,995 | Fuel Use Records and Gas Heat Content |
| 2009 Heat Input (MMBtu/yr) | 5,032,428 | Fuel Use Records and Gas Heat Content |
| 2010 Heat Input (MMBtu/yr) | 5,150,115 | Fuel Use Records and Gas Heat Content |
| 2011 Heat Input (MMBtu/yr) | 4,295,110 | Fuel Use Records and Gas Heat Content |
| 2012 Heat Input (MMBtu/yr) | 4,097,454 | Fuel Use Records and Gas Heat Content |
| 2013 Heat Input (MMBtu/yr) | 4,385,538 | Fuel Use Records and Gas Heat Content |
| 2014 Heat Input (MMBtu/yr) | 4,025,435 | Fuel Use Records and Gas Heat Content |
| Future Actual (MMBtu/yr) | 5,344,237 | Maximum Past Actual Firing Rate (2010) + 4 percent increase (fewer decokes expected for coker unit and new crude heat exchangers). |

**Baseline Emissions and Projected Actual Emissions for No. 1 Reformer**

| Year | NOx [a] (tpy) | CO [a] (tpy) | SO2 [b] (tpy) | PM [c] (tpy) | PM10/PM2.5 [c] (tpy) | VOC [a] (tpy) | Lead [d] (tpy) | H2SO4 [a] (tpy) | H2S [f] (tpy) | CO2e [e] (tpy) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 287.8 | 0.2 | 85.1 | 5.0 | 20.1 | 4.5 | 1.2E-03 | 2.8 | -- | 284,710 |
| 2006 | 305.5 | 0.3 | 90.0 | 5.3 | 21.3 | 4.8 | 1.2E-03 | 3.0 | -- | 302,236 |
| 2007 | 246.1 | 0.2 | 83.4 | 4.3 | 17.1 | 3.8 | 9.9E-04 | 2.4 | -- | 243,417 |
| 2008 | 297.5 | 0.2 | 100.6 | 5.2 | 20.7 | 4.6 | 1.2E-03 | 2.9 | -- | 294,271 |
| 2009 | 307.0 | 0.3 | 89.9 | 5.3 | 21.4 | 4.8 | 1.2E-03 | 3.0 | -- | 303,649 |
| 2010 | 314.2 | 0.3 | 75.0 | 5.5 | 21.9 | 4.9 | 1.3E-03 | 3.1 | -- | 310,750 |
| 2011 | 262.0 | 0.2 | 58.3 | 4.6 | 18.3 | 4.1 | 1.1E-03 | 2.6 | -- | 259,161 |
| 2012 | 249.9 | 0.2 | 40.0 | 4.4 | 17.4 | 3.9 | 1.0E-03 | 2.5 | 9.1E-03 | 247,234 |
| 2013 | 267.5 | 0.2 | 45.0 | 4.7 | 18.6 | 4.2 | 1.1E-03 | 2.6 | 2.3E-02 | 264,617 |
| 2014 | 245.6 | 0.2 | 61.6 | 4.3 | 17.1 | 3.8 | 9.9E-04 | 2.4 | 7.3E-03 | 242,889 |
| Baseline Average (tpy) | 256.0 | 0.2 | 95.3 | 5.0 | 20.1 | 4.0 | 1.2E-03 | 2.5 | 1.6E-02 | 284,956 |
| Baseline Period | 2011-2012 | 2010-2011 | 2008-2009 | 2010-2011 | 2010-2011 | 2012-2013 | 2010-2011 | 2013-2014 | 2012-2013 | 2010-2011 |
| Baseline Ave Heat Input (MMB | 4,196,282 | 4,722,613 | 4,954,711 | 4,722,613 | 4,722,613 | 4,241,496 | 4,722,613 | 4,205,487 | 4,241,496 | 4,722,613 |
| COA Heat Input (MMBtu/yr) | 5,150,115 | 5,150,115 | 5,150,115 | 5,150,115 | 5,150,115 | 5,150,115 | 5,150,115 | 5,150,115 | 5,150,115 | 5,150,115 |
| Excludable Emissions (tpy) | 58.2 | 0.02 | 3.8 | 0.5 | 1.8 | 0.9 | 1.0E-04 | 0.57 | 3.4E-03 | 25,795 |
| BAE + Excludable (tpy) | 314.2 | 0.3 | 99.0 | 5.5 | 21.9 | 4.9 | 1.3E-03 | 3.1 | 2.0E-02 | 310,750 |
| Baseline EF (lb/MMBtu) | 0.122 | 0.0001 | 0.038 | 0.0021 | 0.0085 | 0.0019 | 4.90E-07 | 0.0012 | 7.6E-06 | 120.7 |
| Future EF (lb/MMBtu) | 0.122 | 0.0001 | 0.032 | 0.0021 | 0.0085 | 0.0019 | 4.90E-07 | 0.0012 | 8.7E-06 | 120.7 |
| Projected Act. Emissions (tpy) | 326.0 | 0.3 | 84.6 | 5.7 | 22.7 | 5.1 | 1.3E-03 | 3.2 | 2.3E-02 | 322,464 |
| Emission Increase (tpy) | 11.8 | 0.010 | -14.4 | 0.206 | 0.83 | 0.18 | 4.8E-05 | 0.12 | 3.5E-03 | 11,713 |

Notes:

a - NOx, CO, VOC (as VOC), and H2SO4 emission factors based on 6/26/2007 source test.

b - Baseline SO2 emissions from the reformer based on BP's monthly emission summaries. Future SO2 emissions based on average SO2 emission factor with a 27% increase due to additional coker offgas and projected fuel gas usage.

c - PM10 emission factor based on 2009 & 2013 refinery source test data. PM emission factor based on 25 percent of PM10 emission factor (average from #2 DHDS Charge Heater and #3 DHDS Charge Heater source tests, fraction of filterable particulate in total particulate).

d - lead emission factor from AP-42 Section 1.4, converted to lb/MMBtu.

e - GHG emissions based on carbon in RFG for CO2 and CH4 and N2O emission factors from AP-42 Section 1.4, converted to lb/MMBtu. CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).

f - Baseline H2S emissions from the BP TRI Reporting. Future H2S emissions based on baseline average H2S emission factor with a 15% percent increase due to additional coker offgas generation.

## Greenhouse Gas Emission Factors

| Greenhouse Gas | Emission Factor [b] lb/MMBtu |
|---|---|
| CO2 [a] | 120 |
| CH4 [b] | 0.0023 |
| N2O [b] | 0.0022 |
| CO2e [c] | 120.7 |

notes:

a - CO2 emission factor based on refinery fuel gas analysis and 100% conversion of carbon in fuel to CO2.

b - CH4 and N20 emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf)

BP - Cherry Point

## Coker Heater Replacement Project - Increased Utilization of the No. 2 Reformer Heaters

**This spreadsheet identifies the increases in emissions of PSD pollutants attributable to increased utilization of the reformer unit.**

### Criteria and PSD Pollutant Emissions

**Baseline Heat Input for No. 2 Reformer Heaters**

| | No. 2 Reformer | Basis |
|---|---|---|
| 2005 Heat Input (MMBtu/yr) | 869,563 | Fuel Use Records and Gas Heat Content |
| 2006 Heat Input (MMBtu/yr) | 792,781 | Fuel Use Records and Gas Heat Content |
| 2007 Heat Input (MMBtu/yr) | 975,574 | Fuel Use Records and Gas Heat Content |
| 2008 Heat Input (MMBtu/yr) | 801,512 | Fuel Use Records and Gas Heat Content |
| 2009 Heat Input (MMBtu/yr) | 795,856 | Fuel Use Records and Gas Heat Content |
| 2010 Heat Input (MMBtu/yr) | 867,054 | Fuel Use Records and Gas Heat Content |
| 2011 Heat Input (MMBtu/yr) | 755,929 | Fuel Use Records and Gas Heat Content |
| 2012 Heat Input (MMBtu/yr) | 736,572 | Fuel Use Records and Gas Heat Content |
| 2013 Heat Input (MMBtu/yr) | 825,197 | Fuel Use Records and Gas Heat Content |
| 2014 Heat Input (MMBtu/yr) | 850,432 | Fuel Use Records and Gas Heat Content |
| Future Actual (MMBtu/yr) | 1,012,346 | Maximum Past Actual Firing Rate (2007) + 4 percent increase (fewer decokes expected for coker unit and new crude heat exchangers). |

**Baseline Emissions and Projected Actual Emissions for No. 2 Reformer**

| Year | NOx [a] (tpy) | CO [a] (tpy) | SO2 [b] (tpy) | PM [c] (tpy) | PM10/PM2.5 [c] (tpy) | VOC [a] (tpy) | Lead [d] (tpy) | H2SO4 [e] (tpy) | H2S [g] (tpy) | CO2e [f] (tpy) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 36.5 | 0.7 | 15.7 | 0.9 | 3.7 | 0.8 | 2.1E-04 | 0.5 | -- | 52,468 |
| 2006 | 33.3 | 0.7 | 14.0 | 0.8 | 3.4 | 0.8 | 1.9E-04 | 0.5 | -- | 47,835 |
| 2007 | 41.0 | 0.8 | 20.3 | 1.0 | 4.1 | 0.9 | 2.4E-04 | 0.6 | -- | 58,865 |
| 2008 | 33.7 | 0.7 | 18.1 | 0.9 | 3.4 | 0.8 | 2.0E-04 | 0.5 | -- | 48,362 |
| 2009 | 33.4 | 0.7 | 14.1 | 0.8 | 3.4 | 0.8 | 2.0E-04 | 0.5 | -- | 48,021 |
| 2010 | 36.4 | 0.7 | 12.5 | 0.9 | 3.7 | 0.8 | 2.1E-04 | 0.5 | -- | 52,317 |
| 2011 | 31.7 | 0.6 | 10.4 | 0.8 | 3.2 | 0.7 | 1.9E-04 | 0.5 | -- | 45,612 |
| 2012 | 30.9 | 0.6 | 7.0 | 0.8 | 3.1 | 0.7 | 1.8E-04 | 0.4 | 1.6E-03 | 44,444 |
| 2013 | 34.7 | 0.7 | 8.3 | 0.9 | 3.5 | 0.8 | 2.0E-04 | 0.5 | 4.4E-03 | 49,791 |
| 2014 | 35.7 | 0.7 | 13.1 | 0.9 | 3.6 | 0.8 | 2.1E-04 | 0.5 | 1.5E-03 | 51,314 |
| Baseline Average (tpy) | 31.3 | 0.7 | 16.1 | 0.9 | 3.4 | 0.7 | 2.0E-04 | 0.5 | 3.0E-03 | 48,964 |
| Baseline Period | 2011-2012 | 2010-2011 | 2008-2009 | 2010-2011 | 2010-2011 | 2012-2013 | 2010-2011 | 2013-2014 | 2012-2013 | 2010-2011 |
| Baseline Ave Heat Input (MMBt | 746,251 | 811,491 | 798,684 | 811,491 | 811,491 | 780,885 | 811,491 | 837,815 | 780,885 | 811,491 |
| COA Heat Input (MMBtu/yr) | 975,574 | 975,574 | 975,574 | 975,574 | 975,574 | 975,574 | 975,574 | 975,574 | 975,574 | 975,574 |
| Excludable Emissions (tpy) | 9.6 | 0.14 | 3.6 | 0.2 | 0.7 | 0.2 | 4.0E-05 | 0.08 | 7.4E-04 | 9,900 |
| BAE + Excludable (tpy) | 41.0 | 0.8 | 19.7 | 1.0 | 4.1 | 0.9 | 2.4E-04 | 0.6 | 3.8E-03 | 58,865 |
| Baseline EF (lb/MMBtu) | 0.084 | 0.0017 | 0.040 | 0.0021 | 0.0085 | 0.0019 | 4.90E-07 | 0.0012 | 7.6E-06 | 120.7 |
| Future EF (lb/MMBtu) | 0.084 | 0.0017 | 0.032 | 0.0021 | 0.0085 | 0.0019 | 4.90E-07 | 0.0012 | 8.7E-06 | 120.7 |
| Projected Act. Emissions (tpy) | 42.5 | 0.9 | 16.0 | 1.1 | 4.3 | 1.0 | 2.5E-04 | 0.6 | 4.4E-03 | 61,083 |
| Emission Increase (tpy) | 1.5 | 0.031 | -3.6 | 0.039 | 0.16 | 0.03 | 9.0E-06 | 0.02 | 6.4E-04 | 2,219 |

Notes:
a - NOx and CO emission factors based on 12/15/2011 source test. VOC emission factor (as VOC) based on 6/26/2007 source test for #1 Reformer.
b - Baseline SO2 emissions from the reformer based on BP's monthly emission summaries. Future SO2 emissions based on average SO2 emission factor with a 27% increase due to additional coker offgas and projected fuel gas usage.
c - PM10 emission factor based on 2009 & 2013 refinery source test data. PM emission factor based on 25 percent of PM10 emission factor (average from #2 DHDS Charge Heater and #3 DHDS Charge Heater source tests, fraction of filterable particulate in total particulate).
d - lead emission factor from AP-42 Section 1.4, converted to lb/MMBtu.
e - H2SO4 emission factor based on #1 Reformer Heater Source Test (6/26/07).
f - GHG emissions based on carbon in RFG for CO2 and CH4 and N2O emission factors from AP-42 Section 1.4, converted to lb/MMBtu. CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).
g - Baseline H2S emissions from the BP TRI Reporting. Future H2S emissions based on baseline average H2S emission factor with a 15% percent increase due to additional coker offgas generation.

### Greenhouse Gas Emission Factors

| Greenhouse Gas | Emission Factor [b] lb/MMBtu |
|---|---|
| CO2 [a] | 120 |
| CH4 [b] | 0.0023 |
| N2O [b] | 0.0022 |
| CO2e [c] | 120.7 |

notes:
a - CO2 emission factor based on refinery fuel gas analysis and 100% conversion of carbon in fuel to CO2.
b - CH4 and N20 emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf)

BP - Cherry Point

**Coker Heater Replacement Project - Increased Utilization of the No. 1 Hydrogen Plant Furnaces**

**This spreadsheet identifies the increases in emissions of PSD pollutants attributable to increased utilization of the No. 1 Hydrogen Plant Furnaces**

## Criteria and PSD Pollutant Emissions

**Baseline Heat Input for No. 1 Hydrogen Plant Furnaces**

| | #1 Furnace | #2 Furnace | Total | Basis |
|---|---|---|---|---|
| 2005 Heat Input (MMBtu/yr) | 2,275,949 | 2,201,916 | 4,477,865 | Fuel Use Records and Gas Heat Content |
| 2006 Heat Input (MMBtu/yr) | 2,073,681 | 1,980,931 | 4,054,612 | Fuel Use Records and Gas Heat Content |
| 2007 Heat Input (MMBtu/yr) | 2,238,477 | 2,165,276 | 4,403,753 | Fuel Use Records and Gas Heat Content |
| 2008 Heat Input (MMBtu/yr) | 2,404,814 | 2,386,783 | 4,791,597 | Fuel Use Records and Gas Heat Content |
| 2009 Heat Input (MMBtu/yr) | 2,312,758 | 2,271,256 | 4,584,015 | Fuel Use Records and Gas Heat Content |
| 2010 Heat Input (MMBtu/yr) | 2,554,180 | 2,559,269 | 5,113,449 | Fuel Use Records and Gas Heat Content |
| 2011 Heat Input (MMBtu/yr) | 2,405,607 | 2,541,137 | 4,946,744 | Fuel Use Records and Gas Heat Content |
| 2012 Heat Input (MMBtu/yr) | 2,105,045 | 2,048,562 | 4,153,607 | Fuel Use Records and Gas Heat Content |
| 2013 Heat Input (MMBtu/yr) | 990,155 | 990,155 | 1,980,310 | Fuel Use Records and Gas Heat Content |
| 2014 Heat Input (MMBtu/yr) | 1,206,877 | 1,206,877 | 2,413,755 | Fuel Use Records and Gas Heat Content |
| Future Actual (MMBtu/yr) | | | 5,306,189 | Maximum Past Actual Firing Rate (2010) + 4 percent increase (fewer decokes expected for coker unit and new crude heat exchangers). |

**Baseline Emissions and Projected Actual Emissions for Naphtha Heaters**

| Year | NOx [a] (tpy) | CO [a] (tpy) | SO2 [b] (tpy) | PM [c] (tpy) | PM10/PM2.5 [c] (tpy) | VOC [a] (tpy) | Lead [a] (tpy) | H2SO4 [d] (tpy) | H2S [g] (tpy) | CO2e [e] Comb. (tpy) | CO2e [f] Proc. (tpy) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 219.5 | 184.4 | 80.8 | 4.8 | 19.0 | 12.1 | 1.1E-03 | 2.7 | -- | 270,188 | 358,996 |
| 2006 | 198.8 | 167.0 | 73.0 | 4.3 | 17.2 | 10.9 | 9.9E-04 | 2.4 | -- | 244,649 | 325,063 |
| 2007 | 215.9 | 181.3 | 90.4 | 4.7 | 18.7 | 11.9 | 1.1E-03 | 2.6 | -- | 265,716 | 353,054 |
| 2008 | 234.9 | 197.3 | 105.0 | 5.1 | 20.4 | 12.9 | 1.2E-03 | 2.9 | -- | 289,118 | 384,148 |
| 2009 | 224.7 | 188.8 | 81.7 | 4.9 | 19.5 | 12.4 | 1.1E-03 | 2.8 | -- | 276,593 | 367,506 |
| 2010 | 250.7 | 210.6 | 66.7 | 5.4 | 21.7 | 13.8 | 1.3E-03 | 3.1 | -- | 308,538 | 409,951 |
| 2011 | 242.5 | 203.7 | 67.3 | 5.3 | 21.0 | 13.3 | 1.2E-03 | 3.0 | -- | 298,479 | 415,886 |
| 2012 | 203.6 | 171.0 | 40.0 | 4.4 | 17.7 | 11.2 | 1.0E-03 | 2.5 | 0.009 | 250,623 | 316,795 |
| 2013 | 97.1 | 81.5 | 19.8 | 2.1 | 8.4 | 5.3 | 4.9E-04 | 1.2 | 0.011 | 119,489 | 293,661 |
| 2014 | 118.3 | 99.4 | 38.7 | 2.6 | 10.3 | 6.5 | 5.9E-04 | 1.4 | 0.004 | 145,642 | 293,661 |
| Baseline Average (tpy) | 223.0 | 207.1 | 93.3 | 5.3 | 21.4 | 8.3 | 1.2E-03 | 1.3 | 0.010 | 303,509 | 412,919 |
| Baseline Period | 2011-2012 | 2010-2011 | 2008-2009 | 2010-2011 | 2010-2011 | 2012-2013 | 2010-2011 | 2013-2014 | 2012-2013 | 2010-2011 | 2010-2011 |
| Baseline Ave Heat Input (MMBt | 4,550,175 | 5,030,096 | 4,687,806 | 5,030,096 | 5,030,096 | 3,066,959 | 5,030,096 | 2,197,033 | 3,066,959 | 5,030,096 | 5,030,096 |
| COA Heat Input (MMBtu/yr) | 5,113,449 | 5,113,449 | 5,113,449 | 5,113,449 | 5,113,449 | 5,113,449 | 5,113,449 | 5,113,449 | 5,113,449 | 5,113,449 | 5,113,449 |
| Excludable Emissions (tpy) | 27.6 | 3.43 | 8.5 | 0.1 | 0.4 | 5.5 | 2.0E-05 | 1.75 | 7.7E-03 | 5,029 | 6,682 |
| BAE + Excludable (tpy) | 250.7 | 210.6 | 101.8 | 5.4 | 21.7 | 13.8 | 1.3E-03 | 3.1 | 0.0177 | 308,538 | 419,601 |
| Baseline EF (lb/MMBtu) | 0.098 | 0.082 | 0.040 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 7.6E-06 | 120.7 | -- |
| Future EF (lb/MMBtu) | 0.098 | 0.082 | 0.032 | 0.0021 | 0.0085 | 0.0054 | 4.90E-07 | 0.0012 | 8.7E-06 | 120.7 | -- |
| Projected Act. Emissions (tpy) | 260.1 | 218.5 | 84.0 | 5.6 | 22.6 | 14.3 | 1.3E-03 | 3.2 | 0.023 | 320,168 | 425,404 |
| Emission Increase (tpy) | 9.4 | 7.94 | -17.7 | 0.2 | 0.8 | 0.5 | 4.7E-05 | 0.12 | 0.005 | 11,630 | 5,802 |

Notes:

a - NOx, CO, VOC, and lead emission factor from AP-42 Section 1.4, converted to lb/MMBtu.

b - Baseline SO2 emissions from the furnaces based on BP's monthly emission summaries. Future SO2 emissions based on average SO2 emission factor with a 27% increase due to additional coker offgas and projected fuel gas usage.

c - PM10 emission factor based on 2009 & 2013 refinery source test data. PM emission factor based on 25 percent of PM10 emission factor (average from #2 DHDS Charge Heater and #3 DHDS Charge Heater source tests, fraction of filterable particulate in total particulate).

d - H2SO4 emission factor based on #1 Reformer Heater Source Test (6/26/07).

e - GHG combustion emissions based on carbon in RFG for CO2 and CH4 and N2O emission factors from AP-42 Section 1.4, converted to lb/MMBtu. CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).

f - Process CO2 emissions for 2011 - 2013 based on GHG reporting. 2005 - 2010 process CO2 emissions based on annual heat input and the 2011 & 2012 average process CO2 emitted per heat input (0.080 ton CO2/MMBtu).

g - Baseline H2S emissions from the BP TRI Reporting. Future H2S emissions based on baseline average H2S emission factor with a 15% percent increase due to additional coker offgas generation.

