BART DETERMINATION
SUPPORT DOCUMENT FOR
BP CHERRY POINT REFINERY
BLAINE, WASHINGTON

Prepared by

Washington State Department of Ecology
Air Quality Program

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EXECUTIVE SUMMARY

The Best Available Retrofit Technology (BART) program is part of the larger effort under the federal Clean Air Act Amendments of 1977 to eliminate human-caused visibility impairment in all mandatory federal Class I areas. Sources that are required to comply with the BART requirements are those sources that:

1. Fall within 26 specified industrial source categories.
2. Commenced operation or completed permitting between August 7, 1962 and August 7, 1977.
3. Have the potential to emit more than 250 tons per year (tpy) of one or more visibility impairing compounds.
4. Cause or contribute to visibility impairment within at least one mandatory federal Class I area.

BP West Coast Products, LLC (BP) owns and operates the BP Cherry Point Refinery (refinery). The refinery is located on Cherry Point near Blaine, Washington. The petroleum refining process results in the emissions of particulate matter (PM), sulfur dioxide (SO_2), volatile organic compounds (VOCs), nitrogen oxides (NO_X), and other pollutants. The pollutants considered to be visibility impairing are PM, SO_2, and NO_X.

Petroleum oil refineries are one of the 26 listed BART source categories. The BP Cherry Point Refinery started operations in 1971, and has had many modifications since then. As a component of a national Consent Decree between BP and the United States Environmental Protection Agency (EPA), most of the refinery's heaters and boilers have been evaluated for upgrading to lower emitting units within the last 10 years. As part of this Consent Decree program, many heaters have had been retrofitted with low-NO_X burners (LNBs) or ultra-low-NO_X burners (ULNBs).

Twenty-two of the refinery's emission units were determined to be BART eligible. BART-eligible emissions units as a group have the potential to emit more than 250 tons per year (tpy) of NO_X, SO_2, or PM_{10}. The units are as follows:

- Boiler #1
- Boiler #3
- Crude Charge Heater
- South Vacuum Heater
- #1 Reformer Heaters
- Naphtha Hydrodesulfuriztion (HDS) Charge Heater
- Naphtha HDS Stripper Reboiler
- 1st Stage Hydrocracker (HC) Fractionator Reboiler
- 2nd Stage HC Fractionator Reboiler
- R-1 HC Reactor Heater
- R-4 HC Reactor Heater

- Coker Charge Heater (#1 North)
- Coker Charge Heater (#2 South)
- #1 Diesel HDS Charge Heater
- Diesel HDS Stabilizer Reboiler
- Steam Reforming Furnace #1
- Steam Reforming Furnace #2
- Two Sulfur Recovery Units (SRUs) and one of the associated Tail Gas Unit (TGU)
- High Pressure Flare
- Low Pressure Flare
- Green Coke Load Out equipment

Modeling of visibility impairment from all BART-eligible units except Boilers #1 and #3 was done following the Oregon/Idaho/Washington/EPA-Region 10 BART modeling protocol.[1] Modeled visibility impacts of baseline emissions show impacts on the 22nd highest value in the 2003-2005 modeling period (the 98th percentile value) of greater than 0.5 deciviews (dv) at only one Class 1 area, Olympic National Park where the impact was 0.84 dv. NO_X and SO_2 emissions were responsible for 78.4 percent and 20.5 percent of the impacts, respectively. All NO_X and most SO_2 were emitted from combustion sources.

BP prepared a BART technical analysis for the 20 modeled units subject to BART using Washington State's BART Guidance.[2] The other two BART-eligible units (Boilers #1 and #3) are being replaced with new units as permitted under Prevention of Significant Deterioration (PSD) permit 07-01. The replacement boilers (Boilers #6 and #7) are under construction. Installation will be completed in 2009 and the older boilers decommissioned. Selective Catalytic Reduction (SCR) on the replacement boilers will provide significantly lower NO_X emissions.

The Washington State Department of Ecology (Ecology) has determined BART for all eligible emission units at the BP Cherry Point Refinery. Except for the two power boilers that are being replaced, the existing emission controls are determined to meet BART. The replacement boilers are determined to be BART for the original boilers.

[1] Modeling protocol available at http://www.deq.state.or.us/aq/haze/docs/bartprotocol.pdf.
[2] "Best Available Retrofit Technology Determinations Under the Federal Regional Haze Rule," Washington State Department of Ecology, June 12, 2007.

Table ES-1. ECOLOGY'S DETERMINATION OF EMISSION CONTROLS THAT CONSTITUTE BART

Emission Unit	BART Control Technology	Emission Limitations Contained in the Listed Permits, Orders, or Regulations
Crude Charge Heater	Current burners and operations	OAC 159, RO 28 (40 CFR 60 Subpart J), OAC 689a
South Vacuum Heater	Existing UNLB	RO 28 (40 CFR 60 Subpart J), OAC 902a
Naphtha HDS Charge Heater	Current burners and operations	RO 28 (40 CFR 60 Subpart J)
Naphtha HDS Stripper Reboiler	Current burners and operations	RO 28 (40 CFR 60 Subpart J)
#1 Reformer Heaters	Current burners and operations	RO 28 (40 CFR 60 Subpart J)
Coker Charge Heater (#1 North)	Current burners and operations	OAC 689a, RO 28 (40 CFR 60 Subpart J)
Coker Charge Heater (#2 South)	Current burners and operations	OAC 689a, RO 28 (40 CFR 60 Subpart J)
#1 Diesel HDS Charge Heater	Existing ULNB and operations	RO 28 (40 CFR 60 Subpart J), OAC 949a
Diesel HDS Stabilizer Reboiler	Existing ULNB and operations	RO 28 (40 CFR 60 Subpart J), OAC 949a
Steam Reforming Furnace #1 (North H2 Plant)	Current burners and operations	RO 28 (40 CFR 60 Subpart J)
Steam Reforming Furnace #2 (South H2 Plant)	Current burners and operations	RO 28 (40 CFR 60 Subpart J)
R-1 HC Reactor Heater	Existing ULNB and operations	RO 28 (40 CFR 60 Subpart J), OAC 966a
R-4 HC Reactor Heater	Current burners and operations	RO 28 (40 CFR 60 Subpart J)
1st Stage HC Fractionator Reboiler	Current burners and operations	OAC 149, OAC 351d, RO 28 (40 CFR 60 Subpart J)
2nd Stage HC Fractionator Reboiler	Existing UNLB and operations	OAC 149, RO 28 (40 CFR 60 Subpart J), OAC 847a
Refinery Fuel Gas (hydrogen sulfide)	Currently installed fuel gas treatment system.	RO 28 (40 CFR 60 Subpart J)
SRU & TGU (Sulfur Incinerator)	Current burners and operations	OAC 890b, 40 CFR 60 Subpart J (250 ppm SO_2 incinerator stack and 162 H_2S refinery fuel gas as supplemental fuel for incinerator), 40 CFR 63 Subpart UUU.
High and Low Pressure Flares		
NO_X	Good operation and maintenance including use of the flare gas recovery system and limiting pilot light fuel to pipeline grade natural gas.	40 CFR 63 Subpart A, NWCAA 462, 40 CFR 63 Subpart CC
SO_2	Good operating practices, use of natural gas for pilot.	40 CFR 63 Subpart A, NWCAA 462, 40 CFR 63 Subpart CC
PM	Good operating practices, use of an steam-assisted smokeless flare design, use of flare gas recovery system.	40 CFR 63 Subpart A, NWCAA 462, 40 CFR 63 Subpart CC
Green Coke Load out	Maintain as unused equipment for possible future use.	Emergency use only per criteria in the BART order and operation per applicable NWCAA regulatory order and regulations.
Power Boilers 1 and 3	Replacement with new Power Boilers 6 and 7	PSD 07-01 and NWCAA Order OAC #1001a

1. INTRODUCTION

This document is to support Ecology's determination of the Best Available Retrofit Technology (BART) for the BP Cherry Point Refinery on Cherry Point near Blaine, Washington.

1.1 The BART Program and BART Analysis Process

The federal Clean Air Act Amendments of 1977 (CAA) established a national goal of eliminating man-made visibility impairment in all mandatory federal Class I areas. The CAA requires certain sources to utilize BART to reduce visibility impairment as part of the overall plan to achieve that goal.

Requirements for the BART program and analysis process are given in 40 CFR 51, Subpart P, and Appendix Y to Part 51.[3] Sources are required to comply with the BART requirements if they:

1. Fall within 26 specified industrial source categories.
2. Commenced operation or completed permitting between August 7, 1962 and August 7, 1977.
3. Have the potential to emit more than 250 tons per year of one or more visibility impairing compounds including sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM), and volatile organic compounds (VOCs).

Emission units that meet the source category, age, and potential to emit criteria must also make the facility "cause or contribute" to visibility impairment within at least one mandatory federal Class I area for the facility to remain BART applicable. Ecology has adopted the "cause and contribute" criteria that the EPA suggested in its guideline. BART-eligible units at a source cause visibility impairment if their modeled visibility impairment is at least 1.0 deciview (dv). Similarly, the criterion for contributing to impairment means that the source has a modeled visibility impact of 0.5 dv or more.

The BART analysis protocol in Appendix Y Sections III–V uses a 5-step analysis to determine BART for SO_2, NO_X, and PM. The five steps are:

1. Identify all available retrofit control technologies.
2. Eliminate technically infeasible control technologies.
3. Evaluate the control effectiveness of remaining control technologies.
4. Evaluate impacts and document the results.
5. Evaluate visibility impacts.

Ecology requires an applicable facility to prepare a BART technical analysis report and submit it to Ecology. Ecology then evaluates the report and makes a final BART determination decision.

[3] Appendix Y to 40 CFR 51 – Guidelines for BART Determinations Under the Regional Haze Rule.

This decision is issued to the source owner as an enforceable Order, and included in the State's Regional Haze State Implementation Plan (SIP).

As allowed by the EPA BART guidance, Ecology has chosen to consider all five factors in its BART determinations. To be selected as BART, a control has to be available, technically feasible, cost effective, provide a visibility benefit, and have a minimal potential for adverse non-air quality impacts. Normally, the potential visibility improvement from a particular control technology is only one of the factors weighed for determining whether a control constitutes BART. However, if two available and feasible controls are essentially equivalent in cost effectiveness and non-air quality impacts, visibility improvement becomes the deciding factor for the determination of BART.

