Washington State Regional Haze State Implementation Plan

Appendix L

Best Available Retrofit Technology Technical Support Documents and Compliance Orders

.

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Overview of Appendix L

One of the major requirements of the Regional Haze Rule is the determination and implementation of Best Available Retrofit Technology (BART). Sources are eligible for BART controls if they meet a specific set of criteria. BART-eligible sources that cause or contribute to visibility impairment in a mandatory Class I Area are subject to BART. More background on BART may be found in Chapter 11.

Seven of the 15 BART-eligible sources in Washington had modeled visibility impairment above the 0.5 deciview (dv) threshold. Each was subject to a full engineering analysis to determine the controls on visibility-impairing pollutants that would constitute BART for the source. Ecology then developed draft compliance orders to implement BART.

Each of the draft BART technical support documents and draft compliance orders were subject to a public comment period and hearing in October 2009. One public hearing addressed 6 of the 7 sources. A second public hearing was held for the TransAlta Centralia Generation, LLC BART source.

The second part of this appendix contains the final technical support document and the final compliance order for each of the 7 sources subject to BART. Ecology revised the initial draft BART technical support documents for INTALCO Aluminum Corporation–Ferndale, Tesoro Refining and Marketing Company, Port Townsend Paper Company, and TransAlta Centralia Generation, LLC in response to comments received during the public comment period and hearing. The initial draft compliance orders for INTALCO Aluminum Corporation–Ferndale, Tesoro Refining and Marketing Company and Port Townsend Paper Company were revised as well. The final documents are organized into subsections as follows:

- L-1 BP Cherry Point Refinery
- L-2 INTALCO Aluminum Corporation–Ferndale
- L-3 Tesoro Refining and Marketing Company
- L-4 Port Townsend Paper Company
- L-5 Lafarge North America
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Additional materials related to the seven BART sources are available on Ecology's web site at http://www.ecy.wa.gov/programs/air/globalwarm_RegHaze/bart/BARTInformation.html. These include technical documents and correspondence related to the initial draft BART technical support documents and initial draft compliance orders that were taken to public hearing in October 2009.

The third part of this appendix contains materials related to the two public comment periods and hearings held in October 2009 on the draft BART technical support documents and draft compliance orders. These include:

- Public notice for the October 27, 2009 hearing on 6 of the 7 sources subject to BART
- Ecology's response to comments on the 6 draft BART technical support documents and compliance orders
- Public notice for the October 13, 2009 hearing on BART for TransAlta Centralia Generation, LLC
- Ecology's response to comments on the TransAlta Centralia Generation, LLC draft BART technical support document and compliance order

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 29-110	Low Pressure Flare High Pressure Flare	Yes Yes
Boilers and Cooling Towers	30-1601 30-1603 30.104 30.105 30	Utility Boiler #1 Utility Boiler #3 Utility Boiler # 4 Utility Boiler #5 Cooling Tower #1	Yes Yes No No Yes
	24	Cooling Tower #2	No
Crude/Vacuum	10-1401 10.11 10-1451	Crude Charge Heater North Vacuum Heater South Vacuum Heater	Yes No Yes
	11-1401 11-1402 11-1403-1406	Naphtha HDS Charge Heater Naphtha HDS Stripper Reboiler #1 Reformer Heaters	Yes Yes Yes
	21-1421-1424	#2 Reformer Heaters	No
Delayed Coker	12-1401-01 12-1401-02	North Coker Charge Heater #1 South Coker Charge Heater #2	Yes Yes
Diesel Hydrodesulfurization (HDS)	13-1401 13-1402	#1 Diesel HDS Charge Heater Diesel HDS Stabilizer Reboiler	Yes Yes
	26-1401	#2 Diesel HDS Charge Heater	No
Hydrogen Plant	14-1401 14-1402	North Reforming Furnace #1 South Reforming Furnace #2	Yes Yes
Hydrocracker	15-1401 15-1402 15-1451 15-1452	R-1 Hydrocracker Reactor Heater R-4 Hydrocracker Reactor Heater 1st Stage Fractionator Reboiler 2nd Stage Fractionator Reboiler	Yes Yes Yes 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 20-71 20-72	Calciner Stack #1 (Hearths #1 & #2) Calciner Stack #2 (Hearth #3) Coke Silos and Loading – Baghouses and Vents	No No Yes/No[4]
Wastewater	32	API Separators Slop Oil, equalization and recovered oil tanks	No 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.

[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.

LNBs: 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.

SCR: 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.

BP's BART Proposal: 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.

LNBs: 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.

SCR: 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.

LNBs plus Selective Catalytic Reduction: 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.

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

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.

Emission Standards Division, U.S. Environmental Protection Agency, "Alternative Control Techniques Document–NO_X Emissions from Process Heaters (revised)," September 1993.

N. Confuorto and J. Sexton, "Wet Scrubbing Based NO_X Control Using $LoTO_X$™ Technology–First Commercial FCC Start-Up Experience," presented at NPRA Environmental Conference, September 24-25, 2007.

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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)

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600 • Olympia, WA 98504-7600 • 360-407-6000
711 for Washington Relay Service • Persons with a speech disability can call 877-833-6341

July 7, 2010

Mr. Jeff Pitzer
Business Unit Leader
BP Cherry Point Refinery
4519 Grandview Road
Blaine, WA 98230

Dear Mr. Pitzer:

Regional Haze Best Available Retrofit Technology (BART) Determination

Best Available Retrofit Technology (BART) is required to reduce the regional haze impacts of emissions of your facility. The enclosed Order #7836 contains our BART determination for your facility including a schedule for compliance.

If you have questions or requests relating to this order, please contact Alan Newman at (360) 407-6810 or alan.newman@ecy.wa.gov.

Sincerely,

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Air Quality Program

jj/te

Enclosure

By certified mail

cc: Mark Buford, NWCAA
Valerie Lagen, BP Cherry Point Refinery
Alan Newman, Ecology

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN ADMINISTRATIVE ORDER AGAINST: BP Cherry Point Refinery	]]]]]	ORDER NO. 7836

TO: Mr. Jeff Pitzer
BP Cherry Point Refinery
4519 Grandview Road
Blaine, WA 98230

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions which are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the federal and state visibility protection program (WAC 173-400-151 and 40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitutes Best Available Retrofit Technology (BART) for the eligible emission units at your facility. The rules also require the installation and use of those emission controls on the BART-eligible emission units. The emission controls are to be installed as expeditiously as possible, but in no event can the State allow them to start operation later than five years after the State's Regional Haze SIP amendment is approved by the United States Environmental Protection Agency (EPA).

FINDINGS

The BP Cherry Point Refinery operates an oil refinery near Blaine, Washington, that contains emission units that are subject to BART.

A. The BART-eligible emission units at the BP Cherry Point Refinery are:

   a. Process heaters and boilers:

      1. 30-1601, Boiler #1
      2. 30-1603, Boiler #3
      3. 10-1401, Crude Charge Heater
      4. 10-1451, South Vacuum Heater
      5. 11-1401, Naphtha HDS Charge Heater

6. 11-1402, Naphtha HDS Stripper Reboiler
7. 11-1403-1406, #1 Reformer Heaters
8. 12-1401-01, Coker Charge Heater (#1 North)
9. 12-1401-02, Coker Charge Heater (#2 South)
10. 13-1401, #1 Diesel HDS Charge Heater
11. 13-1402, #1 Diesel HDS Stabilizer Reboiler
12. 14-1401, Steam Reforming Furnace #1 – (North Hydrogen (H2) Plant)
13. 14-1402, Steam Reforming Furnace #2 – (South (H2) Plant)
14. 15-1401, R-1 HC Reactor Heater
15. 15-1402, R-4 HC Reactor Heater
16. 15-1451, 1st Stage HC Fractionator Reboiler
17. 15-1452, 2nd Stage HC Fractionator Reboiler

b. Other units:

1. 17, 19, SRU & TGU
2. 29.110, High Pressure Flare
3. 29-111, Low Pressure Flare
4. Green Coke Load Out

B. BART emission limitations for the BART-eligible emission units is a combination of:

a. Use of existing burners on process heaters and reboilers.

b. Continued use of the current refinery fuel gas sulfur scrubbing system for control of sulfur dioxide (SO_2) emissions.

c. Replacement of Boilers #1 and #3 with Boilers #6 and #7 as permitted in Prevention of Significant Deterioration (PSD) 07-01 and Order of Approval to Construct (OAC) #1001a.

C. Treatment of Specific Units

a. Boilers #1 and #3 will be decommissioned by no later than March 27, 2010.

Additional information and analysis is available in the BART Determination Support Document for the BP Cherry Point Refinery, Blaine, Washington, prepared by the Washington State Department of Ecology, March 2009, and the Best Available Retrofit Technology Determination, BP Cherry Point Refinery, prepared by Geomatrix Consultants, March 2008.

YOU ARE ORDERED: To install and operate emission control equipment in accordance with the following conditions:

BART EMISSION LIMITATIONS

1. Particulate Matter Emissions

   1.1. PM_{10} emissions from Boilers #6 or #7 (each) shall not exceed 3.4 lb/hr on a calendar day average.

   1.2. For all other BART-eligible units, meet the emission limitations for particulate matter found in NWCAA's Regulation 455.1 given below.

      1.2.1. Emissions shall not exceed 0.10 grain/dscf (corrected to seven percent oxygen), except from all gaseous and distillate fuel burning equipment (the definition of fuel burning equipment does not include internal combustion engines), emissions shall not exceed 0.05 grain/dscf (0.11 g/m^3) corrected to seven percent oxygen.

   1.3. Compliance with the particulate emission limits above will be determined as follows:

      1.3.1. For Boilers #6 and #7, continuous compliance shall be demonstrated by an annual emissions test on each exhaust stack using 40 CFR 60 Appendix A Method 5 front half, and 40 CFR 51 Appendix M Method 202 for the back half, or an equivalent test method if approved in advance by Ecology. After three consecutive years of annual tests on each boiler stack have demonstrated compliance, testing of each boiler stack may be reduced to once every five years. If a test demonstrates noncompliance, a retest along with resumption of annual testing is required for the unit until three consecutive years demonstrate compliance.

      1.3.2. Burn only gaseous fuels.

      1.3.3. For all BART-eligible units, perform particulate emissions testing to determine compliance when requested in writing by NWCAA or Ecology. Particulate testing is performed using EPA Test Method 5 in 40 CFR Part 60 Appendix A and Method 202 in 40 CFR 51 Appendix M.

2. Nitrogen Dioxide (NO_X) Emissions

   2.1. Boilers #6 and #7

2.1.1. NO_X emissions shall not exceed the following emission limits:

2.1.1.1. During periods of normal operation, as defined as firing the boiler above 91 MMBtu HHV/hr (25 percent capacity), 9.0 ppm NO_X by volume, dry basis, corrected to three percent oxygen, based on a 1-hour average.

2.1.1.2. During periods of hot standby, as defined as firing the boiler below 18 MMBtu HHV/hr (five percent capacity), 40.0 ppm NO_X by volume, dry basis, corrected to three percent oxygen, based on a 1-hour average.

2.1.1.3. Operation of each boiler in transition mode, defined as a firing rate at or above 18 MMBtu HHV/hr (five percent capacity) to at or below 91 MMBtu HHV/hr (25 percent capacity), shall not exceed 100 hours per 12-month rolling period. Compliance shall be demonstrated by recording the number of hours operated in this firing range for each calendar month, and submitting the most recent 12-month cumulative total transition mode hours on monthly emission reports submitted to the NWCAA.

2.1.2. NO_X limits will apply and SCR will be operated at inlet temperatures above 500.0 degrees F.

2.1.3. Compliance with Condition 2.1.1 shall be determined by installing NO_X and oxygen continuous emission monitors (CEM) in each boiler stack. The CEM shall be calibrated, maintained, and operated in accordance with NWCAA Appendix A: Ambient Monitoring, Emission Testing, and Continuous Emission and Opacity Monitoring and 40 CFR Part 60 Appendices B and F.

2.2. South Vacuum Heater, Unit 10-1451

2.2.1. NO_X emissions shall not exceed 10.5 lb/hr based on a calendar day average.

2.2.2. Compliance with this condition shall be determined by a CEM installed, calibrated, maintained, and operated to measure NO_X and oxygen in the stack.

2.2.3. Each monitor shall meet the appropriate sections of NWCAA Section 366 and NWCAA Appendix A.

2.2.4. Hourly emission rates for NO_X shall be recorded. On-site documentation shall be kept showing the method of calculating the mass emission rate.

2.2.5. Report data in monthly monitoring report.

2.3. Coker Charge Heater (#1 North), 12-1401-01

2.3.1. NO_X emissions shall not exceed 15.2 lb/hr and 66 tons per year.

2.3.2. Compliance shall be determined by biennial performance tests on one of two identical heaters (#2 North or #2 South) using 40 CFR 60 Appendix A Method 7A or 7E.

2.4. Coker Charge Heater (#2 South), 12-1401-02

2.4.1. NO_X emissions shall not exceed 15.2 lb/hr and 66 tons per year.

2.4.2. Compliance shall be determined by biennial performance tests on one of two identical heaters using 40 CFR 60 Appendix A Method 7A or 7E.

2.5. Number 1 Diesel HDS Charge Heater, 13-1401 and Diesel HDS Stabilizer Reboiler, 13-1402

2.5.1. NO_X emissions from the #1 Diesel Hydrotreater Charge Heater shall not exceed 0.040 lb/MMBtu (higher heating value), or if this emission limit is exceeded, 1.9 lb/hr.

2.5.2. NO_X emissions from the Stabilizer Reboiler Heater shall not exceed 26 ppmv (dry basis corrected to seven percent O_2) based on a 24-hour rolling average. If this concentration is exceeded, a secondary limit to demonstrate compliance is 2.2 lb/hr based on a 24-hour rolling average.

2.5.2.1. Ongoing compliance with this condition shall be determined by a continuous emission monitor (CEM) installed, calibrated, maintained, and operated to measure NO_X and O_2 in the stack by no later than December 1, 2008. Each monitor shall meet the appropriate specifications of 40 CFR 60 Appendices B and F, NWCAA Section 367, and NWCAA Appendix A.

2.6. R-1 HC Reactor Heater, 15-1401

2.6.1. Nitrogen oxides (NO_X) from the Hydrocracker R-1 Heater shall not exceed the following emission limits:

2.6.1.1. 26 ppm by volume, dry basis, corrected to seven percent oxygen, based on a 24-hour rolling average. Or, if this concentration based limit is exceeded, the following mass emission rate limit shall be used to demonstrate compliance.

2.6.1.2. 3.6 lb/hr based on a 24-hour rolling average.

2.6.2. Biennial source testing shall be completed within two months of the anniversary date of the initial test. The test shall be performed under representative operating conditions and at a heater firing rate that corresponds to the operating condition of the Hydrocracker Unit on the scheduled test day. The test shall be conducted in accordance with USEPA Reference Method 7E, NWCAA Regulation Section 367, and NWCAA Appendix A.

2.6.3. NO_X emissions shall be continuously monitored by a certified continuous emission monitoring system (CEMS) for nitrogen oxides and oxygen. The CEMS shall be installed, calibrated, maintained, and operated in accordance with appropriate specifications of 40 CFR 60 Appendices B and F, NWCAA Section 367, and NWCAA Appendix A.

2.6.4. An operating and maintenance manual that contains O&M information on the ultra-low NO_X burners shall be maintained on site.

2.7. 1st Stage HC Fractionator Reboiler, 15-1451

2.7.1. NO_X emissions from the boiler stack shall not exceed 0.07 lb/MMBtu monthly average, or 56.2 tons per calendar year.

2.7.2. A continuous emission monitor or equivalent method approved by the NWCAA shall be used to measure nitrogen oxide emissions.

2.7.3. An operating and maintenance manual that contains O&M information on the low NO_X burners shall be maintained on site.

2.8. 2nd Stage HC Fractionator Reboiler, 15-1452

2.8.1. Emission of NO_X from the heater stack shall not exceed 0.07 lb/MMBtu based on a 24-hour average and shall not exceed 56.2 tpy on a calendar year rolling average.

2.8.2. Report NO_X emissions based on firing rates on a calendar month basis within 30 days after the end of the previous month.

2.8.3. Conduct periodic source testing once every five years within three months of the anniversary of the initial test. Follow 40 CFR 60 Appendix A Method 20.

2.8.4. An operating and maintenance manual that contains O&M information on the low NO_X burners shall be maintained on site.

2.9. No nitrogen dioxide emission limitations are applicable to the following units:

2.9.1. Crude Charge Heater Unit 10-1401, the Naphtha HDS Charge Heater Unit 11-1401.

2.9.2. Naphtha HDS Stripper Reboiler Unit 11-1402.

2.9.3. Number 1 Reformer Heaters 11-1403-1406.

2.9.4. Steam Reforming Furnace #1 (North Hydrogen (H_2)) Plant Unit 14-1401.

2.9.5. Steam Reforming Furnace #2 (South H_2 Plant) Unit 14-1402.

2.9.6. R-4 HC Reactor Heater, Unit 15-1402.

3. Sulfur Dioxide Emissions

3.1. For Boilers #6 and #7

3.1.1. SO_2 emissions from Boilers #6 or #7 (each) shall not exceed 39.3 lb/hr based on a 1-hour average.

3.1.2. SO_2 emissions from Boilers #6 or #7 (each) shall not exceed 59.6 tons per year.

3.1.3. Compliance with Condition 3.1 shall be demonstrated by:

3.1.3.1. Test once per calendar month for total sulfur in the boiler fuel using ASTM Test Method D-5504 or another method approved by Ecology. A minimum of three samples, taken at least an hour apart, shall be run per quarterly test.

3.1.3.2. Monitor fuel H_2S content using a CEMS that continuously monitors and records the concentration (dry basis) of H_2S in the fuel gas.

3.1.3.3. As an alternative to Conditions 3.1.3.1 and 3.1.3.2, BP may monitor using a CEMS that measure and records SO_2 emissions from the Boilers #6 and #7 exhaust stacks and meets the requirements contained in 40 CFR, Part 60, Appendix B, Performance Specification 2 and 40 CFR Part 60, Appendix F, Quality Assurance Procedures.

3.2. Coker Charge Heaters #1 North and #1 South

3.2.1. SO_2 emissions shall not exceed 14.9 lb/hr and 66 tons per year per heater.

3.2.2. Compliance shall be determined by biennial performance tests on one of two identical heaters using 40 CFR 60 Method 6 or 6C or Fuel Gas Analysis using Method 11 or 15.

3.3. Plant-wide refinery fuel gas requirements

3.3.1. All units shall meet the emissions limitations for fuel gas contained in the NWCAA's RO #28 dated May 15, 2002.

3.3.1.1. Fuel gas is limited to a composition of H_2S<230 mg/dscm (0.10 gr/dscf). Equivalent to 162 ppm H_2S, 3-hour rolling average.

3.3.2. Operate CEM for H_2S concentration at the fuel feed line in accordance with NWCAA 367 and Appendix A – "Ambient Monitoring, Emission Testing, and Continuous Emission and Opacity Monitoring," 40 CFR 60 Subpart J and 40 CFR 60 Appendices B and F.

3.3.3. Periods of excess emissions that shall be determined and reported are defined as follows. All rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under §60.105(a)(4) exceeds 162 ppmv.

3.3.4. Report average H_2S content (3-hour rolling average) in monthly report.

4. All Other BART Units

4.1. SRU and TGU

4.1.1. Sulfur dioxide emissions from TGU stacks 1 and 2 shall not exceed any of the following emission limits:

4.1.1.1. 250 (2.50×10^2) ppm by volume, dry basis, corrected to zero percent oxygen, based on a 12-hour rolling average. The 12-hour rolling average shall be calculated based on corrected hourly averages for the 12 most recent, consecutive clock hours.

4.1.1.2. 1500 (1.50×10^3) ppm by volume, dry basis, corrected to zero percent oxygen, based on a 1-hour average.

4.1.1.3. Compliance with this condition shall be determined by a continuous emission monitor (CEM) installed, calibrated, maintained, and operated to measure sulfur dioxide and oxygen in each TGU stack. Each monitor shall meet the appropriate specifications of 40 CFR 60 Appendices B and F, NWCAA Regulation Section 367, and NWCAA Appendix A.

4.1.1.4. Total tons of sulfur dioxide emitted from the sulfur recovery unit shall not exceed 135 tons based on each consecutive 12-month rolling period. The most recent 12-month rolling total shall be reported to the NWCAA on each monthly emissions report.

SCHEDULE FOR COMPLIANCE

5. For all requirements in Conditions 1, 2, 3 and 4, compliance is required upon the effective date of this Order.

MONITORING AND RECORDKEEPING REQUIREMENTS

6. Sulfur Dioxide Emissions

6.1. The monthly total sulfur test results required by Condition 3.1.3.1 shall be submitted to NWCAA and Ecology upon request.

6.2. SO_2 performance tests required by Conditions 3.2.2 shall be submitted to NWCAA and Ecology upon request.

6.3. Operate CEMS measuring H_2S concentration in accordance with NWCAA 367 and NWCAA Appendix A, 40 CFR 60 Subpart J, and 40 CFR 60 Appendices B and F.

6.4. CEMS data including daily average H_2S concentrations of the refinery fuel gas shall be recorded and retained at the facility available for review by NWCAA or Ecology inspectors.

OTHER REQUIREMENTS

7. Boilers #1 and #3 shall be decommissioned by no later than March 27, 2010. The Northwest Clean Air Agency (NWCAA) shall be notified in writing of the decommissioning date of each boiler. Notifications shall be postmarked no later than 15 days after each decommissioning event.

8. BP may request this compliance Order be rescinded after all of the following occur:

   8.1. All BART units at the plant have continuously complied with the emissions limitations in Conditions 1 through 4 for a period of three years.

   8.2. The emission limitations in this Order have been incorporated into one or more enforceable orders or permits issued under the criteria of RCW 70.94.152 or 70.94.153 and NWCAA regulations implementing these provisions.

   8.3. The emission limitations in the enforceable orders or permits have been incorporated into the Air Operating Permit issued by NWCAA to BP.

9. Issuance of this order indicates requirements of Order 5069 have been complied with.

Within 20 days of receipt of this Order, you may request a delay in the submittal date. Any such request must be accompanied by a written justification for the delay.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.

- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal, you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:

The Pollution Control Hearings Board
P.O. Box 40903
Olympia, WA 98504-0903

OR

Deliver your appeal in person to:

The Pollution Control Hearings Board
4224–6th Avenue SE Rowe Six, Bldg 2
Lacey, WA 98503

To serve your appeal on the Department of Ecology:

Mail appeal to:

Department of Ecology
Appeals Coordinator
P.O. Box 47608
Olympia, WA 98504-7608

OR

Deliver your appeal in person to:

Department of Ecology
Appeals Coordinator
300 Desmond Drive SE
Lacey, WA 98503

And send a copy of your appeal packet to:

Alan Newman
Department of Ecology
Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600

For additional information, go to the Environmental Hearings Office website at http://www.eho.wa.gov.

To find laws and agency rules, go to the Washington State Legislature website at http://www1.leg.wa.gov/CodeReviser.

Your appeal alone will not stay the effectiveness of this Order. Stay requests must be submitted in accordance with RCW 43.21B.320. These procedures are consistent with Chapter 43.21B RCW.

DATED this 7 day of July, 2010 at Olympia, Washington.

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Department of Ecology
Air Quality Program

BART DETERMINATION SUPPORT DOCUMENT FOR ALCOA INTALCO WORKS FERNDALE, WASHINGTON

Prepared by

Washington State Department of Ecology
Air Quality Program

August 2009
Revised February 4, 2010

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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/year of one or more visibility impairing compounds.
4. Cause or contribute to visibility impairment within at least one mandatory federal Class I area.

The Alcoa Intalco Works (Intalco) is a primary aluminum smelter facility utilizing the prebake process. The smelter is located on Cherry Point near Ferndale, Washington. The aluminum smelting process produces emissions of particulate matter (PM), fluorides, sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NO_X), and hydrocarbons. The pollutants considered to be visibility impairing are PM, SO_2, and NO_X.