## Greenhouse Gas Emission Factors

| Greenhouse Gas | Emission Factor [b] lb/MMBtu |
|---|---|
| CO2 [a] | 120 |
| CH4 [b] | 0.0023 |
| N2O [b] | 0.0022 |
| CO2e [c] | 120.7 |

notes:

a - CO2 emission factor based on refinery fuel gas analysis and 100% conversion of carbon in fuel to CO2.

b - CH4 and N20 emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf)

BP - Cherry Point

## Coker Heater Replacement Project - Cooling Tower Emissions Increase

### Increase in Total Criteria Pollutant Emission Increases Attributable to Project

| Year | PM [a] (tpy) | PM10 [b] (tpy) | PM2.5 [b] (tpy) | VOC [a] (tpy) |
|---|---|---|---|---|
| | | | | |
| 2008 | 11.1 | 1.83 | 0.015 | 20.9 |
| 2009 | 13.4 | 2.20 | 0.018 | 20.9 |
| 2010 | 12.6 | 2.08 | 0.017 | 21.6 |
| 2011 | 12.5 | 2.05 | 0.016 | 2.0 |
| 2012 | 26.0 | 4.28 | 0.034 | 1.0 |
| 2013 | 29.0 | 4.77 | 0.038 | 0.0 |
| 2014 | 30.0 | 4.94 | 0.040 | 0.3 |
| Baseline Period | 2010-2011 | 2010-2011 | 2010-2011 | 2012-2013 |
| Baseline | 12.6 | 2.1 | 0.017 | 0.5 |
| Projected Emissions [c] | 32.4 | 5.33 | 0.043 | 2.2 |
| Emission Increase | 19.8 | 3.26 | 0.0261 | 1.7 |

a - Particulate matter and VOC emissions based on annual BP emission reporting.
b - PM10 and PM2.5 are 16.45% and 0.13% of PM emissions, based Calculating Realistic PM10 Emissions from Cooling Towers, Greystone Environmental Consultants
c - Projected emission increase based on an 8% increase in cooling tower utilization as part of the project. Projected VOC emissions based on highest historical actual emissions (2011 - 2014) and an 8% increase.

**Cooling Tower Reference Data**

| Drift (%) | TDS (ppmw) | TDS Specific Gravity * |
|---|---|---|
| 0.0006% | 7,357 | 2.2 |

* TDS specific gravity corresponding to NaCl.

***Calculations***

Cooling Tower Particulate Emissions Size Distribution

Volume of drift droplet = $(4/3)p(D_d/2)^3$

Droplet mass = (Volume of drift droplet)($r_w$)

Mass of solids in drift droplet = (TDS)($r_w$)(Volume of drift droplet)

Solid particle volume = (Particle mass of solids) / ($r_{TDS}$)

$D_p = D_d\ [(TDS)(\rho_w/\rho_{TDS})]^{1/3}$

where:

$D_p$ = diameter of solid particle (µm)

$D_d$ = diameter of drift droplet (µm)

TDS = total dissolved solids content (ppmw)

$\rho_w$ = density of water = 1E-6 mg/mm3

$\rho_{TDS}$ = density of solid particles (assume NaCl)

**Size Distribution for Cooling Tower Particulate Emissions ***

| EPRI Droplet Diameter (mm ) | Droplet Volume ($mm^3$ ) | Droplet Mass (mg ) | Particle Mass (Solids) (mg ) | Solid Particle Volume ($mm^3$ ) | Solid Particle Diameter (mm ) | EPRI % Mass Smaller |
|---|---|---|---|---|---|---|
| 10 | 524 | 5.24E-04 | 3.85.E-06 | 1.75 | 1.50 | 0.00 |
| 20 | 4,189 | 4.19E-03 | 3.08.E-05 | 14.01 | 2.99 | 0.20 |
| 30 | 14,137 | 1.41E-02 | 1.04.E-04 | 47.3 | 4.49 | 0.23 |
| 40 | 33,510 | 3.35E-02 | 2.47.E-04 | 112.1 | 5.98 | 0.51 |
| 50 | 65,450 | 6.54E-02 | 4.82.E-04 | 219 | 7.48 | 1.82 |
| 60 | 113,097 | 1.13E-01 | 8.32.E-04 | 378 | 8.97 | 5.70 |
| 70 | 179,594 | 1.80E-01 | 1.32.E-03 | 601 | 10.47 | 21.35 |
| 90 | 381,704 | 3.82E-01 | 2.81.E-03 | 1,276 | 13.5 | 49.81 |
| 110 | 696,910 | 6.97E-01 | 5.13.E-03 | 2,331 | 16.4 | 70.51 |
| 130 | 1,150,347 | 1.15E+00 | 8.46.E-03 | 3,847 | 19.4 | 82.02 |
| 150 | 1,767,146 | 1.77E+00 | 1.30.E-02 | 5,909 | 22.4 | 88.01 |
| 180 | 3,053,628 | 3.05E+00 | 2.25.E-02 | 10,211 | 26.9 | 91.03 |
| 210 | 4,849,048 | 4.85E+00 | 3.57.E-02 | 16,215 | 31.4 | 92.47 |
| 240 | 7,238,229 | 7.24E+00 | 5.33.E-02 | 24,205 | 35.9 | 94.09 |
| 270 | 10,305,995 | 1.03E+01 | 7.58.E-02 | 34,464 | 40.4 | 94.69 |
| 300 | 14,137,167 | 1.41E+01 | 1.04.E-01 | 47,275 | 44.9 | 96.29 |
| 350 | 22,449,298 | 2.24E+01 | 1.65.E-01 | 75,072 | 52.3 | 97.01 |
| 400 | 33,510,322 | 3.35E+01 | 2.47.E-01 | 112,060 | 59.8 | 98.34 |
| 450 | 47,712,938 | 4.77E+01 | 3.51.E-01 | 159,554 | 67.3 | 99.07 |
| 500 | 65,449,847 | 6.54E+01 | 4.82.E-01 | 218,868 | 74.8 | 99.07 |
| 600 | 113,097,336 | 1.13E+02 | 8.32.E-01 | 378,203 | 89.7 | 100.00 |

PM10 Emissions from Cooling Towers."

**$PM_{10}$ and $PM_{2.5}$ Fractions Interpolated from Size Distribution**

| $PM_{2.5}$ Fraction of Total PM (%) | $PM_{10}$ Fraction of Total PM (%) |
|---|---|
| 0.13 | 16.5 |

BP - Cherry Point
**Clean Fuels Project - Increased Utilization of WWTP**

### Increase in Total Criteria Pollutant Emission Increases Attributable to Project

BP conservatively projects a 7% increase in cooling water and wastewater for the project.

| Year | VOC [a] (tpy) | H2S [b] (tpy) |
|---|---|---|
| 2007 | 25.3 | -- |
| 2008 | 20.6 | -- |
| 2009 | 25.1 | -- |
| 2010 | 22.6 | -- |
| 2011 | 12.6 | -- |
| 2012 | 13.0 | 2.6 |
| 2013 | 20.0 | 2.4 |
| 2014 | 13.0 | 2.5 |
| Baseline Period | 2012-2013 | 2012-2013 |
| Baseline (2012-2013) | 16.5 | 2.5 |
| Projected Emissions [c] | 17.7 | 2.7 |
| Emission Increase | 1.2 | 0.2 |

a - Past actual VOC emissions based on Water 9 Model results waste water input rate, VOC concentrations in waste water, and treatment plant design (APIs, Aeration Basin, Clarifiers).
f - Baseline H2S emissions from the BP TRI Reporting.
c - Projected VOC and H2S emission increase conservatively based on a 7% increase in emissions from the baseline.

BP - Cherry Point

# Coker Heater Replacement Project - Increased Utilization of Storage Tanks

## This spreadsheet identifies the increases in emissions of PSD pollutants attributable to the Project.

BP conservatively projects a 4% increase in liquid product storage for the project.

## Criteria and PSD Pollutant Emissions

**Baseline Emissions and Projected Actual Emissions for refinery floating roof and fixed roof storage tanks**

| Year | VOC [a] (tpy) |
|---|---|
| 2005 | 117.0 |
| 2006 | 127.0 |
| 2007 | 133.0 |
| 2008 | 133.2 |
| 2009 | 152.8 |
| 2010 | 173.4 |
| 2011 | 176.0 |
| 2012 | 127.0 |
| 2013 | 204.0 |
| 2014 | 144.0 |
| Baseline Average (tpy) | 165.5 |
| Baseline Period | 2012-2013 |
| Projected Act. Emissions (tpy) | 171.7 |
| Emission Increase (tpy) | 6.2 |

Notes:

a - Past actual VOC emissions based on annual BP reporting using EPA's TANKS program.

b - Projected actual emissions based on a 4% increase in annual crude throughput at refinery. Baseline emissions conservatively scaled up by 4%.

BP - Cherry Point

**Coker Heater Replacement Project - Increased Utilization of Truck Loading**

**This spreadsheet identifies the increases in emissions of PSD pollutants attributable to 1% increase in crude processing.**

BP conservatively projects a 4% increase in product loadout for the project.

**Criteria and PSD Pollutant Emissions**

Truck Loading Rack and VCU

| Year | NOx [a] (tpy) | CO [a] (tpy) | SO2 [a] (tpy) | PM [a] (tpy) | PM10/PM2.5 [a] (tpy) | VOC [a] (tpy) | CO2e [b] (tpy) |
|---|---|---|---|---|---|---|---|
| 2005 | 2.6 | 6.2 | 0.00 | 0.3 | 0.3 | 3.9 | 1,067 |
| 2006 | 2.3 | 5.0 | 0.01 | 0.3 | 0.3 | 3.4 | 944 |
| 2007 | 2.4 | 0.3 | 0.01 | 0.3 | 0.3 | 0.1 | 985 |
| 2008 | 2.7 | 0.3 | 0.02 | 0.3 | 0.3 | 0.1 | 1,108 |
| 2009 | 2.4 | 0.3 | 0.01 | 0.3 | 0.3 | 0.1 | 1,004 |
| 2010 | 3.1 | 0.3 | 0.02 | 0.4 | 0.4 | 0.1 | 1,292 |
| 2011 | 5.6 | 1.8 | 0.03 | 0.6 | 0.6 | 0.3 | 2,282 |
| 2012 | 6.0 | 2.0 | 0.04 | 1.0 | 1.0 | 0.3 | 2,691 |
| 2013 | 6.0 | 2.0 | 0.00 | 1.0 | 1.0 | 0.0 | 1,924 |
| 2014 | 6.2 | 1.5 | 0.04 | 0.7 | 0.7 | 0.1 | 1,809 |
| Baseline Average (tpy) | 5.8 | 1.1 | 0.02 | 0.5 | 0.5 | 0.2 | 1,787 |
| Baseline Period | 2011-2012 | 2010-2011 | 2008-2009 | 2010-2011 | 2010-2011 | 2012-2013 | 2010-2011 |
| COA (tpy) [c] | 6.2 | 6.2 | 0.04 | 1.0 | 1.0 | 3.9 | 2,691 |
| Excludable Emissions (tpy) | 0.4 | 5.1 | 0.02 | 0.5 | 0.5 | 3.8 | 905 |
| BAE + Excludable (tpy) | 6.2 | 6.2 | 0.04 | 1.0 | 1.0 | 3.9 | 2,691 |
| Projected Act. Emissions (tpy) [d] | 6.4 | 6.4 | 0.04 | 1.0 | 1.0 | 4.0 | 2,793 |
| Emission Increase (tpy) | 0.23 | 0.23 | 1.5E-03 | 0.038 | 0.038 | 0.15 | 101 |

Notes:

a - Past actual emissions based on annual BP reporting.

b - Greenhouse gas emissions based on calculations from 2011 and 2012. 2005 - 2011 annual GHG emission estimates based on scaling 2011 emissions.

c - Capable of accomodating based on highest loading emissions during lookback period.

d - Projected actual emissions based on a 4% increase in annual crude throughput at refinery. Maximum baseline annual emissions conservatively scaled up by 4%.

Marine Loading and VCU

| Year | NOx [a] (tpy) | CO [a] (tpy) | SO2 [a] (tpy) | PM [a] (tpy) | PM10/PM2.5 [a] (tpy) | VOC [a] (tpy) | CO2e [b] (tpy) |
|---|---|---|---|---|---|---|---|
| 2005 | 33.0 | 2.0 | 0.00 | 0.0 | 0.0 | 61.2 | 3,328 |
| 2006 | 23.0 | 2.0 | 0.00 | 0.0 | 0.0 | 49.3 | 3,328 |
| 2007 | 35.0 | 2.0 | 0.02 | 0.3 | 0.3 | 66.1 | 3,328 |
| 2008 | 36.5 | 1.8 | 0.02 | 0.3 | 0.3 | 55.7 | 2,995 |
| 2009 | 43.9 | 4.5 | 0.05 | 0.1 | 0.1 | 58.1 | 7,499 |
| 2010 | 35.9 | 2.0 | 0.02 | 0.3 | 0.3 | 89.1 | 3,379 |
| 2011 | 29.7 | 2.2 | 0.03 | 0.3 | 0.3 | 37.7 | 3,627 |
| 2012 | 27.8 | 2.4 | 0.03 | 0.4 | 0.4 | 13.9 | 4,067 |
| 2013 | 20.0 | 2.0 | 0.00 | 0.0 | 0.0 | 29.0 | 3,414 |
| 2014 | 18.7 | 1.8 | 0.02 | 0.3 | 0.0 | 33.4 | 3,132 |
| Baseline Average (tpy) | 28.8 | 2.1 | 0.04 | 0.3 | 0.3 | 21.5 | 3,503 |
| Baseline Period | 2011-2012 | 2010-2011 | 2008-2009 | 2010-2011 | 2010-2011 | 2012-2013 | 2010-2011 |
| COA (tpy) [c] | 43.9 | 4.5 | 0.05 | 0.4 | 0.4 | 89.1 | 7,499 |
| Excludable Emissions (tpy) | 15.1 | 2.4 | 0.02 | 0.1 | 0.1 | 67.7 | 3,996 |
| BAE + Excludable (tpy) | 43.9 | 4.5 | 0.05 | 0.4 | 0.4 | 89.1 | 7,499 |
| Projected Act. Emissions (tpy) [d] | 45.5 | 4.7 | 0.05 | 0.4 | 0.4 | 92.5 | 7,782 |
| Emission Increase (tpy) | 1.7 | 0.17 | 2.0E-03 | 0.014 | 0.014 | 3.4 | 283 |

Notes:

a - Past actual emissions based on annual BP reporting.

b - Greenhouse gas emissions based on calculations from 2011 and 2012. 2005 - 2011 annual GHG emission estimates based on scaling 2011 emissions.

c - Capable of accomodating based on highest loading emissions during lookback period.

d - Projected actual emissions based on a 4% increase in annual crude throughput at refinery. Maximum baseline annual emissions conservatively scaled up by 4%.

Railcar Loading

| Year | VOC [a] (tpy) |
|---|---|
| 2009 | 5.3 |
| 2010 | 8.2 |
| 2011 | 8.0 |
| 2012 | 0.0 |
| 2013 | 0.0 |
| 2014 | 0.0 |
| Baseline Average (tpy) | 0.0 |
| Baseline Period | 2012-2013 |
| COA (tpy) [b] | 8.2 |
| Excludable Emissions (tpy) | 8.2 |
| BAE + Excludable (tpy) | 8.2 |
| Projected Act. Emissions (tpy) [c] | 8.5 |
| Emission Increase (tpy) | 0.3 |

Notes:

a - Past actual emissions based on annual BP reporting.

b - Capable of accomodating based on highest loading emissions during lookback period.

c - Projected actual emissions based on a 4% increase in annual crude throughput at refinery. Maximum baseline annual emissions conservatively scaled up by 4%.

BP - Cherry Point

## Coker Heater Replacement Project - Increased Flaring

### HP Flare Emission Calculations for Replacement of Catalysts in DHDS units, Naphtha, and ISOM

- Typically shutdown emissions will be captured by flare gas recovery system, but to be conservative emission calcs were included.
- Assume one additional reactor shutdown (replacement of catalyst) for each process unit during their 5 - 6 year cycle. Conservatively estimate emissiosn based on one per year.

| | |
|---|---|
| Number of Shutdowns | 1 shutdown/yr |
| Historical Flare Heat Input | 5,882 MMBtu/shutdown |

- Shutdown depressurizing catalyst reactor (hydrocarbons), depressurizing reactor with nitrogen until opened to atmosphere, and then pressurizing reactor to bring back into service.

| Flare Stack Parameter Calculations [a] | | Shutdown long-term (1 shutdown/yr) |
|---|---|---|
| Total Heat release | cal/s | 47,033 |
| Radiative Heat Loss | % | 25.0 |
| Net Heat Release | cal/s | 35274.7 |
| Effective Stack Diameter | m | 0.186 |
| Physical Stack Height | m | 68.0 |
| Effective Stack Height | m | 68.8 |

a - Flare release parameters calculated using EPA Guidance Document: EPA-450/4-88-010 (Screening Procedures for Estimating the Air Quality Impact of Stationary Sources).

### Criteria and PSD Pollutant Emissions

| | Pollutant | HP Flare - Shutdown Emission Factor lb/MMBtu | Emission Rate [g] tpy |
|---|---|---|---|
| 10102-44- | NOx [a] | 0.068 | 0.20 |
| 630-08-0 | CO [a] | 0.37 | 1.09 |
| 7446-09-0 | SO2 [b] | -- | 0.15 |
| | PM (Filt.) [c] | 0.0021 | 0.0062 |
| | PM10 (Filt. & Cond.) [c] | 0.0085 | 0.0250 |
| | PM2.5 (Filt. & Cond.)[c] | 0.0085 | 0.0250 |
| | VOC (as CH4) [a] | 0.14 | 0.41 |
| 7439-92-1 | Lead [d] | 4.9E-07 | 1.4E-06 |
| 7664-93-9 | H2SO4 [e] | -- | 0.0060 |
| | CO2e [f] | 1.4 | 4.21 |

notes:
a - NOx, CO, and VOC emission factors based on AP-42, Secion 13.5 (Industrial Flares).
b - SO2 emission rate based on historical maximum yearly emissions from shutdown/start-up (DHDS units, naphtha, and ISOM).
c - PM10 emission factor based on 2009 & 2013 refinery source test data. PM emission factor based on 25 percent of PM10 emission factor (average from #2 DHDS Charge Heater and #3 DHDS Charge Heater source tests, fraction of filterable particulate in total particulate).
d - Lead emission factor based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf).
e - H2SO4 emission rate based on 2.63 percent of sulfur converting to H2SO4 (Source Test of #1 Reformer firing RFG).
f - GHG emissions based on carbon in RFG for CO2 and CH4 and N2O emission factors from AP-42 Section 1.4, converted to lb/MMBtu. CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).
g - Hourly and annual emission rates based on 5,882.0 mmBtu/shutdown and 1 shutdown per year.

### Greenhouse Gas Emissions

| Greenhouse Gas | HP Flare - Shutdown Emission Factor [b] lb/MMBtu |
|---|---|
| CO2 [a] | 0.732 |
| CH4 [b] | 0.0023 |
| N2O [b] | 0.0022 |
| CO2e [c] | 1.4 |

notes:
a - CO2 emission factor based on #3 DHDS gas composition and 100% conversion of carbon to CO2.
b - CH3 and N20 emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/mmBtu using natural gas heat content (1,020 btu/cf)
c - GHG emissions based on carbon in RFG for CO2 and CH4 and N2O emission factors from AP-42 Section 1.4, converted to lb/MMBtu. CO2e calculated based on global warming potential (GWP) for each Greenhouse gas: CO2 = 1; CH4 = 25; and N2O = 298 (40 CFR Part 98, Subpart A).

BP - Cherry Point

## Coker Heater Replacement Project - Increased Utilization of the Crude Unloading

**This spreadsheet identifies the increases in emissions of PSD pollutants attributable to increased utilization of ship unloading. (Emissions from Ship unloading are considered secondary and not part of the Refinery. BP has estimated the annual increase in ship em**

### Criteria Pollutant Emissions

**Baseline Emissions and Projected Actual Emissions for the Crude Unloading**

| Year | NOx [a] (tpy) | CO [a] (tpy) | SO2 [a, b] (tpy) | PM [a] (tpy) | PM10/PM2.5 [a] (tpy) | VOC [a] (tpy) |
|---|---|---|---|---|---|---|
| 2011 | 31.8 | 4.4 | 263.7 | 8.7 | 8.7 | 2.8 |
| 2012 | 40.0 | 5.0 | 254.0 | 11.0 | 11.0 | 4.0 |
| Average (tpy) | 35.9 | 4.7 | 258.9 | 9.9 | 9.9 | 3.4 |
| Emission Increase (tpy) | 1.4 | 0.177 | 0.98 | 3.7E-01 | 3.7E-01 | 1.3E-01 |

Notes:
a - Emission increase from shiop unloading based on 4% higher crude throughput at the refinery. Calculated average from 2011 and 2012 and then scaled up by 4%.
b - SO2 emission increase includes a drop from 1.0% sulfur in marine fuel oil to 0.1% in 2015.