1.2 The BP Cherry Point Refinery

The BP Cherry Point Refinery (refinery) is located on Cherry Point near Blaine, Washington. It began operation in 1971 as the Atlantic Richfield Company (ARCO) refinery. Starting in 2000 and completed by Jan. 1, 2002, the refinery was acquired by BP and is operated by BP West Coast Products, LLC. The plant location is in northwest Washington in Whatcom County, about eight miles south of the U.S.-Canada Border. The land surrounding the refinery is primarily rural and agricultural, with some low density residential development. Three other major industrial operations exist within a six mile radius of the plant.

The crude oil processing capacity of the refinery is 230,000 barrels per day. Crude oil is principally delivered by tanker ship, though a pipeline to bring crude from Canada is available. The crude is processed into a wide variety of products including gasoline, diesel, low-sulfur diesel, jet fuel, calcined coke, green coke, sulfur, liquefied petroleum gas (LPG), butane, pentane, as well as intermediates such as reformate. A diagram of the refinery is included as Appendix C at the end of this report.

Products are sent to market in several ways. Ship and barges carry gasoline, jet fuel, diesels, and intermediate refined products. Pipelines are used to carry gasoline, diesels, and jet fuels. Rail cars are used to ship LPG, butanes, sulfur, green coke, and calcined coke. Finally, trucks are used to carry LPG, gasoline, diesels, jet fuel, calcined coke, and sulfur. The mode of transport is determined by location of the purchaser.

When originally constructed, the refinery did not include coke calciners. All coke produced was "green" or uncalcined coke. Since 1978, all coke produced is calcined coke. Calcining removes any remaining volatile hydrocarbons and some of the sulfur compounds in the coke. The primary usage of calcined coke is to make anodes for aluminum smelting. When the refinery produced and shipped green coke, a specific rail and car loading facility was built and used to ship green coke. The calcined coke system uses different rail car and truck loading facilities. The coke calciners were permitted in December 1977 after the end of the BART period. As a result, these units are not BART eligible.

Table 1-1 below lists all the emitting equipment operating at the refinery. The BART eligibility of each unit is indicated in the table.

Table 1-1. BP CHERRY POINT REFINERY'S EMISSION UNITS AND BART ELIGIBILITY

Operational Area	Process Unit Number	Description of Major Emission Units	BART Eligible? Yes/No
Flares	28	Flare Gas Recovery	N/A
	29-111	Low Pressure Flare	Yes
	29-110	High Pressure Flare	Yes
Boilers and Cooling Towers	30-1601	Utility Boiler #1	Yes
	30-1603	Utility Boiler #3	Yes
	30.104	Utility Boiler # 4	No
	30.105	Utility Boiler #5	No
	30	Cooling Tower #1	Yes
	24	Cooling Tower #2	No
Crude/Vacuum	10-1401	Crude Charge Heater	Yes
	10.11	North Vacuum Heater	No
	10-1451	South Vacuum Heater	Yes
	11-1401	Naphtha HDS Charge Heater	Yes
	11-1402	Naphtha HDS Stripper Reboiler	Yes
	11-1403-1406	#1 Reformer Heaters	Yes
	21-1421-1424	#2 Reformer Heaters	No
Delayed Coker	12-1401-01	North Coker Charge Heater #1	Yes
	12-1401-02	South Coker Charge Heater #2	Yes
Diesel Hydrodesulfurization (HDS)	13-1401	#1 Diesel HDS Charge Heater	Yes
	13-1402	Diesel HDS Stabilizer Reboiler	Yes
	26-1401	#2 Diesel HDS Charge Heater	No
Hydrogen Plant	14-1401	North Reforming Furnace #1	Yes
	14-1402	South Reforming Furnace #2	Yes
Hydrocracker	15-1401	R-1 Hydrocracker Reactor Heater	Yes
	15-1402	R-4 Hydrocracker Reactor Heater	Yes
	15-1451	1st Stage Fractionator Reboiler	Yes
	15-1452	2nd Stage Fractionator Reboiler	Yes
Sulfur Complex	17, 19	#1 TGU Stack and #2 TGU Stack	Yes
LEU/LPG	22	Light End Unit (LEU) and Liquefied Petroleum Gas	No
Isomerization		IHT Heater	No
Calciner/Coke Handling	20-70	Calciner Stack #1 (Hearths #1 & #2)	No
	20-71	Calciner Stack #2 (Hearth #3)	No
	20-72	Coke Silos and Loading – Baghouses and Vents	Yes/No[4]
Wastewater	32	API Separators	No
		Slop Oil, equalization and recovered oil tanks	No

[4] Green coke loading is BART-eligible, calcined coke loading is not.

Operational Area	Process Unit Number	Description of Major Emission Units	BART Eligible? Yes/No
Storage and Handling		Tank Farm Butane/Pentane Spheres	No No
Shipping, Pumping and Receiving	35	Marine Dock Dock Thermal Oxidizer	No[5] No[5]
	33	Truck Rack Truck Rack Thermal Oxidizer	No No
	37	Rail Car Loading LPG Loading Racks	No No

Many tanks are also BART-eligible based on age, however, the potential to emit (PTE) for VOC from these tanks as currently configured to meet requirements of various NSPS and NESHAP MACT requirements does not meet the BART eligibility criteria for emissions rate.

In the late 1990s, the EPA conducted a nation-wide enforcement initiative of the petroleum refining industry, targeting alleged violations of the Clean Air Act (CAA), Resource Conservation and Recovery Act (RCRA) and the Toxic Substances Control Act (TSCA). Following this in-depth investigation, the refinery's parent company, British Petroleum Exploration & Oil Company, entered into Consent Decree agreements with the EPA and intervening parties that will result in a reduction of air pollution emissions at their nine petroleum refineries.

As one of the nine affected refineries listed in the BP Consent Decree, the BP Cherry Point Refinery has been implementing control strategies to reduce emissions of VOCs, NO_X, and SO_2 from refinery process units. The BART-eligible units that have been recently retrofitted with low-NO_X or ultra-low-NO_X burners have been retrofitted to comply with the Consent Decree. In addition, the refinery has adopted an enhanced fugitive emission control program for VOC emissions from all plant operations.

Another result of the Consent Decree is that all refinery fuel gas must be processed to meet the sulfur content requirements of 40 CFR 60 Subpart J.

The refinery is a Title V source operating under Air Operating Permit #015 issued by the Northwest Clean Air Agency (NWCAA). Petroleum refineries are one of the 26 BART-eligible source categories. The Washington State Department of Ecology (Ecology) received a BART Analysis and Determination Report from BP on March 28, 2008, and additional information on June 25, 2008.

[5] Only the VOC emissions from the South Dock are BART eligible. The VOC emissions are now controlled by the thermal oxidizer permitted in 2001 to control the VOC emissions from the new North Dock. Under requirements of 40 CFR Part 63, Subpart CC, piping to collect and route VOC from the South Dock was permitted for installation and operation in 2001. The Thermal Oxidizer is not BART eligible. The North Dock is not BART eligible.

1.3 BART-Eligible Units at the BP Refinery

Twenty-two of the plant's individual emission units were found to be BART eligible. Two BART-eligible units (Boilers No. 1 and 3) were not reviewed for BART because new units (Boilers No. 6 and 7) will replace the BART-eligible units. The replacement units have gone through PSD permitting, are currently under construction, and are scheduled to begin operation in 2009.

The other 20 BART-eligible units were modeled to determine visibility impacts on Class I Areas. Table 1-2 identifies the modeled BART-eligible units and the emission rates used for BART modeling.

Table 1-2. BASELINE MODELING EMISSION RATES FOR BART-ELIGIBLE UNITS

Emission Unit		Baseline Modeling Emission Rates (lb/hr)		
BART-Eligible Unit	**Baseline Firing Rate (MMBtu/hr)**	**NO_X**	**SO_2**	**PM_{10}**
Crude Charge Heater	593	109. 7	20.0	5.5
South Vacuum Heater	186	7.3	7.7	1.7
Naphtha HDS Charge Heater	106	10.4	3.9	1.0
Naphtha HDS Stripper Reboiler	64	6.3	2.3	0.6
#1 Reformer Heater	709	106.4	25.9	6.6
Coker Charge Heater (#1 North)	143	8.9	7.8	1.3
Coker Charge Heater (#2 South)	145	9.0	7.9	1.3
#1 Diesel HDS Charge Heater	34	3.3	1.2	0.3
#1 Diesel HDS Stabilizer Reboiler	56	5.5	2.0	0.5
Steam Reforming Furnace #1 (North Hydrogen (H2) Plant)	308	30.2	11.2	2.9
Steam Reforming Furnace #2 (South H2 Plant)	302	29.6	11.0	2.8
R-1 HC Reactor Heater	89	8.7	3.3	0.8
R-4 HC Reactor Heater	42	4.1	1.5	0.4
1st Stage HC Fractionator Reboiler	173	25.9	6.3	1.6
2nd Stage HC Fractionator Reboiler	145	8.2	5.3	1.3
SRU & TGU	---	1.4	8.5	0.2
High Pressure Flare	---	2.6	2.7	0.3
Low Pressure Flare	---	3.8	4.6	0.4
Green Coke Load Out	---	0.0	0.0	0.0
Note: The bolded units are those that have had controls (ULNBs) installed since 2005.				

1.4 Visibility Impact of the BP Refinery's BART-Eligible Units

Class I Area visibility impairment modeling was performed by BP using the BART modeling protocol developed by Oregon, Idaho, Washington, and EPA Region 10.[6] This protocol uses three years of metrological information to evaluate visibility impacts. As specified in the protocol, BP used the highest 24-hour emission rates that occurred in the 3-year period to model impacts on Class I Areas.

A source causes visibility impairment if its modeled visibility impact is above one deciview and contributes to visibility impairment if its modeled visibility impact is above 0.5 deciview. The modeling indicates that the emissions from this plant contributes to visibility impairment on the 8th highest day in any one year and the 22nd highest day over the three years (the 98th percentile days, respectively) at only the Olympic National Park. The modeling indicates the plant does not cause or contribute to visibility impairment at any other mandatory federal Class 1 area. NO_X and SO_2 emissions were responsible for 78.4 percent and 20.5 percent of the impacts, respectively. Primary particulate emissions are responsible for the remaining one percent of the refinery's visibility impact. For further information on visibility impacts of this facility, see Section 3.

2. OVERVIEW OF BP'S BART TECHNOLOGY ANALYSIS

Section 2 is a review of the BART technical analysis provided by BP to Ecology. The company used the five step process defined in BART guidance and listed in Section 1.1 of this report.

The BART units were divided into five groups:

1. Major combustion units (heaters and boilers) (Section 2.1)
2. Flares (Section 2.2)
3. Sulfur recovery units (Section 2.3)
4. Tail gas units (Section 2.3)
5. Green coke load out operation (Section 2.4)

BP looked at Cooling Tower #1 and its large diameter particulates and concluded these particulates would not leave the plant site. As a result, the emissions from this unit were not looked at further.