Aluminum smelters such as the Intalco facility are one of the 26 listed BART source categories. The Intalco plant was constructed in 1965 and has the potential to emit more than 250 tons/year of PM and SO_2. Most of the plant's emission units are BART-eligible. Intalco's major sources of visibility impairing pollutants are three potlines and an anode bake furnace.

Modeling of visibility impairment was done following the Oregon/Idaho/Washington/EPA-Region 10 BART modeling protocol.[1] Modeled visibility impacts of baseline emissions show impacts on the 8th highest day in any year (the 98th percentile value) to be greater than 0.5 deciviews (dv) at seven Class 1 areas. The highest impact was 2.36 dv on Olympic National Park. Modeling showed that SO_2 emissions from the existing dry alumina/baghouse potline emission control system created 94 percent of the facility's total visibility impact.

Intalco prepared a BART technical analysis using Washington State's BART Guidance.[2]

The Washington State Department of Ecology (Ecology) determined that the current level of emissions control is BART for the applicable units at the Alcoa Intalco Works primary aluminum smelter facility. The potlines and anode bake furnace are currently well controlled for particulate emissions. A wet scrubber on each source would be required to control SO_2 emissions. Modeling indicated that addition of a wet scrubber system on the potlines could reduce the visibility impact on Olympic National Park by over a deciview. However, the potline scrubber system's estimated $7,500 cost per ton of SO_2 removed was determined to be excessive.

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[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.

Ecology also determined that the wet scrubber would have an excessive capital cost of $234.5 million and unacceptable impacts on solid waste generation, electrical power use, and water consumption. Ecology determined that a scrubber on the anode bake furnace would have an excessive $36,400 cost per ton of SO_2 removed.

1. INTRODUCTION

1.1 The BART Program and 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 Act requires certain sources to utilize Best Available Retrofit Technology (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 "BART-eligible" 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/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 a "BART-eligible facility" to be "subject to BART." Ecology has adopted the "cause and contribute" criteria that the United States Environmental Protection Agency (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 causes a modeled visibility change of 0.5 dv or more.

The BART analysis protocol in Appendix Y to Part 51, Sections III–V uses a 5-step analysis to determine BART for SO_2, NO_X, and PM. The five steps are:

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

Ecology requires a facility that is "subject to BART" to prepare a BART technical analysis report and submit it to Ecology. Ecology then evaluates the report and makes a BART determination decision. This decision is then issued to the source owner as an enforceable Order, and included in the state's Regional Haze State Implementation Plan (SIP).

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

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 Alcoa Intalco Plant

Alcoa Intalco Works (Intalco) is a primary aluminum smelter facility located in Ferndale, Washington, near Cherry Point along the Strait of Georgia. The facility produces primary aluminum metal by the Hall-Heroult reduction process. It was originally constructed in 1965, and began operation in 1966. Intalco is a Title V source operating under Air Operating Permit No. 000295-0. Primary aluminum ore reduction plants are one of the 26 BART-eligible source categories. Intalco submitted a BART Determination Report to the Washington State Department of Ecology (Ecology) on December 4, 2007 as required by Order #5070.

1.3 BART-Eligible Units at Intalco

A review of the Intalco emission sources found that:

1. All of the plant's individual emission units except for one remelt furnace are BART-eligible by construction date.
2. The individual emission units in total have a potential to emit greater than or equal to 250 tons/year of both sulfur dioxide (SO_2) and particulate matter (PM).
3. A baseline Class I area visibility impact analysis of 2003-2005 emissions using the CALPUFF model indicated impacts for the entire facility exceeded the 0.5 deciview (dv) contribution threshold in at least one Class I area. This confirmed that Intalco was subject to BART, and was required to prepare a BART Determination.

Intalco's primary aluminum reduction operations include three potlines, an electrode manufacturing operation consisting of a paste production operation and a green anode baking furnace, and miscellaneous material handling operations. These units were placed into six groups:

1. Potlines (3)
2. Anode bake furnace (1)
3. Aluminum holding furnaces (12)
4. Various material handling and transfer operations
5. Combustion sources (natural gas, diesel, propane)
6. Other small miscellaneous sources

1.3.1 Existing Potline Emissions Control

The potline operation manufactures metallic aluminum by the electrolytic reduction of alumina in the side-worked prebake cells. Direct electrical current passes between the anodes and the carbon cathode that lines the cell walls. This current electrolytically reduces the alumina to metallic aluminum and oxygen. Molten aluminum is deposited and accumulates over time at the cathode beneath a layer of molten cryolite bath. Periodically the molten aluminum is siphoned from beneath the cryolite bath and processed to achieve specific metal properties or is retained as pure aluminum. The produced aluminum is solidified into intermediate or final products.
The major pollutants emitted from the cells are PM, hydrogen fluoride, SO_2, and carbon monoxide. PM includes particulate fluoride and alumina. SO_2 comes from the sulfur in the petroleum coke and pitch components used to make the anodes that are consumed by the process. NO_X emissions are minimal since there is no external fuel or combustion zone and there are no large sources of nitrogen in the raw materials.

The potlines at Intalco consist of six potroom groups of electrolytic reduction cells connected in series that produce molten aluminum. There are two potroom groups per potline. Each potroom is comprised of 120 reduction cells (or pots) with 18 anodes per cell. All pots at Intalco are hooded to control emissions. Emissions captured by the hoods are drawn through one of six primary control systems. Each primary control system consists of a dry alumina injection system followed by a baghouse for the control of PM and fluoride emissions. The six primary control systems are located in the courtyards between the potrooms. The system at Intalco is large, treating approximately 1,815,000 acfm of 180°F exhaust gases. This primary PM control system has an efficiency of about 97.7 percent.

A small fraction of the pot emissions escape capture by the hoods and are released inside the potrooms. These secondary emissions are drawn through a secondary control system which consists of a series of 159 wet roof scrubbers that control PM and fluoride emissions. PM control efficiency for this secondary system is approximately 82 percent.

1.3.2 Existing Anode Bake Furnace Emissions Control

Anodes are manufactured in an ancillary on-site anode plant. Purchased calcined petroleum coke and anode butt material is crushed and sized, mixed together with pitch, and formed into blocks called “green anodes.” The green anodes are then cooled prior to being baked in the anode bake furnace. Only after the anodes have been baked can they be used in the potlines.

The anode bake furnace structure is a series of interconnected refractory flues connected to side main exhaust manifolds. The furnace is fueled with natural gas. Exhaust gases are routed so that flue gases preheat the next section of the furnace to be fired. Flue gases from the anode bake furnace contain PM, hydrogen fluoride, SO_2, NO_X, carbon monoxide, and hydrocarbons.

The bake furnace emissions are controlled by an alumina dry scrubber which is similar to the ones used for the potline primary control system. The bake oven gas stream is cooled by a water

spray to reduce the inlet temperature before it enters the scrubber. Fresh and recycled alumina are injected into the gas stream, gaseous fluoride and polycyclic organic matter (POM) are adsorbed onto the alumina surface, and fabric filters on top of the reactor compartments collect entrained particulate matter present in the gas stream. The control system for the anode bake furnace treats approximately 216,000 acfm of 205°F exhaust gases. The fabric filters reduce PM emissions by as much as 99 percent.

1.3.3 Existing Aluminum Holding Furnace Emissions Control

The 12 holding furnaces at Intalco vary in size. They are heated by natural gas burners. The largest of these furnaces has a natural gas rated burner rated at 22 MMBtu/hr. There are no emission controls associated with the aluminum furnaces at Intalco. Emissions come from combustion of natural gas in the burners and the activities associated with treating molten metal while being processed in the furnaces.

1.3.4 Existing Controls for Material Handling and Transfer Operations, Other Natural Gas Combustion, and Other Small Miscellaneous Sources

The remaining emission units are various material handling and transfer operations, natural gas, diesel, and propane combustion, and other small miscellaneous sources that support the potlines, anode bake furnace and holding furnace operations. Aside from the natural gas combustion products, emissions from most of the support operations consist of relatively small amounts of PM that are controlled by fabric filter-type control devices. Fabric filters effectively remove about 99 percent of particulate emissions.

Natural gas consumption is mostly in the previously discussed anode bake furnace and aluminum holding furnaces. The balance comes from burners in the paste plant. Propane is used in forklifts. There are five small auxiliary diesel generators.

2. BART TECHNOLOGY ANALYSIS

The Intalco BART technology analysis was based on the 5-step process defined in BART guidance and listed in Section 1.1 of this report. Intalco's analysis included a review of available and technically feasible retrofit technologies (Steps 1 and 2), determination of control effectiveness for feasible options (Step 3), evaluation of cost and secondary impacts for feasible alternatives (Step 4), and analysis of impacts and visibility improvements (Step 5). The analysis looked at controls for SO_2, PM, and NO_X from each category of emission units: the potlines, anode bake furnace, aluminum holding furnaces, handling and transfer operations, combustion sources, and other small sources.

2.1 Potline Control Options

2.1.1 SO_2 Control Options

Alcoa evaluated eight different SO_2 add-on control options along with pollution prevention as having potential application for potline SO_2 emission control. Six of the control options use wet scrubbing and two use dry scrubbing technology. A description of each technology is found in Appendix A.

Wet Scrubbing Technologies

- Limestone slurry scrubbing with forced oxidation (LSFO)
- Limestone slurry scrubbing with natural oxidation (LSNO)
- Conventional lime wet scrubbing
- Seawater scrubbing
- Dual alkali sodium/lime scrubbing (dilute mode)
- Conventional sodium scrubbing

Dry Scrubbing Technologies

- Dry sorbent injection
- Semi-dry scrubbing (spray dryer)

Limestone Slurry Forced Oxidation (LSFO) was determined to be a technically feasible wet scrubbing retrofit control option for the potroom reactors even though it is not ideally suited for scrubbing SO_2 concentrations that are less than or equal to 105 ppm. LSFO was also selected to be the best choice of the wet scrubbing technologies.

Dry sorbent injection downstream of the potline reactor fabric filters is not technically feasible because of the low temperatures (less than or equal to 205°F) and low SO_2 concentrations (less than or equal to 105 ppm). Spray dry scrubbing downstream of the potline reactors fabric filters is not technically feasible because of the low temperatures (less than or equal to 205°F) and low SO_2 concentrations (less than or equal to 105 ppm).

Pollution Prevention

The guidelines for BART determinations under the Regional Haze Rule recommend consideration of pollution prevention options in addition to add-on controls. The primary opportunity for pollution prevention in the smelting process to minimize SO_2 emissions is through controlling the sulfur content in the incoming petroleum coke used to make the anodes.

Intalco's Title V operating permit currently has a number of operational limits that cap allowable emissions of SO_2 from the facility, including a net potline aluminum production limit of 307,000 tons/year; a daily potline SO_2 limit of 37,780 lb/day; limits on sulfur in coke and pitch at 3.0 percent and 0.6 percent, respectively; and a carbon consumption limit of 0.425 pounds of carbon per pound of aluminum produced.

The current levels of sulfur in petroleum coke used by other aluminum smelters was evaluated to determine whether a pollution prevention option using lower sulfur content coke would be a

feasible BART option for Intalco. This analysis indicated that some smelters currently utilize coke with sulfur contents as low as two percent. An analysis was also done to determine whether coke with sulfur levels below three percent can be anticipated to be available into the future. The primary conclusions from this analysis indicate that:

- There will be a continuing increase in the sulfur content of available coke. Low sulfur crude oil supplies are becoming less available and more expensive for petroleum refineries. In the future, refineries with coking capacity are expected to minimize their raw material costs by using more of the higher sulfur crude oils and oil sands that are less costly.
- As oil fields age, the sulfur content of the crude oil is known to increase and the crude oil in the fields becomes more viscous and harder to extract. This effect is expected to increase the sulfur content of the petroleum materials available to produce anode grade coke.
- Coke is a relatively small, low revenue component of a refinery's product profile. It is a low value product made from the thick, tar-like refinery wastes left over after all of the more valuable components have been removed from the petroleum crude. The aluminum industry has little influence in controlling the quantity, quality, and price of the coke produced by refineries.
- Global primary aluminum production is expected to grow, resulting in a commensurate growth in demand for anode grade coke. Growth in aluminum production will continue to outpace the growth in coke production.
- Coke providers are blending imported, high cost, lower sulfur coke with domestically sourced coke in attempts to meet the current specification requirements for coke.
- Removal or reduction of the sulfur content of the coke once it has been received is not feasible.

Feasible SO_2 Control Options from RBLC Database

The data in the USEPA's RACT/BACT/LAER (RBLC) database supports the approach of limiting raw material sulfur content as a control option for the potlines and the anode bake furnace. Many facilities have limited sulfur content in coke to limit SO_2 emissions. Two facilities have limits of three percent sulfur content in coke and one has a 2.95 percent sulfur content limit. One facility is shown in the RBLC to have a wet scrubber to control SO_2 emissions;[4] however, an investigation revealed that the wet scrubber was not required as part of a best available control technology (BACT) determination and that the facility currently does not operate a wet scrubber to control SO_2 emissions. That facility's current Title V permit for "Potline 5" limits coke sulfur content to three percent, coal tar pitch sulfur to 0.8 percent, potline SO_2 emissions to 364.52 lb/hr from the primary emissions control unit, 7.44 lb/hr from the roof

[4] RBLC ID ky-0070 for NSA–A division of Southwire Company on Potline 5 now Century Aluminum of Kentucky, LLC, Kentucky Title V Permit #V-01-019.

scrubbers, and 49.356 lb/ton of aluminum produced. Alcoa Intalco has a current limit of 44.8 lb SO_2 emitted per ton of aluminum produced.

Cost and Other Impacts of Feasible SO_2 Potline Controls

Wet scrubber costs for Intalco were estimated based on cost quotes received by Alcoa from two flue gas desulphurization equipment vendors. The cost quotes were originally provided as part of the BART analysis for Alcoa's Tennessee Operations in Alcoa, TN. Both vendors provided cost proposals for wet scrubbing systems based on LSFO scrubbers. Lime or sodium based scrubbers could also be used for potlines, but lime and sodium are less desirable reagents considering that these reagents are much more expensive. An advantage of the limestone forced oxidation process is that the spent slurry is oxidized to gypsum, which dewaters more efficiently, resulting in less waste materials requiring disposal. An LFSO scrubber was determined to be the most appropriate control device for the cost analysis.

Neither of the two vendors provided a comprehensive installed cost estimate. Both preliminary designs were based on a central scrubbing center as the least cost approach, where exhaust from all dry scrubbing systems would be ducted to a centralized scrubbing system. Both design estimates were based on systems that would provide 100 percent availability of emissions control on each day of the year, given that potlines cannot be easily shutdown and restarted for control system outages. To achieve this 100 percent availability, the proposed designs includes two scrubber towers, one to be active, and one to be held in reserve.

The capital and total annualized costs for a potline wet scrubber system as proposed was $234.5 million and 46.8 million per year, respectively. The wet scrubber cost effectiveness was $7,500 per ton of SO_2 removed. A lower cost option based on a single absorber tower based on information supplied by Intalco was analyzed by Ecology. A discussion of this option is included in Section 4, Ecology's BART determination.

The LSFO scrubber process oxidizes the spent slurry to gypsum sludge. The sludge volume would be 27,130 tons annually from the potline wet scrubber. It was not known at the time of the BART report preparation whether the gypsum would have commercial value or whether there would be any demand for it. If not sold, the sludges must be land filled.

It is estimated that 182.5 million gallons of water will be required annually to operate the potline wet scrubber at a cost of approximately $97,000. This would increase Intalco's daily water demand by approximately nine percent.

A total of approximately 64.8 million kWh would be needed to operate the potline scrubber annually. This is equivalent to adding over 6,000 new households to the community.[5] Table B-2 in Appendix B summarizes the impacts analysis.

[5] Calculated based on 2001 average energy usage per household for the U.S. as reported by the Department of Energy. See http://www.eia.doe.gov/emeu/reps/enduse/er01_us_tab1.html.

Cost of anode grade coke is predicted to continue to rise in the future, as discussed in the previous pollution prevention section. Both increasing demand by the aluminum industry and the need of refineries to move toward using higher sulfur containing crude oil stocks drive Intalco's prediction. US Gulf calcined anode grade coke increased from $118.50/mt to $244.75/mt between 1994 and 2006. The future rate of cost increase is anticipated to be greater due to the reasons discussed in the pollution prevention section.

2.1.2 PM Control Options

Fabric Filters

Fabric filters generally provide high collection efficiencies for both coarse and fine (submicron) particles. They are relatively insensitive to fluctuations in gas stream conditions. Efficiency is relatively unaffected by large changes in inlet dust loadings. Filter outlet air is very clean.[6] Collected material is dry, which usually simplifies processing or disposal. Fabric filters are currently applied for controlling PM emissions from the potrooms at Intalco.

Electrostatic Precipitators

Electrostatic Precipitators (ESPs) are capable of very high removal efficiencies for large and small particles.[7] They offer control efficiencies that are comparable to fabric filters. Because of their modular design, ESPs, like fabric filters, can be applied to a wide range of system sizes. The operating parameters that influence ESP performance include particulate mass loading, particle size distribution, particulate electrical resistivity, space velocity, and precipitator voltage and current.

Dusts with high resistivities are not well-suited for collection in dry ESPs because the particles are not easily charged. An ESP is technically feasible for control of PM from the potrooms at Intalco.

Fabric filtration with dry alumina scrubbing has been widely used in the primary aluminum industry. Most smelters constructed within the past 20 years have used dry alumina scrubbing (either alumina injection or fluidized bed) with fabric filters to control particulate and fluoride emissions from potlines. A few plants use control systems consisting of ESPs to collect PM followed by spray towers to scrub gaseous fluoride. Wet systems have many disadvantages, such as corrosion by hydrofluoric acid, scaling, and acidic wastewater. ESPs and wet systems are no longer installed on new smelters in the U.S.

[6] EPA 2003, "Air Pollution Control Technology Fact Sheet–Fabric Filter," EPA-452/F-03-025, August 7.
[7] EPA 2003, "Air Pollution Control Technology Fact Sheet–Dry Electrostatic Precipitator," EPA-452/F-03-028, August 7.

Cyclones, Inertial Separators, and Wet Scrubbers

Cyclones and inertial separators are used for collection of medium-sized and coarse particles. Wet scrubbers generally remove large particles and can remove small particles with the use of high-pressure drops. However, none of these devices are as effective at removing small and submicron particles as fabric filters and ESPs.[8]

Cost and Other Impacts of Feasible Particulate Potline Controls

Fabric filters are currently used on Intalco's potlines. Since fabric filters have high control effectiveness similar to ESPs, are widely used for potline particulate control in the aluminum industry, and have process advantages relative to ESPs, no benefit was seen to switch from fabric filters to ESPs for PM control. Because no benefit was seen, no cost analysis of switching to an ESP-based particulate control was done.

2.1.3 NO_X Control Options

Potentially applicable NO_X emission controls include combustion controls and post-combustion controls. The pots are heated solely through the action of the electric reduction process. There is no combustion of fuel. There are also no large sources of nitrogen in the raw materials. This makes use of traditional combustion controls like staged combustion or low NO_X burners not applicable to the potlines. The temperature of the potroom exhaust is approximately 180°F and the NO_X concentration is less than one parts per million (ppm).

Possible post combustion controls include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). Both involve injecting ammonia or urea into the gas stream to react with NO_X to produce nitrogen and water. SNCR requires an operating temperature of 1,600°F to 2,100°F and inlet NO_X concentrations typically from 200 to 400 ppm to be about 30-50 percent effective. SCR uses a catalyst to reduce the operating temperature requirement to between 500°F to 800°F, and can achieve up to 90 percent reduction of inlet NO_X concentrations to as low as 20 ppm.

Since there is no external fuel or combustion zone in the smelting cells, there are no technically feasible pre-combustion NO_X controls. Low temperature and NO_X concentration make both SNCR and SCR post process NO_X controls technically infeasible.

2.1.4 Intalco's BART Proposal for the Potlines

For potline SO_2 emissions, Intalco proposed BART to be the current level of control, which includes a maximum of three percent sulfur in the coke used to manufacture anodes. Use of wet scrubbing technology to reduce potline SO_2 emissions was rejected as BART due to excessive costs: total cost effectiveness of $7,500 per ton of SO_2 removed and capital and total annualized

[8] AWMA 2000, "Air Pollution Engineering Manual," Second Edition.

costs of $234.5 million. A potline wet scrubber would also have substantial non air quality impacts, including increased energy usage, added water consumption, and solid waste generation.

For PM emissions, Intalco proposed BART to be the current level of control, which is the use of baghouses to control PM emissions from the alumina dry scrubbers, and wet roof scrubbers to control secondary PM emissions from the potroom roofs.

For NO_X emissions, Intalco proposed BART to be no controls.

2.2 Anode Bake Furnace Control Options

The anode bake furnace process is discussed in Section 1.3.2 of this report. Emissions due to anode coke and pitch are similar to those from the potlines, so the same BART control options considered for the potlines are applicable to the bake furnace emissions exhaust. It is smaller, with only about 12 percent of the airflow volume of the combined potlines emission scrubber. It is natural gas fired rather than electrically heated, so it has products of combustion including NO_X.

2.2.1 SO_2 Control Options

A wet scrubber was identified as a technically feasible add-on pollution control option for the anode bake furnace. The anode bake furnace is a smaller source than the potlines and has a lower exhaust gas flow rate. A separate vendor cost proposal was not obtained for the anode bake furnace, but an SO_2 removal efficiency of 95 percent is assumed to be feasible. Wet scrubber costs for the anode bake furnace were scaled from the LSFO potline wet scrubber vendor quotes.

The estimated installed capital cost to add a wet scrubber to remove 95 percent of the SO_2 from the anode bake furnace exhaust would be approximately $29.5 million with an annualized cost of $6.3 million per year. The wet scrubber cost effectiveness is $36,400 per ton of SO_2 removed. The wet scrubber also has an energy impact of 6,570,000 kW-hr/yr as well as solid waste impacts associated with disposal of gypsum sludge from the scrubber and water use impacts from scrubber operation. The impacts are summarized in Table B-2 of Appendix B.

The pollution prevention option of reducing the sulfur content of the anode coke is available for the anode bake oven as well as the potlines. See the potline pollution prevention discussion in Section 2.1.1.

2.2.2 PM Control Options

Dry alumina injection with fabric filtration is currently used for PM control on the anode bake furnace. An ESP is also a technically feasible control, with a similar fine particulate PM capture

efficiency. As described in Section 2.1.2, cyclones, inertial separators, and wet scrubbers are not as effective at removing small and submicron particles as fabric filters and ESPs.

2.2.3 NO_X Control Options

Advanced firing system: NO_X emissions from anode baking depend on operating practices and burner controls. The traditional methods of preventing NO_X formation using staged combustion or low NO_X burners are not applicable because of the unique configuration of an anode baking ring furnace, with fuel injected at several points in narrow flues. However, advanced firing systems that measure and regulate fuel flow precisely using a computerized control system can reduce total fuel usage. This will also reduce NO_X emissions. Prevention of NO_X formation using a more efficient advanced firing control system is technically feasible for the anode bake furnace at Intalco. Total gas usage is projected to be reduced by 20 percent, which would result in a corresponding 20 percent reduction in NO_X emissions, or approximately 27 tons/year.

The LoTO$_X$™ system is the patented technology of BOC Gases. In this NO_X removal system, ozone is injected into the exhaust gas stream in order to oxidize insoluble NO_X to soluble nitrogen compounds, including N_2O_5. N_2O_5 is highly soluble and reacts with moisture in the gas stream to form nitric acid. A scrubber is required downstream of the LoTOx™ system to remove the nitric acid formed by the reaction of N_2O_5 and moisture in the gas stream. The ozone is typically generated on site and on demand. Since LoTOx™ is a low temperature system, it does not require heat input and the low operating temperature (150 to 250°F) allows for stable and consistent control even with variations in flow, load, and NO_X concentrations.[9]

Use of the LoTOx™ system has not been demonstrated at an aluminum plant. Research indicates that application of the LoTOx™ technology has been limited to a sulfuric acid regeneration plant, a lead smelting reverbatory furnace, a stainless steel plant, a coal-fired electric generation unit, and two fluidized-bed catalytic cracking units (FCCU) at refineries.[10] [11] Reported NO_X removal efficiencies for the LoTOx™ system are on the order of 90 to 95 percent.