# Appendix D

## Secondary Aerosol Analysis

## *Appendix D: Secondary $PM_{2.5}$ Analysis*

Air emission sources complying with the federal Prevention of Significant Deterioration (PSD) rules are required to assess the influence of primary particulate matter less than 2.5 micrometers in aerodynamic diameter ($PM_{2.5}$) and, additionally, the impacts of potential formation of secondary $PM_{2.5}$.

Precursors of $PM_{2.5}$ include nitrogen oxides ($NO_X$), sulfur dioxides ($SO_2$), and volatile organic compounds (VOCs). These precursors, under specific atmospheric conditions, and in the presence of other chemicals integral to the photochemical processes that form secondary $PM_{2.5}$, may coagulate on existing particles or nucleate into new particles. Understanding the state of $PM_{2.5}$ chemical composition near a PSD source is essential to assessing the influence that the PSD source could have on secondary $PM_{2.5}$ formation.

The U.S. Environmental Protection Agency (USEPA) has provided guidance that allows for a hybrid qualitative and quantitative assessment of secondary $PM_{2.5}$ formation attributable to new or modified sources subject to PSD. The intent of the assessment is to provide sufficient evidence that the potential formation of secondary $PM_{2.5}$ would not result in total $PM_{2.5}$ levels (i.e., primary plus secondary $PM_{2.5}$) that exceed the NAAQS. Provided that the hybrid approach demonstrates adequate margin between the total $PM_{2.5}$ impacts and the NAAQS, a quantitative photochemical grid modeling assessment is not required.

This memo has been prepared in response to the USEPA guidance regarding secondary $PM_{2.5}$ formation. Included is a hybrid assessment akin to the example provided within the USEPA guidance. Historic sulfate and nitrate composition at nearby $PM_{2.5}$ speciation monitors were reviewed and interpollutant trading ratios for $PM_{2.5}$ offsets were applied to conservatively assess the project-specific influence of secondary $PM_{2.5}$.

### *Historic Evaluation of Sulfate and Nitrate Composition*

Monitoring data from two Interagency Monitoring of Protected Visual Environments (IMPROVE) sites were reviewed for the period between 2004 and 2014 to document regional nitrate and sulfate composition near the project site. The analyzed IMPROVE sites are located in Whatcom (AQS Site: 053-073-0022) and Clallam (AQS Site: 053-009-0020) counties. Additionally, the nitrate and sulfate composition measured at a Snohomish county Chemical Speciation Network site (AQS Site: 053-061-1007) was reviewed for the period between 2009 and 2014. No speciation data was available at this site prior to 2009.

The results of the historic composition analysis indicate that approximately 12-23 percent of 24-Hr $PM_{2.5}$ samples are attributable to sulfate and 4-9 percent of the $PM_{2.5}$ is attributable to nitrate. In an effort to understand whether sulfate or nitrate were driving peak $PM_{2.5}$ concentrations, the composition of the top ten $PM_{2.5}$ 24-hour observations were also assessed. These top $PM_{2.5}$ concentrations corresponded with smaller fractions of both nitrate and sulfate than the mean

values, indicating that high concentrations of $PM_{2.5}$ were largely due to species other than nitrate or sulfate. Overall, the monitored data demonstrate that $PM_{2.5}$ composition is composed of a larger fraction of sulfate than nitrate, and that neither component plays a role in driving peak $PM_{2.5}$ concentrations. The results of the historic analysis are provided in Table 1.

Table 1: 2004-2013 $PM_{2.5}$ sulfate and nitrate composition

| Site | AQS | $SO_4$ (% of 24-Hr $PM_{2.5}$ concentration [ug/m$^3$]) | | $NO_3$ (% of 24-Hr $PM_{2.5}$ concentration [ug/m$^3$]) | |
|---|---|---|---|---|---|
| | | Mean of Observations | Top 10 | Mean of Observations | Top 10 |
| Port Angeles, Clallam County | 053-009-0020 | 21.42% | 13.00% | 8.77% | 3.32% |
| North Cascades, Whatcom County | 053-073-0022 | 22.95% | 9.77% | 4.39% | 1.51% |
| Marysville, Snohomish County[a] | 053-061-1007 | 12.04% | 2.38% | 8.93% | 4.02% |

[a]Data in Marysville for $SO_4$ and $NO_3$ were only available for the 2009-2014 period

The relationship between nitrogen oxide and sulfur dioxide emissions to respective nitrate and sulfate compositions were also explored. The Washington Department of Ecology provides the Large Business Prevention of Significant Deterioration Modeling Inventory for the years 2005-2008. These data provide an estimate of the annual emissions of nitrogen oxides and sulfur dioxide for large emission sources within Washington. This inventory provided the Whatcom and Clallam emissions for comparison to the annual averaged nitrate and sulfate fraction in measured $PM_{2.5}$. The Snohomish $PM_{2.5}$ composition data were not compared to the Snohomish county emissions because speciation measurements were not available until 2009.

At both sites, the $PM_{2.5}$ composition of nitrate and sulfate did not have a strong correlation with their respective emissions of nitrogen dioxides and sulfur dioxides. The variation in the $PM_{2.5}$ composition of nitrate and sulfate was minimal compared to the magnitude of change in emissions. The nitrate composition of $PM_{2.5}$ did not vary by more than a percent and the sulfate composition varied at most by five percent. Comparison plots of the emissions and the monitored composition are provided in Figure 1 and Figure 2. While the corresponding emissions data are not available, it's worth noting that the year-to-year composition data measured in Snohomish County (2009-2014) were consistent with the stability in composition seen in Whatcom and Clallam. These results demonstrate that despite large changes in county-wide emissions of $PM_{2.5}$ precursors, the overall formation of secondary $PM_{2.5}$ in this region is expected to be minimal.

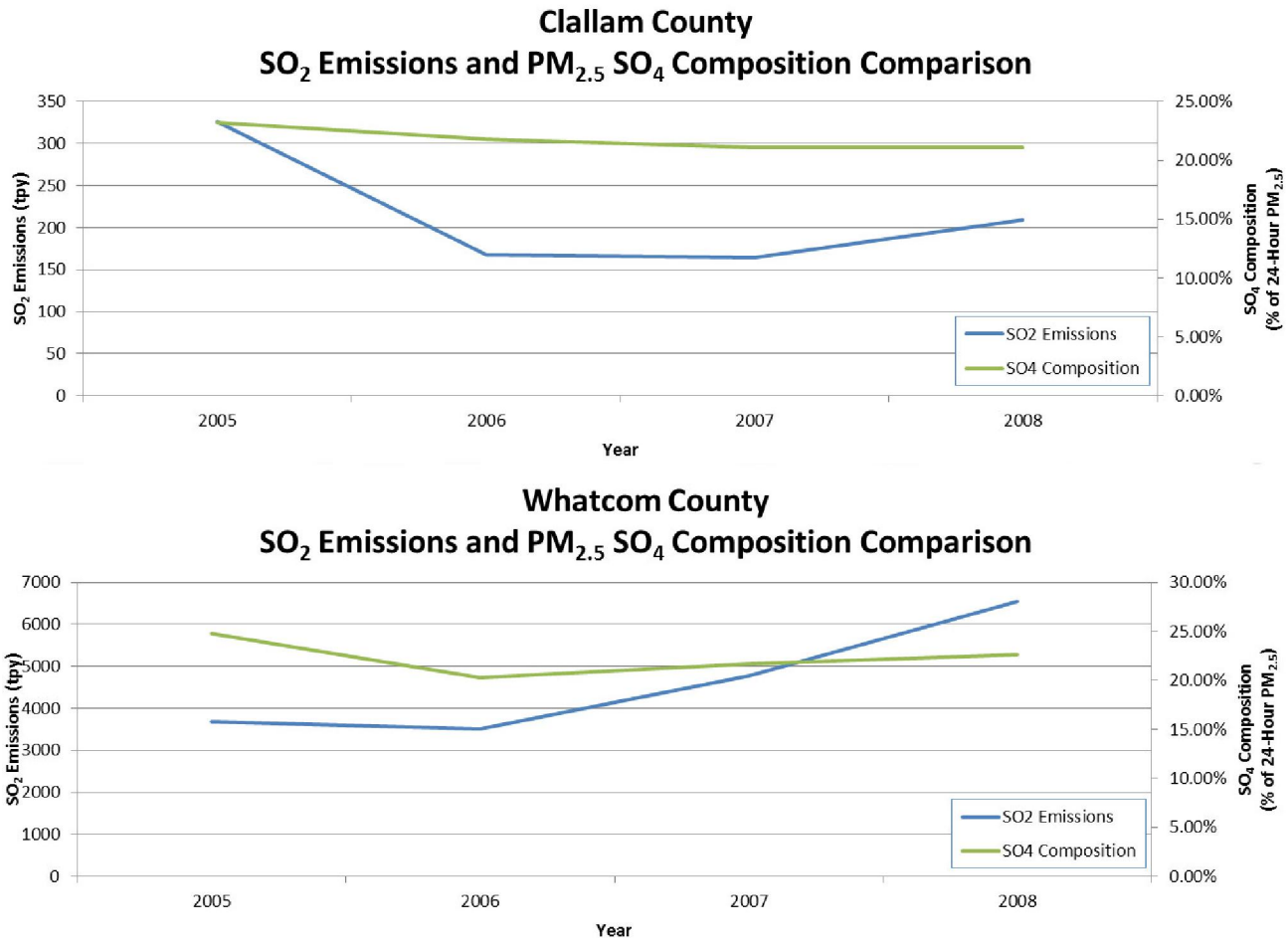



Figure 1: Comparison of Clallam and Whatcom Counties $SO_2$ Emissions and Particulate $SO_4$ Measurements

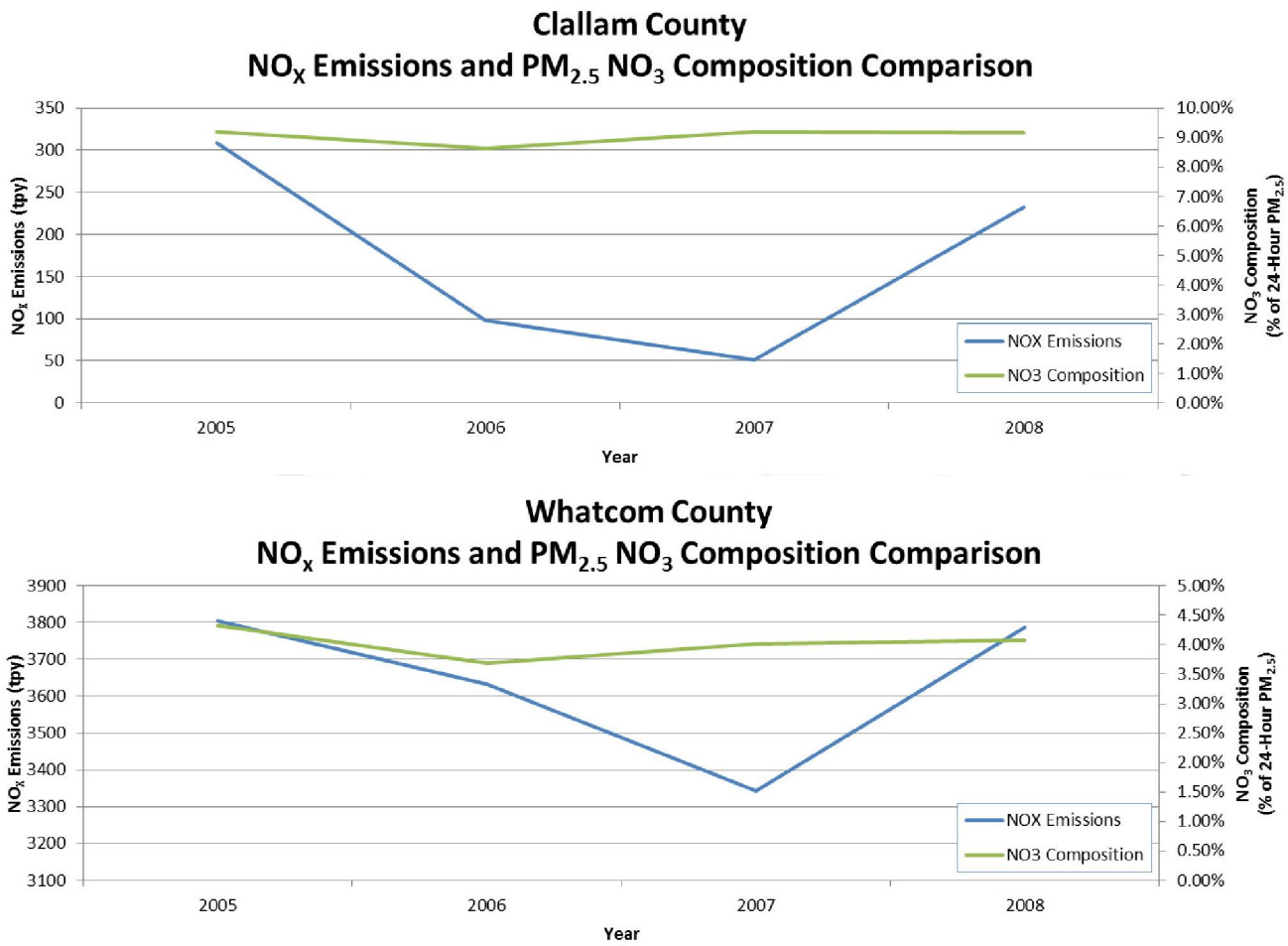



Figure 2: Comparison of Clallam and Whatcom Counties $NO_X$ Emissions and Particulate $NO_3$ Measurements

## *Application of Interpollutant Trading Ratios*

The analysis of historical composition of $PM_{2.5}$ near the project site and a comparison to the secondary $PM_{2.5}$ precursor emissions indicates that the likely impact from secondary $PM_{2.5}$ formation is minimal. An estimate of the secondary $PM_{2.5}$ contribution to the modeling results was made using the previously approved interpollutant trading ratios[1]. These estimates are conservative due to the low likelihood of the primary and secondary impacts being paired in time and space. Within the Western U.S., the interpollutant trading ratios were defined as 1 ton per year (tpy) of $PM_{2.5}$ for every 100 tpy of $NO_X$ or 40 tpy of $SO_2$ emitted. These trading ratios were applied to the project emission rates of $NO_X$ and $SO_2$ to conservatively estimate the increase in $PM_{2.5}$ due to

[1] "Details on Technical Assessment to Develop Interpollutant Trading Ratios for $PM_{2.5}$ Offsets", U.S. Environmental Protection Agency, Docket # EPA-HQ-OAR-2003-0062, July 23, 2007.

secondary formation. These secondary emissions were added to the primary $PM_{2.5}$ emissions to obtain a new overall $PM_{2.5}$ emission rate. The increased $PM_{2.5}$ emission rate was divided by the primary emission rate to obtain a scaling value for use with the AERMOD results. The results of this assessment are provided in Table 2.

Table 2: Interpollutant Trading Ratio Analysis

| Pollutant | Project Net Emission Increase (tpy) | Interpollutant Trading Ratio | $PM_{2.5}$ Equivalent (tpy) |
|---|---|---|---|
| $SO_2$ | 221 | 40 | 6 |
| $NO_X$ | 268 | 100 | 3 |
| $PM_{2.5}$ | 62 | 1 | 62 |
| TOTAL $PM_{2.5}$ Emission (tpy) | | | 70 |
| Modeled $PM_{2.5}$ Scaling Value | | | 1.13 |

The maximum AERMOD-predicted concentrations of $PM_{2.5}$ were 0.9 ug/m$^3$ and 0.24 ug/m$^3$ for 24-hour and annual averaging times respectively. These concentrations increase to 1.0 ug/m$^3$ and 0.28 ug/m$^3$ for the 24-hour and annual periods respectively when the model scaling factor from the interpollutant trading ratio assessment is applied. These conservative estimates of impacts due to secondary $PM_{2.5}$ formation fall below the SIL for 24-hour average and rounded to the SIL for annual average. A summary of the interpollutant trading ratio assessment applied to the AERMOD results is provided in Table 3.

Scaling AERMOD-predicted concentrations is very conservative because it assumes primary and secondary $PM_{2.5}$ impacts occur at the same location and time period. The 24-hour and annual average primary $PM_{2.5}$ impacts occur on the facility fenceline, and AERMOD-predicted concentrations decrease significantly from peak concentrations after only a couple of kilometers from the fenceline. Formation of secondary nitrate and sulfate particulate is a slow process occurring over several hours to days. Therefore, the highest secondary $PM_{2.5}$ impacts would occur downwind of the highest primary $PM_{2.5}$ impacts.

Table 3: Interpollutant Trading Ratio Analysis Results

| Averageing Period | AERMOD Maximum Concentration (µg/m$^3$) | Scaled AERMOD Concentration (µg/m$^3$) | Significant Impact Level (µg/m$^3$) |
|---|---|---|---|
| 24-Hour | 0.9 | 1.0 | 1.2 |
| Annual | 0.24 | 0.28 | 0.3 |

# Appendix E

## Regional Ozone Analysis

## Regional Ozone Analysis

Ramboll Environ has evaluated how the increase in emissions attributable to the Coker Heater Project would affect local and regional ozone concentrations. This simulation used the US EPA's Community Multi-scale Air Quality model (CMAQ) to simulate July 25-30, 1998. This is one of the more severe historical ozone episodes, and similar modeling analyses have been used several times to estimate the effects of increases in NOx and VOC emissions greater than 100 tons per year.

The modeling simulations were based on those developed by Washington State University (WSU) Laboratory for Atmospheric Research in support of a state implementation plan (SIP) for Ozone for the Portland, OR/Vancouver, WA region[1]. This is essentially the same dataset used by WSU as the base case scenario to analyze future emission scenarios for the Puget Sound Clean Air Agency (PSCAA)[2]. In those analyses, as well as this, a three-day period beginning July 26, 1998 was selected because the episode had the highest observed ozone levels in recent years for the Seattle/Portland airshed.

The base case scenario emissions inventory is based on the 1999 National Emissions Inventory, using its point sources, area sources and some non-road sources (ships, locomotives, aircraft, etc.). A detailed discussion of the base case scenario emission inventory is presented in the appendixes of the WSU SIP and PSCAA reports.

The PTE scenario included all the emissions in the base case, plus emissions from the new point sources and increases in existing point sources associated with the project. Emission rates are summarized in Table 3-2, and emission release parameters are provided in Table 5-2 of the application. These emission source data were prepared for use with CMAQ using SMOKE preprocessing programs.

Both the base case and Project simulations were modeled. Maximum increases in ozone concentration with the Project occurred in the 4$^{th}$ hour of the simulation (i.e, during the spin-up portion of the model) and were less than 0.75 ppb. Generally speaking, the Project NOx emissions decreased ozone concentrations near the facility by a few tenths of a ppb due to ozone titration, and increased the ozone concentration far from the facility by a few hundredths of a ppb. For comparison, the ozone NAAQS value is 70 ppb. Figure E-1 shows that the maximum ozone concentration occurs in Canada for this episode, at 14:00 LST on July 27, 1998.

---

[1] Historical and Future Ozone Simulations using the MM5/SMOKE/CMAQ System in the Portland/Vancouver Area, Ying Xie and Brian Lamb, Laboratory of Atmospheric Research, Department of Civil & Environmental Engineering, WSU. December 31, 2005.

[2] Modeling Analysis of Future Emission Scenarios for Ozone Impacts in the Puget Sound Area, Brian Lamb and Ying Xie, Laboratory of Atmospheric Research, Department of Civil & Environmental Engineering, WSU; Clint Bowman, Sally Otterson, and Doug Schneider, Washington State Department of Ecology; and Kathy Himes, John Anderson, Kwame Agyei, and Beth Carper, PSCAA. August, 2006.