2.1 Controls Affecting All Combustion Units – Heaters and Boilers

The refinery maintains 15 heaters and two boilers that are subject to BART. All BART heaters and boilers are permitted to combust refinery fuel gas and natural gas. The maximum day heat input rates of all subject to BART combustion units are shown in Table 1-2. Actual operation is somewhat less than the maximum day heat input rates.

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[6] A copy of the modeling protocol is available at http://www.deq.state.or.us/aq/haze/docs/bartprotocol.pdf.

The two BART-eligible boilers (Boilers No. 1 and No. 3) were not evaluated for BART impacts or controls by BP. BP considered them to not be subject to BART since they were scheduled to be replaced by two new boilers in 2009. See Section 4 of this document for more discussion of these units.

The following sections discuss the BART determination analysis performed for NO_X, SO_2, and PM_{10}/$PM_{2.5}$ for the refinery heaters.

2.1.1 NO_X Control Options for Refinery Heaters

A Summary of BP's review of NO_X control technologies that were determined to be commercially available for a retrofit on existing refinery heaters is given in Table 2-1. A more complete description and discussion of each technology follows.

Table 2-1. POTENTIAL NO_X CONTROL TECHNOLOGIES FOR REFINERY HEATERS

Options/Methods	Description	Potentially Applicable To	Overall Technical Feasibility
Selective Catalytic Reduction (SCR)	Injection of ammonia into a catalyst bed within the flue gas path.	All	Yes
Low-NO_X Burners (LNBs/ULNBs)	Reducing NO_X emissions through burner design.	All	Yes
Selective Non-Catalytic Reduction (SNCR)	Injection of ammonia directly into the flue gas path at a specific temperature.	All	No – Small operating range
External Flue Gas Recirculation (FGR)	Flue gas is recirculated via fan and external ducting and is mixed with combustion air stream.	More applicable to boilers. Safety concern with process heaters.	No – Potential safety issues
Low Excess Air Operation – CO Control	Reduce excess air level by maintaining CO at minimum threshold using in-situ CO analyzer in the flue gas stream.	All	No – Potential safety issues and small operating range.
Steam Injection	Steam is injected into the root of the flame or directly via the fuel stream which lowers the flame temperature.	All	Not feasible except 1st Stage HC Fractionator Reboiler.
Lower Combustion Air Preheat	Reduce combustion air temperature on systems with air preheat.	Units with air preheat	No
CETEK - Descale & Coat Tubes	Reduces the fire box temperature by improving heat transfer in applications where the tubes are externally scaled.	Units with externally scaled tubes.	No
Modify Existing Burners to Improve NO_X	Burner tip modification.	All	Yes

Selective Catalytic Reduction (SCR) is a post-combustion control device in which ammonia is injected as the flue gas passes through a catalyst bed. NO_X reacts with the ammonia aided by the catalyst to form nitrogen and water. SCR is technically feasible for all refinery heaters and boilers. According to corporate experience, BP has found SCR capable of meeting the higher of a 98 percent emission reduction or five ppm NO_X.

Selective Non-Catalytic Reduction (SNCR) consists of injecting ammonia or urea into combustion unit flue gases in a specific temperature zone of between approximately 1600ºF and 2000ºF. The process relies on good mixing at high temperature to reduce NO_X to nitrogen (N_2) as the flue gas moves through the ductwork. For efficient NO_X removal using SNCR, the exhaust gas must remain within this temperature range for the appropriate length of time. The ammonia injector must be carefully located to ensure that the exhaust gas temperature is within the acceptable range. Due to the variability in the hydrogen content and heat content (collectively known as "specific gravity swings" or "gravity swings") of refinery fuel gas, the exhaust temperature can vary significantly due to normal changes in refinery operation, even when the burner/heater operation remains constant. These variations make SNCR a poor candidate to control NO_X on the refinery heaters and boilers. As a result, BP considered SNCR to be technically infeasible for the refinery process heaters.

Low-NO_X Burners/Ultra-Low-NO_X Burners: Conventional burners can be retrofitted to reduce their NO_X emissions with either low-NO_X burners (LNBs) or ultra-low-NO_X burners (ULNBs). As the name implies, ultra-low-NO_X burners have lower emissions of the two types of burners. However, each has specific retrofit requirements and is not necessarily suited for all applications. Key feasibility criteria include the burner's performance with fuel gas specific gravity change (a.k.a. "gravity swings") for units with high turndown ratios and whether the boiler or heater can accommodate the longer flame pattern that is characteristic of LNBs. BP acquired an evaluation of whether low or ultra-low-NO_X burners were available for each BART-eligible heater from two burner vendors. BP's BART analysis used based the type of burner recommended by the vendors as most appropriate for the unit's design. Discussions of low-NO_X burners later in this support document generally refer to a burner replacement as LNB replacement regardless of the specific type of burner recommended by the vendors.

In **External Flue Gas Recirculation (FGR)**, flue gas is recirculated using a fan and external ducting and is mixed with the combustion air stream thereby reducing the flame temperature and decreasing NO_X formation. Generally, when a unit is retrofitted with external FGR, it will require an additional or larger forced draft (FD) fan. Application of external FGR is normally limited to boilers because there is a risk of recirculating hydrocarbons leaked from the heat transfer tubing into the process heater fire box potentially causing an unsafe situation. Therefore, external FGR was considered technically infeasible overall for use on refinery process heaters.

Low Excess Air Operation minimizes the amount of excess air (i.e., oxygen) during the initial stages of combustion and decreases the amount of NO_X formed. However, reducing the amount of oxygen can cause incomplete combustion, which increases carbon monoxide (CO) emissions. The combustion unit can be operated using the flue gas CO concentration to control the amount of excess air and, therefore, controlling the amount of NO_X generated. This CO level would be monitored by an in-situ CO analyzer in the flue gas stream. This technique requires a moderate amount of instrumentation and automation required for burner control (e.g., actuators for draft and air control). All of the process heaters at the refinery already utilize optimized combustion conditions that minimize excess air while maximizing fuel combustion efficiency and minimizing emissions.

Low oxygen operation results in longer flames that could cause flame impingement (flames directly striking the tubing) upon the heat transfer tubing or the fire bricks behind them. Historical operation has shown it is difficult to maintain safe operating conditions at low oxygen levels. Due to the limited viable operating range and potential safety issues, BP considers this technique technically infeasible for use on refinery heaters.

Steam Injection (a.k.a. flame tempering) decreases NO_X formation by injecting steam with the combustion air or fuel to reduce the peak flame temperature. Steam injection can impact combustion unit operation by changing the flame shape, reducing unit thermal efficiency, and affecting unit operating stability. The modest NO_X reductions at the heater may be offset by NO_X emissions resulting from increased steam generation elsewhere. Minimal NO_X reductions are gained in units already fitted with low-NO_X burners. Due to the technical issues and incompatibilities with some installed burners, BP considers steam injection to be technically infeasible for all but one of the BART-eligible refinery heaters, the 1st Stage HC Fractionator Reboiler.

Lower Combustion Air Preheat is another technique that can decrease NO_X formation by reducing flame temperature. This technique is only applicable to units equipped with air preheaters. For units that are not equipped with air preheat, combustion air is already entering at ambient air temperature. If cooler air is introduced into the heater as combustion air, the heater has to utilize additional fuel to heat the air for the combustion process which ends up negating any NO_X reductions generated. These issues make reducing the combustion air temperature technically infeasible for the BART refinery heaters.

CETEK is a commercial treatment that involves removing existing external tube scale and coating the cleaned tubes with a coating that reduces the rate of scale formation. Removing the scale and applying a coating to the heat transfer surfaces can allow less fuel to be burnt in the heater, yet supply the same heat to the petroleum product being heated. Reducing the fuel usage and possibly the peak flame temperature will lead to a decrease in NO_X emissions. This technique is only applicable to units where the heat transfer tubes are externally scaled.

This method of NO_X reduction is applicable to only the #1 Reformer Heater. This is the only BART unit that has scaling. The flames from the burners in the #1 Reformer Heaters currently impinge somewhat on the tubes and the scale protects the tubes from being damaged by the flames. As such, this emission control method cannot be implemented until the flame impingement issue is addressed in the #1 Reformer Heaters. Therefore, descaling and coating the tubes was eliminated from consideration in the BART analysis.

As an alternative to installation of LNB or ULN burners, the existing **burners could be modified** to reduce NO_X**.** Although it is possible to modify burner tips to change fuel distribution among different burner zones, each burner in each heater at the refinery has been engineered for optimum performance, reliability, and safety. It is important to understand all the ramifications prior to attempting to redesign existing burners to achieve lower NO_X. For example, modifying the burners to achieve a longer flame that might result in cooler combustion temperatures and reduced NO_X formation can result in flame impingement on heat transfer surfaces or refractory materials which may damage the heater. BP found that modifying existing burners was technically feasible for only the 1st Stage HC Fractionator Reboiler.

BP's Unit Specific Evaluation of NO_X Control Effectiveness

Based on their review of the available NO_X controls, BP considers only the following controls to be the only NO_X control technologies applicable to the BART-eligible refinery heaters:

1. LNB plus SCR (vendor guarantee burner emission rate plus the less effective of 95 percent or five ppm).
2. SCR (95 percent or five ppm, whichever results in higher emissions).
3. LNB (vendor guarantee burner emission rate).

Five aspects of these control technologies were analyzed. They are costs of compliance, energy impacts, non-air quality environmental impacts, collateral emissions impacts, and remaining useful life. The remaining useful life of all refinery heaters was assumed to be 20 years. A discussion of these aspects as applied to each refinery heater follows.

Crude Charge Heater

The Crude Charge Heater is rated at 720 MMBtu/hr heat input and currently operates at 593 MMBtu/hr. This heater currently uses conventional design burners dating from the time of original installation.

<u>LNBs</u>: Installing LNBs on the Crude Charge Heater is not technically feasible due to the high heat density in the fire box. Flame impingement is likely and use of these burners would require reducing rated heater capacity (derating) and unit throughput.

<u>SCR</u>: Involves construction of a new SCR unit and possibly a new exhaust stack for this heater. The BART cost effectiveness analysis to install a SCR on the Crude Charge Heater was determined to be $14,658/ton. If lost refinery production due extended turnaround time required to install the new control is considered, the cost effectiveness is increased to $32,001/ton. BP proposed that this control option is not BART due to the high costs.

<u>LNBs plus SCR</u>: Because a LNB installation is technically infeasible, the combination of LNB and SCR is also technically infeasible.