The temperature of the anode baking emission exhaust (approximately 200°F) is within the temperature range where LoTOx™ could be used. Although this technology has not been demonstrated on an anode bake furnace, low-temperature oxidation technology may be technically feasible for reducing anode bake furnace NO_X emissions. At a control efficiency of 90 percent for NO_X emissions when combined with wet scrubbing, the resulting reduction in NO_X emissions would be 122 tons/year.

Intalco made the case that cost data for the LoTOx™ system was not readily available. To show some cost estimation, Intalco noted that the LoTOx™ system would also require a scrubber

[9] BOC Process Gas Solutions, 2001, Low Temperature Oxidation System Demonstration at RSR Quemetco, Inc., City of Industry, California, June 28. See www.arb.ca.gov/research/icat/projects/boc.pdf.
[10] EPA, February 2005, "Using Non-Thermal Plasma to Control Air Pollutants," EPA-456/R-05-001. See www.epa.gov/ttn/catc/dir1/fnonthrm.pdf.
[11] EPA RACT/BACT/LAER Clearinghouse (RBLC) database.

similar to the one described earlier for SO_2 control. That would make the cost of the entire LoTOx™ system installation more than the previously estimated SO_2 scrubber cost of $29.5 million. NO_X emissions are lower than SO_2 emissions for the anode bake furnace, so the cost per ton values for NO_X would be higher than the $36,400 estimated for SO_2. Since cost for the LoTOx™ system itself was not available, it is not possible to calculate a cost per ton for the total system based on both NO_X and SO_2. To give a sense of the possible minimum cost, if the LoTOx™ system were free, the cost would be greater than $18,000 per ton of total pollutants removed.

2.2.4 Intalco's BART Proposal for the Anode Bake Furnace

Intalco proposed that the existing potline SO_2 control pollution prevention limit of three percent sulfur in the coke to be BART for anode bake furnace SO_2 emissions. The cost effectiveness of wet scrubbing to reduce SO_2 emissions was determined to be excessive at $36,400 per ton of SO_2 removed. As discussed below in Section 3, addition of a wet scrubber to the anode bake furnace would reduce the visibility impact on Olympic National Park by only 0.024 dv.

The existing level of control (based on baghouses on the alumina dry scrubbers) was proposed to be BART for PM emissions.

BART for anode bake furnace NO_X emissions was proposed to be no additional controls. The use of an advanced firing system for reduced energy use was rejected as BART because the 20 percent reduction in NO_X emissions would result in a negligible 27 ton per year NO_X reduction and visibility improvement. Emissions of all pollutants (SO_2 and NO_X) from the anode bake furnace are responsible for only about one percent of the visibility impact on Olympic National Park; the most impacted Class I Area (see Section 3 below). The use of LoTOx™ was rejected as BART because the technology is not available or demonstrated in practice for aluminum anode bake furnace exhausts.

2.3 Aluminum Holding Furnaces

2.3.1 Aluminum Holding Furnaces Control Options

The 12 holding furnaces at Intalco are heated by natural gas burners, and vary in size, with the largest of these furnaces having a natural gas rated burner capacity of 22 MMBtu/hr. Emissions come from combustion of natural gas in the burners. There is currently no emission controls associated with the aluminum furnaces at Intalco.

2.3.2 Intalco's BART Proposal for the Aluminum Holding Furnaces

Intalco proposed that BART for the aluminum holding furnaces was no controls. The proposal rejected additional controls as BART because the modeling analysis discussed in Section 3 below showed that any visibility improvement would be negligible because the existing burners have a negligible contribution to visibility impacts.

2.4 Material Handling and Transfer Operations

2.4.1 Material Handling and Transfer Operations and Other Miscellaneous Operations Control Options

The remaining emission units are various material handling and transfer operations, natural gas, diesel, and propane combustion, and other small miscellaneous sources that support the potlines and anode bake furnace. Aside from emissions from natural gas combustion, emissions from most of the support operations consist of relatively small amounts of PM that are controlled by fabric filter control devices.

2.4.2 Intalco's BART Proposal for the Material Handling and Transfer Operations

Intalco showed that PM emissions from the BART-eligible material handling and transfer operations were all controlled using fabric filter technology. This existing level of emissions control was proposed to be BART for these material handling and transfer operations.

3. VISIBILITY IMPACTS AND DEGREE OF IMPROVEMENT

A baseline Class I area visibility impact analysis was performed on the BART-eligible emission units at Intalco using the CALPUFF model with four kilometer grid spacing as recommended by the Oregon/Idaho/Washington/EPA-Region 10 BART modeling protocol. The modeled or projected 98th percentile visibility impacts for the entire facility exceed the 0.5 deciview (dv) contribution threshold in seven Class I areas as shown in Table 3-1.

Table 3-1. BASELINE VISIBIITY MODELING RESULTS

Class I Area	2003		2004		2005	
	Modeled 98th Percentile (deciview)	Number of Days Exceeding 0.5 dv	Modeled 98th Percentile (deciview)	Number of Days Exceeding 0.5 dv	Modeled 98th Percentile (deciview)	Number of Days Exceeding 0.5 dv
Alpine Lakes Wilderness Area	1.244	36	0.965	37	0.881	23
Goat Rocks Wilderness Area	0.500	8	0.579	10	0.317	3
Glacier Peak Wilderness Area	1.161	37	1.156	38	0.736	23
Mount Adams Wilderness Area	0.456	7	0.472	6	0.357	2
Mount Rainier National Park	0.843	22	1.052	26	0.629	15
North Cascades National Park	1.376	65	1.395	56	1.138	32
Olympic National Park	2.363	59	1.858	53	2.136	45
Pasayten Wilderness Area	0.866	30	0.871	33	0.659	13

Intalco's modeling consultant evaluated the effects of the different emission sources at the Intalco facility to determine which operations resulted in the greatest visibility impacts. This

analysis indicated that the potlines are responsible for 98 percent of the visibility impact on the most impacted Class I area, and 96 percent of that impact is from the SO_2 emissions. Of the remaining two percent of the visibility impact, the anode bake furnace is the next largest source at about one percent of the impact. The other sources in total are the sources of the remaining one percent of the impact.

An evaluation of the potential improvement in visibility that would result from application of feasible pollution prevention/add-on control options was done. CALPUFF modeling was performed for two control scenarios: one with wet SO_2 scrubbing applied to the potline and one with wet SO_2 scrubbing applied to the anode bake furnace. In general, this modeling was the same as the baseline modeling except stack data and emission data associated with the application of the feasible add-on controls were used as model inputs. Emission information for both baseline and control scenario modeling is found in Appendix B.

The addition of a potline wet scrubber reduced modeled visibility impacts in all Class I areas. For example, the baseline modeling results indicate that the highest 98th percentile visibility impact from Intalco's BART-eligible sources at Olympic National Park estimated that wet scrubbers installed on the potlines would provide up to 1.172 dv of visibility improvement. The modeled visibility improvements from adding a wet scrubber at the anode bake furnace only are much smaller. The post-control modeling results for the anode bake furnace indicate visibility might be improved by up to 0.024 dv at Olympic National Park.

4. ECOLOGY'S BART DETERMINATION

Ecology's BART determination for Intalco is given in Table 4-1. A more detailed description of each decision follows.

Table 4-1. BART DETERMINATION FOR INTALCO

Pollutant	BART Determination
	Potlines
SO_2	Use of the current level of control, which is a pollution prevention limit of 3% sulfur in the coke used to manufacture anodes.
PM	Use of the current level of control, which is the use of baghouses to control PM emissions from the alumina dry scrubbers, and wet roof scrubbers to control secondary PM emissions from the potroom roofs.
NO_X	No control
	Anode Bake Furnace
SO_2	Use of the current level of control, which is a pollution prevention limit of 3% sulfur in the coke used to manufacture anodes.
PM	Use of the current level of control, which is the use of a baghouse.
NO_X	No control
	Aluminum Holding Furnaces
SO_2	No control

Pollutant	BART Determination
PM	No control
NO_X	No control
	Material Handling and Transfer Operations
SO_2	No control
PM	Use of the current level of control, which is use of fabric filters.
NO_X	No control

Aluminum Potlines

Ecology determined that for SO_2 emissions from the potlines, BART is the current level of control, which is a pollution prevention limit of three percent sulfur in the coke used to manufacture anodes.

Ecology agrees with Intalco that a pollution prevention limit based on coke sulfur content below three percent is infeasible as BART based on an evaluation of the future availability of petroleum coke with lower sulfur content.

Ecology rejected the use of wet scrubbing technology as BART to reduce potline SO_2 emissions because of its excessive costs. Ecology has evaluated the cost estimate provided by Alcoa for this plant including adjusting Alcoa's cost estimates for various items like operational and maintenance labor. For the proposed two absorption tower design, our revised annualized cost was $6,574 per ton of SO_2 removed. The capital and total annualized costs were estimated to be $208.5 million and $40.9 million per year, respectively.

A single absorption tower design option was included in one of the two original Tennessee plant scrubber system proposals (by Babcock), but not evaluated by Intalco's within its BART proposal for Intalco This design would cost less, principally by eliminating the second, backup scrubber tower. With the single absorber tower configuration, if the scrubber tower needed to be taken down for maintenance, the primary control system emissions would need to bypass the absorber tower while maintenance occurs, resulting in SO2 emissions identical to the current rates during the bypassing. Unlike an electrical power plant where routine and planned shutdowns occur during which maintenance can be carried out, an aluminum smelter does not normally stop operating once it has started. Babcock estimated that the single tower design reduced the Total Capital Investment Costs (TCIC) by 28.1 percent, or to 71.9 percent of their two scrubber system proposal. Ecology scaled this cost reduction to the Intalco cost estimate, and included additional cost reductions in annual operating labor and maintenance labor as much as practical. The resulting capital and total annualized costs were $185.1 million and $38.7 million respectively. This gave a cost effectiveness of $6,145 per ton of SO_2 removed assuming an identical SO_2 removal rate. Any direct venting of the emission gasses during maintenance of the absorber tower would lower the SO_2 tons removed and increase this dollars/ton cost effectiveness estimate. Ecology finds the single absorber option to not be cost effective.

Any potline wet scrubber system would also have substantial energy and non air quality impacts, including electricity, water, and waste disposal. Specifically for the limestone control option, Intalco has estimated that there would be an increased energy usage of 64,824,000 kWh of electricity per year, added water consumption of 183 million gallons per year, a need to discharge wastewater from the scrubber system, and solid waste generation of 27,000 tons/year.

In response to comments by Ecology on the wet scrubber option, Intalco identified additional impediments to utilizing a wet scrubbing system. The most important for implementing a wet scrubbing system is that they currently purchase potable water for industrial purposes and have turned over water rights previously issued to Intalco to the water district. The result of this water transfer is the plant would have difficulty in acquiring water rights for this consumptive industrial purpose.

Based on the cost effectiveness and the non air quality impacts of a wet scrubbing system, Ecology determined BART for SO_2 is the current level of emissions control.

Ecology determined that for PM emissions from the potlines, BART is the current level of control, which is the use of baghouses to control PM emissions from the alumina dry scrubbers, and wet roof scrubbers to control secondary PM emissions from the potroom roofs.

Ecology determined that there are no feasible technologies for the control of NO_X from the potlines. BART for NO_X is determined to be no controls.

Anode Bake Furnace

Ecology determined that the petroleum coke sulfur limit accepted as BART for the potlines is also BART for anode bake furnace SO_2 emissions. The cost of wet scrubbing to reduce SO_2 emissions would be excessive at $36,400 per ton of SO_2 removed while providing minimal visibility improvement.

Ecology determined that the existing level of control (based on baghouses on the alumina dry scrubbers) is BART for PM emissions.

Ecology determined that BART for anode bake furnace NO_X emissions is no controls. The use of an advanced firing system for reduced energy use was rejected as BART because the technology would result in a negligible emission reduction and visibility improvement. Similarly, the use of LoTOx™ was rejected as BART because the cost of the technology would be excessive and it has not been demonstrated in practice on aluminum plant anode bake furnaces.

Aluminum Holding Furnaces

Ecology determined that BART for the aluminum holding furnaces is no controls. The use of additional controls was rejected as BART because any visibility improvement would be negligible due to the low level of emissions from the natural gas-fired burners.

Material Handling and Transfer Operations

Ecology determined that since PM emissions from the BART-eligible material handling and transfer operations are all controlled using fabric filter technology, the existing level of emissions control is BART for these material handling and transfer operations.

Ecology determined that BART for NO_X and SO_2 emissions from material handling and transfer operations is no controls. Material handling and transfer operations are a negligible source of NO_X and SO_2 emissions. Additional control of these pollutants would provide negligible visibility improvement.

APPENDIX A

DESCRIPTION OF AVAILABLE SO_2 POTLINE CONTROL OPTIONS

Technology	Description
Limestone Slurry Forced Oxidation (LSFO)	Limestone slurry forced oxidation (LSFO) is used extensively in the utility flue gas desulphurization (FGD) market. It has not been used on an aluminum smelter. The raw material is finely ground limestone. The most commonly used equipment is an open, multi-level, countercurrent spray tower scrubber equipped with spray nozzles to inject the limestone slurry droplets into the gas stream. Liquor is collected at the bottom of the tower and sparged with air to oxidize the calcium sulfite to calcium sulfate to enhance the settling properties of the calcium sulfate. Recirculation pumps circulate the scrubbing liquor to the spray nozzles. SO_2 removal efficiencies of 90% have been achieved. The bleed from the scrubber is sent to a dewatering system to remove excess moisture. For an aluminum smelter, the process will produce either solid gypsum waste or commercial-grade gypsum suitable for reuse as a cement additive if a cement production facility is available and willing to accept the material. Only a very small purge or blowdown stream is required.
Limestone Slurry Natural Oxidation (LSNO)	Limestone slurry natural oxidation (LSNO) is very similar to LSFO. The major difference is the absence of an oxidation stage. The gypsum/calcium sulfite product is essentially a waste product with limited possibilities of use for agricultural purposes.
Conventional Lime Wet Scrubbing	Conventional lime wet scrubbing is also similar to LSFO except that the raw material is hydrated lime or quick lime that is either slaked on-site or purchased in the slaked form. The system typically uses forced oxidation, although natural oxidation is possible. The process will produce either solid gypsum waste or commercial-grade gypsum suitable for reuse as a cement additive if a cement production facility is available and willing to accept the material.
Seawater Scrubbing	Seawater scrubbing is a method for controlling SO_2 emissions in which seawater is used to absorb SO_2 in exhaust gases. Seawater is slightly alkaline (with a pH of approximately 8). SO_2 has a high solubility in seawater. Absorbed SO_2 is subsequently oxidized to sulfates by the use of aeration and the pH is adjusted by the addition of additional seawater. There are three main steps in this process: absorption, oxidation, and neutralization. Seawater is passed countercurrent through the gaseous exhaust stream, typically using a spray column in the aluminum industry. SO_2 preferentially dissolves in the seawater. Removal efficiencies of 85 to 95% have been measured in practice. The clean

Technology	Description
	exhaust gas is de-misted prior to release to the atmosphere. The acidified seawater is then passed to an oxidation basin in which air is blown through the effluent. The additional oxygen ensures that the dissolved SO_2 is converted to sulfates. Finally, additional fresh seawater is added to raise the pH to neutral (or slightly alkaline) and the seawater is discharged back into the ocean. The effluent from this process will typically have a temperature increase of about 1°C and will have a change in sulfate concentration of approximately 2 to 5% above background.[12] [13] Scrubbing of the potline emissions also adds fluoride and trace amounts of polycyclic aromatic hydrocarbons (PAHs) to the effluent seawater. The volume of seawater required varies with exhaust flow rate and SO_2 loading in the gaseous exhaust stream. At Intalco, the volumetric flow rate needed was estimated to be approximately 2.2 million gallons per hour. A global review of feasible control technologies identified seawater scrubbing as having been installed at seven aluminum smelters, none of which are in the U.S. Even though this technology has been identified as a control technology in operation at six primary aluminum ore reduction plants in Norway and one primary aluminum ore reduction plant in Sweden, there are two reasons why this technology is not feasible at Intalco: 1. Federal Clean Water Act Section 304(b) effluent limitations guidelines would not allow discharge of the scrubber solutions to the nearby salt water without extensive treatment to remove the sulfides, fluorides, and other pollutants. Removal of potline fluoride from the seawater scrubber effluent may be feasible, but would also require precipitation of many other naturally occurring salts in the seawater (chlorides, sulfates, other fluorides, etc.), resulting in the unnecessary generation of large amounts of sludge for land disposal. Seawater scrubbing is, therefore, not a viable alternative for smelters in the U.S., especially when compared with other scrubbing technologies that use fresh water and require treatment/disposal for only those salts present in the potline exhaust. 2. The portion of Puget Sound where seawater would be withdrawn and discharged has been included as part of the Cherry Point

[12] Information from the ALSTOM Seawater FGD–Environmental Impact website at www.environment.power.alstom.com/home/power/seawater_fgd/environmental_impact.htm.
[13] Kwawaji, Akili D., et al. 2005. "Seawater Scrubbing for the Removal of Sulfur Dioxide in a Steam Turbine Power Plant." Proceeding of the PWR2005 ASME Power Conference. April 5-7. Chicago, IL.

Technology	Description
	Aquatic Reserve that was established in 2000. The construction of intake and/or discharge structures within the Cherry Point Aquatic Reserve would require an impact analysis, assessment, and DNR authorization of any environmental impacts associated with a seawater scrubbing system. Since more than seven years have passed since Cherry Point was designated as an aquatic reserve and the initial SEPA evaluation has yet to be completed, the time required to complete an analysis of the environmental impacts associated with a seawater scrubbing system and obtain the requisite authorizations for a system that withdraws seawater from and discharges scrubber liquor into the Cherry Point Aquatic Reserve would make this technology infeasible for BART compliance.
Dual Alkali Sodium/Lime Scrubbing (dilute mode)	Dual alkali sodium/lime scrubbing (dilute mode) uses a caustic sodium solution in the scrubber tower. A portion of the scrubbing liquid is discharged to a neutralization stage where lime slurry is used to regenerate the caustic, which is returned to the scrubber. The bleed from the scrubber is sent to a dewatering system to produce a gypsum byproduct. The process will produce either solid gypsum waste or commercial-grade gypsum suitable for reuse as a cement additive. Dual alkali sodium/lime scrubbing (dilute mode) is not currently marketed by major FGD vendors because the system is too complicated and expensive. Because of lack of availability and anticipated excessive cost, dual alkali sodium/lime scrubbing is determined to be not technically feasible.
Conventional Sodium Scrubbing	Conventional sodium scrubbing has been installed in at least 12 aluminum smelters around the world. An alkaline solution of either soda ash or sodium hydroxide is pumped into the scrubbing tower and recirculated through a network of spray nozzles. Atomized droplets contact the up-flowing gas containing SO_2. Where this technology has been deployed, the liquid effluent containing dissolved salts, including sodium and fluorides, has been discharged into a large receiving stream or an open body of water without treatment. As discussed earlier in conjunction with seawater scrubbing, untreated discharge is not feasible for Intalco. As a result of the inability to discharge effluent, treated or otherwise, into a receiving water, Alcoa determined conventional sodium scrubbing to not be technically feasible.
Dry Injection	In dry injection, a reactive alkaline powder is injected into a furnace, ductwork, or a dry reactor. Typical removal efficiencies with calcium adsorbents are 50 to 60% and up to 80% with sodium base adsorbents. However, as with wet scrubbing, disposal of waste using sodium

Technology	Description
	adsorbents must consider their high solubility in water compared to those from calcium adsorbents. The temperature range over which scrubbing has been used is 300 to 1,800°F; the minimum temperature is 300 to 350°F. Dry systems are rarely used and according to EPA, only 3% of FGD systems installed in the U.S. are dry systems.[14] The dry waste material is removed using particulate control devices such a fabric filter or an electrostatic precipitator (ESP).
Semi-Dry Scrubbing	Semi-dry scrubbing is more commonly referred to as spray drying. Calcium hydroxide slurry (lime mixed with water) is introduced into a spray dryer tower. Sodium compounds can be used, but as with the dry scrubber, the high solubility of the sodium-based waste products in water complicates disposal of the waste. The slurry is atomized and injected into a reactor with the exhaust gases, where droplets react with SO_2 as the liquid evaporates. This system is categorized as a semi-dry system because the end product of the SO_2 conversion reaction is a dry material. The dry waste product is collected in the bottom of the spray dryer reactor and a fabric filter or ESP downstream of the spray dryer removes the $CaSO_3$, $CaSO_4$, and unreacted lime. This air pollution control system uses water for evaporative cooling and for the SO_2 reaction. It operates in a temperature range of 300 to 350°F because the temperature of the gases must be high enough to evaporate the water portion of the slurry. Approximately 12% of the FGD systems installed in the U.S. are spray-dry systems[15] with typical SO_2 removal efficiencies in the range of 80 to 90 percent. Unlike a wet scrubbing system, there is no liquid blow-downstream from the dry system and the collected solids are typically land filled.

[14] EPA 2003, "Air Pollution Control Technology Fact Sheet–Flue Gas Desulfurization," EPA-452/F-03-034.
[15] Ibid.

APPENDIX B. LSFO SCRUBBER CONTROL SCENARIOS–EMISSIONS AND IMPACTS

Table B-1. EMISSION RATES FOR SO_2 CONTROL SCENARIOS[1]

Control Scenario	SO_2 Control Technology Evaluated	SO_2		NO_2		$PM_{2.5}$		PM_{10}	
		Emissions (tons/yr)	% Reduction (increase)[2]	Emissions (tons/yr)	% Reduction (increase)[2]	Emissions (tons/yr)	% Reduction (increase)[2]	Emissions (tons/yr)	% Reduction (increase)[2]
Current Allowable Emissions	Operating Limit of 3% Sulfur in Coke	7,076		136		693		869	
Scenario 1	Plus LSFO Scrubber Only for Potlines	854	88	136	0	984	(42)	1,113	(28)
Scenario 2	Plus LSFO Scrubber Only for Anode Bake Furnace	6,904	2	136	0	747	(8)	921	(6)

1. Total emission rate for the potline primary control system, the potline secondary control system emissions, and the anode bake furnace.
2. Compared with current potential emissions. Intalco's BART technical analysis provides information on increases in emissions of particulates due to LSFO scrubbers. Because sulfate dominates visibility impacts on Class I areas, these small increases in particulates were not a factor in the BART determination.

Table B-2. SUMMARY OF THE IMPACTS ANALYSIS FOR SO_2 CONTROL SCENARIOS

Control Scenario	SO_2 Control Technology Evaluated	SO_2 Emission Rate[1] (tons/yr)	SO_2 Emission Reductions[2] (tons/yr)	Installed Capital Cost	Total Annualized Control Costs	Cost Effectiveness (per ton SO_2 removed)	Energy Impact (kW-hr/yr)	Non-Air Quality Environmental Impacts
Current Allowable Emissions	Operating Limit of 3% Sulfur in Coke	7,076						
Scenario 1	Plus LSFO Scrubber Only for Potlines	854	6,223	$234,531,049	$46,820,000	$7,500	64,824,000	27,130 tons/yr of solid waste disposal 182.5 million gallons/yr makeup water
Scenario 2	Plus LSFO Scrubber Only for Anode Bake Furnace	6,904	172	$29,482,194	$6,227,000	$36,400	6,570,000	639.5 tons/yr of solid waste disposal 12.8 million gallons/yr makeup water

1. Total emission rate for the potline primary control system, the potline secondary control system, and the anode bake furnace.
2. Compared with current potential emissions.