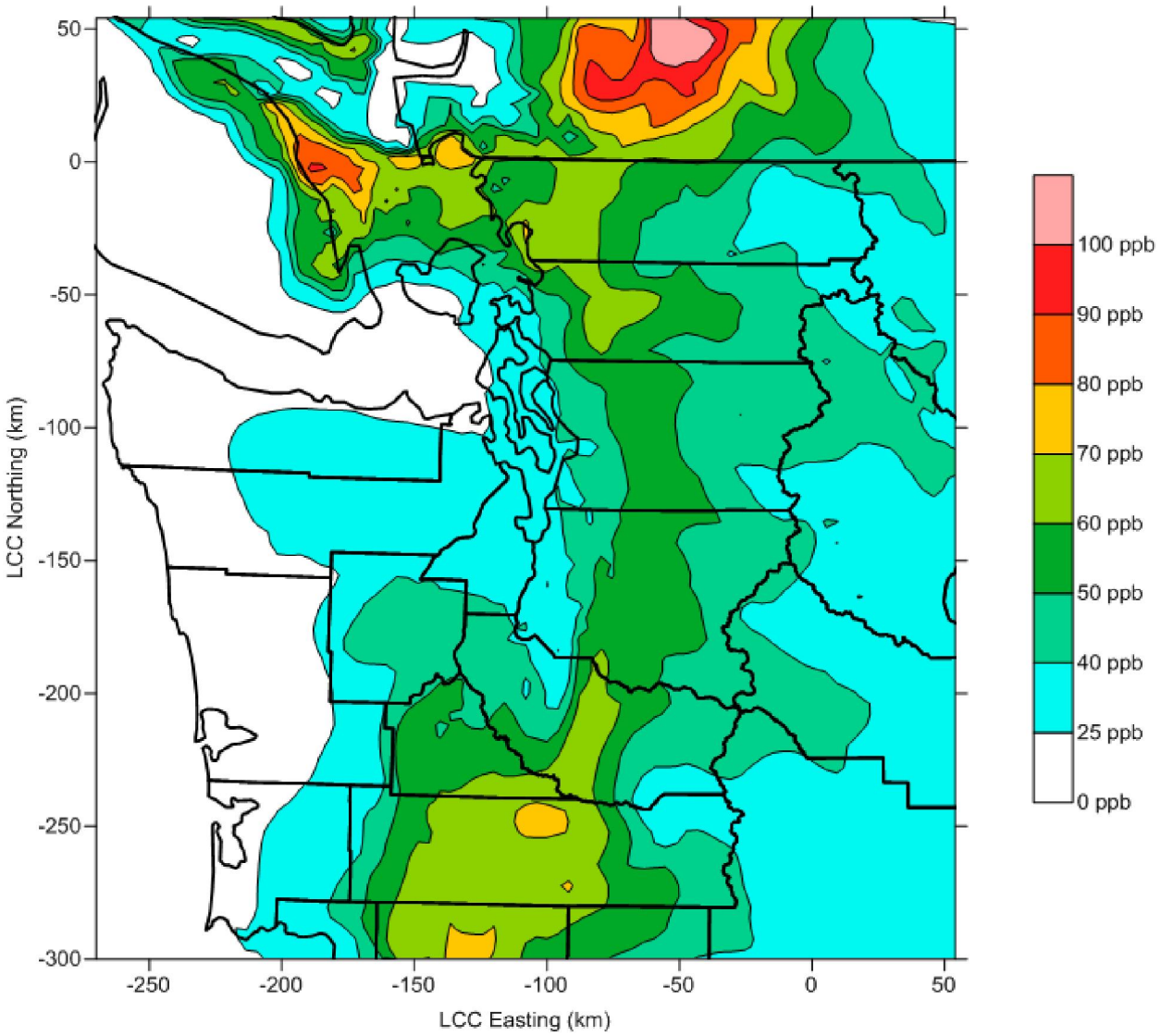



Figure E-1: Simulated 8-hr average $O_3$ concentration at 14:00 LST on July 27, 1998.

A side-by-side comparison of the output is not useful, as the changes attributable to the Project are hard to see. Instead, the difference between the two runs was investigated to examine the impact of the Project. Figure E-2 shows the spatial variation of 8-hour average ozone concentration difference between the PTE case and the base case, during the period of maximum difference in Canada. The increases of ozone concentrations in Canada due to this project are very small, less than 0.25 ppb. The near-field NOx titration effect is clearly shown by the decrease in $O_3$ concentrations near the facility. The ozone even decreased in portion of the lower Frasier Valley, while increasing by about the same amount further east.

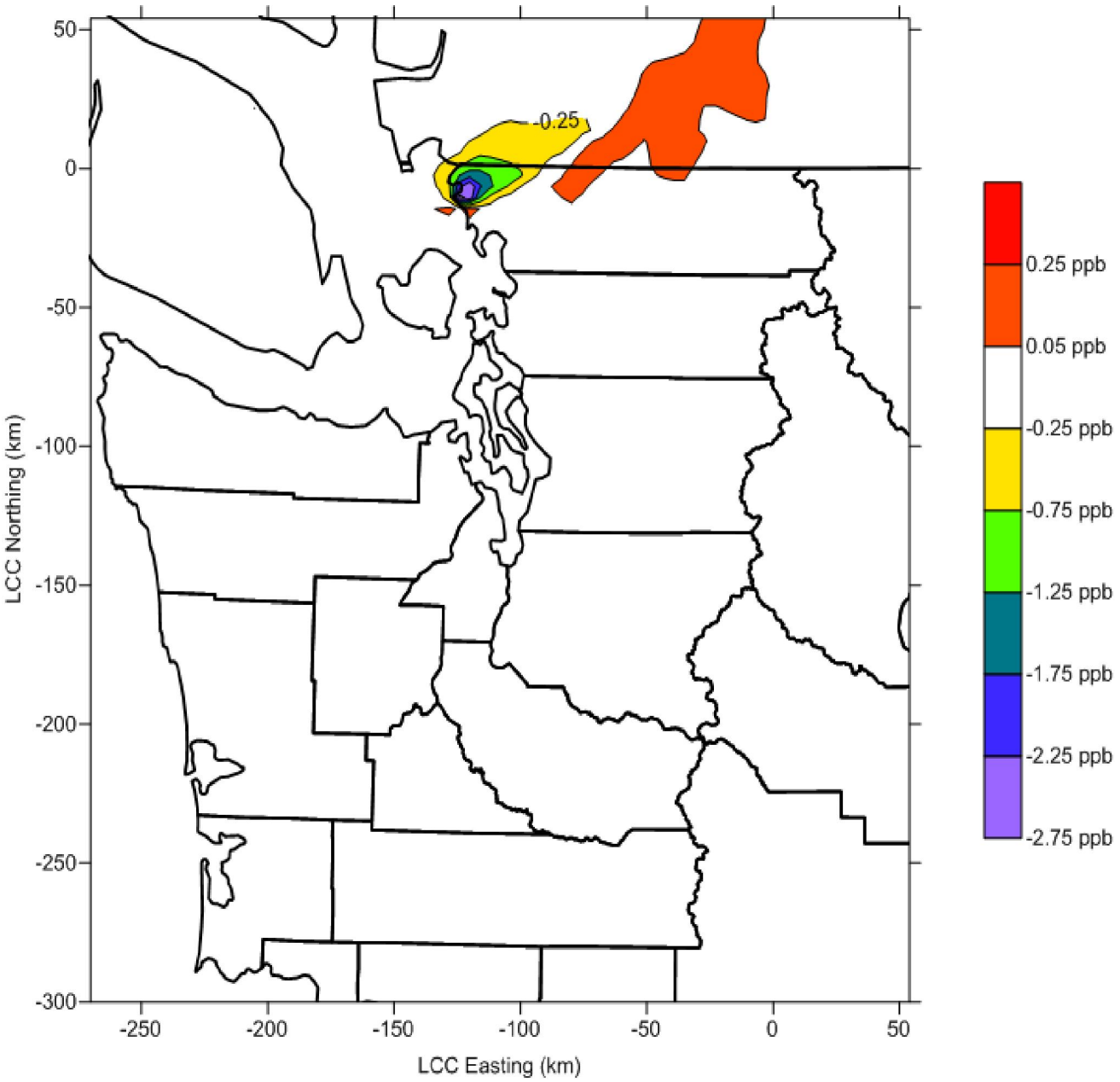



Figure E-2: Simulated 8-hr average $O_3$ concentration difference at 11:00 LST on July 27, 1998.

# Appendix F

## Response to Canadian Agency Comments

# Canadian Air Regulator Comments and Questions

## BP Cherry Point

## Coker Heater Replacement Project

Ramboll Environ Project: 29-30623E

# 1 Comments and Responses

The September 2014 PSD/NOC application for the coker heater replacement project included a series of responses to modeling protocol questions asked by air quality regulators in the U.S. and Canada. Representing the Canadian regulatory agencies (Metro Vancouver, Fraser Valley Regional District, BC Ministry of Environment, and Environment Canada), Greg Okrainetz[1] of the British Columbia (BC) Ministry of Environment provided additional questions from the Canadian air quality agencies on October 31, 2014. The response includes five concerns about air quality and visibility in the Lower Fraser River Valley. Each of the five topics is addressed below.

*Is the condensable fraction included in the $PM_{2.5}$ emissions for the modeling assessment? If not, how would this change the modelled incremental impacts of $PM_{2.5}$?*

Yes, condensable $PM_{2.5}$ emissions are included in the air quality modeling assessment.

*Regarding the background levels in B.C., the use of multiple stations throughout the airshed would have been more appropriate rather than the single station at Langley, and would better represent the range of concentrations experienced in B.C. closer to the point of emissions. Depending on the pollutant being assessed, other stations may have been more appropriate. For example, while Langley may be the closest station, it is at the low end of the range for $NO_2$ concentrations experienced in the Lower Fraser Valley (LFV). In addition to Langley, recommended stations would be Abbotsford Airport for the eastern part of the valley, while North Delta would be appropriate for the western portion (or north-west), in a populated and trafficked part of Metro Vancouver (MV). What would be the air quality impacts at those two additional stations? Would the selection of these alternate stations make any difference in the conclusions regarding the air quality impacts of the project?*

Please see the response to the last question.

[1] Greg Okrainetz, Manager, Clean Air Section, BC Ministry of Environment, Victoria, BC, Canada (250) 387-9938

*Regarding the ozone modeling assessment, the use of updated emissions inventories (2010) and meteorological scenarios should provide a more accurate picture of the incremental ozone impacts of the project emissions in the LFV that would be expected in the future. For example, based on the recent (2010) emissions inventory for the LFV (includes MV, Fraser Valley Regional District and Whatcom County) and comparing to the year 2000 EI indicates the following:*

- *$NO_X$ emissions in 2010 are 60% of the year 2000 emissions.*
- *VOC emissions in 2010 are 78% of the year 2000 emissions.*

*If it is assumed that the 1999 emissions inventory used in the ENVIRON analysis is similar to the year 2000 EI, given the extent of these emission differences it is possible that incremental ozone changes due to this project may be greater than the analysis conducted here using dated information. While re-running CMAQ using the 2010 EI would not be practical at this time, as per the questions posed earlier on the modeling protocol, any insights that ENVIRON can provide on the project incremental ozone impacts regarding the 1 hour, lower percentile (i.e. 50$^{th}$ percentile for 1 hour and 8 hour averages) and longer term averages (annual) would be appreciated.*

Ozone production is due to emissions of ozone precursors (NOx and VOCs) into an atmospheric situation that is favorable to ozone formation. Because this assessment looked at the ozone production due to the increased emissions, approximately the same amount of added ozone would be produced regardless of the ambient NOx or VOC concentrations. It's the effect from the NOx and VOC emitted by the project, not the background NOx or VOC, we are assessing.

The maximum increase of ozone in the CMAQ runs occurs on the first night of the run, which is referred to as the "model spin-up" period. After spin-up, CMAQ predictions ozone concentration decreases in Canada due to NOx titration. Because NOx emissions have decreased more than VOC emissions in the intervening decade, the ozone chemistry is even more likely to be NOx-limited and for the effects of the project's increase in NOx to dominate.

The maximum CMAQ-predicted ozone concentration increases in Canada were less than 0.25 ppb (8-hour average) and 1.4 ppb (1-hour average). The maximum 1-hour average ozone increase in Canada after the model spin-up period was less than 0.3 ppb. The BC Ambient Air Quality Objectives for 8-hour and 1-hour ozone are 63 ppb (4$^{th}$ highest daily 8-hour maximum, averaged over three years) and 82 ppb, respectively. The CMAQ-predicted ozone increases from the project are 0.4 percent of the 8-hour objective and less 1.7 percent of the 1-hour objective.

Long-term statistics, including annual averages and 50$^{th}$ percentiles, cannot be directly calculated from the CMAQ scenario predictions. Screening models (i.e. AERSCREEN) provide multiplication factor of 0.08 to extrapolate 1-hour model predictions to annual average model predictions. The maximum CMAQ-predicted 1-hour ozone concentration increase was 1.4 ppb during a favorable ozone production period. Using the AERSCREEN conversion factor the annual average increase is estimated at 0.14 ppb, which is less than 0.5 percent of the annual average ozone concentration observed in BC over the last several years (~29 ppb).[2] Again, the maximum 1-hour ozone increase predicted by CMAQ occurred only for a few hours on the first night of the model simulation. During the rest of the simulation the ozone was reduced due to NOx titration.

[2] See https://www.ec.gc.ca/indicateurs-indicators/default.asp?lang=en&n=9EBBCA88-1, the last plot on page.

*Further, please clarify if the emissions inventory used for this analysis (1999 National Emissions Inventory) includes any emission sources located in Canada. If not, please comment on how the inclusion of these emissions sources might affect the analysis, given that the maximum ozone concentration is expected to occur in Canada for the modeled episode.*

Although the US NEI data does not include Canadian emissions, Washington State University (WSU) specifically included Canadian emissions as a separate category, and merged them with the US emissions as part of the SMOKE (emissions processing) run. Ramboll Environ used all the emissions that were prepared by WSU in our CMAQ simulations.

*Table 2 in the Appendix F uses the Canadian (National) Ambient Air Quality Objectives and not the Ambient Objectives for MV. As the maximum concentrations may be within MV, please provide an additional comparison Table that uses the MV Ambient Objectives (provided earlier). The Langley and North Delta stations would be compared with MV objectives, while the Abbotsford Airport station would be compared with Canadian Objectives.*

*Further to Table 2, please add a column that indicates the locations of the maximum CALPUFF concentrations in Canada. IN addition, what would the maximum concentrations be in BC if the results of AERMOD were used to the extent of the 35 km domain, instead of CALPUFF?*

The maximum CALPUFF-predicted concentrations for receptors located in the Lower Fraser River Valley are presented in Table 1 below. Figures 1 and 2 provide the spatial extent of 24-hour and annual $PM_{2.5}$ CALPUFF-predicted concentrations. The maximum model predictions in Canada occur north of the refinery along the U.S.-Canada border. The Metro Vancouver and Canadian Ambient air quality objectives are included in Table 1. Overall, maximum CALPUFF-predictions for the Project are less than 1 percent of the most stringent air quality objectives.

Although model-predicted concentrations are very low, the Canadian regulatory agencies have requested the model predicted concentrations be combined with background concentrations for comparison with the applicable air quality objectives. Table 2 presents CALPUFF-predicted concentrations and 2014 monitoring data from Langley and North Delta for comparison with the Metro Vancouver Air Quality Objectives. Table 3 presents CALPUFF-predicted concentrations and 2014 monitoring data from Abbotsford Airport for comparison with the Canadian Air Quality Objectives.

The maximum observed 24-hour rolling $PM_{2.5}$ concentrations at the Langley, North Delta, and Abbotsford Airport monitor sites were above the Metro Vancouver air quality objective (25 $\mu g/m^3$) during a seven day period in November 2014. Stagnant conditions (low wind or no wind) were observed during November 14 - 20, 2014, which lead to the increase $PM_{2.5}$ concentration observations. We would not expect emissions from the BP Cherry Point Refinery to impact the BC monitor locations during stagnant meteorological conditions because there would be no wind to transport emissions from the refinery.

The maximum observed 24-hour $PM_{10}$ concentrations at the Langley monitor during November 17 and 18, 2014 were above the Metro Vancouver air quality objective (50 $\mu g/m^3$). Stagnation conditions were observed during these higher than normal $PM_{10}$ observations. There were only a few hours with spikes in observed hourly $PM_{10}$ concentrations that resulted in

higher 24-hour average $PM_{10}$ concentrations. The cause of the high hourly observations is unknown but, but Canadian regulators suspect it was caused by local emission sources.[3] We would not expect emissions from the BP Cherry Point Refinery to impact the BC monitor locations during stagnant meteorological conditions because there would be no wind to transport emissions from the refinery.

All predicted concentrations in Canada attributable to the Project would be deemed insignificant based on EPA screening criteria, and would not warrant a cumulative impact assessment. In general, the total maximum concentrations (sum of the maximum CALPUFF-predicted concentrations for the Project and the maximum background values) are all below Metro Vancouver and Canadian air quality criteria for the respective pollutants. In the cases where background concentrations are greater than the air quality objectives, the concentrations predicted from the Project are negligible.

Table 1: Maximum Pollutant Concentrations Predicted in Canada

| Pollutant | Avg. time | Maximum CALPUFF Conc. in Canada (µg/m³) | Conc. Location [a] (LCC Coordinates in km) | Metro Vancouver Air Quality Objectives [b] (µg/m³) | Provincial and Canadian Air Quality Objectives [c] (µg/m³) |
|---|---|---|---|---|---|
| $NO_2$ | 1-hr | 1.7 | -114, 2 | 200 | 188 |
| | annual | 0.1 | -118, 2 | 40 | 60 |
| $SO_2$ | 1-hr | 2.2 | -114, 2 | 196 | 200 |
| | 24-hr | 0.3 | -118, 2 | 125 | -- |
| | annual | 0.1 | -118, 2 | 30 | -- |
| $PM_{2.5}$ | 24-hr | 0.2 | -118, 2 | 25 | 25 |
| | annual | 0.04 | -118, 2 | 8 | 8 |
| $PM_{10}$ | 24-hr | 0.2 | -118, 2 | 50 | 50 |
| | annual | 0.04 | -118, 2 | 20 | -- |

Notes:

[a] LCC coordinates based on an origin of 49N, 121W and standard latitudes of 30N and 60N.

[b] Metro Vancouver objectives from http://www.metrovancouver.org/services/air-quality/AirQualityPublications/2014_LFV_AQ_Monitoring_Report.pdf, accessed January 1, 2016.

[c] British Columbia, Canada Ambient Air Quality Objectives (updated January 18, 2016), available at: http://www.bcairquality.ca/reports/pdfs/aqotable.pdf

[3] Page 64 of http://www.metrovancouver.org/services/air-quality/AirQualityPublications/2014_LFV_AQ_Monitoring_Report.pdf

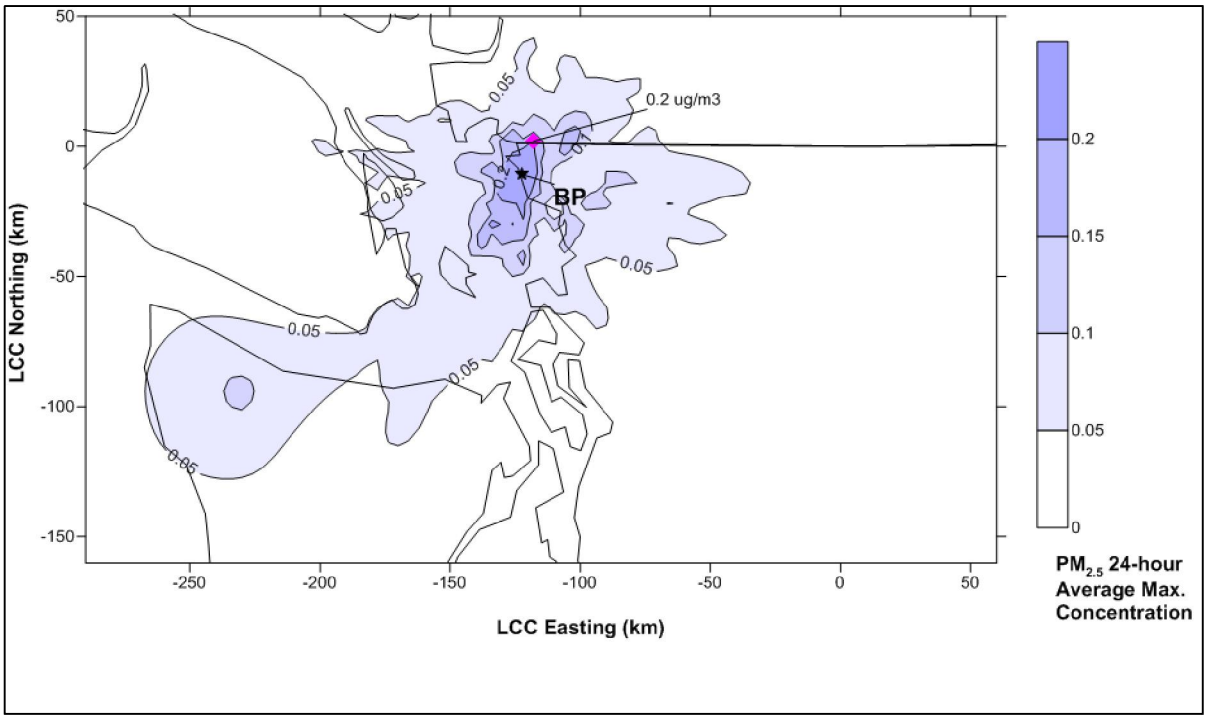



Figure 1. Maximum 24-hour $PM_{2.5}$ Concentrations

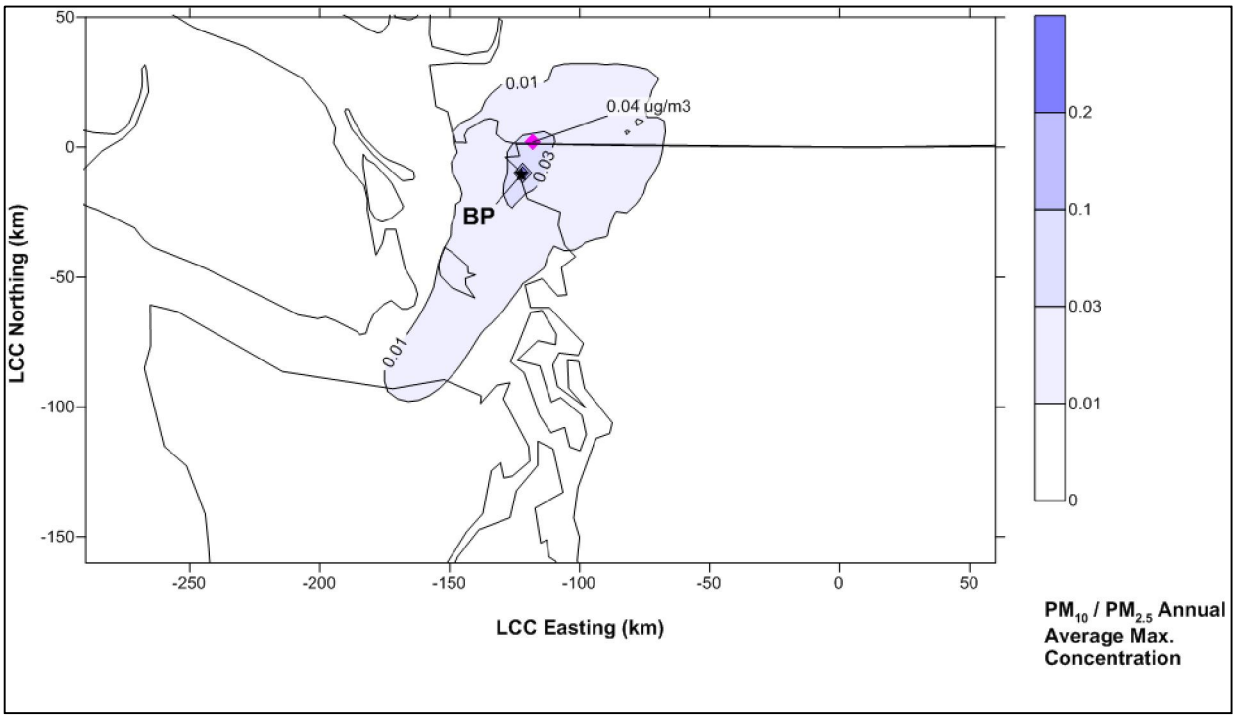



Figure 2. Maximum Annual $PM_{10}/PM_{2.5}$ Concentrations

Table 2: Maximum Pollutant Concentrations Compared to Metro Vancouver Objectives

| Pollutant | Avg. time | Maximum CALPUFF Conc. in Canada (µg/m³) | Langley Maximum Background Conc. [a] (µg/m³) | North Delta Maximum Background Conc. [a] (µg/m³) | Total max. conc. [b] (µg/m³) | Metro Vancouver Air Quality Objectives (µg/m³) |
|---|---|---|---|---|---|---|
| $NO_2$ | 1-hr | 1.7 | 65 | 151 | 153 | 200 |
| | annual | 0.1 | 11 | 26 | 26 | 40 |
| $SO_2$ | 1-hr | 2.2 | 35 | -- | 37 | 196 |
| | 24-hr | 0.3 | 5 | -- | 5 | 125 |
| | annual | 0.1 | 0.5 | -- | 0.5 | 30 |
| $PM_{2.5}$ | 24-hr | 0.2 | 34 | 27 | 34 | 25 |
| | annual | 0.04 | 6 | 7 | 7 | 8 |
| $PM_{10}$ | 24-hr | 0.2 | 55 | -- | 55 | 50 |
| | annual | 0.04 | 11 | -- | 11 | 20 |

Notes:

[a] 2014 Langley and North Delta background data were accessed using http://envistaweb.env.gov.bc.ca/

[b] Total Maximum Concentration is the sum of maximum CALPUFF prediction and maximum background observation (Langley or North Delta).