BP proposed continued use of the existing conventional burners as BART for NO_X for the Crude Charge Heater.

South Vacuum Heater

In response to the requirements of the Consent Decree, the South Vacuum Heater has had ultra-low-NO_X Burners installed and permitted by the Northwest Clean Air Agency (NWCAA) Order of Approval to Construct (OAC) #902, February 7, 2005, revised November 1, 2005. The heater is rated at 222 MMBtu/hr and currently operates at186 MMBtu/hr.

<u>LNBs</u>: ULNBs were installed on the South Vacuum Heater in 2005. Further NO_X reduction is not possible using burner upgrades due to high air preheat.

<u>SCR</u>: The BART cost effectiveness analysis to install a SCR on the South Vacuum Heater with existing ULNB was calculated to be $54,551/ton. If lost refinery production due extended turnaround time required to install the new control is considered, the cost effectiveness is increased to $82,643/ton. This control option was eliminated as BART.

<u>BP's BART Proposal</u>: The existing ULNBs are BART for NO_X for the South Vacuum Heater.

Naphtha HDS Charge Heater & Naphtha HDS Stripper Reboiler

The Naphtha HDS Charge Heater (design heat input of 110 MMBtu/hr, operating rate of 106 MMBtu/hr) and the Naphtha HDS Stripper Reboiler (design heat input of 86 MMBtu/hr), operating rate of 64 MMBtu/hr are currently fitted with conventional burners.

<u>LNBs</u>: The fire boxes of these two heaters are relatively small. Installing LNBs on these two units would result in flame impingement and require a significant derating of each unit to avoid tubing burn through. As a result, BP does not consider LNBs to be technically feasible for these two heaters.

<u>SCR</u>: Due to stack location, it is not possible to duct these two heaters to a single SCR unit. As a result, a separate SCR would be required for each unit. The BART cost effectiveness analysis to install SCRs on the Naphtha HDS Charge Heater or the Naphtha HDS Stripper Reboiler is estimated to be $26,667/ton for the Naphtha HDS Charge Heater and $31,467/ton for the Naphtha HDS Stripper Reboiler. If lost refinery production due extended turnaround time required to install the new control is considered, the cost effectiveness is increased to $32,175/ton and $40,711/ton, respectively. BP considers SCR to be financially infeasible for these two heaters.

<u>LNBs plus Selective Catalytic Reduction</u>: Because a ULNB installation is technically infeasible, the combination of ULNB and SCR is also technically infeasible.

BP's BART Proposal: BP proposed that BART for NO_X for both the Naphtha HDS Charge Heater and the Naphtha HDS Stripper Reboiler is the current conventional burners.

#1 Reformer Heater

The #1 Reformer Heater (design heat input of 1,075 MMBtu/hr, operating rate of 709 MMBtu/hr) has a complex design with four independent fire boxes and two stacks. It is currently fitted with conventional burners.

LNBs: Installing LNBs on the #1 Reformer Heaters is not technically feasible. The existing burners produce the shortest, most compact flame available yet flame impingement on the tubes is a serious problem. The LNBs currently available produce a longer flame which would be expected to result in even greater levels of flame impingement. BP considers LNBs to be technically infeasible for this heater and eliminated from consideration as BART.

SCR: The SCR cost effectiveness analysis was predicted to be $15,253/ton. If lost refinery production due extended turnaround time required to install the new control is considered, the cost effectiveness is increased to $17,299/ton. This control option is eliminated as BART.

LNBs plus SCR: Because a LNB installation is technically infeasible, the combination of LNB and SCR is also technically infeasible.

BP's BART Proposal: BP proposed that BART for NO_X for the #1 Reformer Heater is the current conventional burners.

Coker Charge Heater (#1 North) and Coker Charge Heater (#2 South)

The Coker Charge Heater (#1 North (design heat input of 190 MMBtu/hr, operating rate of 143 MMBtu/hr)) and Coker Charge Heater (#2 South (design heat input of 190 MMBtu/hr, operating rate of 145 MMBtu/hr)) are currently fitted with early design LNBs which incorporate staged air combustion and flue gas recirculation. The installation of these burners was permitted in 1999. The operation of coker heaters is unique due to the cyclic nature of the unit which limits the effectiveness of NO_X control technologies.

LNBs: BP has estimated the cost effectiveness to install replacement LNBs was estimated to be of $31,301/ton for the north heater and $30,762/ton for the south heater. BP has considered installation of LNBs to be financially infeasible for BART for both of these heaters.

SCR: BP estimated the cost effectiveness to add SCR to the existing LNB installation was estimated to be $35,202/ton for the north heater and $34,597/ton for the south heater. The incremental cost to go from LNB to SCR as the next most stringent control device is $38,832/ton for the north heater and $38,164/ton for the south heater. Considering the cost effectiveness values, BP has considered SCR to be economically infeasible for use on these units.

LNBs plus SCR: BP's evaluation of cost effectiveness assumes that the LNB installation and cost will not change. The SCR costs were adjusted downward to account for the lower post-LNB NO_X concentration. Lower NO_X concentrations result in a need for less catalyst and ammonia consumption. BP's corporate experience has found SCR controls NO_X emissions to either 95 percent or five ppm, whichever results in higher emissions. With a cost effectiveness of $43,460/ton for the north heater and $42,738/ton for the south heater, this combined control option was determined by BP to be not cost effective for these heaters.

BP's BART Proposal: BP proposed the existing LNBs with staged air combustion coupled as BART for NO_X for both Coker Charge Heater (#1 North) and Coker Charge Heater (#2 South).

#1 Diesel HDS Charge Heater and Diesel HDS Stabilizer Reboiler

The #1 Diesel HDS Charge Heater (design heat input of 71 MMBtu/hr, operating rate of 34 MMBtu/hr) and Diesel HDS Stabilizer Reboiler (reported design heat input of 53 MMBtu/hr, operating rate of 56 MMBtu/hr) have been fitted with ultra-low-NO_X burners (NWCAA OAC #949, March 31, 2006) to comply with terms of the Consent Decree.

LNBs: ULNBs are currently installed on the #1 Diesel HDS Charge Heater and Diesel HDS Stabilizer Reboiler.

SCR: The BART cost effectiveness analysis to add SCRs on the #1 Diesel HDS Charge Heater and Diesel HDS Stabilizer Reboiler was calculated to be $192,586/ton for the #1 Diesel HDS Charge Heater and $145,094/ton for the Diesel HDS Stabilizer Reboiler. If lost refinery production due extended turnaround time required to install the new control is considered, the cost effectiveness is increased to $282,388/ton and $206,592/ton, respectively. BP considers SCR to be economically infeasible as BART for both of these heaters.

BP's BART Proposal: BP proposed that the existing ULNBs are BART for NO_X for both #1 Diesel HDS Charge Heater and Diesel HDS Stabilizer Reboiler.

Steam Reforming Furnace #1 (North H2 Plant) and Steam Reforming Furnace #2 (South H2 Plant)

The Steam Reforming Furnace #1 (North H2 Plant (design heat input of 325 MMBtu/hr, operating rate of 308 MMBtu/hr)) and the Steam Reforming Furnace #2 (South H2 Plant (design heat input of 325 MMBtu/hr, operating rate of 302 MMBtu/hr)) are fitted with conventional burners.

CETEK: The Steam Reforming Furnace #1 is subject to scaling of the heat transfer tubes inside of the heater. As discussed above, the CETEK process involves descaling the tubes and coating them with a material that resists the formation of scale. Since the scaling in the Steam Reforming Furnace #1 also protects the tubing from damage from the flame impingement that also occurs, BP eliminated this technique from further consideration.

LNBs: The BART cost effectiveness analysis to install ULNB on the Steam Reforming Furnace #1 (North H2 Plant) and Steam Reforming Furnace #2 (South H2 Plant) was estimated to be $21,234/ton for the north furnace and $21,682/ton for the south furnace. If lost refinery production due extended turnaround time required to install the new control is considered, the cost effectiveness is increased to $31,430/ton and $32,045/ton, respectively. BP considers the installation of LNBs to not be cost effective for use on these heaters.

SCR: The BART cost effectiveness analysis to install SCR on the Steam Reforming Furnaces was estimated to be $28,378/ton for the north furnace and $28,900/ton for the south furnace. If lost refinery production due extended turnaround time required to install the new control is considered, the cost effectiveness is increased to $46,449/ton and $47,320/ton, respectively. The incremental cost to go from LNB to SCR as the next most stringent control device was estimated at $59,622/ton for the north furnace and $60,719/ton for the south furnace. BP considers the use of SCR to not be cost effective for use on these heaters.

LNBs plus SCR: The cost effectiveness calculation assumes that the LNB installation and cost will not change as a result of the SCR installation. The SCR costs were adjusted downward to account for the lower SCR inlet NO_X concentration. Lower NO_X concentrations result in a need for less catalyst and ammonia consumption. BP's corporate experience has found SCR controls NO_X emissions to either 95 percent or five ppm, whichever results in higher emissions. With a cost effectiveness of $29,555/ton for the north furnace and $30,104/ton for the south furnace ($55,197/ton and $56,242/ton, respectively, if lost refinery production is considered), BP considered LNBs and SCR to not be economically feasible as BART for these furnaces.

BP's BART Proposal: BP proposed the current burners and operation are BART for NO_X for both Steam Reforming Furnace #1 (North H2 Plant) and Steam Reforming Furnace #2 (South H2 Plant).

R-1 HC Reactor Heater

The R-1 HC Reactor Heater (design and operating heat input of 89 MMBtu/hr) has been fitted with ULNBs (NWCAA OAC #966, August 9, 2006) to comply with the requirements of the Consent Decree.

LNBs: ULNBs have already been installed on the R-1 HC Reactor Heater.

Selective Catalytic Reduction: The BART cost effectiveness analysis to install SCRs on the R-1 HC Reactor Heater was estimated to be $214,726/ton. BP has determined that this control option is not economically feasible as BART for this heater.

BP's BART Proposal: BP proposed the existing ULNBs are BART for NO_X for the R-1 HC Reactor Heater.

R-4 HC Reactor Heater

The R-4 HC Reactor Heater (design heat input of 79 MMBtu/hr, operating rate of 42 MMBtu/hr) is fitted with conventional burners.

LNBs: Installing ULNBs on the R-4 HC Reactor Heater is not technically feasible. A serious risk exists due to the high heat density, flame impingement, flame shape, and an exceedance of the API guidelines for burner spacing.

SCR: The BART cost effectiveness analysis to install SCR on the R-4 HC Reactor Heater was estimated to be $36,620/ton. This control option was eliminated as BART for this heater.