APPENDIX C. ACRONYMS/ABBREVIATIONS

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
dv	Deciview(s)
CO	Carbon Monoxide
Ecology	Washington State Department of Ecology
EPA	United States Environmental Protection Agency
ESPs	Electrostatic Precipitators
Intalco	Alcoa Intalco Works
LSFO	Limestone Slurry Forced Oxidation
LSNO	Limestone Slurry Natural Oxidation
mt	Metric Ton
NO_X	Nitrogen Oxides
PM	Particulate Matter
PM_{10}	Particulate Matter (with a mean diameter less than 10 microns)
ppm	Parts per Million
PSCAA	Puget Sound Clean Air Agency
SIP	Regional Haze State Implementation Plan
SO_2	Sulfur Dioxide
VOC	Volatile Organic Compound

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600 • Olympia, WA 98504-7600 • 360-407-6000
711 for Washington Relay Service • Persons with a speech disability can call 877-833-6341

July 7, 2010

Mr. Mike Rousseau
Alcoa Intalco Works
4050 Mountain View Road
Ferndale, WA 98248-0937

Dear Mr. Rousseau:

Regional Haze Best Available Retrofit Technology (BART) Determination

Best Available Retrofit Technology (BART) is required to reduce the regional haze impacts of emissions of your facility. The enclosed Order #7837 contains our BART determination for your facility including a schedule for compliance.

If you have questions or requests relating to this order, please contact Alan Newman at (360) 407-6810 or alan.newman@ecy.wa.gov.

Sincerely,

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Air Quality Program

jj/te

Enclosure

By certified mail

cc: James Jones, EHS Services North America
Alan Newman, Ecology
Judy Schwieters, Industrial Section

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN ADMINISTRATIVE ORDER AGAINST: Alcoa Intalco Works	]]]]]	ORDER NO. 7837

TO: Mr. Mike Rousseau
Alcoa Intalco Works
4050 Mountain View Road
Ferndale, WA 98248-0937

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions that are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the federal and state visibility protection program (WAC 173-400-151 and 40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitutes Best Available Retrofit Technology (BART) for the eligible emission units at your facility.

FINDINGS

A. The Alcoa Intalco Works (Intalco) is a primary aluminum smelter facility subject to BART.

B. The BART-eligible emission units at Intalco are the three potlines, anode bake furnace, 13 aluminum holding furnaces, material handling and transfer operations, and a number of small miscellaneous units.

C. Emissions from existing BART units are controlled by:

   a. Use of six existing primary control systems each consisting of a dry alumina injection system followed by a baghouse for the primary control of PM and fluoride emissions from the potline buildings.

   b. Use of a series of 159 wet roof scrubbers to control secondary PM and fluoride emissions from the potline buildings.

   c. Use of a dry alumina injection system followed by a baghouse for control of PM and fluoride emissions from the Anode Bake Furnace.

d. Use of sulfur content limitations to limit SO_2 emissions due to the manufacture and consumption of anodes.

e. Use of baghouses and fabric filters to control PM emissions from various Material Handling and Transfer Operations throughout the facility.

D. Ecology has determined that the emission controls currently installed at Intalco meet the requirements of BART.

E. Ecology has determined that Intalco has met the requirements of Administrative Order No. #5070 which required submittal of a BART Technical Analysis for the Intalco facility.

Additional information and analysis is available in the BART Determination Support Document for Alcoa Intalco Works, Ferndale, Washington, prepared by the Washington State Department of Ecology, and the BART Determination for Alcoa Intalco Works Ferndale, Washington, prepared by ENVIRON Corporation on behalf of Alcoa Intalco Works, November 2007.

YOU ARE ORDERED: To operate existing emission control equipment in accordance with the following conditions:

1. BART Emission Limitations

   1.1. Meet the emission limitations for particulate matter, nitrogen oxides, and sulfur dioxide found in Order No. 02AQIS-3967 issued to Alcoa Intalco Works Aluminum Corporation on April 15, 2004, by the Washington State Department of Ecology's Industrial Section.

   1.2. Compliance will be determined as specified in Order No. 02AQIS-3967.

2. Schedule for Compliance

   2.1. Compliance with the emission limitations for particulate matter, nitrogen oxides, and sulfur dioxide is required upon the effective date of this Order.

3. Monitoring and Recordkeeping Requirements

   3.1. Monitoring and recordkeeping requirements for particulate matter, nitrogen oxides, and sulfur dioxide are contained in Order No. 02AQIS-3967 issued to Alcoa Intalco Works Aluminum Corporation on April 15, 2004, by the Washington State Department of Ecology's Industrial Section.

4. Reporting Requirements

   4.1. Reporting requirements for particulate matter, nitrogen oxides, and sulfur dioxide are contained in Order No. 02AQIS-3967 issued to Alcoa Intalco Works Aluminum Corporation on April 15, 2004, by the Washington State Department of Ecology's Industrial Section.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.

- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal, you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:		Deliver your appeal in person to:
The Pollution Control Hearings Board P.O. Box 40903 Olympia, WA 98504-0903	OR	The Pollution Control Hearings Board 4224–6th Avenue SE Rowe Six, Bldg 2 Lacey, WA 98503

To serve your appeal on the Department of Ecology:

Mail appeal to:		Deliver your appeal in person to:
Department of Ecology Appeals Coordinator P.O. Box 47608 Olympia, WA 98504-7608	OR	Department of Ecology Appeals Coordinator 300 Desmond Drive SE Lacey, WA 98503

And send a copy of your appeal packet to:

Alan Newman
Department of Ecology
Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600

For additional information, go to the Environmental Hearings Office website at http://www.eho.wa.gov.

To find laws and agency rules, go to the Washington State Legislator website at http://www1.leg.wa.gov/CodeReviser.

Your appeal alone will not stay the effectiveness of this Order. Stay requests must be submitted in accordance with RCW 43.21B.320. These procedures are consistent with Chapter 43.21B RCW.

DATED this 7 day of July, 2010 at Olympia, Washington.

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Department of Ecology
Air Quality Program

BART DETERMINATION
SUPPORT DOCUMENT FOR
TESORO MARKETING AND REFINING COMPANY
ANACORTES REFINERY

Prepared by

Washington State Department of Ecology
Air Quality Program

August 2009

Revised Feb, 22, 2010

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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.

Tesoro Refining and Marketing Company (Tesoro) operates a petroleum (a.k.a. oil) refinery on March Point near Anacortes, Washington. The petroleum refining process results in the emissions of particulate matter (PM), sulfur dioxide (SO_2), volatile organic compounds (VOCs), and nitrogen oxides (NO_X). All of these pollutants are visibility impairing.

Petroleum (oil) refineries are one of the 26 listed source categories. Construction on the Tesoro refinery began in 1955 with commercial operation starting a year later. Additional units started operation in 1963-1964 and during a major expansion in 1971. The BART-eligible emission units at the refinery have the potential to emit more than 250 tpy of SO_2, NO_X, and PM. Fourteen of the 26 combustion units at the plant are BART-eligible. A number of the crude oil and oil product storage tanks are BART-eligible as sources of VOC. VOC emissions were not evaluated for visibility impairment or BART control technology due to the inability of the visibility model to evaluate visibility impact of VOCs. The combustion units are the major sources of visibility impairing pollutants from the oil refinery.

Modeling of visibility impairment was done following the Oregon/Idaho/Washington/EPA Region 10 BART modeling protocol.[1] Modeled visibility impacts of baseline emissions show impacts on the 8th highest day in any year (the 98th percentile value) of greater than 0.5 deciviews (dv) at five Class 1 areas. The highest impact was 1.72 dv on Olympic National Park. Modeling showed that on the most impacted days at Olympic National Park, approximately 57 percent of the visibility impairment is due to NO_X emissions and 41 percent is due to SO_2 emissions.

Tesoro prepared a BART technical analysis following Washington State's BART Guidance.[2]

The Washington State Department of Ecology (Ecology) has determined BART at the Tesoro refinery for PM/PM_{10}, SO_2, and NO_X, as depicted in Table ES-1.

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[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.

- BART for PM/PM_{10} (all particulates) is the use of refinery fuel gas or natural gas for fuel and the current combination of emission controls on Unit F-304.
- BART for SO_2 is the elimination of routine use of fuel oil in Unit F-103 and meeting current requirements on sulfur content of refinery fuel gas.
- BART for SO_2 for Unit F-304 is the continued use of current wet scrubber emission controls
- BART for NO_X is based on continued use of the existing burners and controls except for Unit F-103 which will install new ultra-low-NO_X burners.

The BART controls selected by Ecology will result in a visibility improvement at Olympic National Park of less than half of a deciview.

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

	BART Control Technology	Emission Limitation
F-103		
PM/PM_{10}	Ending routine use of fuel oil. Use of refinery fuel gas or natural gas as primary fuel.	Fuel oil allowed only under the following conditions: • Natural gas curtailment. • Periods with limited refinery fuel gas availability, such as start-up and shutdown of major refinery process units, while major refinery process units are not operating and producing refinery gas, and emergency conditions as necessary to maintain safe operations or equipment shutdown. Test firing on fuel oil is allowed for up to 24 hours per calendar year.
SO_2	Ending routine use of fuel oil. Use of refinery fuel gas or natural gas as primary fuel.	Same as for PM/PM_{10}.
NO_X	Ultra-low-NO_X burners	Not to exceed 59.1 tpy, rolling annual (365) total calculated daily.
All Other BART-Eligible Units		
F-104, F-304, F-654, F-6600, F-6601, F-6602, F-6650, F-6651, F-6652, F6653, F-6654, F-6655, Flare X-819, Cooling Towers 2 and 2a	Currently installed combustion and other controls.	Per applicable NWCAA regulatory orders and regulations.

1. INTRODUCTION

This document is to support Ecology's determination of the Best Available Retrofit Technology (BART) for the Tesoro Refining and Marketing Company (Tesoro) petroleum (a.k.a. oil) refinery on March Point near Anacortes, Washington.

The Tesoro refinery processes crude oil to produce refined oil products, including ultra low sulfur diesel oil, jet fuel, #6 fuel oil, and gasoline. Fourteen of the 26 process heaters, flares, and boilers, plus two cooling towers at the plant are BART-eligible. The primary emission units of concern are the process heaters, boilers, and flares. The process heaters, boilers, and flares emit SO_2 and NO_X. Direct PM emissions from BART-eligible units are low because almost all of them combust either refinery fuel gas or natural gas. Only one BART unit is currently permitted to use fuel oil.

Eleven of the 74 storage tanks are also BART-eligible sources of VOCs. The CALPUFF model used to evaluate visibility impairment cannot model VOCs. Ecology directed that VOC emissions BART-eligible storage tanks and other units not be evaluated for visibility impact or BART control technology. The BART determination for the Tesoro refinery focuses only on PM, SO_2 and NO_X.

1.1 The BART Analysis Process

Tesoro and Ecology used the United States Environmental Protection Agency's (EPA's) BART guidelines contained in Appendix Y to 40 CFR Part 51, as annotated by Ecology, to determine BART. The BART analysis protocol reflects utilization of a 5-step analysis to determine BART for SO_2, NO_X, and PM_{10}. 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.

The BART guidance limits the types of control technologies that need to be evaluated in the BART process to available control technologies. Available control technologies are those which have been applied in practice in the industry. The State can consider additional control techniques beyond those that are 'available', but is not required to do so. This limitation to available control technologies contrasts to the Best Available Control Technology (BACT) process where innovative technologies and techniques that have been applied to similar flue gases must be considered.

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 Basic Description of the Tesoro Refinery

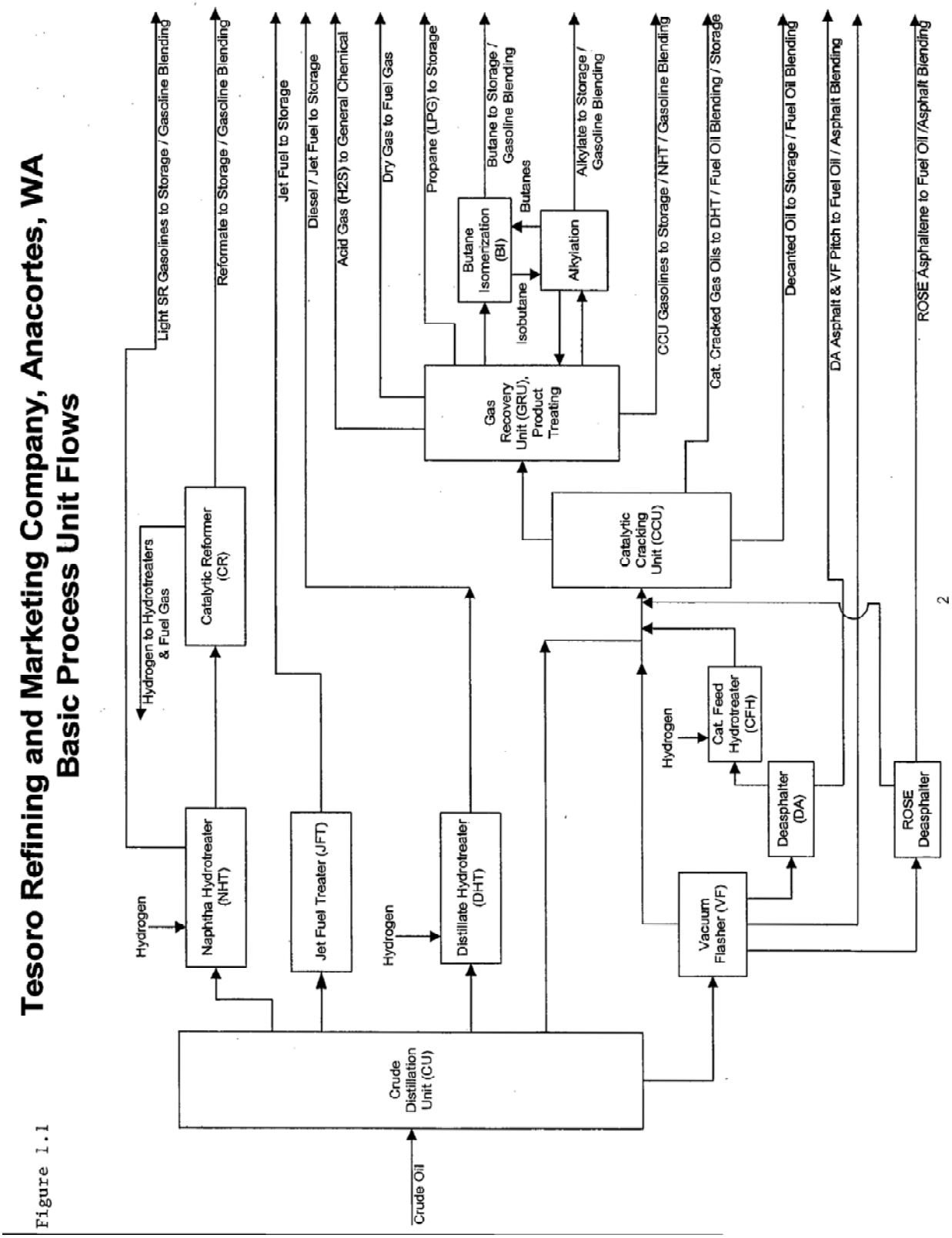
The Tesoro refinery purchases crude oil on the open market for processing into a variety of petroleum products, including gasoline and ultra low sulfur diesel. Current refinery throughput is approximately 115,000 barrels per day of crude oil. Crude oil is heated and sent to the crude distillation unit where the crude oil is separated into various fractions based on boiling point of the hydrocarbons. The various crude fractions are sent for further processing and refining in other units of the plant. De-asphalted heavy oil from the crude unit is hydrotreated prior to being sent to the Fluid Catalytic Cracking Unit (FCCU) to be split into lighter fractions for blending. The refinery also produces heavy fuel oil (a.k.a. #6 oil or bunker C) and paving asphalts. Figure 1-1[3] is a simplified process flow diagram of the overall refinery process.

Catalyst used in the FCCU is regenerated in a separate regenerator unit. In the regenerator unit, the carbon, sulfur and other impurities are burned off the catalyst. The exhaust gas from the regenerator is routed to the two carbon monoxide boilers (F-302, CO Boiler No. 1 and F-304, CO Boiler No. 2) to be combusted and the energy recovered. Exhaust gas from the two carbon monoxide boilers is routed to a single Flue Gas Scrubber for particulate and SO_2 control.

The principle air pollution control authority for this facility is the Northwest Clean Air Agency (NWCAA).

[3] Copied from Air Operating Permit Statement of Basis, Tesoro Refining and Marketing Company, for Air Operating Permit No. 013, issued November 25, 2002.

Figure 1.1


Tesoro Refining and Marketing Company, Anacortes, WA
Basic Process Unit Flows
Crude Oil
Crude Distillation Unit (CU)
Hydrogen
Naphtha Hydrotreater (NHT)
Hydrogen to Hydrotreaters & Fuel Gas
Catalytic Reformer (CR)
Light SR Gasolines to Storage / Gasoline Blending
Reformate to Storage / Gasoline Blending
Jet Fuel Treater (JFT)
Jet Fuel to Storage
Diesel / Jet Fuel to Storage
Hydrogen
Distillate Hydrotreater (DHT)
Acid Gas (H2S) to General Chemical
Dry Gas to Fuel Gas
Propane (LPG) to Storage
Gas Recovery Unit (GRU), Product Treating
Butane Isomerization (BI)
Butane to Storage / Gasoline Blending
Isobutane
Butanes
Alkylation
Alkylate to Storage / Gasoline Blending
Catalytic Cracking Unit (CCU)
CCU Gasolines to Storage / NHT / Gasoline Blending
Cat. Cracked Gas Oils to DHT / Fuel Oil Blending / Storage
Vacuum Flasher (VF)
Hydrogen
Cat. Feed Hydrotreater (CFH)
Deasphalter (DA)
Decanted Oil to Storage / Fuel Oil Blending
DA Asphalt & VF Pitch to Fuel Oil / Asphalt Blending
ROSE Deasphalter
ROSE Asphaltene to Fuel Oil /Asphalt Blending
2

1.3 BART-Eligible Units at the Tesoro Refinery

Fourteen of the 26 process heaters, flares, and boilers and the two cooling towers at the Tesoro refinery are BART-eligible. This means that these 14 emission units have the potential to emit more than 250 tpy of SO_2, NO_X, and PM/PM_{10} and commenced operation within the 15-year BART period.[4] The refinery was constructed during 1955-1956 and reported to have begun commercial operation in 1956.

Table 1-1 identifies the BART-eligible units and the emissions used in the BART modeling.

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

Emission Unit			BART Impact Modeling Emissions (lb/hr)		
Source Designation	**Service**	**Design Heat Input (MMBtu/hr)**	**NO_X**	**SO_2**	**PM_{10}**
F-103	Crude Oil Distillation	145	53.5	160.5	9.1
F-104	Gasoline Splitter/Reboiler	53	0.8	39.8	0.4
F-304	CO Boiler No. 2	322	242.7	24.9	14.1
F-654	Catalytic Feed Hydrotreater	16.5	1.3	11.7	0.1
F-6600	Naphtha Hydrotreater	71.5	13.1	56.0	0.9
F-6601	Naphtha Hydrotreater	75	8.0	77.5	0.6
F-6602	Naphtha Hydrotreater	75	8.3	25.6	0.6
F-6650/6651	Catalytic Reformer	286	101.3	332.0	2.8
F-6652/6653	Catalytic Reformer	105	19.2	86.1	1.5
F-6654	Catalytic Reformer	35	4.0	32.2	0.3
F-6655	Catalytic Reformer	30	2.9	15.1	0.2
X-819	Flare	244	2.0	10.0	0.4
CWT #2	Cooling Water Tower		0	0	0.1
CWT #2a	Cooling Water Tower		0	0	0.1

Tesoro and Ecology reviewed the currently installed and potential controls for all BART-eligible emission units listed above. Tesoro's review was focused on the combustion units because of the contribution of these units to visibility impairment and availability of emission controls.

[4] The 15-year period ending with August 7, 1977, the date of passage of the Clean Air Act amendments of 1977.

Some of the combustion units listed above have been subject to BACT review as part of projects to upgrade or increase plant production capacity. Others have had emission controls added to comply with federal hazardous air pollutant control requirements or to reduce ambient air quality impacts of other projects at the refinery. The results of these actions are incorporated in the modeled emission rates shown in Table 1-1.

1.3 Visibility Impact of BART-Eligible Units at the Tesoro Refinery

Emission units that meet the source category, age, and potential to emit criteria are "BART-eligible." To be "subject to BART," the actual emissions from the "BART-eligible" units at the facility must "cause or contribute" to visibility impairment within at least one mandatory federal Class I area. Ecology has adopted the "cause and contribute" criteria that 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 causes a modeled visibility change of 0.5 dv or more.

Class I area visibility impairment and improvement modeling was performed by Tesoro using the BART modeling protocol developed by Oregon, Idaho, Washington, and EPA Region 10.[5] This protocol uses three years of metrological information to evaluate visibility impacts. As directed in the protocol, Tesoro used the highest 24-hour emission rates that occurred in the 3-year period to model its impacts on Class I areas.

Modeled visibility impacts of baseline emissions show impacts on the 8th highest day in any year (the 98th percentile value) of greater than 0.5 deciviews (dv) at five Class 1 areas. The highest impact was 1.72 dv at Olympic National Park. Modeling showed that on the most impacted days at Olympic National Park, approximately 57 percent of the visibility impairment is due to NO_X emissions and 41 percent is due to SO_2 emissions. For more information on visibility impacts of this facility, see Section 3 below.

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

2. BART TECHNOLOGY ANALYSIS

The Tesoro BART technology analysis was based on the 5-step process defined in BART guidance and listed in Section 1.1 of this report. The first subsection below deals with an overview of the controls evaluated for combustion units, the second with, evaluation of plant-wide SO_2 controls and specific controls on individual combustion units, and the third with controls on the cooling towers. The latter two sections provide an overview of the potentially feasible emission controls evaluated by Tesoro followed by Tesoro's BART proposal.

In Tesoro's evaluation of costs in the 2008 BART analysis, they assumed that all control installations would occur at a regularly scheduled maintenance turn-around. These are the costs presented in sections 2.2 and 2.3. Tesoro subsequently submitted additional cost analyses for implementation of the BART controls on 5 units at other than a regularly scheduled maintenance turn-around. This is discussed in Section 2.4.

2.1 Controls Evaluated for Combustion Units

The Tesoro refinery has 14 fuel combustion units subject to BART. The three subsections below provide an overview of the NO_X, SO_2, and PM/PM_{10} control techniques that were evaluated by Tesoro. While the units differ in firing rate, usage, and specific design features, most of the NO_X, SO_2, and PM/PM_{10} controls could be used on all units.

2.1.1 NO_X Controls Evaluated for All Combustion Units

There are a variety of controls that can be used for reducing the quantity of NO_X emitted to the atmosphere from the process heaters and CO Boiler which are subject to BART. Specifically, the company evaluated eight different technologies, including variations of several of them. NO_X emissions control from refinery fuel gas and flue gas combustion can be achieved with eight technologies or combinations of technologies.

- Flue gas recirculation (FGR)
- Low-NO_X burners (LNBs)
  - Staged-air LNBs
  - Staged-fuel LNBs
- Ultra-low-NO_X burners (ULNBs)
- Selective non-catalytic reduction (SNCR)
  - SNCR
  - LNBs + SNCR
  - ULNBs + SNCR
- Selective catalytic reduction (SCR)
  - SCR
  - LNBs + SCR
  - ULNBs + SCR

- $LoTO_X^{TM}$ process (evaluated only for Unit F-304, CO Boiler No. 2)
- Sulfur Recovery Unit with Tail Gas Unit (SRU/TGU; evaluated for only Unit F-304, CO Boiler No. 2).

Additional control techniques were considered by Tesoro and are not listed here due to their lack of applicability to the Tesoro emission units. The following are more detailed descriptions of the NO_X control and reduction technologies evaluated by Tesoro for use at the refinery. Control techniques that are applicable to only one or two units are specifically noted.