Table 3: Maximum Pollutant Concentrations Compared to Canadian Objectives

| Pollutant | Avg. time | Maximum CALPUFF Conc. in Canada (µg/m³) | Abbotsford Airport Background Conc. [a] (µg/m³) | Total max. conc. [b] (µg/m³) | Provincial and Canadian Air Quality Objectives [c] (µg/m³) |
|---|---|---|---|---|---|
| $NO_2$ | 1-hr | 1.7 | 58 | 60 | 188 |
| | annual | 0.1 | 11 | 11 | 60 |
| $SO_2$ | 1-hr | 2.2 | 17 | 19 | 200 |
| $PM_{2.5}$ | 24-hr | 0.2 | 28 | 28 | 25 |
| | annual | 0.04 | 6 | 6 | 8 |
| $PM_{10}$ | 24-hr | 0.2 | 41 | 41 | 50 |

Notes:

[a] 2014 Abbotsford Airport background data were accessed using http://envistaweb.env.gov.bc.ca/

[b] Total Maximum Concentration is the sum of maximum CALPUFF prediction and Abbotsford Airport background observation.

Canadian regulatory agencies requested a comparison between maximum AERMOD-predicted concentrations and CALPUFF-predicted concentrations in British Columbia. Table 4 presents a comparison of the maximum model-predicted concentrations and maximum receptor locations.

Table 4: AERMOD and CALPUFF Prediction Comparison for Canada

| Pollutant | Avg. time | Maximum CALPUFF Conc. in Canada (μg/m³) | CALPUFF Conc. Location [a] (LCC Coord. in km) | Maximum AERMOD Conc. in Canada (μg/m³) | AERMOD Conc. Location [b] (LCC Coord. in km) |
|---|---|---|---|---|---|
| $NO_2$ | 1-hr | 1.7 | -114, 2 | 4.3 | -118, 2 |
| | annual | 0.1 | -118, 2 | 0.2 | -118, 2 |
| $SO_2$ | 1-hr | 2.2 | -114, 2 | 3.9 | -118, 2 |
| | 24-hr | 0.3 | -118, 2 | 0.4 | -118, 2 |
| | annual | 0.1 | -118, 2 | 0.1 | -118, 2 |
| $PM_{2.5}$ | 24-hr | 0.2 | -118, 2 | 0.4 | -117, 2 |
| | annual | 0.04 | -118, 2 | 0.04 | -118, 2 |
| $PM_{10}$ | 24-hr | 0.2 | -118, 2 | 0.4 | -117, 2 |
| | annual | 0.04 | -118, 2 | 0.05 | -118, 2 |

Notes:

[a] LCC coordinates based on an origin of 49N, 121W and standard latitudes of 30N and 60N.

[b] UTM coordinates from AERMOD analysis converted to LCC units with basis described in note a.

# Appendix G

## Post-Submittal Correspondence

BP West Coast Products LLC
BP Cherry Point Refinery
4519 Grandview Road
Blaine, WA 98230
United States of America
Telephone: +1 (360) 371-1500

April 14, 2016

Gary J. Huitsing, P.E.
Washington State Department of Ecology
300 Desmond Drive
Lacey, WA 98503

**Subject:** **PSD Permit Application – Incompleteness Response Letter**
**BP Cherry Point Refinery – Coker Heater Replacement Project**

Dear Mr. Huitsing:

BP West Coast Products, LLC (BP) owns and operates the Cherry Point Refinery located at 4519 Grandview Road near the community of Birch Bay, Washington. In September 2014, BP submitted a combined Notice of Construction/Prevention of Significant Deterioration permit application to Ecology and the Northwest Clean Air Agency seeking authorization to replace two existing coker heaters with two new coker heaters.

BP received a letter dated October 22, 2014 with comments on the permit application. Since that time, we have discussed project scope changes with Ecology and prepared an updated PSD/NOC application that was submitted to Ecology on March 22, 2016. As part of your initial review of the updated application, you requested a summary of responses to Ecology's 2014 comment letter. The enclosure summarizes each of Ecology's 2014 comments and references the locations in the updated application that address each comment. Please feel free to call me at (360) 599-4712 if you have any questions. Thank you for your prompt processing of our permit application.

Sincerely yours,

Scott Inloes
Sr. Environmental Engineer
BP Cherry Point Refinery

cc: Agata McIntyre, NWCAA

Enclosure

# Response to Comments

**Ecology Question 1:** *Page 21 of the application states that sulfur plant modification "emission increases are already included in the Coker Heater Replacement Project emissions." Address why the project itself isn't included as part of this PSD project application.*

Ecology's February 12, 2015 determination that the sulfur plant modification project should be considered separate and distinct from the Coker Heater Replacement Project is referenced in Section 3 (Page 23) of the updated PSD/NOC application.

**Ecology Question 2:** *Ecology found discrepancies in baseline emissions listed in the application versus the Ecology's emission inventory. Discrepancies were found for one or more of $NO_X$, $PM_{10}/PM_{2.5}$, VOC, $SO_2$, and $H_2S$ for the following units: Coker Venting, Hydrocracker (R4 heater and 1st Frac Reboiler), Crude Heater, North and South Vacuum Heaters, No. 1 and No. 2 Reformers, No. 1 H2 Plant (north and south), and Railcar Loading. In accordance with 40 CFR 52.21(b)(48)(ii), the baseline emission rates used must be at the rate "at which the emission unit actually emitted the pollutant." Any adjustment to baseline emissions must be in accordance with the allowed adjustments listed in subsections of 40 CFR 52.21(b)(48)(ii). If the application includes adjustments to baseline emissions that are not allowed, modeling results will need to be addressed. Reevaluate the application's baseline emissions so that they agree with emission inventory data, or can be justified through allowed adjustments.*

The majority of the discrepancies noted by Ecology are a result of BP obtaining more accurate emission factors for emission units at the refinery. The emission factors used to develop the original annual emission inventories previously submitted to Ecology were based on the best data available at the time. In most instances, the best available data at the time of submittal were AP-42 emission factors. BP has conducted numerous source tests across the refinery since the past emission inventories were submitted and BP believes the recent data represent more accurate estimates of baseline actual emissions. No changes to the 2016 application are necessary. Each of the differences between past emission inventories and baseline actual emissions reflected in the PSD/NOC application is described below.

<u>$PM_{10}$ and $PM_{2.5}$ Emissions from Emission Units Combusting Refinery Fuel Gas</u>
Historical BP emission reports include $PM_{10}$ and $PM_{2.5}$ emissions based on AP-42 natural gas combustion emission factor of 0.00745 lb/MMBtu (7.6 lb/MMscf natural gas normalized to a heat input basis using 1020 Btu/scf) and annual heat input to the emission unit. During the past few years BP has collected filterable and condensable particulate matter data from refinery fuel gas combustion units at the refinery. $PM_{10}/PM_{2.5}$ source test results for the No. 2 DHDS charge heater and No. 3 DHDS charge heater were 0.008 and 0.009 lb/MMBtu, respectively. Additional information on the two $PM_{10}/PM_{2.5}$ source tests is provided in response to Question 15 from Ecology.

BP updated baseline actual $PM_{10}$ and $PM_{2.5}$ emissions from refinery fuel gas sources using the average of the two DHDS source tests (0.0085 lb/MMBtu). The source test results specific to refinery fuel gas combustion at the refinery are more accurate than an AP-42 natural gas emission factor.

<u>Hydrocracker R4 Heater</u>
In 2008, BP reported $NO_X$ emissions of 17 tpy based on an AP-42 natural gas combustion emission factor of 0.098 lb/MMBtu (100 lb/MMscf natural gas normalized to a heat input basis using 1020 Btu/scf) and annual heat input to the R4 heater. BP updated the baseline actual $NO_X$ emissions from the heater using an emission factor developed with actual engineering test data

(0.014 lb/MMBtu). The engineering test data for the heater are more accurate than an AP-42 natural gas emission factor.

North Vacuum Heater

Reported 2011 and 2012 $NO_X$ emissions of 41 tpy and 36 tpy were based on emission factors developed from annual source tests and annual heat input to the north vacuum heater. The baseline $NO_X$ emissions were inadvertently updated using 2013 source test data (0.1576 lb/MMBtu) for the heater, which are slightly lower than the 2011 and 2012 source test data. The project triggers PSD review for $NO_X$ and re-adjusting the baseline $NO_X$ emissions from the north vacuum heater does not change the determination. The $NO_X$ baseline would be higher than the value presented in the updated PSD/NOC application if the 2011 and 2012 $NO_X$ emissions were updated, leading to a smaller projected increase in $NO_X$ emissions from the North Vacuum Heater. Therefore, the model-predicted annual $NO_X$ concentrations from the north vacuum heater presented in the application are conservatively overestimated.

Calciner

Calciner emissions are reported monthly, and monthly emission calculations are updated as new test data are available. BP tested the two calciner stacks in July 2013 and July 2014. The updated PSD/NOC application incorporates data from annual reports (i.e. 2013 emission factor and 2013 calcined coke throughput). The difference between the two actual calculation methodologies is approximately 4.3 tpy of $H_2SO_4$ emissions. Regardless of the calculation methodology, the project will continue to be subject to PSD review for $H_2SO_4$ emissions. Washington's air toxic rule requires an evaluation of daily $H_2SO_4$ emission increases from the project, but the project will not increase maximum daily $H_2SO_4$ emissions from the calciners.

**Ecology Question 3:** *Section 5.3.1: $PM_{2.5}$ SIL Evaluation: Monitoring data from sites further away have been used, not all of which are FRMs or FEMs. Closer sites such as Custer, Anacortes, Mount Vernon, Oak Harbor, and Darrington were not used. These data should be included in the analysis.*

The PM2.5 SIL evaluation is updated in Section 5.3.1 (pages 65 – 67) of updated PSD/NOC application

**Ecology Question 4:** *Use of EPA's $PM_{2.5}$ SIL has been justified, but not those of other pollutants. For $SO_2$ design values, data from Anacortes, Beacon Hill, and Custer can be used. Trace CO is measured at Beacon Hill and Custer. $NO_2$ is being measured at Beacon Hill ($NO_y$ - NO) and has been at Custer.*

The $PM_{2.5}$ SILs were vacated from the federal PSD regulations after the 2013 DC Circuit ruling in Sierra Club versus EPA. However, the PSD SILs for regulated pollutants are still included in the requirements for state implementation plans (SIPs) in 40 CFR 165(b)(2). EPA specifically provided May 2014 guidance for $PM_{2.5}$ air quality modeling analyses based on the DC Circuit ruling. To our knowledge there are no similar court rulings for other regulated pollutants and continued use of the SILs provided in 40 CFR 165(b)(2) and EPA's interim 1-hour $NO_2$ and 1-hour $SO_2$ SILs is appropriate.

**Ecology Question 5:** *Section 5.3.2: AERMOD-predicted concentrations: $PM_{2.5}$ 24-hour maximum concentration is 1.05 as per the modeling files, not 0.9 as stated in Table 5-4. And, there are several receptors outside (south of) the fenceline where modeled hourly $SO_2$ concentrations are over 7.8 $\mu g/m^3$ (EPA interim SIL). The maximum is 8.76, not 5.9 as stated in the table. While it is unlikely that this plume would combine with that from Intalco (located to the south of BP) and cause a NAAQS exceedance, this should be adequately explained.*

Section 5.3.2 (page 68) of the updated PSD/NOC application describes the methodology to compare AERMOD-predicted concentrations to the applicable significant impact levels (SILs). For the more recent probability-based NAAQS ($PM_{2.5}$, 1-hour $NO_2$, and 1-hour $SO_2$) EPA guidance calls for comparing the 5-year average of the maximum model-predicted 1-hour, 24-hour, or annual concentrations each year at each receptor to the applicable SILs.[1]

**Ecology Question 6:** *Section 6.2.2: Combining stacks for Calpuff modeling: Emission rates and stack heights are correct, but exit velocities and diameters of combined stacks are not. If exit velocities are averaged across stacks, the diameter needs to be calculated by conserving volumetric flow. Or if the diameter is averaged, the exit velocity should be back calculated assuming flow conservation. The latter could potentially have a small effect on concentrations at receptors > 50km downwind.*

The updated Class I modeling analysis includes combined stacks, and Ramboll Environ calculated the average exit velocity from the combined stacks and then calculated the combined stack exit diameter based on conserving an average air flow rate from the stack. Section 6.2.2 of the updated PSD/NOC application presents the stack parameters for the combined stacks included in the Class I modeling analysis.

**Ecology Question 7:** *Table 6-4: Calpuff-predicted Class I area impacts: $NO_2$ and $SO_2$ impacts are reported as maxima (and correctly reflect the model output) while $PM_{2.5}$ concentrations are the highest 3-year averages. A reason for averaging when comparing against the EPA Class I SIL must be provided. The modeled maximum 24-hour $PM_{10}$ value is 0.095 $\mu g/m^3$, which is over the Class I area SIL. However, Ecology recognizes that the model (Calpost) reports $PM_{10}$ concentrations, not $PM_{2.5}$. If ENVIRON can demonstrate that the maximum ($PM_{10}$ minus CALPUFF's PM Coarse) concentration is below the SIL, that should suffice.*

As described in response to Question 5 above, EPA's May 2014 $PM_{2.5}$ modeling guidance recommends comparing the average of the maximum model-predicted 24-hour or annual $PM_{2.5}$ concentrations each year at each receptor across all years of available representative meteorology. BP has five years of on-site meteorology for Class II modeling analyses and three years of processed CALMET files for Class I modeling analyses and averaged the maximum concentrations calculated for each year.

**Ecology Question 8:** *Table 6-6: Contrary to the text, there is one day where the visibility at Olympic National Park is projected to degrade by more than 5 percent. However, this happens on the day with the highest impacts, not the 98th percentile day as a fraction of the natural visibility conditions, as recommended in the FLAG Phase I report. Text should clarify this.*

Ecology is correct there was only day with a 5 percent change to 24-hour extinction; however, the FLAG Phase I Report recommends the 98th percentile day be compared with the 5 percent threshold. Section 6.4 of the updated PSD/NOC application confirms the 98th percentile daily

---

[1] See http://www.epa.gov/ttn/scram/guidance/guide/Guidance_for_PM25_Permit_Modeling.pdf
See https://www.epa.gov/ttn/scram/guidance/clarification/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

changes in extinction for all Class I areas are less than the 5 percent threshold established by the FLMs.

**Ecology Question 9:** *Appendix D: Historic evaluation of Sulfate & Nitrate composition: A Chemical Speciation Network (CSN) site has been operational at Marysville (AQS Site: 53-061-1007) since 2009. For completeness, its data metrics should be included in Appendix D Table 1 and Appendix D Figures 1 -2.*

Table 1 in Appendix D of the updated PSD/NOC application has been updated to include the statistics from the Marysville CSN site. The figures in Appendix D were not updated because the emissions data (2005-2008) and Snohomish county speciation data (2009-2014) are not temporally aligned. However, it is noted in the text that the year-to-year variability in sulfate and nitrate composition are stable (i.e., consistent with the speciation trends in Whatcom and Clallam).

**Ecology Question 10:** *Use of the "adjusted u*" option in AERMOD: BP's application cannot be considered complete while EPA's final decision on its use is still pending.*

There have been several regulatory changes since the 2014 application. EPA has proposed to revise the guideline on air quality models to make the U* adjustment option a regulatory default to correct known deficiencies in the model during low windspeed conditions; and Ecology confirmed the use of the U* adjustment option in AERMOD during the November 19, 2015 meeting with NWCAA, BP, and Ramboll Environ staff.

**Ecology Question 11: BACT** *Other than "variability in the coker off gas sulfur concentrations," provide additional justification for not proposing at least one shorter term average range $SO_2$ ppm limit.*

Section 2.6.3 of Appendix B in the updated PSD/NOC application provides additional justification on the proposed short-term coker heater $SO_2$ emission limit.

**Ecology Question 12: BACT** *For Appendix B "gas phase Merox treatment" and "pressurizing off-gas with new compressor" BACT cost estimates: Provide clearer analysis of how BP determined the cost per ton effectiveness for these options. Specifically, on what basis were the "BP estimate(d)" values in the table derived for these units (such as but not limited to: Merox unit annual operations and maintenance cost at 5 percent of total capital investment). Provide vendor cost quote and calculation spreadsheets. Is the 7 percent annual interest used in the calculations for both units outdated? Greater potential $SO_2$ reductions may be obtainable if a reevaluation shows cost per ton estimates in the range that would allow for implementing these options.*

Cost quote sheets and cost effectiveness calculations for Merox and for adding compression to the lean oil absorption system are enclosed with Appendix B of the updated PSD/NOC application.

Merox cost effectiveness calculations are included as Attachment 3 to Appendix B. Jacobs Engineering prepared annual operation and maintenance cost (5 percent of total capital investment) as part of the 2008 Best Available Retrofit Technology (BART) analysis for specific units at the refinery. Ramboll Environ used the Jacobs Engineering annual Merox operating and maintenance cost estimate to evaluate the cost effectiveness of installing Merox as part of the Coker Heater Replacement Project.

Section 1.2 of Appendix B provides justification for calculating the capital recovery factor used to annualize total capital investments in the BACT analysis.

**Ecology Question 13: BACT** *In addition to the dry ESP BACT discussion addressed in Section 2.2.11 of Appendix B in the application, BP should also include wet ESPs in the BACT analysis.*

Sections 2.1.2.8 and 2.2.11 of Appendix B provide an evaluation of wet electrostatic precipitators (ESP).

**Ecology Question 14: BACT** *For the greenhouse gas BACT review, how was the 90 percent heat efficiency (Appendix B page 24) calculated? Provide a discussion for how the top five modifications were considered and rejected as part of the review.*

Sections 2.3.2.2 and 2.7.5 of Appendix B describe heat efficiency calculation and design considerations evaluated as part of the project.

**Ecology Question 15: BACT** *The application provides a footnote for the proposed particulate matter BACT emission factor of 0.01 lb/MMBtu, stating: "Based on refinery source test data and safety factor." What percent of the proposed emission factor is based on the source test data and what percent is based on the safety factor? What is the basis for using a safety factor instead of using source test results alone?*

Section 2.5.3 and Table 2 of Appendix B provide a summary of particulate matter source test data collected by the refinery and used to calculate emissions for the coker heaters.