LNBs plus SCR: Because a LNB installation is technically infeasible, the combination of LNB and SCR is also technically infeasible.

BP's BART Proposal: BP proposed the current burners and operations are BART for NO_X for the R-4 HC Reactor Heater.

1st Stage HC Fractionator Reboiler

The 1st Stage HC Fractionator Reboiler (reported design heat input of 150 MMBtu/hr, operating rate of 173 MMBtu/hr) is fitted with conventional burners.

Steam Injection: BP evaluated the installation of this technique to reduce NO_X on this burner. However, BP did not perform a detailed evaluation and instead focused on the more effective technique of installation of LNBs.

Burner Modification: BP evaluated the installation of this technique to reduce NO_X on this burner. However, BP did not perform a detailed evaluation and instead focused on the more effective technique of installation of LNBs.

LNBs: The BART cost effectiveness analysis to install ULNBs on the 1st Stage HC Fractionator Reboiler was estimated by BP to be $12,044/ton. This control option is not cost effective as BART for this heater. Nonetheless, BP proposes to install ULNB on this unit to achieve 0.05 lb NO_X/MMBtu.[7]

SCR: The BART cost effectiveness analysis to install SCR on the 1st Stage HC Fractionator Reboiler was estimated to be $19,470/ton; the incremental cost to go from LNB to SCR as the next most stringent control device was estimated to be $36,945/ton. BP considers these cost effectiveness values to be too high and eliminated SCR as BART for this heater.

[7] Although burner vendors indicated they could achieve 0.04 lb NO_X/MMBtu, BP's operating experience with these burners indicated this was an extremely aggressive limit. Because BP lacks confidence that 0.04 lb/MMBtu can be achieved on a continuous basis, BP proposed 0.05 lb/MMBtu.

LNBs plus SCR: The cost effectiveness calculation assumes that the LNB installation and cost will not change as a result of the SCR installation. The SCR costs were adjusted downward to account for the lower inlet NO_X concentration. The lower NO_X concentration results in needing less catalyst and less ammonia consumption. The cost effectiveness value is $23,518/ton; the incremental cost to go from LNB to SCR is $402,903/ton. BP considers these cost effectiveness values to be too high and eliminated SCR as BART for this heater.

BP's BART Proposal: BP proposed installation of ULNBs as BART for NO_X on the 1st Stage HC Fractionator Reboiler. BP recognized that the cost effectiveness to install LNBs on this heater is high. See Ecology's BART decision in Section 4 for this unit.

2nd Stage HC Fractionator Reboiler

The 2nd Stage HC Fractionator Reboiler (design heat input of 183 MMBtu/hr, operating rate of 145 MMBtu/hr) has been fitted with LNBs (NWCAA OAC #847, November 13, 2003) installed to comply with terms of the Consent Decree.

LNBs: The BART cost effectiveness analysis to replace the existing LNBs with ULNBs on the 2nd Stage HC Fractionator Reboiler was estimated to be $36,395/ton. This control option was eliminated as BART for this heater.

SCR: The BART cost effectiveness analysis to install SCRs on the 2nd Stage HC Fractionator Reboiler was estimated to be $37,810/ton. BP considers this cost to not be economically feasible and eliminated SCR as BART for this heater.

LNBs plus SCR: The cost effectiveness calculation assumes that the LNB installation and cost will not change as a result of the SCR installation. The SCR costs were adjusted downward to account for the lower inlet NO_X concentration. The lower NO_X concentration results in needing less catalyst and less ammonia consumption. With a cost effectiveness of $40,768/ton, this combined control option was eliminated by BP as BART for this heater as not economically feasible.

BP's BART Proposal: BP proposed the existing low-NO_X burners are BART for NO_X for the 2nd Stage HC Fractionator Reboiler.

2.1.2 SO_2 Control Options for Refinery Heaters and Other Combustion Devices

SO_2 emissions from combustion are the result of oxidation of sulfur compounds in the fuel. There are generally two methods of reducing SO_2 emissions from fired sources – reducing the sulfur in the fuel or use of add-on flue gas desulfurization technologies.

Overview of Available Retrofit SO_2 Emission Control Techniques

A review of the current SO_2 control technologies was conducted and those technologies that were determined to be commercially available for a retrofit on existing refinery heaters include:

- Emerachem EMX
- Dry Scrubbing
- Fuel Gas Conditioning (sulfur content reduction)
- Spray Tower Scrubbing

Emerachem EMX (previously known as SCONOX) is an add-on technology that utilizes a catalyst to absorb the SO_2 in the flue gas. The catalyst is periodically regenerated using hydrogen. The regeneration stream is treated in a sulfur recovery unit or adsorbed on carbon. This technology has not been proven to run longer than one year without major maintenance. It has only been used on a small number of natural gas combustion turbines for NO_X control, not on oil refinery heaters. As was mentioned previously, BP requires the refinery heaters to be able to operate five years between turnarounds. As such, BP did not consider Emerachem EMX to be technically feasible for use on the refinery heaters.

Dry scrubbing is an add-on technology where the SO_2 in the flue gas reacts with injected bicarbonate; the products of the reaction are removed in a baghouse. Each process heater would be required to have its own dry scrubbing system. This technology requires a turnaround approximately every two years due to equipment plugging and wear. Therefore, BP does not consider this technology to be technically feasible for its refinery heaters.

Two remaining options, fuel gas conditioning and spray tower scrubbing, are considered technically feasible.

BP evaluated expanded **fuel gas conditioning** to reduce the concentration of sulfur in refinery fuel gas to 50 ppmv. Currently, all refinery fuel gas is required to meet the NSPS limit of 162 ppm H_2S. Based on an engineering assessment performed by Jacobs Engineering for BP, improvements to the current refinery fuel gas treatment system to continuously meet a 50 ppmv concentration would reduce the average total sulfur concentration in fuel gas combusted by BART-eligible heaters by 89 percent. Fuel gas conditioning would be applied to all of the refinery's fuel gas, so would affect all refinery gas combustion sources, both BART and non-BART.

This technique reduces SO_2 emissions from all refinery fuel gas combustion units. The additional sulfur removal would increase the sulfur quantity sent to the current sulfur recovery system by one ton per day, within the current capacity of the system. Upgrading the current refinery fuel gas treatment system to reliably meet a 50 ppmv level has a cost effectiveness of $22,282/ ton when the capital and operating costs are applied to only the SO_2 reduction from the combustion units that are subject to BART. Using the plant wide SO_2 emissions reduction to calculate the cost effectiveness (estimated to be a reduction of 715 tons per year), results in a cost effectiveness of $14,428 /ton reduced.

For **spray tower scrubbing (wet flue gas desulfurization)**, the most stringent control effectiveness was considered to be 95 percent control. In its work for BP, Jacobs Engineering has found that vendors are reluctant to guarantee a higher removal rate for fuel sulfur contents like BP currently has due to measurement inaccuracies.

Due to the locations of the various process heaters, each unit would have its own wet FGD system. In rare situations like the #1and #2 Reformer Furnaces, more than one stack may be able to be combined into a single FGD system. BP evaluated the possibility of installing wet FGD systems on the process heaters. As a result of the already low fuel sulfur concentration,[8] the cost effectiveness to install wet FGD systems on the process heaters and modify the wastewater treatment system to handle the wet FGD system effluent would result in cost effectiveness values of $29,982 to $102,068 (not including the cost of lost production to install the systems). BP considers the installation of wet FGD systems to reduce sulfur emissions to not be cost effective.

Fuel gas conditioning and spray tower scrubbing can be used together. BP evaluated the cost of this combination and found cost effectiveness values of $49,743 to $179,151/ton SO_2 removed. BP determined that the cost effectiveness of implementing both a refinery fuel gas sulfur reduction system and adding wet FGD systems to the process heaters was not cost effective.

<u>BP's BART Proposal</u>: Based on cost effectiveness, BP proposed continued operation of the existing refinery fuel gas treatment system as BART for SO_2 emissions from the BART-eligible refinery heaters and other combustion units.

2.1.3 PM Control Options for Refinery Heaters

PM emissions from gaseous fuel combustion are inherently low. The particles are also very small with most below $PM_{2.5}$, and the majority of these below one micron in size. PM is comprised of filterable and condensable fractions. The filterable portion exists in either the solid or the liquid state. Condensable particulate matter exists as a gas in the stack but condenses in the cooler ambient air to form $PM_{10}/PM_{2.5}$.

Overview of Available Retrofit PM Emission Control Techniques

BP reviewed information in EPA's RACT/BACT/LAER Clearinghouse (RBLC) database and control technology literature to find available technologies to control particulate emissions from refinery heaters. Control methods listed in the RBLC generally fell into three categories:

1. Use of low sulfur gaseous fuel.
2. Good combustion practices.

[8] 162 ppmv is approximately 0.1 grain/dscf.

3. Proper design and operation.

No add-on control technologies were listed.
BP reviewed the current $PM_{10}/PM_{2.5}$ control technologies that were determined to be commercially available for a retrofit on existing refinery heaters. The complete listing is in Table 3-11 of the Best Available Retrofit Technology Determination, BP Cherry Point Refinery, submitted by BP to Ecology. Table 2-2 also lists a brief description of each technology and the two options are found to be technically feasible: fuel gas conditioning and wet electrostatic precipitators (WESPs).

Table 2-2. POTENTIAL $PM_{10}/PM_{2.5}$ CONTROL TECHNOLOGIES FOR REFINERY HEATERS

Options/Methods	Description	Potentially Applicable To	Overall Technical Feasibility
Fuel Gas Conditioning	The removal of sulfur compounds from fuel gas before burned in heaters.	Universally applied	Yes
Wet Electrostatic Precipitator (WESP)	A spray contactor circulates a neutralizing agent to react with sulfur compounds in the flue gas. The flue gas is then fed to a electric grid that enhances coalescing of sub-micron particles.	All	Yes

Fuel gas conditioning at the refinery is performed to remove sulfur from the fuel prior to combustion. Reducing sulfur in the refinery fuel gas reduces SO_2 emissions from all refinery combustion sources. SO_2 emissions can result in sulfate particulates that are usually collected in the back half of the particulate sampling train (i.e., measured as condensable particulates) and form in the atmosphere. A reduction in fuel gas sulfur content results in a reduction in condensable particulate emissions. Meeting the 50 ppm refinery fuel gas sulfur concentration evaluated for SO_2 emission reduction, BP estimated that fuel gas conditioning would result in a 25 percent reduction in the already low particulate emissions from the refinery heaters.

The capital costs to upgrade the refinery fuel gas sulfur removal system are the same as for SO_2 control. However, since the number of tons of particulate that could be controlled is significantly lower, the cost effectiveness is much higher. As a result, BP does not consider refinery fuel gas treatment to be cost effective for particulate control.