Flue gas recirculation (FGR) generally involves mixing some of the flue gas from the heater or boiler with the air fed to the burner(s). FGR can be integrated into the construction of the unit or can be added to an existing unit. In the FGR process, approximately 15 to 30 percent of the air supplied to the burner's primary combustion zone is flue gas.[6] The flue gas reduces the peak flame temperature and the local oxygen concentrations resulting in less thermal NO_X formation. Thermal NO_X is the principal kind of NO_X produced in combustion of most gaseous and liquid fuels. FGR has been used on only a few oil refinery process heaters. These installations require extensive modification to the heater to accommodate the changed combustion characteristics and to avoid the introduction of hydrocarbon vapors that may leak from the heat transfer tubing to the flue gas.

Tesoro regards flue gas recirculation of flue gases at process heaters as an unacceptable safety risk due to the potential of formation of explosive gas mixtures in the event of a heater tube failure. Few applications have been made to refinery process heaters due to this risk. Therefore, this technology was not explored further.

Low- and ultra-low-NO_X burners come in two principle designs: staged-air and the staged-fuel burners. Both function by adjusting the mixture of fuel and air to reduce peak temperatures and minimize the production of NO_X. Some LNBs and ULNBs include flue gas recirculation in their design. Both designs generally have longer flame zones than the 'standard' burners that they replace in retrofit situations. The longer flame is not an issue in new heater installations due to the heaters being designed to accommodate the LNB or ULNB burners. Emission factors from EPA's RACT/BACT/LAER Clearinghouse range from 0.08 to 0.1 lb/MMBtu (NO_X) for LNBs and ULNBs.

LNB and ULNB retrofits are commonly installed as a result of BACT and LAER determinations or as a result of federal Consent Order requirements.

Staged-air, low-NO_X burners limit NO_X production by reducing flame oxygen concentrations in the primary combustion zone. The initial fuel combustion takes place in a fuel-rich, reducing atmosphere with a flame high temperature due to the low combustion air/fuel ratio. The low O_2 concentration limits NO_X formation.

[6] (CPPI, 1990), (Campbell, 1991), (Martin, 1993), (Shareef, 1988)

For this burner design, retrofitting heaters with less than three feet between the burner and the opposite wall of the firebox may not be practical due to potential flame impingement on the firebox refractory materials or heat transfer tubes. Emission reductions achieved by staged-air LNBs range from 30 to 40 percent below emissions from conventional burners. Tesoro used a 40 percent NO_X reduction for its initial cost analysis review.

Staged-fuel, low-NO_X burners separate the combustion zone into two regions. The first is a lean primary region in which all the combustion air is injected with a small fraction of the fuel. This is followed by a second region where the remaining fuel is injected and combustion is completed.

Staged-fuel LNBs have several advantages over staged-air LNBs. First, the improved fuel/air mixing reduces the excess air necessary to ensure complete combustion. The lower excess air both reduces NO_X formation and improves heater efficiency. Second, for a given peak flame temperature, staged-fuel LNBs have a more compact (shorter) flame than staged-air LNBs. Up to 72 percent NO_X emissions reductions for staged-fuel LNBs have been reported over conventional burners based on vendor test data. Tesoro used a 60 percent average NO_X reduction for its initial cost analysis review. Ecology has only included information using this version of LNB in the unit-specific discussions below.

Ultra-low-NO_X burners (ULNBs) recirculate hot, oxygen-depleted flue gas from the flame or firebox back into the combustion zone. This reduces the average oxygen concentration within the flame maintaining the temperatures necessary for optimal combustion efficiency. ULNBs are physically larger than the conventional or LNB burners that might be used but compensate by having shorter flames than LNBs and are occasionally more efficient at combusting the fuel. They may require fans to provide combustion air rather than using a natural draft combustion air system. The conventional burner equipped heaters at Tesoro all use natural draft combustion air delivery systems. Burner mount modifications may be required because ULNBs usually do not fit into conventional burner mounts.

ULNBs now have the following features available:

- Compact sizes
- Shorter flame paths
- High turndown ratios

Tesoro used a 75 percent average NO_X reduction for its initial cost analysis based on EPA methods. After receiving vendor guaranteed average NO_X emission reductions ranging from 60 to 73.5 percent for specific units, Tesoro developed a vendor cost factor analysis for each unit based on the vendor guarantee and the unit-specific emission rate.

Selective Non-Catalytic Reduction (SNCR) is a post-combustion technology that involves directly injecting ammonia or urea into the hot flue gas. The reaction requires the flue temperatures required range from 1,600 to 1,750°F for ammonia and from 1,000 to 1,900°F for

urea-based reagents. Other chemicals such as hydrogen, hydrogen peroxide, fuel gas, and methanol may be added to improve performance and lower the minimum threshold temperatures. The injection point must be at a location where temperature of the flue gas is within the required temperature range for enough time for the reaction to occur.

Not all of the ammonia or urea is used. Unreacted ammonia in the emissions (ammonia slip) is potentially higher in SNCR systems than in an SCR system due to higher reactant injection ratios (2:1). The degree of ammonia slip can be minimized through consistent operation of the heaters and good operational controls.

Vendors contacted by Tesoro have projected potential NO_X reductions at a maximum 25 ppm ammonia slip. SNCR systems may increase fuel gas consumption by approximately 0.3 percent in addition to the power required to vaporize aqueous ammonia. One result of the SNCR process is the formation of small amounts of nitrous oxide (N_2O), a greenhouse gas.

Ammonia used in the process is delivered and stored on site as either anhydrous ammonia or aqua-ammonia. If urea is used, it is delivered and stored as a dry material. Anhydrous and aqua-ammonia at concentrations above 19 percent ammonia require special reporting, handling, and worker safety requirements be followed. Urea is either dissolved in water and injected into the flue gas or converted to ammonia prior to injection.

SNCR may be used as the sole NO_X control technique or in combination with LNBs or ULNBs. At optimum temperatures, NO_X destruction efficiencies range from 30 to 50 percent. Tesoro used a 50 percent NO_X reduction for its initial cost analysis review.

Vendor NO_X reduction guarantees ranged from 35 to 40 percent based on Tesoro's fuel gas compositions and measured bridgewall temperatures. EPA's RACT/BACT/LAER Clearinghouse lists an emission limit of 127 ppmdv NO_X at seven percent oxygen for a SNCR used to control emissions from a Fluid Catalytic Cracking Regenerator unit followed by a CO Boiler.

NO_X tempering (steam or water injection) was proposed by Peerless Manufacturing Company as a technique that could be combined with SNCR on Units F-103 and F-304. Water or steam injection is a common NO_X control for large combustion turbines permitted prior to 2000. Peerless proposed a patented process in which water is injected into the burner flame to reduce the peak flame temperature. For each 190°F of flame temperature reduction, the NO_X is reduced by 50 percent.[7] Peerless estimated that NO_X tempering would reduce NO_X formation by 30 to 35 percent.

Flame temperature cooling is likely to reduce bridgewall (a.k.a. arch) temperatures and thus reduce the heat energy available to heat the crude oil. To overcome this reduction in heat energy, fuel use in the two units would need to increase, but this potentially reduces the

[7] EPA, 2003 and EPA, 1993.

effectiveness of tempering. Other potentially adverse effects are anticipated to occur. Finally, to date, NO_X tempering has only been used on large utility boilers. Tesoro did not analyze this technique any further.

Selective Catalytic Reduction (SCR) is a post-combustion gas treatment technique to reduce NO_X in the exhaust stream through the use of a catalyst. As with SNCR, an ammonia or urea solution is injected in the flue gas upstream of a catalyst bed where it selectively reduces the nitrogen oxide compounds in the exhaust to produce elemental nitrogen and water. The catalyst's function is to reduce the reaction temperature from the range needed for SNCR.

Catalysts have been formulated to operate at three temperature ranges, a low temperature range based on platinum, and middle and high temperature catalysts based on a mixture of vanadium, titanium, and tungsten oxides. The operating temperature of the SCR system defines the catalyst type used. A conventional (middle range) SCR catalyst functions at temperatures of 600 to 750°F (the high temperature is often given as 850°F). Low temperature catalysts operate best in the range of 470 to 510°F. High temperature catalysts operate at temperatures of 900 to 1000°F.

Other than the catalyst bed reactor, major components of an SCR system are ammonia storage sources, vaporizer, and an ammonia injection grid. Catalyst deactivation and residual ammonia slip in the flue gas are the two key drawbacks in an SCR system. Catalyst activity decreases with operating time and with catalyst fouling. Disposal of the fouled catalyst presents another environmental concern due to the toxic metals contained in the catalyst. This concern is minimized as the result of the vendors recycling used catalysts.

Ammonia slip can be held to levels below five ppm in many situations, though the vendors contacted by Tesoro projected potential NO_X reductions using a maximum slip of 25 ppm ammonia.

SCR catalysts will oxidize a small portion of the SO_2 in the flue gas to SO_3 which can combine with water vapor to form sulfuric acid mist.

Typical SCR NO_X removal efficiencies range from 70 to 90^+ percent removal, depending on the unit being controlled. Tesoro used a 90 percent NO_X removal in its cost analyses.

The **LoTOx™** process is available from BELCO under license from BOC. It uses ozone to convert NO and NO_2 to N_2O_5 which is removed from the flue gas by water where it is converted to nitric acid or is removed with a caustic scrubber and converted to a nitrate. Specifically, ozone (O_3) is generated from industrial-grade oxygen using common industrial methods. O_3 is injected into the flue gas at a suitable, low temperature. O_3 oxidizes the NO_X to N_2O_5. In a wet scrubber, the N_2O_5 combines with water vapor in the flue gas to form nitric acid (HNO_3). Following the reaction zone, multiple spray levels scrub the flue gas to absorb nitric acid mist

and unreacted O_3 in the final step. The reported LoTOx™ NO_X removal efficiency is 80 percent.[8]

NO_X concentration changes in the flue gas do not adversely affect the removal efficiency of the $LoTO_X$™ process. This means the Refinery Operations staff can optimize the combustion process to achieve the most cost-efficient burner conditions without considering NO_X generation. Continuous NO_X monitors within the system provide the O_3 flow rates necessary to achieve a set stack NO_X level.
LoTOx™ systems require a downstream caustic or water based scrubber. The use of the water based scrubber would require either a use for the dilute nitric acid produced or a separate acid neutralization tank or other denitrifying wastewater treatment process. The scrubber must be compatible with the LoTOx™ system.

Currently, EDV® Wet Scrubbing systems with the LoTOx™ process for NO_X control are installed on five Fluid Catalytic Cracking Units (FCCUs). One of these began operation in 2006 and the other units were commissioned during 2007. Tesoro considered adding LoTOx™ only to unit F-304, CO Boiler No. 2.

Use of a LoTOx™ unit with caustic scrubbing liquor will also produce a sodium or calcium nitrate-, sulfate-, and sulfite-rich wastewater which must be discharged to the plant's industrial waste water system. The increased nitrates to the treatment system could have a beneficial or detrimental effect. Beneficial effects would come from reduced need to add nitrogen to the industrial treatment system for nutrient balancing of the biological treatment process. Detrimental effects could come from the need for denitrification in the final clarifier prior to discharge. Denitrification in the clarifier would result in increased total suspended solids in the effluent and could lead to violations of the refinery's discharge permit. Tesoro did not perform a detailed evaluation of potential impacts.

A Sulfur Recovery Unit with Tail Gas Treatment (SRU/TGU) can be used to accept ammonia-rich vent gas from the Sour Water Stripper's (SWS) second stage instead of burning it in F-304, CO Boiler No. 2. In this control option, the SWS vent stream would be rerouted from F-304 to a Sulfur Recovery Unit (SRU) where the ammonia would be converted to nitrogen gas rather than nitrogen oxides.

The Tesoro refinery does not operate its own SRU, but routes its H_2S acid gas stream to the SRU and sulfuric acid plant at the neighboring General Chemical facility. Due to a recent upgrade to the sulfur removal system at Tesoro and resulting increase in sulfides sent to it, the General Chemical facility has no additional sulfur processing capacity. The General Chemical facility cannot handle the ammonia-rich SWS gases.

Tesoro's proposal to remove the ammonia-rich SWS vent gas stream from F-304 and treat it in an SRU requires construction of a new and independent SRU. The SRU would provide capacity

[8] (EPA, 2005) BELCO Product Literature.

for future reductions of sulfur in the refinery fuel gas and in the fuel oils produced by the refinery.

The various emission controls described above are summarized in Table 2-1.

Table 2-1. SUMMARY OF NO_X RETROFIT TECHNOLOGIES EVALUATED

Technology	Manufacturer Contacted	Description	EPA Removal Rate	Vendor Removal Rate
FGR	N/A	Recycles 15-30% of inert flue gas to the primary combustion zone.	30%	--
LNB	John Zink (SFG/PSFG Retrofit Kit) & Todd Combustion	Burner upgrade kit includes tile, cone extension, primary riser, four fuel gas tips.	40% staged air 60% staged fuel	28-66%
ULNB	John Zink (Coolstar Burner)	Compact size, short flame, high turndown capabilities.	75%	73%
SNCR	Peerless Manufacturing Group	19% aqueous ammonia injection into radiant and convective regions of firebox (1,600-2,200°F).	50%	35-40%
SCR	CRI Catalyst	19% aqueous ammonia injection and catalyst (470-510°F and 600-750°F), low temperature pelletized extrudate catalyst.	90%	90%
$LoTO_X$	Available through BELCO under license from BOC	Uses ozone to convert NO_X to higher oxidation state which is subsequently hydrolyzed and removed with a caustic scrubber. Cons: High power consumption, creates pressure drops and incompatible when located upstream of existing WGS due to pressure sensitive venturi scrubber. Potential for nitric acid mist.	--	80%
SRU/TGU	Generally available technologies	NO_X emissions from F-304, CO Boiler No. 2 can be reduced by discontinuing the burning of ammonia-rich SWS vent gas. Routing the vent gas to an SRU, where ammonia is converted to nitrogen gas, is an identified option.	--	30%

2.1.2 SO_2 Controls Evaluated for All Combustion Units

All BART-eligible combustion units are permitted to burn refinery fuel gas that has been treated to reduce the sulfur content or natural gas. While there are a number of add-on SO_2 control technologies available, at an oil refinery the most effective method is reduction of the fuel gas (refinery gas) sulfur content.

A review of the current information in the EPA RACT/BACT/LAER clearinghouse database indicates limited use of add-on SO_2 emission controls at oil refineries. The predominant control technology reported is "use of low sulfur fuel." The exception to this is Catalyst Regenerator/CO Boiler stacks where add-on SO_2 controls are often included. The wet scrubber on Unit F-304, CO Boiler No. 2 is discussed in section 2.2.4 below. For its analysis, Tesoro focused on additional methods to reduce the sulfur content of the fuels used in the BART-eligible heaters and boilers.

Eliminating use of high sulfur fuel oil is a proven way to reduce SO_2 emissions from an oil refinery. This involves removal of the ability to fire fuel oil from the affected process heaters and boilers. The units may then be fired exclusively with natural gas, refinery fuel gas, or lower sulfur content distillate oil. At the Tesoro plant, only one of the BART-eligible units (Unit F-103) is still capable of firing a liquid fuel oil.

Tesoro evaluated **additional flare gas recovery** to reduce the amount of untreated gas burned in the flare system. Refinery fuel gas that is not used beneficially is sent to the plant flare system for combustion and disposal. Collection and routing of the recovered gas for use in the refinery fuel gas system reduces both the quantity of the gas flared and the sulfur content of the gas to match the level of the rest of the plant. Flare gas consists of purge gas, pilot burner gas (natural gas), various off gases associated with loading operations and process vents, and occasionally off gases from other process units during upsets, start-up, and shutdown conditions.

Converting equipment to run on exclusively natural gas is another method that can be used to reduce SO_2 emissions. The equipment is disconnected from the refinery fuel gas system and reconnected directly to a natural gas supply. This reduces SO_2 emissions because the total sulfur content of the natural gas is much lower than the refinery fuel gas. To implement this option requires installation of natural gas lines to all affected heaters and boilers or conversion of the entire plant to this option. Natural gas is a fuel that must be purchased and thus increases plant costs.

Natural gas can be added to the "fuel drum" where the **refinery fuel gas is mixed with the natural gas**. Many oil refineries use this practice to meet regulatory requirements, supplement limited refinery fuel gas, or reduce fluctuations in heat content and concentrations of hydrogen, ethane, propane, and butane in the fuel gas. Mixing pipeline or retail quality natural gas into the refinery fuel gas system involves routing a natural gas pipeline to the refinery gas fuel drum for mixing with the refinery gas. Tesoro already adds natural gas to its refinery fuel gas system.

Refinery gas sulfur removal is the most common method of treating refinery fuel gas. In this process, a solvent such as mono- or di-ethylamine is used to remove hydrogen sulfide and other reduced sulfides from the fuel gas. The untreated refinery fuel gas is "washed" with the amine. The sulfides preferentially attach to the amine solvent and are removed from the refinery fuel gas. The used amine solvent is routed to a regenerator system where the sulfide is thermally removed from the amine. The sulfides are routed to a sulfur recovery unit or similar process. The cleaned amine is then returned to the stripping process.

Provision for additional refinery fuel gas sulfur removal has been done within the current fuel gas cleaning system. The sulfur removed by the system must be routed to a sulfur recovery unit or sulfuric acid plant. Currently Tesoro is contracted with General Chemical to provide this service for the refinery. However, the General Chemical facility is at capacity and cannot accept more sulfur. As a result, Tesoro would need to construct a new sulfur recovery unit.

A new **Sulfur Recovery Unit (SRU)** is required to remove additional sulfur. Tesoro has evaluated the costs to install a new, 50 ton/day SRU at their plant as part of a project proposed in 2006. The capital cost was estimated to be $58 million to meet the federal New Source Performance Standard limit for refinery gas H_2S of 152 ppmv. Annual operational costs were not evaluated.

2.1.3 PM/PM_{10} Controls for All Combustion Units

With the exception of emissions from Unit F-304, CO Boiler No. 2 discussed in section 2.2.4 below, PM/PM_{10} controls applicable to the process heaters at this facility are tied directly to the use of fuel. Using low sulfur refinery fuel gas reduces potential particulate emissions as much as possible. The refinery gas system includes process steps to remove particulates and some heavier hydrocarbons from the refinery gas prior to being sent to the various fuel burning units. While reduction of fuel oil use in Unit F-103 is primarily to reduce SO_2 emissions, reduced or even total elimination of fuel oil combustion in this unit will also reduce PM/PM_{10} emissions.

2.2 Evaluation of Controls for All Combustion Units

The subsections below evaluate plant-wide SO_2 reduction first and then the application of controls to each of the 14 combustion units subject to BART.

2.2.1 Plant-Wide SO_2 Control

The Tesoro refinery has 14 combustion units subject to BART that emit SO_2. SO_2 results from the combustion of sulfur containing fuels such as the refinery fuel gas, natural gas, and fuel oil. Tesoro evaluated reduction of SO_2 from Units F-103 and F-304 and Flare X-819 individually and in combination with all other combustion BART units. Applicability of unit specific SO_2 controls on Units F-103 and F-304 and Flare X-819 are discussed in individual subsections below.

2.2.1.1 Evaluation of Plant-Wide Control

SO_2 controls at oil refineries has been studied by EPA who concluded that controlling refinery fuel gas sulfur content is the most efficient method to reduce SO_2 emissions from an oil refinery. The use of "low sulfur fuel" is the most common SO_2 control technique applied to oil refinery process units. "Low sulfur fuel" is usually defined as refinery fuel gas meeting the New Source Performance Standard (NSPS) requirements of 40 CFR Part 60, Subpart J.

In 2007 the Tesoro refinery upgraded the refinery gas sulfur removal system. The upgrade resulted in the refinery fuel gas with an average daily H_2S concentration of 70 ppm. However, short-term concentration "spikes" above 200 ppm can occur for several reasons, including rates of 1000 ppm when the sulfur recovery units or sulfuric acid plant is out of operation. This upgrade reduced the annual emissions of SO_2 from the refinery but not the short-term emissions. The refinery gas system upgrade was not subject to the New Source Review process but was included in OAC 952a issued by NWCAA as part of an order addressing installation of a larger amine system stripper gas pipeline to the sulfuric acid plant.

Sulfur removed from refinery products and the refinery fuel gas system is sent to the sulfur recovery and sulfuric acid production system operated by General Chemical. Tesoro owns the equipment for the system and contracts with General Chemical for operation and maintenance (O&M). General Chemical is responsible for all costs and environmental compliance. Currently the General Chemical plant is at capacity and unable to accept any additional sulfur from the Tesoro refinery. As a result any additional refinery fuel gas sulfur content reductions require the construction of a new sulfur recover unit.

Any additional reduction in refinery fuel gas sulfur content will require construction of a new SRU. In conjunction with a proposal to install a new coking system, Tesoro evaluated the construction of a new 50 ton/day SRU and refinery modifications to route sulfur streams to the new unit. The capital cost is estimated to be $58 million to continuously treat all refinery gas to the level of the NSPS standard (162 ppm of H_2S). Attributing all the cost to the SO_2 reductions to all combustion units (not just the BART eligible units) results in a plant wide reduction from the 2003 – 05 average emissions of 395 tons of SO_2 with a cost effectiveness of $16,100/ton of SO_2 (not including O&M costs). Tesoro also evaluated the cost effectiveness of continuously meeting a limit of 50 ppm of H_2S (a plant wide annual decrease of 451 tons per year), with the use of a new SRU. To meet a 50 ppm H_2S concentration would reduce the cost effectiveness to $14,100/ton, also not including O&M costs.

2.2.1.2 Proposed BART for SO_2

Tesoro proposed to continue use of the current refinery fuel gas system meeting the requirements of NWCAA's OAC 952a for control of plant-wide SO_2.

2.2.2 Unit F-103, Crude Oil Distillation Heater

The Crude Oil Distillation Heater is used to heat crude oil for initial distillation steps. It has 24 burners split between two combustion cells. This 145 MMBtu/hr (average rate 103.5MMBtu/hr) heater was constructed in 1963 and utilizes natural gas, refinery fuel gas, or fuel oil. Currently fuel oil is used as backup fuel to natural gas and refinery fuel gas, though there are no permit restrictions limiting the use of fuel oil in this unit. The burners used are of original equipment design and emit relatively high levels of NO_X compared to current LNB or ULNB designs.

2.2.2.1 NO_X Control

This heater currently uses "default" original manufacturer design burners originally installed in 1963. The current emission rates for this heater are an annual 121 tons per year (tpy) at an average concentration of 193 ppmv. After an evaluation of the technical feasibility of the NO_X controls listed in Table 2-1, Tesoro evaluated the cost effectiveness of ULNB, SCR, SNCR, ULNB plus SCR, and ULNB plus SNCR. Table 2-2 lists pertinent criteria and cost effectiveness.

Table 2-2. UNIT F-103 NO_X CONTROLS EVALUATED IN DETAIL

Control Technology	Emission Reduction Anticipated – EPA Method	Annual NO_X Emission Rate (tpy)	Average Cost Effectiveness ($/ton) – EPA Method	Emission Reduction Anticipated – Vendor Cost Factor Analysis	Average Cost Effectiveness ($/ton) – Vendor Cost Factor Analysis
No controls	--	121	--	--	--
SNCR	50%	61	$6376	40%	$17760
ULNB	75%	30	$3398	66.2%	$4648
ULNB + SNCR	87.5%	15	$6556	80%	$10886
SCR	90%	12	$9444	90%	$6743
ULNB + SCR	97.5%	3	$11331	97%	$8107

All of these controls are capable of being installed on this heater. Tesoro's current understanding of the characteristics of potential ULNB burners suggests that flame impingement is not an issue and adequate space exists to install SCR. Installation of SNCR will reduce the gross heat available to heat crude oil. This reduction is due to the need to evaporate the water included in the aqua-ammonia used in the proposed SNCR system. Within the heat input capacity limits of the existing burners, this evaporation of water can be overcome by burning more fuel with an accompanying increase in emissions of other pollutants.