**Ecology Question 16: BACT** *For the proposed $NO_X$ BACT for natural draft mode, BP indicated that this mode will be used rarely such as during repair. Provide an estimate of how often this might occur.*

Section 2.3.2.2 of Appendix B describes the coker heater design (balanced draft versus natural draft). BP does not plan to operate the coker heaters in natural draft mode during normal operations.

**Ecology Question 17:** *How many times per year are start-up/shutdowns estimated to occur, and what is the basis for the estimate?*

Section 2.9 of Appendix B describes coker heater startup, shutdown, and standby operating modes.

**Ecology Question 18:** *Is the facility set up so that an unanticipated shutdown (or tripping) of residual catalytic cracking units would cause the main fractionator overhead accumulator to vent to cracking unit flares causing releases of $NO_X$, $SO_2$, and VOCs from the additional flaring? Because the main fractionator overhead accumulator will be modified as part of this project, discuss potential emissions emanating from the main fractionator overhead accumulator.*

Section 2.3 (page 11) of the updated PSD/NOC application describes the coker unit main fractionator overhead accumulator. The purpose of overhead accumulator is to separate overhead vapor, distillate, and sour water from the delayed coker main fractionator tower. BP proposes to modify the overhead accumulator to accommodate additional water vapor from periodic online cleaning (spalling) of each replacement coker heater.

There are no atmospheric emissions from the main fractionator overhead accumulator during normal operating conditions. The modifications to the overhead accumulator will not increase the likelihood of an upset or a malfunction event occurring within the delayed coker unit. Pressure control valves in the delayed coker unit are designed to help reduce pressure in coker unit equipment using a controlled approach instead of waiting until a pressure safety valve is lifted. Since 1984, BP has operated a flare gas recovery system to direct flare header gases into the refinery fuel gas mix drum.

| | |
|---|---|
| **From:** | Inloes, Scott |
| **To:** | Kyle Heitkamp |
| **Subject:** | FW: Coker Heater Replacement Project - Updated PSD/NOC Application |
| **Date:** | Wednesday, April 27, 2016 2:40:07 PM |
| **Attachments:** | Documentation of BPs defense of baseline adjustments.docx |

---

**From:** Inloes, Scott
**Sent:** Thursday, April 14, 2016 8:45 AM
**To:** 'Huitsing, Gary (ECY)'
**Cc:** Crooks, Marc (ECY); Kyle Heitkamp (kheitkamp@ramboll.com); Agata McIntyre
**Subject:** Coker Heater Replacement Project - Updated PSD/NOC Application

Gary,

Thank you for sending over the draft table documenting justifications for baseline actual emissions that were different from historical emission inventories reported to Ecology. We have updated the table with additional information we discussed during the March 30, 2016 conference call, including:

- Crude ship unloading is considered secondary emissions from the project and not included in PSD applicability calculations.
- North Vacuum Heater baseline actual NOx emission discussion.
- $PM_{10}/PM_{2.5}$ emission factor data for refinery fuel gas combustion sources at the refinery (i.e. Crude Heater, No.1 Reformer, No.1 Hydrogen Plant).
- Calciner baseline actual $H_2SO_4$ emission discussion.

We also updated references to the PSD regulations from 40 CFR Part 51 to Part 52. It is our understanding that Part 51 includes requirements for developing implementation plans, and Ecology's PSD regulations reference the federal PSD regulations in Part 52.21.

Please call with any questions or concerns you may have.
Thanks,
Scott

Scott Inloes
Sr. Environmental Engineer
BP Cherry Point Refinery
4519 Grandview
Blaine, WA 98230
Email: Scott.Inloes@bp.com
Office: 360/526-3774
Mobile: 360/599-4712
FAX: 360/671-1402

**From:** Huitsing, Gary (ECY) [mailto:ghui461@ECY.WA.GOV]
**Sent:** Tuesday, March 29, 2016 6:09 PM
**To:** Kyle Heitkamp; Inloes, Scott
**Cc:** Crooks, Marc (ECY)
**Subject:** RE: Coker Heater Replacement Project - Updated PSD/NOC Application

Hi Kyle and Scott

As promised, here is a table in progress that is intended to document BP's justifications for using baseline emission values that differ from Ecology's EI.

I did find some information in the application which addresses this issue. However, the attached table highlights instances (see yellow) where more information is needed.

Please address the questions in yellow. It would be helpful, if you added your responses directly to the table. The table will serve as a supplement to the application.

Thank you.

Gary Huitsing, P.E.
Air Quality Program
Washington Department of Ecology
300 Desmond Drive
PO Box 47600
Lacey, WA 98504-7600
360 407-6314

## BP Coker Heater Replacement Project (March 22, 2016) - Deviations from Emission Inventory for Baseline Years:

| Pollutant (24-month period chosen for baseline) | Emission Unit | Actual Emissions Inventory Values: (Years: emissions) | Emissions Used in Application (Years: emissions) | Justification for not using emission inventory values and/or the chosen emission inventory years. |
|---|---|---|---|---|
| $SO_2$ (2008/2009) | Crude Shipping Unloading | Not Applicable | 2011: 264 tpy<br>2012: 254 tpy | See Section 2.5.13 (Crude Unloading), page 19 of the air permit application.<br><br>Emissions from the vessel are considered secondary because they occur when a vessel is docked at the refinery. Secondary emissions are not accounted for in PSD applicability calculations (40 CFR 52.21(b)(4)), but they must be evaluated as part of the air quality impacts analysis (40 CFR 52.21(k)). |
| NOx (2011/2012) | 1st Frac Reboiler | 2011: 137 tpy<br>2012: 125 tpy | 2011: 21 tpy<br>2012: 19 tpy | PSD regulations 40CFR52.21(b)(48)(ii) defines baseline actual emissions as "the average rate, in tons per year, at which the emissions unit actually emitted the pollutant." And subsection (c) "requires the baseline actual emissions to be adjusted downward to account for an emission limit that the source must currently comply."<br><br>Based on the reasons below, BP has adjusted the "actual" 2011/12 emissions from the 1st Frac Reboiler.<br><br>According to the application footnote b on page C-13, NOx baseline actual emissions are now based on past actual fuel use, projected actual heat input requirements, and emission limit from permit OAC #1067a. Section 3.2.5 of the application states that "BP adjusted the baseline actual emissions for this heater as if the emission unit was required to comply with the current 0.04 lb/MMBtu NOx emission limit." This is the limit referred to in the cited PSD regulation section (c), and which was implemented during the 2011-2012 timeframe as explained in section 3.2.5. |
| | Hydrocracker R4 Heater | 2011: 20 tpy<br>2012: 16 tpy | 2011: 29 tpy<br>2012: 24 tpy | PSD regulations 40CFR52.21(b)(48)(ii) defines baseline actual emissions as "the average rate, in tons per year, at which the emissions unit actually emitted the pollutant."<br><br>Based on the reasons below BP has learned that the listed emissions more accurately reflected the "actual" 2012/12 emissions from the R4 heater compared to the values BP reported in the 2011/12 inventory<br><br>According to the application footnote on page C-13 for the R4 Heater, NOx baseline actual emissions are now based on past actual fuel use and engineering estimate emission factor. Section 3.2.5 states that |

| Pollutant (24-month period chosen for baseline) | Emission Unit | Actual Emissions Inventory Values: (Years: emissions) | Emissions Used in Application (Years: emissions) | Justification for not using emission inventory values and/or the chosen emission inventory years. |
|---|---|---|---|---|
| | | | | "engineering test data for the heater are more accurate." BP has used handheld analyzers in the past to estimate emission concentrations which are better emissions estimation compared to a general AP-42 emission factor. |
| | North Vacuum Heater | 2011: 41 tpy<br>2012: 36 tpy | 2011: 37.6 tpy (41.0 tpy)<br>2012: 33.8 tpy (36.1 tpy) | PSD regulations 40CFR52.21(b)(48)(ii) defines baseline actual emissions as "the average rate, in tons per year, at which the emissions unit actually emitted the pollutant."<br><br>The 2011 and 2012 emissions inventories were based on calendar year emission testing. In the application, 2013 source test data was inadvertently used to re-calculate 2011 and 2012 actual emissions. The application under-estimated baseline NOx emissions by 2.8 tpy. The project is PSD major for NOx and re-adjusting the baseline NOx emissions does not change the determination. In addition, adjusting the baseline NOx emissions in the application would result in the project emission increase changing from 4.8 tpy to 2.0 tpy. Therefore, the emissions impacts evaluated in the application are overestimated and no change will be made to the application. |
| $PM_{10}/PM_{2.5}$ (2010/2011) | Crude Heater | 2010: 16 tpy<br>2011: 13 tpy | 2010: 22 tpy<br>2011: 28 tpy | PSD regulations 40CFR52.21(b)(48)(ii) defines baseline actual emissions as "the average rate, in tons per year, at which the emissions unit actually emitted the pollutant."<br><br>Based on the reasons below, BP has learned that the listed emissions data more accurately reflected the "actual" 2010/11 emissions from the crude heater compared to the values BP reported in the 2010/11 inventory.<br><br>Past actual emission inventory $PM_{10}/PM_{2.5}$ emissions were based on AP-42 Section 1.4 (natural gas combustion) emission factors. BP recently conducted PM source testing for two refinery fuel gas-fired heaters (#2 DHDS Charge Heater & #3 DHDS Charge Heater). Emission factors derived from the refinery source tests are more representative of refinery fuel gas composition than the AP-42 emission factors for natural gas combustion. The $PM_{10}/PM_{2.5}$ emission factors in the application were updated to reflect the average of the two BP source tests (0.0085 lb/MMBtu), representing refinery fuel gas composition instead of natural gas composition. |

| Pollutant (24-month period chosen for baseline) | Emission Unit | Actual Emissions Inventory Values: (Years: emissions) | Emissions Used in Application (Years: emissions) | Justification for not using emission inventory values and/or the chosen emission inventory years. |
|---|---|---|---|---|
| | No. 1 Reformer | 2010: 8 tpy<br>2011: 7 tpy | 2010: 22 tpy<br>2011: 18 tpy | PSD regulations 40CFR52.21(b)(48)(ii) defines baseline actual emissions as "the average rate, in tons per year, at which the emissions unit actually emitted the pollutant."<br><br>Based on the reasons below, BP has learned that the listed emissions data more accurately reflected the "actual" 2010/11 emissions from the No.1 reformer compared to the values BP reported in the 2010/11 inventory.<br><br>Past actual emission inventory $PM_{10}/PM_{2.5}$ emissions were based on AP-42 Section 1.4 (natural gas combustion) emission factors. BP recently conducted PM source testing for two refinery fuel gas-fired heaters (#2 DHDS Charge Heater & #3 DHDS Charge Heater). Emission factors derived from the refinery source tests are more representative of refinery fuel gas composition than the AP-42 emission factors for natural gas combustion. The $PM_{10}/PM_{2.5}$ emission factors in the application were updated to reflect the average of the two BP source tests (0.0085 lb/MMBtu), representing refinery fuel gas composition instead of natural gas composition. |
| | No. 1 H2 Plant (north/south) | 2010: 8/8 tpy<br>2011: 7/8 tpy | 2010: 22 tpy<br>2011: 21 tpy | PSD regulations 40CFR52.21(b)(48)(ii) defines baseline actual emissions as "the average rate, in tons per year, at which the emissions unit actually emitted the pollutant."<br><br>Based on the reasons below, BP has learned that the listed emissions data more accurately reflected the "actual" 2010/11 emissions from the No.1 H2 plant compared to the values BP reported in the 2010/11 inventory.<br><br>Past actual emission inventory $PM_{10}/PM_{2.5}$ emissions were based on AP-42 Section 1.4 (natural gas combustion) emission factors. BP recently conducted PM source testing for two refinery fuel gas-fired heaters (#2 DHDS Charge Heater & #3 DHDS Charge Heater). Emission factors derived from the refinery source tests are more representative of refinery fuel gas composition than the AP-42 emission factors for natural gas combustion. The $PM_{10}/PM_{2.5}$ emission factors in the application were updated to reflect the average of the two BP source tests (0.0085 lb/MMBtu), representing refinery fuel gas composition instead of natural gas composition. |

| Pollutant (24-month period chosen for baseline) | Emission Unit | Actual Emissions Inventory Values: (Years: emissions) | Emissions Used in Application (Years: emissions) | Justification for not using emission inventory values and/or the chosen emission inventory years. |
|---|---|---|---|---|
| $H_2SO_4$ (2013/2014) | Calciners 1&2 | 2013: 7.1 tpy<br>2014: 14.5 tpy | 2013: 4.2 tpy<br>2014: 23.2 tpy | PSD regulations 40CFR52.21(b)(48)(ii) defines baseline actual emissions as "the average rate, in tons per year, at which the emissions unit actually emitted the pollutant."<br><br>Based on the reasons below, BP has calculated annual "actual" 2013/14 emissions from the calciners slightly different from than the values BP reported in the 2013/14 inventory.<br><br>From Section 3.2.3 of the application, baseline emissions "are based on annual calciner utilization and emission factors developed from source tests." BP tested the two calciner stacks for $H_2SO_4$ emissions in July 2013 and July 2014.<br><br>The same source test data were used to develop the reported emissions inventories and baseline emissions presented in the application. The reported emissions inventories were based on monthly emissions with the most current emission factor from an emission test (i.e. calciner operations before the July 2014 source test were based on the July 2013 emission data). The application was based on yearly throughput and the emission test during from the calendar year. The difference between the two calculation methodologies is approximately 4.3 tpy. The project triggers PSD review for $H_2SO_4$ regardless of the baseline calculation method for the calciners, and the application contains a BACT analysis for H2SO4 emissions. Washington's air toxic rule requires an evaluation of daily $H_2SO_4$ emission increases from the project; however, the project will not increase daily $H_2SO_4$ emissions from the calciners. No change to the application will be made. |
| | Calciners 3 | 2013: 8.6 tpy<br>2014: 18.6 tpy | 2013: 13.5 tpy<br>2014: 22.8 tpy | |
| | Calciners Total | 2013: 21.6 tpy<br>2014: 33.1 tpy | 2013: 17.7 tpy<br>2014: 46.0 tpy | |
| | Calciners 2013/2014 Avg | 27.5 tpy | 31.8 tpy | |
| $H_2S$ (2012/2013) | Coke Drum venting | 2012: 3 tpy | 2012: 9 tpy | PSD regulations 40CFR52.21(b)(48)(ii) defines baseline actual emissions as "the average rate, in tons per year, at which the emissions unit actually emitted the pollutant."<br><br>Based on the latest coke drum venting emission information as explained in detail in section 3.2.1* of the application, BP has learned that the listed emissions data more accurately reflected the "actual" 2012/13 emissions from coke drum venting compared to the values BP reported in the 2012/13 inventory.<br><br>*According to section 3.2.1 of the application, "Data used to develop the emission calculations were obtained from EPA-requested source |

| Pollutant (24-month period chosen for baseline) | Emission Unit | Actual Emissions Inventory Values: (Years: emissions) | Emissions Used in Application (Years: emissions) | Justification for not using emission inventory values and/or the chosen emission inventory years. |
|---|---|---|---|---|
| | | | | tests conducted at multiple refineries, including the BP-Husky refinery in Toledo….Emissions for 2005 – 2008 were estimated from 2013 actual emissions based on the annual average coker throughput in these years compared to throughput during 2013." |
| VOC (2012/2013) | Crude Heater | 2012: 8 tpy<br>2013: 11 tpy | 2012: 10 tpy<br>2013: 13 tpy | PSD regulations 40CFR52.21(b)(48)(ii) defines baseline actual emissions as "the average rate, in tons per year, at which the emissions unit actually emitted the pollutant."<br><br>Based on the reasons below, BP has learned that the listed emissions data more accurately reflected the "actual" 2010/11 emissions from the crude heater compared to the values BP reported in the 2010/11 inventory.<br><br>As described in section 3.2.7 of the application, "BP updated the baseline actual VOC emissions using the normalized AP-42 natural gas emission factor of 0.0054 lb/MMBtu and annual refinery fuel gas and vacuum tail gas heat inputs to the crude heater. Normalizing the AP-42 natural gas emission factors to an energy input basis is an improved emission calculation approach and is recommended in the AP-42 documentation." |

| | |
|---|---|
| **From:** | Kyle Heitkamp |
| **To:** | Gary Huitsing (ghui461@ECY.WA.GOV) |
| **Cc:** | Scott Inloes (Scott.Inloes@bp.com); Verburg, James E (James.Verburg@bp.com) |
| **Subject:** | BP Coker Heaters - Additional BACT Information |
| **Date:** | Monday, April 25, 2016 3:19:00 PM |
| **Attachments:** | Coker_Heater_FGD_Cost_Effectiveness.xlsx<br>BP Coker Heater NOx and SO2 BACT Summary.docx<br>image003.png |

---

Gary,

The email below contains additional BACT information requested during our phone conversation last week. There are two attachments included with this email to supplement the information provided below.

1. Discuss technical feasibility of installing selective non-catalytic reduction (SNCR).

   SNCR requires very high exhaust gas temperatures (1600 – 2200 degrees F) and a residence time of 0.5 to 1 second to convert NOx to nitrogen and water, in the presence of injected ammonia. Exhaust gas temperatures in refinery process heaters can vary significantly based on normal operations. The coker unit is a semi-batch process and coker off gas composition can fluctuates with each batch processed. NOx emissions actually increase if exhaust temperatures drop below the required SNCR temperature requirements. A review of the RBLC found no evidence of SNCR being installed on a coker heater. SNCR is considered technically infeasible for the coker heaters. The 2008 Best Available Retrofit Technology (BART) analysis also found that SNCR was technically infeasible for all refinery heaters.

2. Include cost calculations for spray towers to control SO2 emissions.

   BP is not aware of any refinery process heaters with spray towers installed to reduce SO2 emissions. However, BP scaled spray tower capital costs and operating costs from 2008 Jacobs Engineering data for installing spray towers. Jacobs provided cost estimates to install spray towers on BART-eligible units at the Cherry Point refinery. BP assumed a spray tower would provide a 95 percent reduction in SO2 and H2SO4 emissions from a coker heater. The costs are conservative because they do not include required upgrades to wastewater treatment to treat additional wastewater or siting the spray tower within the constrained coker unit footprint.

   Total annualized costs for one spray tower, controlling one coker heater, is $988,400 per year. The spray tower would reduce SO2 and H2SO4 emissions from one heater by 67.7 tons per year, which corresponds to more than $20,000 per ton SO2 and H2SO4 removed. Installing a spray tower would therefore not be cost effective. We have attached the cost effectiveness summary to this email.

3. Summarize NOx and SO2 BACT cost effectiveness calculations.

   The attached BACT summary document provides a comparison between baseline emissions

and alternative control options. The summary table provides two cost effectiveness comparisons:

Average Cost Effectiveness = Total annualized cost divided by the emission reduction from baseline.

Incremental Cost Effectiveness = difference in annualized cost between two control alternatives divided by the difference in emissions after implementing the two control alternatives.

Please do not hesitate to call with any questions regarding the information provided in this email.