For the **WESP** option, the most stringent control effectiveness was considered to be 90 percent control. Utilizing both fuel gas conditioning and a wet ESP is assumed to be additive: the fuel gas conditioning brings the particulate emissions down by 25 percent and then the wet ESP removes 90 percent of the remaining $PM_{10}/PM_{2.5}$.

Each process heater will require its own WESP. BP did not perform a cost effectiveness evaluation for each heater. The company assumed that a WESP could be installed on all BART-

eligible process heaters and performed an overall cost effectiveness evaluation for the use of a WESP on heaters. With a cost effectiveness of $24,280 /ton reduced, BP does not consider the installation of WESPs to be cost effective.
BP proposed that BART for particulate control was the current refinery fuel gas treatment system and operation of the currently installed burners.

2.1.4 BP's BART Proposal for the Combustion Unit Heaters

BP Proposal for Heater NO_X Control

BP proposed that BART for all eligible process heaters except the 1st Stage HC Fractionator Reboiler, is the level of control afforded by the currently installed burners. Table 2-3 summarizes BP's BART proposal for NO_X emissions from BART-eligible heaters at the refinery. The only new control technology equipment proposed is a new ULNB for the 1st Stage HC Fractionator Reboiler.

To comply with terms of the Consent Decree, BP installed ULNBs on the #1 HDS Charge Heater, the Diesel HDS Stabilizer Reboiler, and the R-1 HC Reactor Heater after the BART Baseline period. BP considers the NO_X emissions reduction from these three heaters plus the proposed new UNLB on the R-4 HC Reactor Heater as their proposed BART controls.

Table 2-3. SUMMARY OF BP PROPOSED NO_X BART FOR HEATERS THAT ARE SUBJECT TO BART

Process Unit Number	BART Source Point Description	BP Proposed BART Technology for NO_X	Baseline Firing Rate (MMBtu/hr)	NO_X Emission Factor (lb/MMBtu)	Proposed BART NO_X Emission Rate (lb/hr)
10-1401	Crude Charge Heater	Existing burners	593	0.185	109.7
10-1451	South Vacuum Heater	Existing UNLB	186	0.039	7.3
11-1401	Naphtha HDS Charge Heater	Existing burners	106	0.098	10.4
11-1402	Naphtha HDS Stripper Reboiler	Existing burners	64	0.098	6.3
11-1403-1406	#1 Reformer Heaters (4)	Existing burners	709	0.150	106.4
12-1401-01	Coker Charge Heater (#1 North)	Existing burners	143	0.062	8.9
12-1401-02	Coker Charge Heater (#2 South)	Existing burners	145	0.062	9.0
13-1401	#1 Diesel HDS Charge Heater	Existing ULNB	34	0.031	1.0
13-1402	Diesel HDS Stabilizer Reboiler	Existing ULNB	56	0.028	1.6
14-1401	Steam Reforming Furnace #1 (North H2 Plant)	Existing burners	308	0.098	30.2
14-1402	Steam Reforming Furnace #2 - (South H2 Plant)	Existing burners	302	0.098	29.6
15-1401	R-1 HC Reactor Heater	Existing ULNB	89	0.020	1.8
15-1402	R-4 HC Reactor Heater	Existing burners	42	0.098	4.1

15-1451	**1st Stage HC Fractionator Reboiler**	**New ULNB**	**173**	**0.050**	**8.6**
15-1452	2nd Stage HC Fractionator Reboiler	Existing UNLB	144.5	0.057	8.2

BP Proposal for Heater SO_2 Control

BP proposed continued use of the current refinery gas sulfur removal system as BART for SO_2 emissions from BART-eligible refinery heaters.

BP Proposal for Heater PM_{10} Control

BP proposed good operating practices and continued use of the refinery fuel gas sulfur removal system as BART for $PM_{10}/PM_{2.5}$ emissions from BART-eligible refinery heaters.

2.2 Flares Control Options

The refinery maintains two flares that are subject to BART: a high pressure flare and a low pressure flare. The flare system thermally destroys gases of various flow rates and compositions. It also destroys gases released during upsets, malfunctions, and routine operations. Their primary purpose is to safely burn the volatile organic compounds (VOC) and other vented materials from the refinery processes. As a result, the flares emit NO_X, SO_2, and $PM_{10}/PM_{2.5}$, among other pollutants. Because BART is concerned only with normal operation, only emissions controllable during normal operation were considered in the BART analysis.

The high pressure flare serves high pressure process units such as the hydrocracker. The low pressure flare serves low pressure units such as the LPG unit. Both flares meet the applicable portions of 40 CFR 60.18 and are subject to the NSPS requirements for flares. Both flares are of the smokeless design and are steam assisted.

A flare gas recovery system was installed in 1984 that significantly decreased the total volume of gases routinely sent to the flare. In addition, a coker blowdown vapor recovery system was installed in 2007 that further reduced both the volume and sulfur content of the routinely flared gas.

2.2.1 NO_X Control Options

For reliable safe operation, the design of the flares requires the use of a pilot flame (pilot light). The combustion of the support fuel in the pilot light and the combustion refinery gases, flares emit NO_X.

BP searched the RBLC database and emission control literature to find available technologies to control flare emissions. In the RBLC, 37 entries were found regarding NO_X emissions from refinery flares. Several control methods were listed:

- Limit fuel to pipeline grade natural gas.

- Proper operation and maintenance.
- Operate in accordance with 40 CFR 60.18, general control device requirements.
- Proper equipment design and operation, good combustion practices, and use of gaseous fuels.
- Conversion from steam assisted to air assisted.

No add-on control technologies were found or are known to be in commercial use. Three of the listed control methods focus on proper design and operation of the flare. The 4th option addresses the "cleanliness" of the fuel used for the pilot light. This increases the destruction efficiency and reduces the amount of NO_X emitted.

All of the listed control methods found in the RBLC search are technically feasible for the Cherry Point flares. No add-on controls were considered for BART.

BP already uses properly designed flares and the natural gas used for pilot light fuel contains minimal nitrogen and sulfur compounds. BP proposed BART for flare NO_X emissions to be the current system of pilot fuel, gas compressors, and flare design.

2.2.2 SO_2 Control Options

SO_2 emissions from flares primarily result from the combustion of sulfur-containing gases vented from the refinery processes. A minor contributor to SO_2 emissions from the flares is the natural gas combustion of the pilot flame.

A search of the RBLC database and emission control literature was performed to find available technologies to control SO_2 from flare emissions. Ninety-six entries were found regarding control of SO_2 from flares. Several categories of controls were listed:

- Maintain flared gas parameters (e.g., heat content, composition, velocity) to allow for good combustion.
- Good practices.
- Meet 40 CFR 60.18.
- Proper design including knock-out pot and seal drum; monitor for continuous presence of flame.
- Limit on sulfur content of feedstock and fuels (i.e., pollution prevention).

No add-on control technologies were found or are known to be in commercial use.

Three of the listed control methods focus on proper design and operation of the flare. The other two options also address the "cleanliness" of the fuel used for the pilot light. Natural gas is already used as fuel for the pilot light.

BP has performed several projects in the past to reduce the volume of gas sent to the flares and associated with that reduction in volume, the sulfur content in the flare feed gas. BP did not identify any additional opportunities to reduce the volume of gas routinely sent to the flares. As a result, BP proposed BART as continued operation of the flares as currently operated.

2.2.3 $PM_{10}/PM_{2.5}$ Control Options

Due to the combustion of natural gas in the pilot light and the combustion of refinery vent gases, flares emit small quantities of particulate matter ($PM_{10}/PM_{2.5}$).

A search of the RBLC database and emission control literature was performed to find available technologies to control flare emissions. In the RBLC, 15 entries were found regarding control of particulate matter for refinery flares. Two categories of control methods were listed:

- Proper equipment design and operation with good combustion practices.
- Use of an assisted smokeless flare design.

No add-on control technologies for flares were found or are known to be in commercial use. The listed control categories are to promote the proper operation of the flare, thereby increasing the destruction efficiency and reducing the amount of $PM_{10}/PM_{2.5}$ emitted.

The two listed control methods are already in use for the Cherry Point flares.

2.2.4 BP's BART Proposal for Flares

For NO_X, SO_2 and PM_{10} control, BP proposes continued operation and maintenance of the existing high and low pressure flares, including the continued use of the flare gas recovery system, limiting pilot light fuel to pipeline grade natural gas, operating in accordance with 40 CFR 60.18, and conversion from steam assisted to air assisted[9] flares as BART.

2.3 Sulfur Recovery System Control Options

The BP Cherry Point Refinery sulfur recovery system currently consists of two sulfur recovery units (SRUs) and two tail gas units (TGUs). The two SRUs were constructed in 1970 and one TGU was added in 1977. These three units are all BART eligible. In 2005 a second TGU was added in an action unrelated to the requirements of the Consent Decree. Together the combination of SRUs and TGUs are referred to as the SRUs, though all four units have combustion devices installed in them.

The SRUs convert hydrogen sulfide (H_2S) to SO_2 and elemental sulfur through use of the Claus reaction and process. The tail gas units oxidize any of the H_2S not treated in the SRUs before venting to the atmosphere through the "incinerator stack." The primary purpose of the tail gas units is to recover sulfide compounds that escape the SRUs and return a concentrated stream of

[9] The BP BART analysis did not include an explanation of changing from steam assisted to air assisted flares. Ecology does acknowledge that the change would slightly reduce the load on the existing steam boilers and could tend to reduce emissions of NO_X, SO_2, and particulate from the boilers. The change should not change emissions from the flares.

sulfides to the SRUs. Any sulfur compounds not recovered by the TGUs are incinerated prior to being emitted. The two SRUs are operated in parallel with their exhaust gas streams combined and distributed to the two TGUs. One TGU utilizes the SCOT technology and the other utilizes the CANSOLV technology to assist in further collection of sulfur compounds and reducing the quantity of SO_2 discharged via the "incinerator stack."

The primary pollutant from sulfur recovery area is SO_2. Minor amounts of NO_X and $PM_{10}/PM_{2.5}$ are emitted as by-products of fuel combustion during gas treatment. Minor amounts of elemental sulfur can also be emitted from material handling operations.

The SRUs are subject to the requirements of 40 CFR 63 Subpart UUU, which specifies 40 CFR 60 Subpart J compliance as a control option. The SRUs are currently controlled to this MACT standard. The SRUs are not subject to additional controls.

2.3.1 NO_X Control Options

The TGU emits NO_X resulting from combustion of refinery fuel gas in the SRUs and combustion in the TGU.