The most significant adverse impact resulting from SCR or SNCR is an increase in the amount of refinery fuel gas used to overcome heat losses. The increase in fuel use results in incrementally higher emissions of other pollutants from the combustion unit.

2.2.2.2 SO_2 Control

Tesoro evaluated the elimination of routine use of fuel oil combustion in Unit F-103 heater. This option results in a very small cost at this time and would reduce SO_2 emissions from the unit by about eight tpy (current SO_2 emissions are 160.5 tpy). If the actual use of fuel oil in this heater were higher, even approaching the annual heat input requirements of the heater, the SO_2 reductions would be even larger. Tesoro is concerned that in the future as the costs of fuel oil and refinery fuel gas change, fuel oil use could again become cheaper than natural gas/refinery fuel gas costs.

2.2.2.3 PM/PM_{10} Control

Tesoro has evaluated ending the routine use of fuel oil in this heater as a BART technology. As noted above, the alternative has essentially no current cost to the plant and will reduce plant-wide PM emissions by about 26 percent or 7.7 tpy (the current emissions for this unit are 9.1 tpy).

2.2.2.4 Proposed BART

Tesoro has evaluated the technically feasible controls for cost effectiveness and energy consumption and other non-air quality impacts. Based on that evaluation, they propose the installation of ULNBs as BART for NO_X on this heater.

Tesoro has also proposed BART for SO_2 and PM/PM_{10} for this heater as ending the routine use of fuel oil. Tesoro wants to retain fuel oil use in this heater to cover periods of natural gas curtailment, start-up, and shutdown of major process units in the refinery, and emergency conditions that would limit the availability of refinery fuel gas.

2.2.3 Unit F-104, Gasoline Splitter Reboiler

The Gasoline Splitter Reboiler is a heater used to heat the gasoline fraction from the Crude Distillation Unit for further distillation steps. It has six floor-mounted ULNB burners. This 53 MMBtu/hr (average rate 15.5MMBtu/hr) heater was constructed in 1972 and utilizes only refinery fuel gas.

2.2.3.1 NO_X Control

This heater currently uses ULNBs installed in 2004. The current emission rates for this heater are 4.7 tpy, at an average concentration of 48 ppmv. After an evaluation of technical feasibility to retrofit the heater with the NO_X controls in Table 2-1, the only control evaluated for cost effectiveness for this heater was SCR. The average cost effectiveness of SCR was found to exceed $100,000/ton removed. No further analyses were performed.

2.2.3.2 Proposed BART

Based on their cost evaluation, the relative newness of the existing ULNBs installed in this unit and the high cost of SCR, Tesoro proposes the currently installed ULNBs as BART for NO_X on this heater.

Tesoro's continued use of the refinery fuel gas system as plant-wide SO_2 BART applies to Unit F-104. The continued use of low sulfur refinery fuel gas minimizes potential particulate emissions as much as possible and is considered BART for PM/PM10.

2.2.4 Unit F-304, CO Boiler No. 2

The Unit F-304, CO Boiler makes use of the thermal energy in the carbon monoxide rich flue gas from the Fluid Catalytic Cracking Unit (FCCU) catalyst regenerator by combusting the gas and providing steam for many plant processes. This unit exhausts through a common stack with the other CO Boiler (F-302) which also receives off gas from the FCCU regenerator. Refinery fuel gas is used as a supplemental fuel when required. This unit is capable of operating as a conventional refinery fuel gas fired boiler when the catalyst regenerator is not operating. This 322 MMBtu/hr (average rate 184.5 MMBtu/hr) heater was constructed in 1964 and has four wall-mounted burners.

2.2.4.1 NO_X Control

This boiler currently uses "default" original manufacturers design burners as originally installed in 1964. The current emission rates for this heater are 836 tpy. After an evaluation of the technical feasibility of the NO_X controls in Table 2-1, Tesoro evaluated the cost effectiveness of ULNB, SCR, SNCR, ULNB plus SCR, and ULNB plus SNCR. Table 2-3 lists pertinent criteria and cost effectiveness.

Table 2-3. UNIT F-304 NO_X CONTROLS EVALUATED IN DETAIL

Control Technology	Emission Reduction Anticipated – EPA Method	Average Cost Effectiveness ($/ton) – EPA Method	Emission Reduction Anticipated – Vendor Cost Factor Analysis	Annual NO_X Emission Rate (tpy) – Vendor Removal Rates	Average Cost Effectiveness ($/ton) – Vendor Cost Factor Analysis
No controls	--	--	--	836	--
$LoTO_X$™[9]	80%	--	80%	167	$14873
LNB + SNCR	--	--	39%	514	$4592
SNCR	50%	$2403	35%	543	$4534
LNB	--	--	5.5%	790	$6045

Initially, Tesoro evaluated only the use of SNCR with the EPA method screen. Consultation with vendors and receipt of information on performance and price estimates resulted in the evaluation of the additional controls. All of these controls are capable of being installed on this heater.

The installation of SNCR will slightly reduce the gross heat available to provide steam. This reduction is due to the need to evaporate the water included in the aqua ammonia used in the proposed SNCR system. During normal operating rates, the heat input capacity limits of the existing burners is able to overcome this loss by burning more fuel, with an accompanying increase in emissions of other pollutants.

As noted above, the $LoTO_X$™ system has been installed on very few other CO boiler/regenerator units. The installations provide both NO_X and particulate control. The existing particulate and SO_2 control is incompatible with the acidic environment produced in the $LoTO_X$™ process and cannot be retrofitted with the ozone injection step. The vendor has advised Tesoro that if replacement of the current Flue Gas Scrubber system were not possible, the $LoTO_X$™ system would have to be installed after the Flue Gas Scrubber.[10]

As an alternative to installation after the existing Flue Gas Scrubber, it could be replaced with a new $LoTO_X$™ system and BELCO Wet Gas Scrubber. While not analyzed, the cost of removal of the 3-year old Flue Gas Scrubber and replacement with a new $LoTO_X$™ system was considered to be very costly and was not evaluated.

[9] Cost effectiveness shown is the lowest of the four analyses made. The differences in the four $LoTO_X$™ cost analyses are primarily due to the cost of oxygen to produce ozone. The range of oxygen prices is $75/ton to $180/ton.
[10] Response to questions regarding BART analysis, May 2, 2008, pp. 3-6.

2.2.4.2 SO_2 Control

The FCCU Catalyst Regenerator burns carbon contamination off of the catalyst to reactivate it. Sulfur in the catalyst contaminants is also oxidized in the catalyst regenerator step. Gases from the FCCU Catalyst Regenerator are exhausted to Units F-302 and F-304, CO Boilers.

The Flue Gas Scrubber installed on the stack for Units F-302 and F-304 (CO Boilers No. 1 and 2, respectively), provides a large decrease in SO_2 and sulfuric acid emitted. The scrubber was installed to comply with federal hazardous air pollutant (MACT) requirements for the FCCU Catalyst Regenerators. Tesoro selected the Flue Gas Scrubber over a cyclone particulate collector to meet the federal requirement because the scrubber also provided a significant SO_2 emission reduction.

2.2.4.3 PM/PM_{10} Control

Unit F-304, CO Boiler No. 2 includes a Flue Gas Scrubber to remove particulate from the exhaust form the FCCU Catalyst Regenerator. This Flue Gas Scrubber was recently installed by the plant to comply with the MACT requirements to control emissions of particulate Hazardous Air Pollutants from the FCCU Catalyst Regenerator. At that time, Tesoro evaluated installation of an alternate particulate control device but chose to install the Flue Gas Scrubber instead. The choice was based on simplified maintenance, ability to comply with MACT standard, and the ability to reduce SO_2 and SO_3 emissions from the FCCU Catalyst Regenerator and CO Boilers No. 1 and 2. While only Unit F-304 (CO Boiler No. 2) is subject to BART, both boilers exhaust through a common stack.

2.2.4.4 Proposed BART

Tesoro has evaluated the technically feasible controls for cost effectiveness, energy consumption and other non-air quality impacts. There is no adverse energy, air quality, or non-air quality impacts resulting from any of these controls on this unit.

Based on the original evaluation, Tesoro proposed the installation of low-NOX burners and SNCR as BART for NOX on this unit. However, this initial evaluation did not reflect the cost incurred by Tesoro for being required to take the F-304 boiler offline outside the normal turnaround schedule. With these costs included in the analysis, the use of the existing burners has been determined to be BART for NOX. See Section 2.4 for more information. BART for SO2 and PM/PM10 is the existing Flue Gas scrubber

2.2.5 Unit F-6650, Catalytic Reformer Feed Heater

The Catalytic Reformer Feed Heater is used to heat the gasoline (naphtha) fraction for reforming into higher octane isomers. The heater has 10 floor-mounted burners and exhausts into two

common stacks with Units F-6651, F-6652, and F-6653.[11] The heater is rated at 157 MMBtu/hr (average rate 124.7MMBtu/hr). The heater was constructed in 1971 and utilizes refinery fuel gas. The burners used are of original equipment design and emit relatively high levels of NO_X compared to current LNB or ULNB designs.

2.2.5.1 NO_X Control

This heater currently uses "default" original manufacturers design burners as originally installed in 1971. The current emission rates for this heater are 144.7 tpy, at an average concentration of 172 ppmv. After an evaluation of technical feasibility to retrofit the heater with the NO_X controls in Table 2-1, Tesoro evaluated the cost effectiveness of LNB, ULNB, SCR, LNB plus SCR, and ULNB plus SCR. Table 2-4 lists pertinent criteria and cost effectiveness.

Table 2-4. UNIT F-6650 NO_X CONTROLS EVALUATED IN DETAIL

Control Technology	Emission Reduction Anticipated – EPA Method	Annual NO_X Emission Rate (tpy)	Average Cost Effectiveness ($/ton) – EPA Method	Emission Reduction Anticipated – Vendor Cost Factor Analysis	Average Cost Effectiveness ($/ton) – Vender Cost Factor Analysis [12]
No Controls	--	144.7	--	--	--
LNB	60%	36.2	$4938	60%	$3349
ULNB	75%	36.2	$3973	60%	$3349
SCR	90%	14.5	$8473	90%	$10776
ULNB + SCR	97.5%	3.6	$10878	96%	$10772
LNB + SCR	96%	5.8	$11030	96%	$10772

All of these controls are capable of being installed on this heater. Flame impingement from LNB and ULNB burners is not an issue; however, there is inadequate space under the heater to retrofit ULNBs.

Adequate space exists to install SCR. Installation of an SCR system is evaluated for all four heaters because all four heaters exhaust to a common plenum leading to the two common stacks. The SCR addition can be done with or without a duct burner to raise the flue gas temperature. A duct burner would be fueled by refinery fuel gas. The costs for SCR presented in Table 2-4 are for the duct burner option. The non-duct burner option has a marginally different cost (see the Tesoro BART analysis report).

[11] Refer to the Tesoro BART analysis for a more detailed description of how these heaters work together.
[12] Averaged across Units F-6650, F-6651, F-6652, and F-6653.

2.2.5.2 Proposed BART

Tesoro has evaluated the technically feasible controls for cost effectiveness, energy consumption and other non-air quality impacts. There is no adverse energy, air quality, or non-air quality impacts resulting from any of these controls on this unit.

In their original BART evaluation, Tesoro proposed the installation of LNBs as BART for NOX on this heater. However, this initial evaluation did not reflect the cost incurred by Tesoro for being required to take the F-6650 heater offline outside the normal turnaround schedule. With these costs included in the analysis, the use of the existing burners has been determined to be BART for NOX. See Section 2.4 for more information

The unit is fueled by refinery fuel gas. Tesoro proposed its current use of refinery fuel gas to control SO_2 emissions from Unit F-6650. The continued use of low sulfur refinery fuel gas minimizes potential particulate emissions as much as possible and is considered BART for PM/PM10.

2.2.6 Unit F-6651, Catalytic Reformer Inter-Reactor Heater

The Catalytic Reformer Inter-Reactor Heater is used to heat the gasoline fraction at an intermediate point in the process of reforming gasoline into higher octane isomers. The heater has 16 floor-mounted burners in two connected fireboxes and exhausts into two common stacks with Units F-6650, F-6652, and F-6653.[13] The heater is rated at 157 MMBtu/hr (average rate 90.4MMBtu/hr). The heater was constructed in 1971 and utilizes refinery fuel gas. The burners used are of original equipment design and emit relatively high levels of NO_X compared to current LNB or ULNB designs.

2.2.6.1 NO_X Control

This heater currently uses “default” original manufacturers design burners as originally installed in 1971. The current emission rates for this heater are 104.7 tpy, at an average concentration of 171 ppmv. After an evaluation of technical feasibility to retrofit the heater with the NO_X controls in Table 2-1, Tesoro evaluated the cost effectiveness of LNB, ULNB, SCR, LNB plus SCR, and ULNB plus SCR. Table 2-5 lists pertinent criteria and cost effectiveness.

[13] Refer to the Tesoro BART analysis for a more detailed description of how these heaters work together.

Table 2-5. UNIT F-6651 NO_X CONTROLS EVALUATED IN DETAIL

Control Technology	Emission Reduction Anticipated – EPA Method	Annual NO_X Emission Rate (tpy)	Average Cost Effectiveness ($/ton) – EPA Method	Emission Reduction Anticipated – Vendor Cost Factor Analysis	Average Cost Effectiveness ($/ton) – Vendor Cost Factor Analysis[14]
No controls	--	104.7	--	--	--
LNB	60%	42	$4614	60%	$3349
ULNB	75%	26.2	$3722	60%	$3349
SCR	90%	10.5	$11260	90%	$10776
LNB + SCR	96%	4.2	$13440	96%	$10772
ULNB + SCR	97.5%	2.6	$13257	96%	$10772

All of these controls are capable of being installed on this heater. Flame impingement from LNB and ULNB burners is not an issue; however, there is inadequate space under the heater to retrofit ULNBs.

Adequate space exists to install SCR. Installation of an SCR system is evaluated for all four heaters because all four heaters exhaust to a common plenum leading to the two common stacks. The SCR addition can be done with or without a duct burner to raise the flue gas temperature. A duct burner would be fueled by refinery fuel gas. The costs for SCR presented in Table 2-5 are for the duct burner option. The non-duct burner option has a marginally different cost (see the Tesoro BART analysis report).

2.2.6.2 Proposed BART

Tesoro has evaluated the technically feasible controls for cost effectiveness, energy consumption and other non-air quality impacts. There is no adverse energy, air quality, or non-air quality impacts resulting from any of these controls on this unit.

In their original BART evaluation, Tesoro proposed the installation of LNBs as BART for NOX on this heater. However, this initial evaluation did not reflect the cost incurred by Tesoro for being required to take the F-6651 heater offline outside the normal turnaround schedule. With these costs included in the analysis, the use of the existing burners has been determined to be BART for NOX. See Section 2.4 for more information.

The unit is fueled by refinery fuel gas. Tesoro proposed its current use of refinery fuel gas to control SO_2 emissions from Unit F-6651. The continued use of low sulfur refinery fuel gas minimizes potential particulate emissions as much as possible and is considered BART for PM/PM10.

[14] Averaged across Units F-6650, F-6651, F-6652, and F-6653.

2.2.7 Unit F-6652, Catalytic Reformer Inter-Reactor Heater

The Catalytic Reformer Inter-Reactor Heater is used to heat the gasoline fraction at an intermediate point in the process of reforming gasoline into higher octane isomers. The heater has seven floor-mounted burners which exhaust into two common stacks with Units F-6650, F-6651, and F-6653.[15] The heater is rated at 74 MMBtu/hr (average rate 41.7 MMBtu/hr). The heater was constructed in 1971 and utilizes refinery fuel gas. The burners used are of original equipment design and emit relatively high levels of NO_X compared to current LNB or ULNB designs.

2.2.7.1 NO_X Control

This heater currently uses "default" original manufacturers design burners as originally installed in 1971. The current emission rates for this heater are 17.1 tpy, at an average concentration of 61 ppmv. After an evaluation of technical feasibility to retrofit the heater with the NO_X controls in Table 2-1, Tesoro evaluated the cost effectiveness of LNB, ULNB, SCR, LNB plus SCR, and ULNB plus SCR. Table 2-6 lists pertinent criteria and cost effectiveness.

Table 2-6. UNIT F-6652 NO_X CONTROLS EVALUATED IN DETAIL

Control Technology	Emission Reduction Anticipated – EPA Method	Annual NO_X Emission Rate (tpy)	Average Cost Effectiveness ($/ton) – EPA Method	Emission Reduction Anticipated – Vendor Cost Factor Analysis	Average Cost Effectiveness ($/ton) – Vendor Cost Factor Analysis[16]
No controls	--	17.1	--	--	--
LNB	60%	6.8	$16818	60%	$3349
ULNB	75%	4.3	$13648	73.5%	$3349
SCR	90%	1.7	$41599	90%	$10776
LNB + SCR	96%	0.7	$49510	96%	$10772
ULNB + SCR	97.5%	0.4	$48895	96%	$10772

All of these controls are capable of being installed on this heater. Flame impingement from LNB and ULNB burners is not an issue. ULNBs were found to be a good technical fit due to adequate space under the heater. The ULNBs proposed by the manufacturer would have a NO_X emission rate of about 1/3 of their alternate LNB units at a 50 percent increase in cost.

Adequate space exists to install SCR. Installation of an SCR system is evaluated for all four heaters because all four heaters exhaust to a common plenum leading to the two common stacks. The SCR addition will require a duct burner to raise the flue gas temperature enough to

[15] Refer to the Tesoro BART analysis for a more detailed description of how these heaters work together.
[16] Averaged across Units F-6650, F-6651, F-6652, and F-6653.

consistently meet the temperature requirements of a SCR catalyst. The duct burner would be fueled by refinery fuel gas.

2.2.7.2 Proposed BART

Tesoro has evaluated the technically feasible controls for cost effectiveness, energy consumption and other non-air quality impacts. There is no adverse energy, air quality, or non-air quality impacts resulting from any of these controls on this unit.

In their original BART evaluation, Tesoro proposed the installation of ULNBs as BART for NOX on this heater. However, this initial evaluation did not reflect the cost incurred by Tesoro for being required to take the F-6652 heater offline outside the normal turnaround schedule. With these costs included in the analysis, the use of the existing burners has been determined to be BART for NOX. See Section 2.4 for more information.
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The unit is fueled by refinery fuel gas. Tesoro proposed its current use of refinery fuel gas to control SO_2 emissions from Unit F-6652. The continued use of low sulfur refinery fuel gas minimizes potential particulate emissions as much as possible and is considered BART for PM/PM10.

2.2.8 Unit F-6653, Catalytic Reformer Inter-Reactor Heater

The Catalytic Reformer Inter-Reactor Heater is used to heat the gasoline fraction at an intermediate point in the process of reforming gasoline into higher octane isomers. The heater has three floor -mounted burners which exhaust into two common stacks with Units F-6650, F-6651, and F-6652.[17] The heater is rated at 42 MMBtu/hr (average rate 31.4 MMBtu/hr). The heater was constructed in 1971 and utilizes refinery fuel gas. The burners used are of original equipment design, emitting relatively high levels of NO_X compared to current LNB or ULNB designs.

2.2.8.1 NO_X Control

This heater currently uses “default” original manufacturer design burners as originally installed in 1971. The current emission rates for this heater are 13 tpy, at an average concentration of 61 ppmv. After an evaluation of technical feasibility to retrofit the heater with the NO_X controls in Table 2-1, Tesoro evaluated the cost effectiveness of LNB, ULNB, SCR, LNB plus SCR, and ULNB plus SCR. Table 2-7 lists pertinent criteria and cost effectiveness.

[17] Refer to the Tesoro BART analysis for a more detailed description of how these heaters work together.

Table 2-7. UNIT F-6653 NO_X CONTROLS EVALUATED IN DETAIL

Control Technology	Emission Reduction Anticipated – EPA Method	Annual NO_X Emission Rate (tpy)	Average Cost Effectiveness ($/ton) – EPA Method	Emission Reduction Anticipated – Vendor Cost Factor Analysis	Average Cost Effectiveness ($/ton) – Vendor Cost Factor Analysis [18]
No controls	--	13	--	--	--
LNB	60%	6.8	$19190	60%	$3349
ULNB	75%	3.3	$15604	73.5%	$3349
SCR	90%	1.3	$38829	90%	$10776
LNB + SCR	96%	0.7	$48396	96%	$10772
ULNB + SCR	97.5%	0.3	$47845	96%	$10772

All of these controls are capable of being installed on this heater. Flame impingement from LNB and ULNB burners is not an issue. ULNBs were found to be a good technical fit due to adequate space under the heater. The ULNBs proposed by the manufacturer would have a NO_X emission rate of about one-third of their alternate LNB units at a 50 percent increase in cost.

Adequate space exists to install SCR. Installation of an SCR system is evaluated for all four heaters because all four heaters exhaust to a common plenum leading to the two common stacks. The SCR addition will require a duct burner to raise the flue gas temperature enough to consistently meet the temperature requirements of a SCR catalyst. The duct burner would be fueled by refinery fuel gas.

2.2.8.2 Proposed BART

Tesoro has evaluated the technically feasible controls for cost effectiveness, energy consumption and other non-air quality impacts. There is no adverse energy, air quality, or non-air quality impacts resulting from any of these controls on this unit.

In their original BART evaluation, Tesoro proposed the installation of ULNBs as BART for NOX on this heater. However, this initial evaluation did not reflect the cost incurred by Tesoro for being required to take the F-6653 heater offline outside the normal turnaround schedule. With these costs included in the analysis, the use of the existing burners has been determined to be BART for NOX. See Section 2.4 for more information.

The unit is fueled by refinery fuel gas. Tesoro proposed its current use of refinery fuel gas to control SO_2 emissions from Unit F-6653. The continued use of low sulfur refinery fuel gas minimizes potential particulate emissions as much as possible and is considered BART for PM/PM10.

[18] Averaged across Units F-6650, F-6651, F-6652, and F-6653.

2.2.9 Unit F-654, Catalyst Feed Hydrotreater Heater

The Catalyst Feed Hydrotreater Heater is used to heat the deasphalted heavy oil fraction from the crude unit prior to sulfur removal in the hydrotreater. The heater has three floor-mounted burners. The heater is rated at 16.5 MMBtu/hr (average rate 7.6 MMBtu/hr). The heater was constructed in 1964 and utilizes refinery fuel gas. The burners used are of original equipment design and emit relatively high levels of NO_X compared to current LNB or ULNB designs.

2.2.9.1 NO_X Control

This heater currently uses "default" original manufacturers design burners as originally installed in 1964. The current emission rates for this heater are 2.6 tpy, at an average concentration of 52 ppmv. After an evaluation of technical feasibility to retrofit the heater with the NO_X controls in Table 2-1, Tesoro evaluated the cost effectiveness of ULNB, SCR, and ULNB plus SCR. Table 2-8 lists pertinent criteria and cost effectiveness.

Table 2-8. UNIT F-654 NO_X CONTROLS EVALUATED IN DETAIL

Control Technology	Emission Reduction Anticipated – EPA Method	Annual NO_X Emission Rate (tpy)	Average Cost Effectiveness ($/ton) – EPA Method	Emission Reduction Anticipated – Vendor Cost Factor Analysis	Average Cost Effectiveness ($/ton) – Vendor Cost Factor Analysis
No controls	--	2.6	--	--	--
ULNB	75%	0.7	$36131	73.5%	$43093
SCR	90%	0.3	$104352	90%	--
ULNB + SCR	97.5%	0.1	$124119	96%	--

All of these controls are capable of being installed on this heater. Adequate space exists to install ULNBs and SCR. ULNBs were found to be a good technical fit due to adequate space under the heater. A vender provided the price quotation for ULNBs that could be installed in the heater.

A screening analysis using EPA cost estimating procedures was done for installation of an SCR system. As can be seen, the cost of SCR is extremely high, primarily due to the very low uncontrolled NO_X emissions.

There is no adverse energy, air quality, or non-air quality impacts resulting from any of these controls on this unit.

2.2.9.2 Proposed BART

Tesoro has evaluated the technically feasible controls for cost effectiveness, energy consumption and other non-air quality impacts. Based on that evaluation, they propose the currently installed burners as BART for NO_X on this heater.