Kyle

**Kyle Heitkamp**

Senior Manager

D +1 425 412 1803
M +1 406 490 1666
kheitkamp@ramboll.com

Ramboll Environ
19020 33rd Avenue West
Suite 310
Lynnwood, WA 98036
USA
www.ramboll-environ.com

BP Coker Heater Replacement Project
Spray Tower Cost Effectiveness Calculation - One Coker Heater
Cherry Point Refinery, Whatcom County, Washington

| CAPITAL COSTS | | |
|---|---|---|
| **DIRECT COSTS** | **COST** | **Source** |
| A. Purchased Equipment | | |
| a. Blower & Blower Motor Installed Cost | $1,182,092 | Jacobs |
| b. Vessel Installed Cost | $3,618,517 | Jacobs |
| c. Pumps & Pump Motors Installed Cost (2 units) | $1,819,856 | Jacobs |
| d. Duct Installed Cost | $792,437 | Jacobs |
| e. Cyclone Installed Cost | $66,536 | Jacobs |
| ***Primary Equipment Total Installed Cost*** | $7,479,438 | *Calculation* |
| f. CEMS Installation | | Jacobs |
| g. Instrumentation (included in Project Contingency) | $0 | Jacobs |
| h. Sales tax (included in Project Contingency) | $0 | Jacobs |
| i. Freight (included in Project Contingency) | $0 | Jacobs |
| B. Direct Installation Costs (included in Purchased Equipment Installed Costs) | -- | Jacobs |
| ***Total Direct Capital Cost [DCC]*** | $7,479,438 | *Calculation* |
| **INDIRECT COSTS** | | |
| C. Indirect Installation | | |
| a. Engineering and Supervision (included in Project Contingency) | $0 | Jacobs |
| b. Construction and Field Expenses (included in Project Contingency) | $0 | Jacobs |
| c. Contractor Fee (included in Project Contingency) | $0 | Jacobs |
| d. Startup (included in Project Contingency) | $0 | Jacobs |
| e. Performance Testing (included in Project Contingency) | $0 | Jacobs |
| d. Contingencies (included in Project Contingency) | $0 | Jacobs |
| ***Total Indirect Costs [ICC]*** | $0 | |
| D. Project Contingency ([DCC + ICC]*0.4) | $2,991,775 | Jacobs - ROM ± 50% |
| ***Total Plant Cost [TPC] (DCC+ICC+Project Contingency)*** | $10,471,213 | *Calculation* |
| E. Allowance for Funds During Construction (included in Project Contingency) | $0 | Jacobs |
| F. Royalty Allowance (included in Project Contingency) | $0 | Jacobs |
| G. Inventory Capital (included in Project Contingency) | $0 | Jacobs |
| H. Initial Catalyst and Chemicals (included in Project Contingency) | $0 | Jacobs |
| I. Electrical Upgrades, if necessary | $0 | Jacobs |
| I. Production Loss (due to extended turnaround) | $0 | Jacobs |
| ***Total Capital Investment [TCI]*** | $10,471,213 | *Calculation* |
| ***Total Annualized Capital Costs [TACC] (20 years @ 7% interest)*** | **$988,408** | *Calculation* |
| **DIRECT AND INDIRECT ANNUALIZED COSTS** | | |
| **DIRECT OPERATING COSTS (DOC)** | | |
| K. Labor for operations (assumed none add'l for spray tower) | $0 | Jacobs |
| L. Supervisory Labor (assumed none add'l for spray tower) | $0 | Jacobs |
| M. Maintenance Labor and Costs (0.015*TCI) | $157,068 | Jacobs based on OAQPS |
| N. Utility costs | | |
| a. Electricity (fan & pump) | $127,385 | Jacobs |
| b. Sewer | $23,506 | Jacobs |
| O. Caustic costs | $58,765 | Jacobs |
| **INDIRECT OPERATING COSTS (IOC)** | | |
| P. Overhead (assumed none add'l for spray tower) | $0 | Jacobs |
| Q. Administration (assumed none add'l for spray tower) | $0 | Jacobs |
| R. Insurance (assumed none add'l for spray tower) | $0 | Jacobs |
| ***Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)*** | **$366,724** | *Calculation* |
| ***TOTAL ANNUALIZED COSTS [TAC ] (TACC+TDIAC)*** | **$1,355,133** | *Calculation* |
| Coker Off Gas SO2 Emissions = 303 MMBtu/hr * 0.050 lb SO2/MMBtu * 8760 hr/yr / 2000 lb/to | tons/year | 66.0 | *Calculation* |
| Spray Tower SO2 Emissions = Coker Off Gas Emissions * (1 - 0.95) | tons/year | 3.3 | *Calculation* |
| Coker Off Gas H2SO4 Emissions = 303 MMBtu/hr * 0.0040 lb H2SO4/MMBtu * 8760 hr/yr / 200 | tons/year | 5.3 | |
| Spray Tower H2SO4 Emissions = Coker Off Gas Emissions * (1 - 0.95) | tons/year | 0.3 | |
| Reduction from baseline Off Gas Emissions | Percent | 95.0 | Jacobs |
| Total SO2 & H2SO4 Emissions Reduction | tons/year | 67.7 | *Calculation* |
| ***Cost per ton Conrolled*** | ***$/ton*** | **$ 20,016** | *Calculation* |

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).

**NOx BACT Summary**

| Control Alternative | Emission [a] (tpy) | Emission Reduction [a] (tpy) | Total Capital Investment | Total Annualized Cost [b] ($/yr) | Average Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|
| Baseline | 79.6 | -- | -- | -- | -- |
| Baseline + SCR | 13.3 | 66.4 | $9,948,707 | $2,621,652 | $39,508 |

Notes:
a – Emissions are based on NOx from one coker heater. Emission reduction from baseline.
b – Total annualized cost includes total capital investment, operation, maintenance, etc.)

**$SO_2$ and $H_2SO_4$ BACT Summary**

| Control Alternative | Emission [a] (tpy) | Emission Reduction [a] (tpy) | Total Capital Investment | Total Annualized Cost [b] ($/yr) | Average Cost Effectiveness ($/ton) | Incremental Cost [c] ($/ton) |
|---|---|---|---|---|---|---|
| Baseline | 142.5 | -- | -- | -- | -- | -- |
| Baseline + Compressor | 49.8 | 92.7 | $13,557,208 | $1,692,439 | $18,266 | -- |
| Baseline + Spray Tower [d] | 7.1 | 135.4 | $20,942,427 | $2,710,265 | $20,016 | $23,837 |
| Baseline + Merox [e] | 13.3 | 128.3 | $23,671,502 | $3,417,997 | $26,643 | $47,276 |
| Baseline + Cryogenic [f] | -- | 142.5 | $104,000,000 | $9,800,000 | $68,500 | $479,850 |

Notes:
a – Emissions are based on $SO_2$ plus $H_2SO_4$ from both new coker heaters. Emission reduction from baseline.
b – Total annualized cost includes total capital investment, operation, maintenance, etc.)
c – Incremental cost based on difference in annualized cost divided by difference in annual emissions between control alternatives.
d – Total capital investment and annualized costs based on installing two spray towers (one per heater).
e – Incremental cost for installing Merox is compared to the “baseline + compressor” alternative because emission reduction is less than “spray tower” alternative.
f – Annual emissions with cryogenic fuel gas treatment conservatively assumed to be zero for purposes of calculating cost effectiveness. Incremental cost based on difference between cryogenic fuel gas treatment and “baseline + merox” alternative.

| | |
|---|---|
| **From:** | Kyle Heitkamp |
| **To:** | Gary Huitsing (ghui461@ECY.WA.GOV) |
| **Subject:** | BP Coker Heaters - BACT Summary |
| **Date:** | Tuesday, April 26, 2016 6:47:00 AM |
| **Attachments:** | BP Coker Heater BACT Summary.docx<br>image003.png |

---

Gary,

Thank you for the message. For completeness, I have updated the attached BACT cost summary with CO and VOC cost effectiveness calculations.

Kyle

**Kyle Heitkamp**

Senior Manager

D +1 425 412 1803
M +1 406 490 1666
kheitkamp@ramboll.com

Ramboll Environ
19020 33rd Avenue West
Suite 310
Lynnwood, WA 98036
USA
www.ramboll-environ.com

**NOx BACT Summary**

| Control Alternative | Emission [a] (tpy) | Emission Reduction [a] (tpy) | Total Capital Investment | Total Annualized Cost [b] ($/yr) | Average Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|
| Baseline | 79.6 | -- | -- | -- | -- |
| Baseline + SCR | 13.3 | 66.4 | $9,948,707 | $2,621,652 | $39,508 |

Notes:
a – Emissions are based on NOx from one coker heater. Emission reduction from baseline.
b – Total annualized cost includes total capital investment, operation, maintenance, etc.)

**$SO_2$ and $H_2SO_4$ BACT Summary**

| Control Alternative | Emission [a] (tpy) | Emission Reduction [a] (tpy) | Total Capital Investment | Total Annualized Cost [b] ($/yr) | Average Cost Effectiveness ($/ton) | Incremental Cost [c] ($/ton) |
|---|---|---|---|---|---|---|
| Baseline | 142.5 | -- | -- | -- | -- | -- |
| Baseline + Compressor | 49.8 | 92.7 | $13,557,208 | $1,692,439 | $18,266 | -- |
| Baseline + Spray Tower [d] | 7.1 | 135.4 | $20,942,427 | $2,710,265 | $20,016 | $23,837 |
| Baseline + Merox [e] | 13.3 | 128.3 | $23,671,502 | $3,417,997 | $26,643 | $47,276 |
| Baseline + Cryogenic [f] | -- | 142.5 | $104,000,000 | $9,800,000 | $68,500 | $479,850 |

Notes:
a – Emissions are based on $SO_2$ plus $H_2SO_4$ from both new coker heaters. Emission reduction from baseline.
b – Total annualized cost includes total capital investment, operation, maintenance, etc.)
c – Incremental cost based on difference in annualized cost divided by difference in annual emissions between control alternatives.
d – Total capital investment and annualized costs based on installing two spray towers (one per heater).
e – Incremental cost for installing Merox is compared to the “baseline + compressor” alternative because emission reduction is less than “spray tower” alternative.
f – Annual emissions with cryogenic fuel gas treatment conservatively assumed to be zero for purposes of calculating cost effectiveness. Incremental cost based on difference between cryogenic fuel gas treatment and “baseline + merox” alternative.

**CO & VOC BACT Summary**

| Control Alternative | Emission [a] (tpy) | Emission Reduction [a] (tpy) | Total Capital Investment | Total Annualized Cost [b] ($/yr) | Average Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|
| Baseline | 33.7 | -- | -- | -- | -- |
| Baseline + Oxidation Catalyst | 6.3 | 27.5 | $3,085,993 | $1,870,919 | $68,103 |

Notes:

a – Emissions are based on CO + VOC from one coker heater. Emission reduction from baseline.

b – Total annualized cost includes total capital investment, operation, maintenance, etc.)

| | |
|---|---|
| **From:** | Kyle Heitkamp |
| **To:** | "Dhammapala, Ranil (ECY)" |
| **Cc:** | Huitsing, Gary (ECY) |
| **Subject:** | RE: BP Coker Heater Replacement Project - Updated PSD/NOC Application |
| **Date:** | Monday, April 25, 2016 10:31:00 AM |
| **Attachments:** | image003.png<br>image001.png |

---

Ranil,

Thank you for the question.

The coker heater emissions in Tables 6-1 and 6-2 incorporate the emission decreases from removing the existing coker heaters. Section 6.2.2 (page 75 of application) discusses how actual emissions from the existing coker heaters were subtracted from the new coker heater potential emissions. There is no option to model negative emissions in CALPUFF, so the increases in emissions were modeled from the new coker heater stacks.

Sorry for any confusion. Please let me know if this answers your question.

Kyle

**Kyle Heitkamp**

Senior Manager

D +1 425 412 1803
M +1 406 490 1666
kheitkamp@ramboll.com

RAMBOLL ENVIRON

---

**From:** Dhammapala, Ranil (ECY) [mailto:rdha461@ecy.wa.gov]
**Sent:** Monday, April 25, 2016 10:20 AM
**To:** Kyle Heitkamp <kheitkamp@ramboll.com>
**Cc:** Huitsing, Gary (ECY) <ghui461@ECY.WA.GOV>
**Subject:** RE: BP Coker Heater Replacement Project - Updated PSD/NOC Application

Kyle,

As mentioned on the call, the only discrepancy I found with the modeling is this:
The ERs for the "WCOKE" and "ECOKE" units in Tables 6-1 and 6-2 are lower than those in Table 3-3. However Calciner emissions are consistent across these tables and the modeling inputs are the same as Tables 6-1 and 6-2. Is there an explanation for this discrepancy?
Thanks!

~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~

Ranil Dhammapala, PhD

Atmospheric Scientist
Air Quality Program, Washington Department of Ecology
P.O Box 47600, Olympia, WA 98504-7600
Tel: 360-407-6807   Fax: 360-407-7534
Email: ranil.dhammapala@ecy.wa.gov
~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~*~

---

**From:** Huitsing, Gary (ECY)
**Sent:** Tuesday, March 22, 2016 4:07 PM
**To:** Dhammapala, Ranil (ECY) <rdha461@ecy.wa.gov>
**Subject:** FW: BP Coker Heater Replacement Project - Updated PSD/NOC Application

FYI:

---

**From:** Kyle Heitkamp [mailto:kheitkamp@ramboll.com]
**Sent:** Tuesday, March 22, 2016 4:03 PM
**To:** Mark Buford <mark@nwcleanair.org>; Agata McIntyre (amcintyre@nwcleanair.org) <amcintyre@nwcleanair.org>; Crooks, Marc (ECY) <mcro461@ECY.WA.GOV>; Huitsing, Gary (ECY) <ghui461@ECY.WA.GOV>; john_notar@nps.gov; don_shepherd@nps.gov; tonnie_cummings@nps.gov; jamesmiller2@fs.fed.us; Don Dossett (Dossett.Donald@epa.gov) <Dossett.Donald@epa.gov>; derek.jennejohn@metrovancouver.org
**Cc:** Scott Inloes (Scott.Inloes@bp.com) <Scott.Inloes@bp.com>; Steve Mrazek (steven.mrazek@bp.com) <steven.mrazek@bp.com>; chris.kope@bp.com; Eric Hansen <ehansen@ramboll.com>
**Subject:** BP Coker Heater Replacement Project - Updated PSD/NOC Application

Good afternoon everyone.

BP is providing their updated PSD/NOC Application to replace two coker heaters at the Cherry Point Refinery. I have attached an electronic version of the updated permit application to help everyone's review. Hard copies and/or DVDs with the modeling files to follow.

Please do not hesitate to contact Scott Inloes, BP Senior Environmental Engineer, (360-526-3774) or me (425-412-1803) with any questions.

**Kyle Heitkamp**

Senior Manager

D +1 425 412 1803
M +1 406 490 1666
kheitkamp@ramboll.com

---

Ramboll Environ
19020 33rd Avenue West
Suite 310
Lynnwood, WA 98036

USA
www.ramboll-environ.com

This message contains information that may be confidential, privileged or otherwise protected by law from disclosure. It is intended for the exclusive use of the Addressee(s). Unless you are the addressee or authorized agent of the addressee, you may not review, copy, distribute or disclose to anyone the message or any information contained within. If you have received this message in error, please contact the sender by electronic reply to email@ramboll.com and immediately delete all copies of the message.

**From:** Kyle Heitkamp
**To:** "Shepherd, Don"
**Cc:** Mark Buford; Agata McIntyre (amcintyre@nwcleanair.org); Crooks, Marc (ECY) (mcro461@ECY.WA.GOV); Gary Huitsing (ghui461@ECY.WA.GOV); john_notar@nps.gov; tonnie_cummings@nps.gov; jamesmiller2@fs.fed.us; Don Dossett (Dossett.Donald@epa.gov); derek.jennejohn@metrovancouver.org; Scott Inloes (Scott.Inloes@bp.com); Steve Mrazek (steven.mrazek@bp.com); Eric Hansen; Judith Rocchio; Susan Johnson
**Subject:** RE: BP Coker Heater Replacement Project - Updated PSD/NOC Application
**Date:** Tuesday, March 29, 2016 1:47:00 PM
**Attachments:** image003.png
image001.png

---

Don,

Thank you for the quick review of the updated PSD application. Hopefully I can answer a few of your initial questions.

Table 5-2 of the updated application provides the source parameters for all emission units affected by the coker heater replacement project. Please keep in mind these are the same emission units that were evaluated in the original 2014 coker heater replacement application. The application presents modeling results for all increases in short-term and long-term NOx, SO2, CO, PM10, PM2.5, H2SO4, and other state-required toxic air pollutant (TAPs). Emission increases from the project are summarized in Table 3-2 (PSD pollutants) and Table 3-4 (Washington TAPs). Tables 6-1 and 6-2 summarize the short-term and long-term emission increases (SO2, NOx, and speciated particulate matter) included in the Class I modeling analysis.

It is important to note the Class I modeling analysis presented in the application covers potential emission increases from the coker heater replacement project and seven contemporaneous projects from the past five years, including the Clean Fuels Project (#2 Hydrogen Plant Steam Methane Reformer, #2 Hydrogen Plant flare, and #3 Diesel Unit). These emission increases incorporated into the Coker Heater PSD application are conservative because they are based on potential emissions (covering startup conditions, maximum hourly firing rates, and proposed/permitted emission limits). The Class I modeling assumes these potential emissions for every hour of the three year Class I analysis. The BART analysis was based on maximum actual daily emissions from 20 emission units at the refinery. Short-term potential emission increases from the project and contemporaneous projects are summarized in the table below with a comparison to the total short-term emissions evaluated in the BART analysis.

| **Pollutant** | **Coker Heater Replacement Emission Increases (lb/hr)** | **Clean Fuels Emission Increases [a] (lb/hr)** | **Other Contemporaneous Emission Increases [b] (lb/hr)** | **Coker Heater PSD App. Total Emission Increases (lb/hr)** | **BART Analysis Total Emissions [c] (lb/hr)** |
|---|---|---|---|---|---|
| NOx | 6.0 | 17.5 | 2.9 | 26.4 | 357.5 |
| SO2 | 10.1 | 5.9 | 0.2 | 16.2 | 133.2 |
| PM10 | 2.2 | 7.2 | 3.2 | 12.6 | 29.7 |

a – Clean Fuels Project emission increases include short-term flaring emissions from the #2 hydrogen plant due to plant startup, which occurs very infrequently.
b – Other contemporaneous projects include sulfur plant modification and the Boilers 6 & 7 short-term PM10 emission limit revision.

c – BART analysis evaluated maximum actual daily emissions from 20 emission units at the BP Cherry Point Refinery.

Due to difficulties modeling negative emissions in CALPUFF, the Coker Heater PSD Class I analysis conservatively did not incorporate certain emission reduction projects. For example, the May 2012 low-NOx burner retrofit on the 1st Stage Hydrocracker Fractionator Reboiler resulted in approximately a 43.6 lb/hr reduction of NOx emissions, but the reduction was not included in the PSD application visibility analysis. Total hourly emissions included in the Class I analysis was 55.2 lb/hr (NOx + SO2 + PM10), which adjusted for the 1st Stage Hydrocracker Fractionator Reboiler emission reduction is only a 11.6 lb/hr emission increase (combined NOx, SO2, and PM10).

The Class I analysis is based on potential coker heater emissions covering a wide range of operating modes (normal, startup, shutdown, and maintenance). For example, the proposed project includes the installation of a lean oil absorption system and compressor to process the coker off gas and recover C3 and C4 hydrocarbons. A benefit of the lean oil absorption system is additional sulfur removal (up to 39 percent on annual average) from the coker off gas that will be used as fuel in the new coker heaters. However, the short-term coker heater SO2 emissions in the Class I analysis do not account for the additional sulfur removal because there will be instances when regular refinery maintenance could lead to temporary periods of higher sulfur in the coker off gas. BP expects the actual visibility impact to Class I areas to be much lower than the conservative modeling analysis.

The visibility analysis results are presented in Table 6-6 of the application and indicate the maximum 98th percentile change in daily visibility predicted for Olympic NP is 1.83 percent, which is less than the 5 percent threshold from FLAG. The three-year average of 98th percentile change to daily visibility, in units of deciviews, estimated at Olympic National Park from the PSD application (coker heater, clean fuels, etc.) is 0.116 compared to the BART analysis value of 0.842. However, the PSD application Class I modeling analysis is inherently more conservative than the BART analysis.

Actual NOx, SO2, and PM10 emissions from BP Cherry Point Refinery have decreased significantly over the past several years.

| **Year** | **NOx (tons/yr)** | **SO2 (tons/yr)** | **PM10 (tons/yr)** |
|---|---|---|---|
| 2008 | 2,237 | 1,764 | 137 |
| 2009 | 2,228 | 2,134 | 159 |
| 2010 | 2,223 | 1,283 | 155 |
| 2011 | 2,051 | 1,028 | 81 |
| 2012 | 1,877 | 932 | 93 |
| 2013 | 1,959 | 882 | 97 |
| 2014 | 1,890 | 918 | 82 |

Potential emission increases from the coker heater replacement project are conservatively high compared to anticipated actual emissions. The nature of PSD permitting requires the permittee to conservatively estimate future emissions in order to prevent retroactive PSD permitting questions.

We are available anytime to discuss any NPS concerns in more detail. Please let me know a

time that works for you.

Kyle

**Kyle Heitkamp**

Senior Manager

D +1 425 412 1803
M +1 406 490 1666
kheitkamp@ramboll.com

RAMBOLL ENVIRON

**From:** Shepherd, Don [mailto:don_shepherd@nps.gov]
**Sent:** Thursday, March 24, 2016 3:35 PM
**To:** Kyle Heitkamp <kheitkamp@ramboll.com>
**Cc:** Mark Buford <mark@nwcleanair.org>; Agata McIntyre (amcintyre@nwcleanair.org) <amcintyre@nwcleanair.org>; Crooks, Marc (ECY) (mcro461@ECY.WA.GOV) <mcro461@ecy.wa.gov>; Gary Huitsing (ghui461@ECY.WA.GOV) <ghui461@ecy.wa.gov>; john_notar@nps.gov; tonnie_cummings@nps.gov; jamesmiller2@fs.fed.us; Don Dossett (Dossett.Donald@epa.gov) <Dossett.Donald@epa.gov>; derek.jennejohn@metrovancouver.org; Scott Inloes (Scott.Inloes@bp.com) <Scott.Inloes@bp.com>; Steve Mrazek (steven.mrazek@bp.com) <steven.mrazek@bp.com>; chris.kope@bp.com; Eric Hansen <ehansen@ramboll.com>; Judith Rocchio <judy_rocchio@nps.gov>; Susan Johnson <Susan_Johnson@nps.gov>
**Subject:** Re: BP Coker Heater Replacement Project - Updated PSD/NOC Application

Kyle,

I have done a preliminary review of the application and have some initial questions regarding the sources listed in Table 5-2:

- Does Table 5-2 include all significant emission sources/units at the refinery?
- Did you model pollutant emission rates for all of the sources/units in Table 5-2?
- If so, did that modeling include emissions of PM10, NOx, SO2, and H2SO4?
- If so, what emission rates did you model for PM10, NOx, SO2, and H2SO4?

I see that the predicted 98th percentile impact of just the emissions from the proposed major modification is a 1.83% "change in visibility"--is that correct? Please note that previous modeling of just the BART sources at the refinery predicted a 0.84 dv impact at Olympic National Park and we are concerned that the significant emission increases being proposed, along with the existing emissions from the refinery, may exacerbate that impact on visibility.