BP reviewed the RBLC database and control technology literature to find available technologies to control NO_X emissions from the SRUs and the TGU. In the RBLC, 24 entries were found regarding NO_X control for SRUs and TGUs at refineries. Two categories of control methods for NO_X were listed:

- Good Operating Practices (e.g., "proper equipment design and operation, good combustion practices, and use of gaseous fuels", "optimized air-fuel ratio", "good operating practices").
- LNBs. LNBs can be installed either within the SRU itself (usually only as part of the initial design) or in the TGU.

No other add-on control technologies were found or are known to be in commercial use for control of NO_X from SRUs or TGUs.

<u>LNBs in the SRUs</u>: The SRU converts H_2S to SO_2 and elemental sulfur using heat to drive the Claus reaction. The heat needed for operation of an SRU is provided by the main reaction furnace burner operating on refinery fuel gas. This burner could potentially be replaced with a LNB to reduce NO_X emissions. The existing main reaction furnace burners in the SRUs at the refinery are side-entering.[10] Changing out the existing burner with a LNB would increase the flame length causing flame impingement and possible damage to the SRU. Because of flame impingement issues, BP considered using a LNB within the SRU technically infeasible.

[10] The burners are located on the long wall of the rectangular furnace, reducing the distance between burner and heat transfer surfaces and the refractory walls of the furnace.

LNBs in the TGU: After processing, to concentrate the sulfides in the exhaust from the SRUs, the TGU oxidizes the H_2S remaining before venting to the atmosphere. Utilizing a LNB in a TGU can be BACT for a new installation. The original TGU at the refinery was installed in 1977 and utilizes natural draft burners which are not suitable for the direct installation of a LNB. The natural draft design will require addition of fans to supply air to the LNBs. BP looked at the cost to install LNBs on the 1977 TGU and concluded that it would not be cost effective to install LNBs.

2.3.2 SO_2 Control Options

The purpose of the SRUs is to remove hydrogen sulfide from process gas and convert it to elemental sulfur. Hydrogen sulfide not removed by the SRUs and the TGUs are combusted in the TGUs and released as SO_2. Minor contributors to SO_2 emissions are the combustion of refinery fuel gas in the SRU furnaces to drive the Claus reactions and combustion of fuel in the TGU.

BP reviewed the RBLC database and control technology literature to find available technologies to control SO_2 emissions from the SRUs and TGU. Thirty-two entries were found regarding control of SO_2 from SRUs and TGUs. The following two categories of controls were listed:

- Restrictions on fuel sulfur content (e.g., “fuel sulfur content limits as follows: diesel fuel, 0.35% sulfur; natural gas, 0.01% sulfur; liquefied petroleum gas, 0.01% sulfur; refinery gas, 168 ppmv H_2S”).
- Specified additional processing device (e.g., Shell Claus Off-Gas Treating Process (SCOT) unit, tail gas incinerator/thermal oxidizer, selective amine absorbers).

No add-on control technologies specific to SO_2 (e.g., scrubber) were found or are known to be in commercial use.

One entry was found in the California Air Resources Board BACT Clearinghouse for a sulfur recovery plant at a refinery in the Bay Area Air Quality Management District. This determination lists a SCOT unit with a tail gas thermal oxidizer as the additional processing device. A SCOT unit is a patented technology TGU. The old TGU at BP utilizes the SCOT design.

Another entry in the Clearinghouse was for the new TGU utilizing the CANSOLV technology that was installed at the Cherry Point Refinery.

Both restrictions on fuel sulfur content and an additional processing device are technically feasible at the BP Cherry Point Refinery.

Restrictions on Fuel Sulfur Content: The TGU uses uninterruptible natural gas as the support fuel to drive the reaction to completion. Natural gas is the lowest sulfur content fuel available.

Additional Processing Device: As noted above, the original TGU has a SCOT unit. The "new" #2 TGU is based on the newer CANSOLV technology and was installed to provide redundant capacity when the #1 TGU is out of service. BP does not consider replacement of the existing SCOT unit with a new CANSOLV unit as cost effective.

2.3.3 $PM_{2.5}/PM_{10}$ Control Options

The TGU emits a small amount of $PM_{10}/PM_{2.5}$ from the combustion of refinery fuel gas in the SRUs and natural gas in the TGUs. Additionally, small amounts of particulate can be emitted from the storage and handling of elemental sulfur.

BP reviewed the RBLC database and control technology literature to find available technologies to control SRU and TGU $PM_{10}/PM_{2.5}$ emissions. The RBLC contained 16 entries on control of PM for SRUs and the tail gas combustion control. Only a few of the listings included a control method for particulate matter. Control methods included:

- Good combustion practices (e.g., "proper equipment design and operation, good combustion practices, and use of gaseous fuels", "optimized air-fuel ratio", "good maintenance and operation").
- Thermal oxidizer on the SRU such as the TGUs at the refinery.

No add-on control technologies specific to particulate matter, such as scrubbers or baghouses, were found or are known to be in commercial use.

Both listed control methods, good combustion practices and use of a thermal oxidizer, are technically feasible and in use at the refinery.

No information on dust control from sulfur handling was found.

2.3.4 BP's BART Proposal for the SRU and TGU

For NO_X, SO_2, $PM_{10}/PM_{2.5}$ control, BP proposes that continued operation of the existing SRUs and TGUs as BART.

2.4 Green Coke Load Out Control Options

The Green Coke Load Out system was permitted and constructed as part of the original refinery. The equipment was functionally replaced in 1978 by installation of the #1 & #2 calciners and their coke load out system. However, the equipment still physically exists at the refinery. The company desires to retain the ability of the green coke load out system in the event that the calciners are off-line for an extended period. The refinery does not have long-term storage capability for green coke and would use this equipment to export the green coke. Because the green coke load out would only be used during an upset condition, BP proposes that its operation is outside the purview of BART. From a practical perspective, this emission unit has virtually no

effect on Class I visibility because it's only emissions are relatively large particle size fugitive dust.
During the baseline period no green coke was loaded; consequently, there are no baseline emissions.

BP did not propose BART for this equipment. BP desires to retain the ability to operate this unit for possible future use.

2.5 BP's Proposed BART

Sections 2.1 to 2.5 of this report have summarized BP's BART evaluation for the BART-eligible units at the refinery. In summary, BP proposes that ULNB are BART for NO_X emissions from four refinery BART heaters. Two BART-eligible boilers are being replaced with new units, so BP did not consider the new boilers as BART units for BART evaluation purposes.

- #1 Diesel HDS Charge Heater (ULNB installed in 2006).
- Diesel HDS Stabilizer Reboiler (ULNB installed in 2006).
- R-1 HC Reactor Heater (ULNB installed in 2006).
- 1st Stage HC Fractionator Reboiler (proposed ULNB).
- For Boilers No. 1 and 3, replacement with new units (operational in 2009).

For all other units, BP proposes BART to be the existing burners and emission controls

3. VISIBILITY IMPACTS AND DEGREE OF IMPROVEMENT

A Class I area visibility impact analysis was performed on the BART-eligible emission units at BP using the CALPUFF model as recommended by Washington's BART modeling protocol with one exception. A database of actual ozone observations within Washington, Oregon, and Idaho prepared by Oregon DEQ was used to characterize background ozone concentrations instead of the constant 60 ppb ozone value recommended by the protocol. The addition of British Columbia ozone observations to this ozone database was approved by Ecology.[11]

Modeled baseline emission rates for the BART-eligible emission units were given in Table 1-2. Proposed BART emission rates shown in Table 2-3 changes only the NO_X emissions from four units. Table 3-1 shows the baseline modeling and proposed BART emissions for those four units. The first three units listed in Table 3-1 had ULNB burners added since the BART baseline period, so their NO_X emissions reductions were treated as a BART reductions for modeling purposes. The final unit shown in Table 3-1, the 1st stage HC Fractionator Reboiler, was proposed by BP to receive a new ULNB as BART.

[11] E-mail from Clint Bowman, Ecology to Ken Richmond, Geomatrix, Subject: Addition of BC Ozone Observations to Ozone, December 20, 2007.

Table 3-1. PROPOSED BART CHANGES TO BASELINE EMISSIONS RATES

BART Source	Process Unit Number	Baseline NO_X BART Emission Rate (lb/hr)	Proposed NO_X BART Emission Rate (lb/hr)
#1 Diesel HDS Charge Heater	13-1401	3.3	1.0
HDS Stabilizer Reboiler	13-1402	5.5	1.6
R-1 HC Reactor Heater	15-1401	8.7	1.8
1st Stage HC Fractionator Reboiler	15-1451	25.9	8.65

Visibility impacts at each Class I area attributable to the refinery are shown in Table 3-2 for both baseline and proposed BART emission levels. Impacts include the number of days in the 3-year baseline period with impacts greater than 0.5 dv, the maximum 8th highest yearly impact in the 2003-2005 modeling period, and the maximum 22nd highest impact for that 3-year period.

Table 3-2. BASELINE AND BART VISIBILITY IMPACT MODELING RESULTS

Class I Area	Visibility Criterion	Baseline Emissions	BP's Proposed BART
Alpine Lakes Wilderness	# Days Haze Index > 0.5 dv in 2003-2005	7	5
	Max 98% value (8th high)	0.294	0.277
	3-yrs Combined 98% value (22nd high)	0.260	0.244
Glacier Peak Wilderness	# Days Haze Index > 0.5 dv in 2003-2005	0	0
	Max 98% value (Max annual 8th high)	0.290	0.280
	3-yrs Combined 98% value (22nd high)	0.248	0.233
Goat Rocks Wilderness	# Days Haze Index > 0.5 dv in 2003-2005	1	1
	Max 98% value (Max annual 8th high)	0.122	0.117
	3-yrs Combined 98% value (22nd high)	0.110	0.103
Mt. Adams Wilderness	# Days Haze Index > 0.5 dv in 2003-2005	0	0
	Max 98% value (Max annual 8th high)	0.083	0.078
	3-yrs Combined 98% value (22nd high)	0.082	0.078
Mt. Rainier National Park	# Days Haze Index > 0.5 dv in 2003-2005	3	3
	Max 98% value (Max annual 8th high)	0.279	0.266
	3-yrs Combined 98% value (22nd high)	0.222	0.212
North Cascades National Park	# Days Haze Index > 0.5 dv in 2003-2005	5	1
	Max 98% value (Max annual 8th high)	0.370	0.354
	3-yrs Combined 98% value (22nd high)	0.365	0.343
Olympic National Park	# Days Haze Index > 0.5 dv in 2003-2005	57	53
	Max 98% value (Max annual 8th high)	**0.901**	**0.832**
	3-yrs Combined 98% value (22nd high)	**0.842**	**0.786**
Pasayten Wilderness	# Days Haze Index > 0.5 dv in 2003-2005	0	0
	Max 98% value (Max annual 8th high)	0.215	0.202
	3-yrs Combined 98% value (22nd high)	0.196	0.185

The results presented in Table 3-2 indicate that the visibility impact calculated on either an annual or three year 98th percentile basis does not exceed the 0.5 dv contribution threshold for seven of the eight areas modeled. The 98th percentile visibility impact at Olympic National Park does exceed the 0.5 dv contribution threshold.