The unit is fueled by refinery fuel gas. Tesoro proposed its current use of refinery fuel gas to control SO_2 emissions from Unit F-654. The continued use of low sulfur refinery fuel gas minimizes potential particulate emissions as much as possible and is considered BART for PM/PM10.

2.2.10 Unit F-6600, Naphtha Hydrotreater Feed Preheater

The Naphtha Hydrotreater Feed Preheater is used to heat the naphtha fraction prior to sulfur removal in the naphtha hydrotreater. The heater has four floor-mounted burners. The heater is rated at 71.5 MMBtu/hr (average rate 46.3 MMBtu/hr). The heater was constructed in 1971 and utilizes refinery fuel gas. The burners used are of original equipment design and emit relatively high levels of NO_X compared to current LNB or ULNB designs.

2.2.10.1 NO_X Control

This heater currently uses "default" original manufacturers design burners as originally installed in 1971. The current emission rates for this heater are 18.9 tpy, at an average concentration of 61 ppmv. After an evaluation of technical feasibility to retrofit the heater with the NO_X controls in Table 2-1, Tesoro evaluated the cost effectiveness of LNB, ULNB, SNCR, and ULNB plus SNCR. Table 2-9 lists pertinent criteria and cost effectiveness.

Table 2-9. UNIT F-6600 NO_X CONTROLS EVALUATED IN DETAIL

Control Technology	Emission Reduction Anticipated – EPA Method	Annual NO_X Emission Rate (tpy)	Average Cost Effectiveness ($/ton) – EPA Method	Emission Reduction Anticipated – Vendor Cost Factor Analysis	Average Cost Effectiveness ($/ton) – Vendor Cost Factor Analysis
No controls	--	18.9	--	--	--
LNB	60%	8	$26647	--	--
ULNB	75%	5	$21491	73.5%	$17581
SNCR	50%	9	$23779	--	--
LNB + SNCR	80%	4	$34847	--	--
ULNB + SNCR	87.5%	2	$32009	--	--

All of these controls are capable of being installed on this heater. Adequate space exists to install ULNBs and SNCR. ULNBs were found to be a good technical fit due to adequate space under the heater and lower emissions than LNBs.

A screening analysis using EPA's cost estimating procedures was done for installation of these of controls. As can be seen, the costs estimated using EPA's methods is extremely high, primarily due to the very low uncontrolled NO_X emissions. A vendor provided the price quotation for ULNBs that could be installed in the heater.

2.2.10.2 Proposed BART

Tesoro has evaluated the technically feasible controls for cost effectiveness, energy consumption and other non-air quality impacts. There is no adverse energy, air quality, or non-air quality impacts resulting from any of these controls on this unit. Based on that evaluation, they propose the currently installed burners as BART for NO_X on this heater.

The unit is fueled by refinery fuel gas. Tesoro proposed its current use of refinery fuel gas to control SO_2 emissions from Unit F-6600. The continued use of low sulfur refinery fuel gas minimizes potential particulate emissions as much as possible and is considered BART for PM/PM10.

2.2.11 Unit F-6601, Naphtha Hydrotreater Stabilizer Column Reboiler

The Naphtha Hydrotreater Stabilizer Column Reboiler is used to heat the naphtha fraction prior to sulfur removal in the naphtha hydrotreater. The heater has four floor-mounted burners. The heater is rated at 75 MMBtu/hr (average rate 48.3 MMBtu/hr). The heater was constructed in 1971 and utilizes refinery fuel gas. The burners used are of original equipment design and emit relatively high levels of NO_X compared to current LNB or ULNB designs.

2.2.11.1 NO_X Control

This heater currently uses "default" original manufacturers design burners as originally installed in 1971. The current emission rates for this heater are 19.8 tpy, at an average concentration of 61 ppmv. After an evaluation of technical feasibility to retrofit the heater with the NO_X controls in Table 2-1, Tesoro evaluated the cost effectiveness of LNB, ULNB, SNCR, and ULNB plus SNCR. Table 2-10 lists pertinent criteria and cost effectiveness.

Table 2-10. UNIT F-6601 NO_X CONTROLS EVALUATED IN DETAIL

Control Technology	Emission Reduction Anticipated – EPA Method	Annual NO_X Emission Rate (tpy)	Average Cost Effectiveness ($/ton) – EPA Method	Emission Reduction Anticipated – Vendor Cost Factor Analysis	Average Cost Effectiveness ($/ton) – Vendor Cost Factor Analysis
No controls	--	19.8	--	--	--
LNB	60%	8	$28538	--	--
ULNB	75%	5	$22995	73.5%	$17150
SCR	50%	2	$36638	--	--
LNB + SCR	80%	1	$52184	--	--
ULNB + SCR	87.5%	0.5	$51509	--	--

All of these controls are capable of being installed on this heater. Adequate space exists to install ULNBs and SNCR. ULNBs were found to be a good technical fit due to adequate space under the heater and have lower emission rates than LNBs.

A screening analysis using EPA's cost estimating procedures was done for installation of these of controls. As can be seen, the costs estimated using EPA's methods is extremely high, primarily due to the very low uncontrolled NO_X emissions. A vendor provided the price quotation for ULNBs that could be installed in the heater.

2.2.11.2 Proposed BART

Tesoro has evaluated the technically feasible controls for cost effectiveness, energy consumption and other non-air quality impacts. There is no adverse energy, air quality, or non-air quality impacts resulting from any of these controls on this unit. Based on that evaluation, they propose the currently installed burners as BART for NO_X on this heater.

The unit is fueled by refinery fuel gas. Tesoro proposed its current use of refinery fuel gas to control SO_2 emissions from Unit F-6601. The continued use of low sulfur refinery fuel gas minimizes potential particulate emissions as much as possible and is considered BART for PM/PM10.

2.2.12 Unit F-6602, Naphtha Hydrotreater Feed Preheater

The Naphtha Hydrotreater Feed Preheater is used to heat the naphtha fraction prior to sulfur removal in the naphtha hydrotreater. The heater has four floor-mounted burners. The heater is rated at 75 MMBtu/hr (average rate 28 MMBtu/hr). The heater was constructed in 1971 and utilizes refinery fuel gas. The burners used are of original equipment design and emit relatively high levels of NO_X compared to current LNB or ULNB designs.

2.2.12.1 NO_X Control

This heater currently uses "default" original manufacturers design burners as originally installed in 1971. The current emission rates for this heater are 1.3 tpy, at an average concentration of 61 ppmv. After an evaluation of technical feasibility to retrofit the heater with the NO_X controls in Table 2-1, Tesoro evaluated the cost effectiveness of LNB, ULNB, SNCR, and ULNB plus SNCR. Table 2-11 lists pertinent criteria and cost effectiveness.

Table 2-11. UNIT F-6602 NO_X CONTROLS EVALUATED IN DETAIL

Control Technology	Emission Reduction Anticipated – EPA Method	Annual NO_X Emission Rate (tpy)	Average Cost Effectiveness ($/ton) – EPA Method	Emission Reduction Anticipated – Vendor Cost Factor Analysis	Average Cost Effectiveness ($/ton) – Vendor Cost Factor Analysis
No controls	--	18.9	--	--	--
LNB	60%	8	$26647	--	--
ULNB	75%	5	$21491	73.5%	$17581
SNCR	50%	9	$23779	--	--
LNB + SNCR	80%	4	$34847	--	--
ULNB + SNCR	87.5%	2	$32009	--	--

All of these controls are capable of being installed on this heater. Adequate space exists to install ULNBs and SNCR. ULNBs were found to be a good technical fit due to adequate space under the heater.

A screening analysis using EPA's cost estimating procedures was done for installation of these of controls. As can be seen, the costs estimated using EPA's methods is extremely high, primarily to the very low uncontrolled NO_X emissions. A vendor provided the price quotation for ULNBs that could be installed in the heater.

2.2.12.2 Proposed BART

Tesoro has evaluated the technically feasible controls for cost effectiveness, energy consumption and other non-air quality impacts. There is no adverse energy, air quality, or non-air quality impacts resulting from any of these controls on this unit. Based on that evaluation, they propose the currently installed burners as BART for NO_X on this heater.

The unit is fueled by refinery fuel gas. Tesoro proposed its current use of refinery fuel gas to control SO_2 emissions from Unit F-6602. The continued use of low sulfur refinery fuel gas minimizes potential particulate emissions as much as possible and is considered BART for PM/PM10.

2.2.13 Unit F-6654, Catalytic Reformer Stabilizer Column Reboiler

The Catalytic Reformer Stabilizer Column Reboiler is used to heat the gasoline fraction at an intermediate stage in the reforming process. The heater has three floor-mounted burners. The heater is rated at 35 MMBtu/hr (average rate 24.6 MMBtu/hr). The heater was constructed in 1971 and utilizes refinery fuel gas. The burners used are of original equipment design and emit relatively high levels of NO_X compared to current LNB or ULNB designs.

2.2.13.1 NO_X Control

This heater currently uses "default" original manufacturers design burners as originally installed in 1971. The current emission rates for this heater are 10.2 tpy, at an average concentration of 59 ppmv. After an evaluation of technical feasibility to retrofit the heater with the NO_X controls in Table 2-1, Tesoro evaluated the cost effectiveness of LNB, ULNB, SNCR, and ULNB plus SNCR. Table 2-12 lists pertinent criteria and cost effectiveness.

Table 2-12. UNIT F-6654 NO_X CONTROLS EVALUATED IN DETAIL

Control Technology	Emission Reduction Anticipated – EPA Method	Annual NO_X Emission Rate (tpy)	Average Cost Effectiveness ($/ton) – EPA Method	Emission Reduction Anticipated – Vendor Cost Factor Analysis	Average Cost Effectiveness ($/ton) – Vendor Cost Factor Analysis
No controls	--	10.2	--	--	--
LNB	60%	4.0	$18952	--	--
ULNB	75%	2.6	$15483	73.5%	$11069
SCR	50%	5.1	$44084	--	--
LNB + SCR	80%	2.0	$53174	--	--
ULNB + SCR	87.5%	1.3	$52603	--	--

All of these controls are capable of being installed on this heater. Adequate space exists to install ULNBs and SNCR. ULNBs were found to be a good technical fit due to adequate space under the heater and to have lower emissions than LNBs.

A screening analysis using EPA's cost estimating procedures was done for installation of these of controls. As can be seen, the costs estimated using EPA's methods is extremely high, primarily to the very low uncontrolled NO_X emissions. A vendor provided the price quotation for ULNBs that could be installed in the heater.

2.2.13.2 Proposed BART

Tesoro has evaluated the technically feasible controls for cost effectiveness, energy consumption and other non-air quality impacts. There is no adverse energy, air quality, or non-air quality

impacts resulting from any of these controls on this unit. Based on that evaluation, they propose the currently installed burners as BART for NO_X on this heater.

The unit is fueled by refinery fuel gas. Tesoro proposed its current use of refinery fuel gas to control SO_2 emissions from Unit F-6654. The continued use of low sulfur refinery fuel gas minimizes potential particulate emissions as much as possible and is considered BART for PM/PM10.

2.2.14 Unit F-6655, Catalytic Reformer Stabilizer Regeneration Gas Heater

The Catalytic Reformer Stabilizer Regeneration Gas Heater is used to heat the gasoline fraction at an intermediate stage in the reforming process. The heater has three floor-mounted burners. The heater is rated at 30 MMBtu/hr (average rate 11.5 MMBtu/hr). The heater was constructed in 1971 and utilizes refinery fuel gas. The burners used are of original equipment design and emit relatively high levels of NO_X compared to current LNB or ULNB designs.

2.2.14.1 NO_X Control

This heater currently uses "default" original manufacturers design burners as originally installed in 1971. The current emission rates for this heater are 3.3 tpy, at an average concentration of 55 ppmv. After an evaluation of technical feasibility to retrofit the heater with the NO_X controls in Table 2-1, Tesoro evaluated the cost effectiveness of LNB and ULNB. Due to unit size, temperature profiles, and configuration, SCR and SNCR were not technically feasible. Table 2-13 lists pertinent criteria and cost effectiveness.

Table 2-13. F-6655 NO_X CONTROLS EVALUATED IN DETAIL

Control Technology	Emission Reduction Anticipated – EPA Method	Annual NO_X Emission Rate (tpy)	Average Cost Effectiveness ($/ton) – EPA Method	Emission Reduction Anticipated – Vendor Cost Factor Analysis	Average Cost Effectiveness ($/ton) – Vendor Cost Factor Analysis
No controls	--	3.3	--	--	--
LNB	40%	2.0	$73228	--	--
LNB	60%	1.3	$48818	28.6%	$86519
ULNB	75%	0.8	$40047	--	--

At the initial technical evaluations, all of these burner designs were viewed as being able to be installed on this heater. Upon receipt of more detailed information from the vendor, it was found that only a LNB could fit into the space in and under the heater. Flame impingement from the burners is not an issue.

A screening analysis using EPA's cost estimating procedures was done for installation of all three varieties of burners. As can be seen, the costs estimated using EPA's methods is extremely high, primarily to the very low uncontrolled NO_X emissions.

A vendor provided a price quotation for LNBS that could be installed in this application. The vendor quoted removal efficiency is based on the expected and guaranteed emission rates of the burners proposed for installation. Their control efficiency is lower than the generally accepted removal rates of LNBs.

2.2.14.2 Proposed BART

Tesoro has evaluated the technically feasible controls for cost effectiveness, energy consumption and other non-air quality impacts. There is no adverse energy, air quality, or non-air quality impacts resulting from any of these controls on this unit. Based on that evaluation, they propose the currently installed burners as BART for NO_X on this heater.

The unit is fueled by refinery fuel gas. Tesoro proposed its current use of refinery fuel gas to control SO_2 emissions from Unit F-6655. The continued use of low sulfur refinery fuel gas minimizes potential particulate emissions as much as possible and is considered BART for PM/PM10.

2.2.15 Flare X-819

Flare X-819 is used to combust process vent gases and vapors from loading operations that are not routed to the refinery gas system and gases from emergency releases of tank and process vessels. The flare operates all the time, but its primary function is to allow for the safe emergency venting of various process units in the refinery. Operation of the flare during emergency venting situations prevents hazardous conditions from occurring at the Tesoro refinery as a result of the emergency release of hydrocarbon vapors near process heaters.

The flare is a 2-stage, steam assisted flare of the "smokeless" design, rated at 244 MMBtu/hr and 2.6 million standard cubic feet per day (million scfd) of flared gas (0.5 million scfd in first stage and 2.1 million scfd in second stage). The flare was constructed in 1971 and utilizes refinery fuel gas for the pilot light fuel. While the potential to emit is considerably higher, for modeling purposes if the flare operated continuously at the modeled flare gas flow rate, it would emit 43.8 tons of SO_2 and 8.8 tons of NOx per year. Information presented indicates the flare meets the design criteria of 40 CFR 60.18 for elevated flares.

2.2.15.1 NO_X, SO_2, and PM/PM_{10} Control

There are no emission controls directly attributable to operation of flares. Reduction of routine flaring operations is the most common way to reduce non-emergency flare emissions. Tesoro already utilizes a flare gas recovery compressor and other measures to recover combustible gases

and route them to the refinery fuel gas system. Adding a second compressor would recover gas from additional emergency vents that are currently routed directly to the flare system.

Tesoro evaluated addition of a second flare gas recovery compressor to reduce emissions from the flare. They estimated that this would reduce SO_2 emissions by about 10 tpy, have a capital cost of $2 million and a cost effectiveness of $21,960/ton.

2.2.15.2 Proposed BART

Tesoro proposed that BART for operations of the flare system is continued operation of the current system.

2.3 Evaluation of Controls for Cooling Water Towers 2 and 2a

The cooling water towers are used to cool returned "process cooling water" to prepare it for reintroduction to the process cooling water equipment. Current emissions of PM/PM_{10} from the cooling tower are approximately 0.2 lb/hr (0.88 tpy). The cooling towers were constructed in 1971 and include reasonable droplet drift control techniques for the time.

2.3.1 PM/PM_{10} Control

Tesoro requested an estimate for replacement of the current cooling tower drift control with a state-of-the-art system to reduce $PM//PM_{10}$ emissions from the cooling tower. This estimate was "on the order of $150,000" and would provide an 80 to 90 percent reduction in cooling tower drift emissions. Assuming the only cost involved with new drift elimination system is the capital cost, the estimated cost effectiveness is $41,781. Tesoro noted that the particulate formed by cooling towers tends to be larger in size and deposit on the area immediately around the cooling towers.

2.3.2 Proposed BART

After consideration of the cost per ton reduced and the small quantity of PM/PM_{10} that would be controlled, Tesoro proposed continued operation of the current system as BART for the cooling tower.

2.4 Compliance Schedule Based Considerations

Subsequent to the information submitted by Tesoro in 2008, Ecology and Tesoro entered discussions on the BART compliance schedule to install the emission controls proposed by Tesoro as BART. EPA Region 10 was asked to provide specific information on some aspects of the proposed compliance schedules.

The requirements for BART in 40 CFR Part 51, Subpart P include the following requirement addressing when a source is to meet the BART emission limitations.

> A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.[19]

Based on an anticipated implementation plan revision approval about December 2010, all BART controls would need to be in operation by December 2015.

The installation of the proposed controls on Unit F-103 would meet the two primary constraints on the project: it could be accomplished within the normal turn-around schedule and within five years of the anticipated approval date of the state SIP.

The work on the CO Boiler, F-304, and the 4 catalytic reformer heaters, units F-6650–6653, either had to be accomplished outside of the normal turn-around schedule or would not occur till more than five years after the Ecology anticipated date of SIP approval. For these 5 units, Tesoro initially proposed a schedule based on complying with the BART limitation 5 years after the Regional Haze implementation plan was approved by EPA, and that the implementation plan approval date would be no earlier that the end of 2012, unless that date was less than 3 years prior to the routine, scheduled turn-around. One result of this proposal is that for these units, the earliest compliance date would be 2017. The company also proposed a provision that would further extend the compliance date for these units into the future if the SIP were approved after 2014.

The extended BART compliance date request by Tesoro was presented to EPA Region 10. The region advised Ecology that the proposal did not meet the plain requirements of the regional Haze rules.

The basis for Tesoro's proposed compliance dates relates to their schedule for turn-around activities. As appears common in the petroleum refining and other industries, the various process units at the plant are taken out of service for major maintenance and upgrades on a routine cycle between 1 and 7 years for industries in Washington. The petroleum refining industry takes process units out of service for major maintenance and upgrades at five year intervals. The refinery as a whole is never taken fully out of service, though work on primary processing units like the Crude Unit and the Catalytic Reformer significantly affect the quantity of refined products produced during those times.

Corporate policy for Tesoro requires the maintenance needs, modifications, and any desired upgrades to the units involved in a particular turn-around are determined three years before the work is completed. The 3 year period allows for identification of non-routine work or upgrades, planning level cost analysis and approval from plant and corporate management, followed by financing, design, and new equipment purchases , all of which need to occur prior to contracting for the work. Permitting with the local air pollution control agency is not started until financing is approved by company management and design is far enough along to allow the permitting

[19] 40 CFR 51.308(e)(1)(iv)

process to begin. Permitting usually starts 12 to 18 months before the actual start of construction, depending on complexity of permitting.

Ecology has confirmed the outlines of this 3 year planning/construction process through contacts with other refineries and the management of the local air pollution control agency that oversees the 4 largest oil refineries in the Washington. In general this process is the same as at the other refineries, as is the 5 year period between turn-arounds.

CO Boiler 2 (F-304) and the catalytic reformer heaters (F-6650–6653) have a normal turn-around scheduled for 2012, less than 3 years after the BART order is issued, let alone the approval of the Regional Haze implementation plan, which Ecology anticipates to be the end of 2010. The next scheduled turnaround is scheduled for 2017.

As a result of Ecology's requested and EPA's confirmation that a 2017/18 BART compliance date did not comply with the requirements of the federal visibility rules, Tesoro investigated the costs to install the BART controls at a time other than the normal scheduled turn-around schedule, including accelerated installation in 2012. As a result, the cost to install the controls increases, not just in direct costs for installation of the controls, but in "lost opportunity" costs due to taking these units off-line for at an unanticipated time. The "lost opportunity costs" are a direct consequence of taking the units off line outside of the normal schedule. These costs are built into the planning and total cost of the routine turn-around schedule and as such are not an extraordinary cost in that context.

The process to retrofit an existing heater with new low NOx or Ultra low NOx heaters is not a simple process of turning the heater off, letting it cool sufficiently, unbolting the old burners and installing the new burners, and turning it back on, though that is in essence all that is done. The new burners have different flame length characteristics that need to be accounted for in revisions to the refractory brick in the heaters. The heater must be cool enough for a man to get inside to work on the refractory brick. The overall time to turn off the heater, cool it sufficiently to do the burner work, conduct test firings of the burners to assure the flame pattern is what it is supposed to be, and finally return the unit to service will take several weeks.

While the unit is off line, the remainder of the refinery either has to operate at reduced rate, or on purchased intermediate products purchased from others. The plant has inadequate storage tank capacity to handle an outage of the F304 and F-6650 – 6653 units and remain near full operating rate. The 'lost opportunity cost" is an extraordinary expense associated with the off-cycle project. As such, this becomes a site specific consideration in the cost to implement the burner retrofits on the CO Boiler and heaters[20].

[20] "The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option." 40 CFR Part 51, Appendix Y, Section IV.4.a

For Unit F-304, installation of the BART controls off the normal schedule causes the cost effectiveness to install the originally proposed BART controls of low NO_X burners and SNCR system to rise to \$10,802/ton NO_X reduced from the original \$4,592/ton NO_X reduced.

Similarly the costs to install the low and ultra low NO_X burners proposed for the catalytic reformer heaters (F-6650–6653) also increases to \$13,190/ton NO_X reduced from the original \$3,349/ton NO_X reduced.

In this evaluation, Ecology also compared these costs for burner replacement to the costs reported by another Washington state petroleum refinery that is subject to BART. The costs reported by Tesoro are in line with the costs reported by that refinery before the "lost opportunity costs" are removed from that refinery's cost calculations. At the other refinery, the "lost opportunity costs" are primarily due to the additional time required to install low NOx burners compared to a normal turn-around on the same unit.

As a result of the increased costs to install these controls "off schedule" Tesoro proposed that BART for NO_X from these units is the existing burners.

3. VISIBILITY IMPACTS AND DEGREE OF IMPROVEMENT

The results of the Tesoro's modeling are shown in Table 3-1 for all Class I areas within 300 km of the plant plus the Columbia River Gorge National Scenic Area. The table shows the maximum day impairment due to Tesoro, the highest of the annual, 98th percentile days for the three years modeled, and the 98th percentile day of the modeled 3-year period. Also shown is the modeled visibility impairment resulting from the BART controls proposed by Tesoro. The shaded areas indicate values above the 0.5 dv threshold used to determine if a source contributes to visibility impairment.

The modeled emission rates were derived from operating records of the units and reflect the highest 24-hour emission rates within the three years that were modeled except for Unit F-304. Subsequent to the three years of the modeling period, this unit had a Flue Gas Scrubber installed and permitted with significantly lower emission rates. The emissions for Unit F-304 were scaled downward to reflect the currently-permitted emission rate for SO_2. For the other units with proposed BART controls, the effectiveness of the BART control was applied to the baseline emission rate to estimate the effect of BART on visibility impacts. The modeled emission rates are shown in Table 3-2.
Ecology modelers have reviewed the modeling performed by Tesoro and have found that the modeling complies with the Modeling Protocol and produces a reasonable result.

The modeled emission reductions proposed in the 2008 BART analysis result in substantial reduction in the visibility impairment caused by Tesoro in the most heavily impacted Class I areas modeled. At the three most heavily impacted Class I areas, Olympic National Park, North Cascades National Park, and the Alpine Lakes Wilderness, Tesoro's proposed BART controls would provide 0.2 to 0.5 dv reduction in visibility impairment in each of these areas.