I have National Emissions Inventory data for the refinery for 2011--is more recent emissions data available?

thanks,

On Tue, Mar 22, 2016 at 5:02 PM, Kyle Heitkamp <kheitkamp@ramboll.com> wrote:

> Good afternoon everyone.
>
> BP is providing their updated PSD/NOC Application to replace two coker heaters at the Cherry Point Refinery. I have attached an electronic version of the updated permit application to help everyone's review. Hard copies and/or DVDs with the modeling files to follow.
>
> Please do not hesitate to contact Scott Inloes, BP Senior Environmental Engineer, (360-526-3774) or me (425-412-1803) with any questions.
>
> **Kyle Heitkamp**
>
> Senior Manager
>
> D +1 425 412 1803
> M +1 406 490 1666
> kheitkamp@ramboll.com
>
> Ramboll Environ
> 19020 33rd Avenue West
> Suite 310
> Lynnwood, WA 98036
> USA
> www.ramboll-environ.com
>
> This message contains information that may be confidential, privileged or otherwise protected by law from disclosure. It is intended for the exclusive use of the Addressee(s). Unless you are the addressee or authorized agent of the addressee, you may not review, copy, distribute or disclose to anyone the message or any information contained within. If you have received this message in error, please contact the sender by electronic reply to email@ramboll.com and immediately delete all copies of the message.

--
Don Shepherd
National Park Service
Air Resources Division
12795 W. Alameda Pkwy.
Lakewood, CO 80228

Phone: 303-969-2075
Fax: 303-969-2822
E-Mail: don_shepherd@nps.gov
"the man who really counts in the world is the doer, not the mere critic" TR 1891

| | |
|---|---|
| **From:** | Kyle Heitkamp |
| **To:** | "Shepherd, Don" |
| **Cc:** | Mark Buford; Agata McIntyre (amcintyre@nwcleanair.org); Crooks, Marc (ECY) (mcro461@ECY.WA.GOV); Gary Huitsing (ghui461@ECY.WA.GOV); john_notar@nps.gov; tonnie_cummings@nps.gov; jamesmiller2@fs.fed.us; Don Dossett (Dossett.Donald@epa.gov); derek.jennejohn@metrovancouver.org; Scott Inloes (Scott.Inloes@bp.com); Steve Mrazek (steven.mrazek@bp.com); chris.kope@bp.com; Eric Hansen |
| **Subject:** | RE: BP Coker Heater Replacement Project - Updated PSD/NOC Application |
| **Date:** | Wednesday, April 27, 2016 4:10:00 PM |
| **Attachments:** | image003.png<br>image001.png |

---

Don,

The Class I visibility modeling results in Tables 6-6 are correct and correspond to the CALPUFF modeling results provided with the PSD/NOC application. Figure 6-9 is mislabeled and should read the maximum (100$^{th}$ percentile) percent change to visibility. As presented in Table 6-6 of the application, there was only one day within the 3-year modeling period with a predicted change in visibility over 5 percent at any Class I Area. The 98$^{th}$ percentile changes in visibility for all Class I areas are well below the 5 percent threshold established in FLAG2010.

Please do not hesitate to call with any follow-up questions.

Kyle

**Kyle Heitkamp**

Senior Manager

D +1 425 412 1803
M +1 406 490 1666
kheitkamp@ramboll.com

RAMBOLL ENVIRON

**From:** Shepherd, Don [mailto:don_shepherd@nps.gov]
**Sent:** Wednesday, April 27, 2016 3:38 PM
**To:** Kyle Heitkamp <kheitkamp@ramboll.com>
**Cc:** Mark Buford <mark@nwcleanair.org>; Agata McIntyre (amcintyre@nwcleanair.org) <amcintyre@nwcleanair.org>; Crooks, Marc (ECY) (mcro461@ECY.WA.GOV) <mcro461@ecy.wa.gov>; Gary Huitsing (ghui461@ECY.WA.GOV) <ghui461@ecy.wa.gov>; john_notar@nps.gov; tonnie_cummings@nps.gov; jamesmiller2@fs.fed.us; Don Dossett (Dossett.Donald@epa.gov) <Dossett.Donald@epa.gov>; derek.jennejohn@metrovancouver.org; Scott Inloes (Scott.Inloes@bp.com) <Scott.Inloes@bp.com>; Steve Mrazek (steven.mrazek@bp.com) <steven.mrazek@bp.com>; chris.kope@bp.com; Eric Hansen <ehansen@ramboll.com>
**Subject:** Re: BP Coker Heater Replacement Project - Updated PSD/NOC Application

Folks,

I would appreciate it if someone could help me reconcile the data in Table 6-6: "Predicted Class I Area Visibility Results" with the results depicted in Figure 6-9. "98th Percentile Percent Change in Visibility Attributable to Project Emissions" in the attached application. Specifically, Figure 6-9 appears to show that the 98th percentile value in the western edge of Olympic National Park is at least 5% change in extinction--there must be at least eight days with change in extinction greater than 5%. However, Table 6-6 indicates only one day over 5% change at Olympic. Please clarify..

On Tue, Mar 22, 2016 at 5:02 PM, Kyle Heitkamp <kheitkamp@ramboll.com> wrote:

> Good afternoon everyone.
>
> BP is providing their updated PSD/NOC Application to replace two coker heaters at the Cherry Point Refinery. I have attached an electronic version of the updated permit application to help everyone's review. Hard copies and/or DVDs with the modeling files to follow.
>
> Please do not hesitate to contact Scott Inloes, BP Senior Environmental Engineer, (360-526-3774) or me (425-412-1803) with any questions.
>
> **Kyle Heitkamp**
>
> Senior Manager
>
> D +1 425 412 1803
> M +1 406 490 1666
> kheitkamp@ramboll.com
>
> Ramboll Environ
> 19020 33rd Avenue West
> Suite 310
> Lynnwood, WA 98036
> USA
> www.ramboll-environ.com
>
> This message contains information that may be confidential, privileged or otherwise protected by law from disclosure. It is intended for the exclusive use of the Addressee(s). Unless you are the addressee or authorized agent of the addressee, you may not review, copy, distribute or disclose to anyone the message or any information contained within. If you have received this message in error, please contact the sender by electronic reply to email@ramboll.com and immediately delete all copies of the message.

--
Don Shepherd
National Park Service
Air Resources Division
12795 W. Alameda Pkwy.
Lakewood, CO 80228
Phone: 303-969-2075
Fax: 303-969-2822
E-Mail: don_shepherd@nps.gov
"the man who really counts in the world is the doer, not the mere critic" TR 1891

# BP CHERRY POINT
# COKER HEATER REPLACEMENT PROJECT – NPS DISCUSSION
# APRIL 2016

RAMBOLL ENVIRON

# AGENDA

- Project Description
- BACT
- Past Emissions/Project
- Visibility Modelling
- Visibility Olympic Park

# PROJECT DESCRIPTION

- What is a Coker Unit?
  - Thermally crack large hydrocarbon molecules
  - Inputs: residual oil from crude unit and tankage
  - Products: Green Coke,  gas oil, naphtha, fuel gas
- Process
  - Heater: Heat incoming residual oil up to over 900F
    - Delayed coking reaction happens in the coke drum
      - Decoking required for coking in the heater tube
- Coke Drums (two per heater): Coke formed in drum and lighter components routed to prefractionator for separation and distribution
  - As one drum fills, adjacent drum is cooled and drum pressure is lowered before opening
  - Green coke is removed from the drum using high pressure water

# PROJECT DESCRIPTION, CONTINUED

- Decommission Coker Heaters
  - Two Heaters
  - 190 MMBtu/hr per heater
  - Original refinery equipment (1970's vintage design)
  - Off line mechanical cleaning of heaters 1-3 times per year
    - Flaring emissions
    - Reduced crude rate
- Proposed Coker Heaters
  - Two Heaters
  - 303 MMBtu/hr per heater
  - On line steam cleaning "spalling" of heater allows more hours of operation per year (fewer decoking shutdowns)
  - Lean oil absorption system recovers additional product from coker off gas
    - BP to install new compressor to recover additional product.

# BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

- Applies to New or Modified units – New Coker Heaters Only
- NOx
  - Proposed: balanced draft 60 ppm & natural draft 40 ppm
  - Low NOx burners (realistic for a new heater installation)
  - Balanced draft with air preheat to increase thermal efficiency
    - Natural draft only would burn 10% more fuel (12% increase in overall combustion emissions)
  - Several facilities in CA, LA, MN, and TX propose installed SCR due to permit implications (i.e. net out of PSD, non-attainment NSR, or modeling considerations).
    - WA is in attainment of ozone standard.
    - SCR cost effectiveness calculated at $39,000/ton NOx removed

# BACT, CONTINUED

- NOx
  - Selective Non-Catalytic Reduction (SNCR)
    - Exhaust gas must be within 1600 -2200 F for conversion to occur
      - SCR requires lower temperatures (600 – 700 F)
    - Process heater duty fluctuates and fuel gas composition fluctuates
    - Not technically feasible due to high temperature requirements in exhaust gas.
      - Potentially to emit higher NOx with SNCR controls.
    - BART analysis reviewed SNCR for NOx controls and determined not technically feasible for BART-eligible heaters at the refinery.
    - No known SNCR installations on similar refinery process heaters.

# BACT, CONTINUED

- SO2
  - Proposed annual emission limit of 132 tpy
    - Same annual emission limit as current coker heater, but roughly 60% higher rated heat input
    - Process equipment – Lean Oil absorption system
      - Recovers products – Propane and Butane
    - Voluntary installation of additional compressor
      - Not considered cost effective ($18,300/ ton removed), but actual SO2 annual SO2 emissions anticipated at 46 tpy.
    - Merox control equipment - $26,600/ton removed
    - Flue gas desulfurization
      - No known installation on a process heater. Typically found on FCCU units with higher SO2 emission rates.
      - Spray Tower control equipment - $20,000/ton removed

# CLASS I VISIBILITY

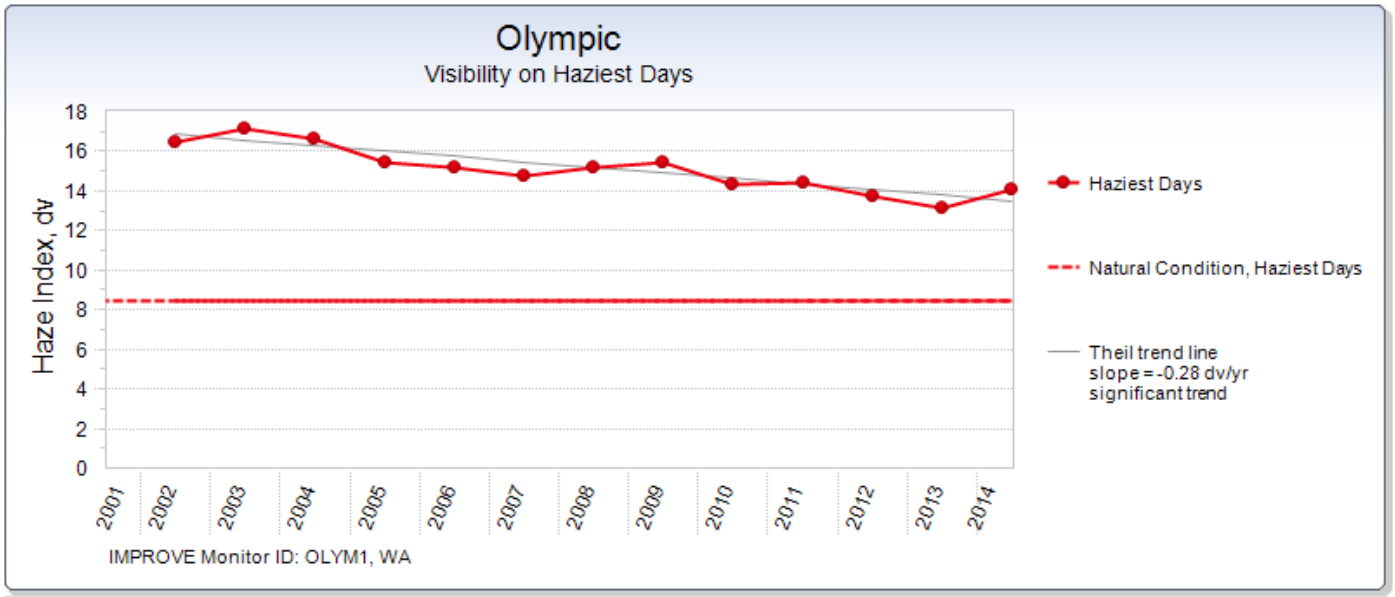
- Best Available Retrofit Technology (BART) analysis completed in 2008
  - Modeled BP BART eligible sources at 0.8 dv impact in Olympic National Park
    - >1.0 dv cause visibility impairment
    - >0.5 dv contribute to impairment
  - Other facilities with BART eligible sources had modeled visibility impacts of 0.65, 1.5, 1.5, 1.7, 3.2, and 4.6 dv
- BP has installed/converted 12 heaters/boilers to lower NOx burners.

| Year | NOx (tons/yr) | SO2 (tons/yr) | PM10 (tons/yr) |
|---|---|---|---|
| 2008 | 2,237 | 1,764 | 137 |
| 2009 | 2,228 | 2,134 | 159 |
| 2010 | 2,223 | 1,283 | 155 |
| 2011 | 2,051 | 1,028 | 81 |
| 2012 | 1,877 | 932 | 93 |
| 2013 | 1,959 | 882 | 97 |
| 2014 | 1,890 | 918 | 82 |

# CLASS I VISIBILITY

- 2010 Regional Haze Plan
  - Source apportionment analysis of most impaired days during baseline (2000-2004)
    - 25% of sulfates originated in Washington (15% from point sources)
    - 53% of nitrates originated in Washington (40% from mobile & 9% from point sources)
  - Progress in Reducing Visibility
    - Diesel Fuel Standards (500 ppm S → 15 ppm S)
      - BP's Clean Fuels project removed over 9,000 tons of SO2 per year from diesel fuel
    - Marine Engine Standards (North American emission control area)
      - NOx emissions decreasing by 80%
      - SO2 emissions decreasing by 90%
    - Vehicle emission standards
    - Shutdown of coal-fired power plant
  - 2018 Reasonable Progress Goal = 16.4 dv
  - 2018 Uniform Progress Goal = 14.8 dv

# CLASS I VISIBILITY




- Hide chart data  Chart data in Microsoft Excel

**Chart Data:**

| Parameter | Statistic | Year | Value | State | Units | Network | Monitor ID |
|---|---|---|---|---|---|---|---|
| Visibility | Annual average haze index, haziest days | 2002 | 16.46 | WA | dv | IMPROVE | OLYM1 |
| Visibility | Annual average haze index, haziest days | 2003 | 17.17 | WA | dv | IMPROVE | OLYM1 |
| Visibility | Annual average haze index, haziest days | 2004 | 16.6 | WA | dv | IMPROVE | OLYM1 |
| Visibility | Annual average haze index, haziest days | 2005 | 15.41 | WA | dv | IMPROVE | OLYM1 |
| Visibility | Annual average haze index, haziest days | 2006 | 15.21 | WA | dv | IMPROVE | OLYM1 |
| Visibility | Annual average haze index, haziest days | 2007 | 14.76 | WA | dv | IMPROVE | OLYM1 |
| Visibility | Annual average haze index, haziest days | 2008 | 15.19 | WA | dv | IMPROVE | OLYM1 |
| Visibility | Annual average haze index, haziest days | 2009 | 15.43 | WA | dv | IMPROVE | OLYM1 |
| Visibility | Annual average haze index, haziest days | 2010 | 14.36 | WA | dv | IMPROVE | OLYM1 |
| Visibility | Annual average haze index, haziest days | 2011 | 14.39 | WA | dv | IMPROVE | OLYM1 |
| Visibility | Annual average haze index, haziest days | 2012 | 13.71 | WA | dv | IMPROVE | OLYM1 |
| Visibility | Annual average haze index, haziest days | 2013 | 13.15 | WA | dv | IMPROVE | OLYM1 |
| Visibility | Annual average haze index, haziest days | 2014 | 14.07 | WA | dv | IMPROVE | OLYM1 |
| Visibility | Natural condition haze index, haziest days | | 8.44 | WA | dv | IMPROVE | OLYM1 |

# CLASS I VISIBILITY

- Visibility Modeling
  - Modeled short term emission increase = 55.2 lb/hr (NOx + SO2 + PM10)
    - Includes increases from Coker Heater Project, Clean Fuels Project, etc.
    - 15 lb/hr from #2 Hydrogen Plant flare (Clean Fuels Project)
      - Only used during startup/shutdown of hydrogen plant
    - Does not include 44 lb/hr NOx reduction from 1st Stage Frac. Reboiler burner retrofit
    - Does not include SO2 reduction from voluntary installation of compressor for lean oil system
  - Maximum 98th percentile change in daily visibility for Olympic was 1.83 percent
    - FLAG 2010 states 5 percent threshold of concern for evaluating a proposed source or modification

# QUESTIONS?

**From:** Kyle Heitkamp
**To:** "Shepherd, Don"
**Cc:** Agata McIntyre; Mark Nuyens; Christos Christoforou; John Notar; Gary Huitsing (ghui461@ECY.WA.GOV); Inloes, Scott; Robyn Jones
**Subject:** RE: BP 2014 emission inventory
**Date:** Friday, May 20, 2016 3:11:00 PM
**Attachments:** image002.png

---

Don,

In response to your question on the 2014 emission inventory, BP reviewed available NOx emission data for the 1st Stage Fractionator Reboiler (one of four heaters within the hydrocracker process unit) and corrected baseline actual NOx emissions from the heater. The review of the 2012, 2013, and 2014 actual emission inventories submitted to NWCAA found that BP had inadvertently continued using a NOx emission factor for a conventional burner when calculating emissions for the period May 2012 –December 2014. The conventional burner NOx emission factor (0.27 lb/MMBtu) is based on a 1992 source test of the heater. As explained below, we have corrected actual NOx emissions for May 2012 through December 2014 based on CEMS data for the heater.

The 1st Stage Fractionator Reboiler was retrofitted with low-NOx burners and a NOx CEMS in May 2012. Condition 4 of OAC #1067a limits the 1st Stage Fractionator Reboiler to 0.05 lb NOx/MMBtu.

PSD regulations (40 CFR 52.21(b)(48)(ii)(c)) require baseline actual emissions to be adjusted downward to account for an applicable emission limit. The March 2016 application inadvertently adjusted The 1st Stage Fractionator Reboiler NOx emissions down using 0.04 lb/MMBtu instead of the actual NOx emission limit of 0.05 lb/MMBtu. The table below presents historical actual emissions from the 1st Stage Fractionator Reboiler, the NOx emission increase from the March 2016 application, and the NOx emission increase after correcting the baseline actual emissions. The NOx emission increase from the 1st Stage Fractionator Reboiler (as a result of the proposed coker heater project) decreases from 10.2 tpy to 7.8 tpy because the corrected baseline actual NOx emissions are now slightly higher than the 2016 application.

**1st Stage Fractionator Reboiler NOx emissions (Actuals, March 2016 Application, and Corrected Baseline)**

| NOx Emission Increase | Actual Emissions | March 2016 Application 1st Frac Reboiler [a] | Corrected 1st Frac Reboiler [b] |
|---|---|---|---|
| 2010 Emissions (tpy) | 140 | 20.9 | 26.2 |
| 2011 Emissions (tpy) | 137 | 20.7 | 25.9 |
| 2012 Emissions (tpy) | 32.9 | 19.3 | 16.9 |
| 2013 Emissions (tpy) | 19.3 | 24.4 | 19.3 |
| 2014 Emissions (tpy) | 16.1 | 24.4 | 16.1 |
| Baseline Average (tpy) 2011 – 2012 | -- | 20.0 | 21.4 |
| Baseline Ave Heat Input (MMBtu/yr) | -- | 1,002,917 | 1,002,917 |
| COA Heat Input (MMBtu/yr) | -- | 1,219,477 | 1,219,477 |
| Excludable Emissions (tpy) | -- | 4.3 | 5.4 |
| BAE + Excludable (tpy) | -- | 24.4 | 26.8 |
| Baseline EF (lb/MMBtu) | -- | 0.04 | 0.05 |
| Future EF (lb/MMBtu) | -- | 0.04 | 0.04 |
| Projected Emissions (tpy) | -- | 34.7 | 34.7 |
| NOx Emission Increase (tpy) | -- | 10.2 | 7.8 |

Notes:
a - 1st Frac Reboiler NOx emissions based on past actual fuel use, projected actual heat input requirements, and a 0.04 lb/MMBtu emission factor.

b – Prior to May 2012, 1st Frac Reboiler NOx emissions based on past actual fuel use and an emission limit 0.05 lb/MMBtu from OAC #1067a. NOx baseline actual emissions based on CEMS data for May 2012 through 2014. Projected emissions based on potential heat input rates and 0.04 lb/MMBtu.

Overall, corrections to the 1st Stage Fractionator Reboiler baseline actual NOx emission results in a smaller NOx emission increase compared to the NOx emission increase modeled in the 2016 permit application. No additional modeling is necessary because the model predicted concentrations would be lower for the corrected NOx emission increase from the 1st Stage Fractionator Reboiler.

Please contact Scott Inloes or me with any questions regarding the NOx baseline actual emission corrections.

Have a great weekend.

Kyle

**Kyle Heitkamp**

Senior Manager

D +1 425 412 1803
M +1 406 490 1666
kheitkamp@ramboll.com

RAMBOLL ENVIRON

# Appendix H

## Dispersion Modeling Files