During the modeling process, the relative contribution of each visibility impairing pollutant to visibility impact was determined. For the baseline period, modeling estimated that NO_X emissions caused an average of 78.4 percent of the refinery's total visibility impact on the Olympic National Park. SO_2 emissions caused 20.5 percent, and particulates only about one percent.

The visibility improvement from replacement of the BART eligible boilers with their replacement boilers was not performed. The new boilers were subject to the PSD permitting program and their visibility impacts were evaluated as part of that process.

Net Visibility Improvement

BP quantified the net visibility improvement from NO_X reduction due to the three new ULNBs installed after the 2003-2005 baseline period, and the proposed new ULNB. Table 3-3 shows the visibility improvement resulting from BP's proposed BART controls.

Table 3-3. NET VISIBILITY IMPROVEMENT OF BP'S PROPOSED BART CONTROLS AT OLYMPIC NATIONAL PARK

	Years			
	2003	**2004**	**2005**	**2003-05**
Modeled Visibility Improvement (dv)	0.062	0.056	0.069	0.056

4. ECOLOGY'S BART DETERMINATION

Ecology has reviewed the information submitted by BP. We agree with BP's proposal for BART with three exceptions.

The controls and emission limitations which Ecology has determined to be BART are summarized in Table 4-1 below. Ecology has made four revisions to BP's proposal for BART.

The first is BP's proposed BART for the 1st Stage HC Fractionator Reboiler. While BP offered to install new ULNB burners on this unit, BP recognized in their presentation that installation of ULNBs on this unit was not cost effective. Because this low NO_X burner installation was the least expensive of all the burner installations evaluated, they offered to install the burners as BART anyway. Ecology agrees that, at $12,044/ton NO_X reduced, installation of ULNBs on this heater is not cost effective. Ecology has decided that the current burners installed in this unit are BART for the 1st Stage HC Fractionator Reboiler.

While Ecology has determined that the installation of ULNBs on the 1st Stage HC Fractionator Reboiler is not BART, we will credit BP in the future for their installation of these burners. Once the burners are installed, Ecology will recognize the installation as a reasonable progress emission reduction in a future regional haze SIP action.

Two other exceptions are Power Boilers No. 1 and No. 3. BP did not evaluate BART for these two boilers since their replacement units (Boilers No. 6 and No. 7) had recently completed the permitting process and were already under construction when their BART application was submitted. BP considered them to not be subject to BART since their replacements were scheduled to start operation in 2009. The boilers were started up in March, 2009.

In addition to not being evaluated for BART, the emissions of Power Boilers No. 1 and No. 3 are not included as BART unit emissions for modeling purposes. The two new boilers (Power Boilers 6 and 7) were permitted in November 2007 by both Ecology[12] and the Northwest Clean Air Agency.[13] As part of the permitting process, the visibility impact of the new boilers was evaluated against the criteria incorporated in the FLAG criteria manual.[14] BACT emission control requirements are incorporated in the permits issued for the installation of the new boilers. The new boilers incorporate SCR for NO_X control and are more fuel efficient; producing 67 percent more steam with only a 10 percent increase in fuel use. Power Boilers No. 1 and No. 3 are required to be decommissioned by March 27, 2010.

Ecology has determined that the new boilers satisfy the requirements of BART for Power Boilers No. 1 and No. 3.

Finally, BP did not evaluate BART for Cooling Tower #1. Cooling towers produce particulate from water droplet drift away from the towers. We have evaluated droplet and particulate drift from cooling towers in the past and found that they produce relatively large particulate that doesn’t drift far from the tower. Ecology has made a qualitative review of BART for the control of particulate from this cooling tower and determined that the existing drift controls satisfy BART for this unit.

The current refinery fuel gas treatment system provides both SO_2 and particulate matter control from all combustion equipment using this fuel. As a result, Ecology agrees that for the combustion equipment using refinery fuel gas, the reduced sulfur concentration limitation met by the refinery fuel gas treatment system provides a BART level of control for SO_2 and particulate matter.

Ecology agrees with BP that the current sulfur recovery system incorporates a BART level of emission control for SO_2 and particulate matter.

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[12] PSD 07-01 is available at http://www.ecy.wa.gov/programs/air/psd/PSD_PDFS/PSD07_01Final.pdf.
[13] OAC #1001a is available from NWCAA or Ecology upon request.
[14] BP Cherry Point Refinery Boiler Replacement Project, Notice of Construction (NOC)/Prevention of Significant Deterioration (PSD) Permit Application, by Geomatrix Consultants, Inc., May 2007.

Ecology recognizes that the Green Coke Load Out system provides a backup handling system to ship green coke off-site if the coker system is off-line for an extended period of time. While the facility has not had any recent use, the ability of the plant to use the system in an emergency situation is important. Ecology's BART determination allows its limited emergency usage. Criteria to allow its usage are contained in the BART order and operation would also have to comply with Ecology and NWCAA visible emissions and other criteria.

Table 4-1. ECOLOGY'S DETERMINATION OF EMISSION CONTROLS THAT CONSTITUTE BART

Emission Unit	BART Control Technology	Emission Limitations Contained in the Listed Permits, Orders, or Regulations
Crude Charge Heater	Current burners and operations	OAC 159, RO 28 (40 CFR 60 Subpart J), OAC 689a
South Vacuum Heater	Existing UNLB	RO 28 (40 CFR 60 Subpart J), OAC 902a
Naphtha HDS Charge Heater	Current burners and operations	RO 28 (40 CFR 60 Subpart J)
Naphtha HDS Stripper Reboiler	Current burners and operations	RO 28 (40 CFR 60 Subpart J)
#1 Reformer Heaters	Current burners and operations	RO 28 (40 CFR 60 Subpart J)
Coker Charge Heater (#1 North)	Current burners and operations	OAC 689a, RO 28 (40 CFR 60 Subpart J)
Coker Charge Heater (#2 South)	Current burners and operations	OAC 689a, RO 28 (40 CFR 60 Subpart J)
#1 Diesel HDS Charge Heater	Existing ULNB and operations	RO 28 (40 CFR 60 Subpart J), OAC 949a
Diesel HDS Stabilizer Reboiler	Existing ULNB and operations	RO 28 (40 CFR 60 Subpart J), OAC 949a
Steam Reforming Furnace #1 (North H2 Plant)	Current burners and operations	RO 28 (40 CFR 60 Subpart J)
Steam Reforming Furnace #2 (South H2 Plant)	Current burners and operations	RO 28 (40 CFR 60 Subpart J)
R-1 HC Reactor Heater	Existing ULNB and operations	RO 28 (40 CFR 60 Subpart J), OAC 966a
R-4 HC Reactor Heater	Current burners and operations	RO 28 (40 CFR 60 Subpart J)
1st Stage HC Fractionator Reboiler	Current burners and operations	OAC 149, OAC 351d, RO 28 (40 CFR 60 Subpart J)
2nd Stage HC Fractionator Reboiler	Existing UNLB and operations	OAC 149, RO 28 (40 CFR 60 Subpart J), OAC 847a
Refinery Fuel Gas (hydrogen sulfide)	Currently installed fuel gas treatment system.	RO 28 (40 CFR 60 Subpart J)
SRU & TGU (Sulfur Incinerator)	Current burners and operations	OAC 890b, 40 CFR 60 Subpart J (250 ppm SO_2 incinerator stack and 162 H_2S refinery fuel gas as supplemental fuel for incinerator), 40 CFR 63 Subpart UUU.
High and Low Pressure Flares		
NO_X	Good operation and maintenance including use of the flare gas recovery system and limiting pilot light fuel to pipeline grade natural gas.	40 CFR 63 Subpart A, NWCAA 462, 40 CFR 63 Subpart CC
SO_2	Good operating practices, use of natural gas for pilot.	40 CFR 63 Subpart A, NWCAA 462, 40 CFR 63 Subpart CC

Emission Unit	BART Control Technology	Emission Limitations Contained in the Listed Permits, Orders, or Regulations
PM	Good operating practices, use of an steam-assisted smokeless flare design, use of flare gas recovery system.	40 CFR 63 Subpart A, NWCAA 462, 40 CFR 63 Subpart CC
Green Coke Load out	Maintain as unused equipment for possible future use.	Emergency use only per criteria in the BART order and operation per applicable NWCAA regulatory order and regulations.
Power Boilers 1 and 3	Replacement with new Power Boilers 6 and 7	PSD 07-01 and NWCAA Order OAC #1001a

APPENDIX A. PRINCIPLE REFERENCES USED

Geomatrix, BP Cherry Point Refinery, et al., "Best Available Retrofit Technology Determination, BP Cherry Point Refinery, Blaine, Washington," March 2008. Amended by letter of June 25, 2008.

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E-mail communications (various) between Dan Mahar of NWCAA and Bob Burmark of Ecology, regarding BP's BART proposal.

E-mail communications (various) between Eric Hansen of Geomatrix (now Environ) and Bob Burmark of Ecology.

E-mail communications between Nick Confuorto of Belco and Alan Newman of Ecology, regarding $LoTO_X$™ NO_X control system, March 3-4, 2008.

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APPENDIX B. ACRONYMS/ABBREVIATIONS

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BP	BP West Coast Products, LLC
dv	Deciview(s)
Ecology	Washington State Department of Ecology
EPA	United States Environmental Protection Agency
FGR	Flue Gas Recirculation
LAER	Lowest Achievable Emission Rate
LNBs	Low-NO_X Burners
$LoTO_X$™	Patented Low Temperature Oxidation Process for Reducing NO_X in Gas Waste Streams
MMBtu	Million British Thermal Units
NO_X	Nitrogen Oxides
NWCAA	Northwest Clean Air Agency
PM	Particulate Matter
ppm	Parts per Million
ppmdv	Parts per Million Dry Volume
ppmv	Parts per Million by Volume
RACT	Reasonably Available Control Technology
Refinery	BP Cherry Point Refinery
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SRU	Sulfur Recovery Unit
TGU	Tail Gas Unit
tpy	Tons per Year
ULNBs	Ultra-low-NO_X Burners
VOC(s)	Volatile Organic Compound(s)