Table 3-1. MODELED BASELINE AND TESORO'S PROPOSED BART CONTROL VISIBILITY IMPACTS

Class I Area	Visibility Criterion	Baseline Emissions	Proposed BART
Alpine Lakes Wilderness	Max delta deciview		
	Max 98% value (8th high)	0.917	0.733
	3 years combined 98% value (22nd high)	0.810	0.640
Glacier Peak Wilderness	Max delta deciview		
	Max 98% value (8th high)	0.908	0.679
	3 years combined 98% value (22nd high)	0.847	0.675
Goat Rocks Wilderness	Max delta deciview		
	Max 98% value (8th high)	0.293	0.239
	3 years combined 98% value (22nd high)	0.281	0.234
Mt. Adams Wilderness	Max delta deciview		
	Max 98% value (8th high)	0.255	0.197
	3 years combined 98% value (22nd high)	0.228	0.185
Mt. Rainier National Park	Max delta deciview	1	
	Max 98% value (8th high)	0.712	0.582
	3 years combined 98% value (22nd high)	0.643	0.542
North Cascades National Park	Max delta deciview		
	Max 98% value (8th high)	1.001	0.751
	3 years combined 98% value (22nd high)	0.915	0.742
Olympic National Park	Max delta deciview		
	Max 98% value (8th high)	1.722	1.248
	3 years combined 98% value (22nd high)	1.399	1.025
Pasayten Wilderness	Max delta deciview		
	Max 98% value (8th high)	0.497	0.388
	3 years combined 98% value (22nd high)	0.497	0.385
Class II area modeled per the Modeling Protocol			
Columbia River Gorge National Scenic Area	Max delta deciview		
	Max 98% value (8th high)	0.162	0.1331
	3 years combined 98% value (22nd high)	0.119	0.105

Table 3-2. MODELED EMISSION RATES

Unit	2002-2005 Rates (lb/hr)			Tesoro's Proposed BART (lb/hr)		
	SO_2	NO_X	PM_{10}	SO_2	NO_X	PM_{10}
F-103	160.5	53.5	9.1	152.5[a]	18.2[b]	1.4
F-104	39.8	0.8	0.4	39.8	0.8	0.4
F-304	24.9	242.7	14.1	24.9	148.0[b]	14.1
F-654	11.7	1.3	0.1	11.7	1.3	0.1
F-6600	56.0	13.1	0.9	56.0	13.1	0.9
F-6601	77.5	8.0	0.6	77.5	8.0	0.6
F-6602	25.6	8.3	0.6	25.6	8.3	0.6
F-6650/6651	332.0	101.3	2.8	332.0	28.3[d]	2.8
F-6652/6653	86.1	19.2	1.5	86.1	5.2[b]	1.5
F-6654	32.2	4.0	0.3	32.2	4.0	0.3
F-6655	15.1	2.9	0.2	15.1	2.9	0.2
X-819	10.0	2.0	0.4	10.0	2.0	0.4
CWT #2	0	0	0.1	0	0	0.1
CWT #2a	0	0	0.1	0	0	0.1

[a] Reflects ending fuel oil usage.
[b] Reflects reduction due to ultra-low-NO_X burners.
[c] Reflects reduction due to SNCR.
[d] Reflects reduction due to low-NO_X burners.

4. ECOLOGY'S BART DETERMINATION

Ecology has reviewed the information submitted by Tesoro. We agree with Tesoro's proposal for BART. Ecology's determination of BART for Tesoro is shown in Table 4-1. In making its determination of BART for these units, Ecology reviewed the types of controls and emission rates required under EPA national Consent Orders issued to oil refineries and BACT and BART determinations or guidance from other states.

Units F-302 and F-304 both exhaust to the same particulate/SO_2 control device, the Flue Gas Scrubber. Currently the emission limitations attributable to the individual units and on the FCCR catalyst regenerator that feeds these two units are added together and regulated at the scrubber stack. For this BART determination, Ecology proposes to continue this practice for particulate and SO_2.

Ecology believes the NO_X emission controls and resulting emission reductions originally proposed as BART by Tesoro are appropriate and cost effective to implement as part of a regularly scheduled turn-around project. These controls may ultimately be required to be installed in the future as further progress toward meeting the visibility goals. However, the increased costs to accomplish the burner and SNCR installations outside of the unit's normal maintenance cycle, we determine that BART for Unit F-304 is the current emission controls and emission limitations.

Similar to Unit F-304, Ecology believes the emission controls and resulting emission reductions originally proposed as BART by Tesoro for the Catalytic Reformer Heaters F-6650–6653 are appropriate and cost effective to implement as part of a regularly scheduled turn-around project. These controls may ultimately be required to be installed in the future as further progress toward meeting the visibility goals. However, the increased costs to accomplish the low and ultra low NO_X burner installations outside of the unit's normal maintenance cycle, we determine that BART for Unit F-304 is the current emission controls and emission limitations.

As a result of the reduced NO_X emission reductions proposed as BART by Ecology when compared to Tesoro's initial BART proposal, the visibility improvement will be considerably less than was modeled by Tesoro and depicted in Section 3. Ecology has not remodeled the visibility improvement or required Tesoro to do so. Using only the 3-year, 98th percentile day at Olympic National Park as an example, we estimate that the visibility improvement due to this proposed BART determination to be about 0.1 dv, compared to Tesoro's modeled improvement for their original proposed BART of 0.37 dv for the same day.

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

	BART Control Technology	Emission Limitation
F-103		
PM/PM_{10}	Ending routine use of fuel oil. Use of refinery fuel gas or natural gas as primary fuel.	Fuel oil allowed only under the following conditions: • Natural gas curtailment. • Periods with limited refinery fuel gas availability, such as start-up and shutdown of major refinery process units, while major refinery process units are not operating and producing refinery gas, and emergency conditions as necessary to maintain safe operations or equipment shutdown. Test firing on fuel oil is allowed for up to 24 hours per calendar year.
SO_2	Ending routine use of fuel oil. Use of refinery fuel gas or natural gas as primary fuel.	Same as for PM/PM_{10}.
NO_X	Ultra-low-NO_X burners	Not to exceed 59.1 tpy, rolling (365 day) annual total calculated daily.
All Other BART-Eligible Units		
F-104, F-654, F-6600, F-6601, F-6602, F-6650, F-6651, F-6652, F6653, F-6654, F-6655, Flare X-819, Cooling Towers 2 and 2a	Currently installed combustion and other controls.	Per applicable NWCAA regulatory orders and regulations.

APPENDIX A. PRINCIPLE REFERENCES USED

Anvil Associates, Tesoro NW, et al., "Tesoro Best Available Retrofit Technologies (BART) Assessment Assistance, Final Engineering Analysis Report," February 2008. Amended by letter of May 2, 2008.

Geomatrix Consultants, "BART Determination Modeling Analysis Tesoro Anacortes Refinery," February 2008.

E-mail communications between John Giboney of Tesoro and Alan Newman of Ecology, regarding modeling input for refinery gas-based SO_2 emissions, January 1-7, 2008.

E-mail communications between Toby Allen of NWCAA and Alan Newman of Ecology, regarding new refinery fuel gas treatment system, January 7, 2008.

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

Emission Standards Division, U. S. Environmental Protection Agency, "Alternative Control Techniques Document–NO_X Emissions from Process Heaters (Revised)," September 1993.

N. Confuorto and J. Sexton, "Wet Scrubbing Based NO_X Control Using $LoTO_X$™ Technology–First Commercial FCC Start-Up Experience," presented at NPRA Environmental Conference, September 24-25, 2007.

Belco Technologies Corp., "Flue Gas Scrubbing of FCCU Catalyst Regenerator Flue Gas–Performance, Reliability, and Flexibility – A Case History," company report, undated.

S. Eaglson, N. Confuorto, S. Singhania, and N. Singahnia, "Controlling Fired Process Heater Emissions to Reduce Fuel Costs and Improve Air Quality," presented at Petrotech 2007, 7th International Oil & Gas Conference and Exhibition, January 24, 2007.

NWCAA, "Air Operating Permit Statement of Basis, Tesoro Refining and Marketing Company, AOP # 013," permit issued, November 25, 2002.

NWCAA, "Air Operating Permit, Tesoro Refining and Marketing Company, AOP # 013," permit issued, November 25, 2002.

Gerald Bouziden, K. Gentile, R.G. Kunz, "Selective Catalytic Reduction of NO_X from Fluid Catalytic Cracking Case Study: BP Whiting Refinery," presented at National Environmental & Safety Conference, April 23-24, 2002.

Edward Sabo, "Status Report: Candidate Stationary Source Control Measures," presented at MRPO Regional Air Quality Workshop, November 16, 2005. Presentation summarizes control techniques applied to oil refineries under federal consent orders.

Mid-Atlantic Regional Air Management Association (MARAMA), "Assessment of Control Technology Options for Petroleum Refineries in the Mid-Atlantic Region, Final Technical Support Document," January 31, 2007.

James H. Wilson, Maureen A. Mullen, "Including the Emission Effects of Refinery Cases and Settlements in Projections for the EPA's CAAA Section 812 Analysis," Review performed under EPA Contract No. EP-D-04-006

Air and Waste Management Association, Editors, Anthony Buonicore and Wayne Davis, "Air Pollution Engineering Manual," Von Nostrand Reinhold, 1992.

EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002.

APPENDIX B. ACRONYMS/ABBREVIATIONS

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
dv	Deciview(s)
Ecology	Washington State Department of Ecology
EPA	United States Environmental Protection Agency
FCCU	Fluid Catalytic Cracking Unit
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
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur dioxide
SRU	Sulfur Recovery Unit
SWS	Sour Water Stripper
Tesoro	Tesoro Refining and Marketing Company
TGU	Tail Gas Unit
tpy	Tons per year
ULNBs	Ultra-low-NO_X Burners
VOC(s)	Volatile organic compound(s)

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600 • Olympia, WA 98504-7600 • 360-407-6000
711 for Washington Relay Service • Persons with a speech disability can call 877-833-6341

July 7, 2010

Mr. Don Sorensen, Refinery Manager
Tesoro Refining and Marketing Company
10200 West March Point Road
P. O. Box 700
Anacortes, WA 98221

Dear Mr. Sorensen:

Regional Haze Best Available Retrofit Technology (BART) Determination

Best Available Retrofit Technology (BART) is required to reduce the regional haze impacts of emissions of your facility. The enclosed Order #7838 contains our BART determination for your facility including a schedule for compliance.

If you have questions or requests relating to this order, please contact Alan Newman at (360) 407-6810 or alan.newman@ecy.wa.gov.

Sincerely,

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Air Quality Program

jj/te

Enclosure

By certified mail

cc: Toby Allen, NWCAA
Alan Newman, Ecology
Rebecca Spurling, Tesoro Refining and Marketing

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN ADMINISTRATIVE ORDER AGAINST: Tesoro Refining and Marketing Co.	]	ORDER NO. 7838

TO: Mr. Don Sorensen, Refinery Manager
Tesoro Refining and Marketing Company
10200 West March Point Road
P. O. Box 700
Anacortes, WA 98221

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions which are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the federal and state visibility protection program (WAC 173-400-151 and 40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitutes Best Available Retrofit Technology (BART) for the eligible emission units at your facility. The rules also require the installation and use of those emission controls on the BART-eligible emission units. The emission controls are to be installed as expeditiously as possible, but in no event can the State allow them to start operation later than five years after the State's Regional Haze SIP amendment is approved by the United States Environmental Protection Agency (EPA).

FINDINGS

The Tesoro Refining and Marketing Company operate an oil refinery on March Point in Washington State that contains emission units that are subject to BART.

A. The BART-eligible emission units at the Tesoro refinery are:

   a. Process heaters and boilers

      1. F-103, Crude Oil Distillation
      2. F-104, Gasoline Splitter/Reboiler
      3. F-304, CO Boiler #2
      4. F-654, Catalytic Feed Hydrotreater
      5. F-6600, Naphtha Hydrotreater

6. F-6601, Naphtha Hydrotreater
7. F-6602, Naphtha Hydrotreater
8. F-6650, Catalytic Reformer
9. F-6651, Catalytic Reformer
10. F-6652, Catalytic Reformer
11. F-6653, Catalytic Reformer
12. F-6654, Catalytic Reformer
13. F-6655, Catalytic Reformer

b. Other units

1. X-819, Flare
2. CWT #2, Cooling Water Tower
3. CWT #2a, Cooling Water Tower

B. BART emission limitations for the BART-eligible emission units are based on usage of the following technologies or a combination of technologies:

a. Use of existing burners on Units F-104, F-654, F-6600, F-6601, F-6602, F-6650, F-6651, F-6652, F-6653, F6654, F-6655, and X-819.

b. Restricted use of fuel oil in Unit F-103 and use of ultra-low-NO_X burners.

c. Use of existing burners for control of nitrogen oxides on Unit F-304.

d. Use of the existing Flue Gas Scrubber (FGS) to control sulfur dioxide (SO_2) and particulate matter emissions from Unit F-304.

e. Continued use of the current, upgraded refinery fuel gas sulfur treatment system for control of sulfur dioxide emissions from all process heaters and boilers fueled with refinery fuel gas.

f. Continued operation of CWT #2 and #2a as currently permitted.

Unit F-304, CO Boiler #2, exhausts to the same particulate and SO_2 emission control device (the Flue Gas Scrubber) with Unit F-302, CO Boiler #1. Currently installed emissions monitoring devices monitor the emissions of the Flue Gas Scrubber. Tesoro proposed and Ecology has accepted continuation of monitoring the emissions from the Flue Gas Scrubber for compliance with the BART limitation for particulate and SO_2 from Unit F-304.

Additional information and analysis is available in the BART Determination Support Document for Tesoro Marketing and Refining Company, Anacortes Refinery, prepared by the Washington State Department of Ecology, October 2008, and the Tesoro Best Available Retrofit Technologies (BART) Assessment Assistance Final Engineering Analysis Report, prepared by Anvil Associates, Geomatrix Consultants, and Tesoro NW, dated February 2008, amended by letters of May 2, 2008, January 30, 2009, and May 5, 2009.

YOU ARE ORDERED: To install and operate emission control equipment in accordance with the following conditions:

BART EMISSION LIMITATIONS

1. Particulate Matter Emissions

1.1. Unit F-304 shall meet the following emission limitation:

1.1.1. Particulate matter less than 10 micron in diameter (PM_{10}) emitted from the Flue Gas Stack shall not exceed 0.11 grains/dscf, 1-hour average, corrected to seven percent oxygen, and

1.1.2. 1.0 lb PM/1000 lb coke burnt off in the Catalyst Regenerator.

1.2. For Units F-104, F-654, F-6600, F-6601, F-6602, F-6650, F-6651, F-6652, F-6653, F6654, F-6655, and X-819, (all other BART-eligible units), emissions shall not exceed 0.05 grain/dscf (0.11 g/m^3), 1-hour average, corrected to seven percent oxygen.

1.3. For Unit F-103, particulate matter emissions shall not exceed 0.05 grain/dscf (0.11 g/m^3), 1-hour average, (corrected to seven percent oxygen), except when burning fuel oil as allowed by Condition 3.1. When burning fuel oil, particulate emissions shall not exceed 0.10 grain/dscf, 1-hour average, corrected to seven percent oxygen.

1.4. For Units CWT #2 and #2a, particulate matter emissions shall not exceed 0.10 grain/dscf (0.23 g/m3), 1-hour average.

1.5. Compliance with the particulate emission limits above will be determined as follows:

1.5.1. For Unit F-304

1.5.1.1. Compliance will be demonstrated through use and continuous operation of the Flue Gas Scrubber as described in the unit's Operation and

Maintenance Manual, including all unit start-up, shutdown, and malfunction procedures.

1.5.1.2. Compliance with Condition 1.1.1 will be determined upon request of NWCAA or Ecology for emissions testing using EPA methods in 40 CFR Part 60 Appendix A. Particulate testing will use EPA Methods 5 and 202.

1.5.1.3. Compliance with Condition 1.1.2 will be determined upon request of NWCAA or Ecology for emissions testing using EPA methods in 40 CFR Part 60 Appendix A. Particulate testing will use EPA Method 5B.

1.5.2. For Unit F-103, when burning oil, visually observe stacks on a daily basis to qualitatively assess whether emissions are visible. The frequency may be reduced to weekly if no visible emissions are observed for 30 consecutive days. Tesoro shall revert to daily observations of individual stacks if any visible emissions are noted during the observation.

1.5.3. For Unit F-103, when burning fuel gas and for Units F-104, F-654, F-6600, F-6601, F-6602, F-6650, F-6651, F-6652, F-6653, F6654, F-6655, X-819 when burning gaseous fuels, visually observe stacks monthly to qualitatively assess whether emissions are visible. The frequency may be reduced to quarterly if no visible emissions are observed for six consecutive months. Tesoro shall revert to monthly observations of individual stacks if any visible emissions are noted during the observation.

1.5.4. If visible emissions are observed from Units F-103, F-104, F-654, F-6600, F-6601, F-6602, F-6650, F-6651, F-6652, F-6653, F-6654, F-6655, or X-819, reduce emissions to zero as soon as possible. If emissions cannot be reduced to zero, the permittee may monitor by Ecology Method 9A no later than 24 hours after detection and daily thereafter until opacity is shown to be less than 20 percent or the permittee will conduct a Method 5 assessment within 30 days.

1.5.5. Keep records of all observations available for inspection.

1.5.6. For Units F-103, F-104, F-654, F-6600, F-6601, F-6602, F-6650, F-6651, F-6652, F-6653, F6654, and F-6655, and upon request of NWCAA or Ecology compliance with Condition 1. 2 and 1.3 will be determined using EPA methods in 40 CFR Part 60 Appendix A. Particulate testing will use EPA Methods 5.

2. Nitrogen Dioxide Emissions

2.1. Unit F-103

2.1.1. Starting no later than the date in Condition 5, emissions of nitrogen dioxide from Unit F-103 is limited to:

2.1.1.1. 59.1 tons/yr, rolling annual (365 days) total calculated daily.

2.1.2. Compliance will be determined by use of a continuous emission monitoring system meeting the criteria of Condition 9.3 or a source-specific emission factor developed and periodically revised per Conditions 9.4 and 9.5.

2.1.3. Emissions testing utilizing EPA Reference Method 7E will be performed within 180 days of the start of operation of the NO_X control system.

2.2. Units F-104, F-304, F-654, F-6600, F-6601, F-6602, F-6650, F-6651, F-6652, F-6653, F-6654, F-6655, X-819

2.2.1. No nitrogen dioxide emission limitations are applicable to these units.

3. Sulfur Dioxide Emissions

3.1. Unit F-103

3.1.1. Starting no later than the date in Condition 5, Unit F-103 is to be fired by refinery fuel gas meeting the requirements of Condition 3.4 below, or natural gas. Fuel oil may be used when the conditions in Condition 3.1.2 are met.

3.1.2. Fuel oil may be used only in the following circumstances:

3.1.2.1. Curtailment of natural gas supply, or

3.1.2.2. Periods with limited refinery fuel gas availability such as start-up and shutdown of major refinery process units, while major refinery process units are not operating and producing refinery gas, and emergency conditions as necessary to maintain safe operations or equipment shutdown, or

3.1.2.3. Test firing on fuel oil is allowed for up to 24 hours per calendar year.

3.2. Unit F-304

3.2.1. Starting no later than the date in Condition 5, emissions of sulfur dioxide in the stack from the Flue Gas Scrubber treating the exhaust from Units F-304 and F-302 is to meet the following:

3.2.1.1. Not exceed, 25 ppmv (dry basis, 0% O_2, 365-day rolling average), or

3.2.1.2. 50 ppmv (dry basis, 0% O_2, 7-day rolling average).

3.2.1.3. Compliance to be demonstrated by a continuous emissions monitor meeting the criteria of Condition 8.1.

3.2.1.4. Bypassing of the Flue Gas Scrubber

3.2.1.4.1. Bypassing of the Flue Gas Scrubber is to be minimized.

3.2.1.4.2. Sulfur dioxide emission when the Flue Gas Scrubber is bypassed shall not exceed 1000 ppmdv, 1-hour average, corrected to seven percent oxygen. Compliance with the 1000 ppmdv limitation must be demonstrated by use of a continuous emissions monitor or mass balance calculation. The mass balance calculation must assume all sulfur entering Units F-302 and F-304 (CO Boilers #1 and #2) is oxidized to SO_2 and discharged to the atmosphere unless demonstrated otherwise by process data and/or analytical methods at representative operating conditions.

3.2.1.4.3. Records and data used to determine compliance with this provision shall be kept for at least five years and made available to NWCAA or Ecology on request.

3.2.1.4.4. Sulfur dioxide emissions during bypass of the Flue Gas Scrubber shall be minimized to the extent reasonably practicable by methods such as FCCU feed rate reduction, FCCU feed sulfur content reduction, catalyst utilization, and/or other actions. These procedures are to be incorporated into the FCCU operations and maintenance procedures.

3.2.1.4.5. Records must be taken during each Flue Gas Scrubber bypass event. The records shall contain the date and time of the beginning and end of the bypass event, all actions taken to reduce SO_2

emissions during the bypass, all actions required to restart the Flue Gas Scrubber and end bypassing. The record may take the form of a checklist. Records of each bypass event shall be retained at the facility for at least five years and be made available to NWCAA or Ecology upon request.

3.3. Units F-104, F-654, F-6600, F-6601, F-6602, F-6650, F-6651, F-6652, F-6653, F-6654, F-6655

3.3.1. Starting no later than the date in Condition 5, these units shall only fire refinery gas meeting the criteria in Condition 3.4 or natural gas.

3.4. Refinery fuel gas requirements

3.4.1. Refinery fuel gas from blend drum V-213 shall not contain greater than 0.10 percent by volume H_2S, 365-day rolling average, measured according to Condition 8.3 of this order.

3.4.2. Bypass of acid gas from the amine regenerator C-1120 system away from the normal processing flow to General Chemical shall be recorded and reported the NWCAA (i.e., any period that PC5265A is opened). A root-cause analysis shall be conducted and recorded for any bypass event.

SCHEDULE FOR COMPLIANCE

4. Particulate Matter Emissions

4.1. For all units, compliance with the emission limitations is required on the issuance date of this Order.

5. Schedule for Compliance with Sulfur Dioxide Emissions Limitation

5.1. For all units, compliance with the emission limitations is required on the issuance date of this Order.

6. Schedule for Compliance with Nitrogen Dioxide Emissions Limitations

6.1. Compliance with the nitrogen dioxide emission limitation for Unit F-103 is to be achieved as follows:

6.1.1. Submittal of Notice of Construction application to NWCAA for the installation of NO_X controls on Unit F-103 no later than June 30, 2014. The facility may submit a request for an extension to Ecology no later than 90 days prior to this date. Ecology will respond to the facility in writing whether it will accept or deny the extension request.

6.1.2. Start of construction for installation of ultra-low-NO_X burners in Unit F-103, no later than March 1, 2015. The facility may submit a request for an extension to Ecology no later than 90 days prior to this date. Ecology will respond to the facility in writing whether it will accept or deny the extension request.

6.1.3. Start operation of emission controls installed to meet the NO_X emission limitation no later than September 30, 2015. The facility may submit a request for an extension to Ecology no later than 90 days prior to this date. Ecology will respond to the facility in writing whether it will accept or deny the extension request.

6.1.4. Compliance with the 365-day rolling average emission limit begins on the 365th day after the date the emission controls start operation unless the criteria of Condition 14 are invoked.

MONITORING AND RECORDKEEPING REQUIREMENTS

7. Particulate Matter (PM_{10})

7.1. For Unit F-304, Flue Gas Scrubber Stack

7.1.1. Particulate emissions stack test results shall be submitted to NWCAA and Ecology upon request.

7.1.2. Emissions testing shall use EPA Methods 5 and 202 to demonstrate compliance with Condition 1.1.1.

7.1.3. Emissions testing shall use the procedures of 40 CFR 63.1564(c) and 63.1572 to demonstrate compliance with Condition 1.1.2.

7.1.4. Visual emissions monitoring data shall be recorded and retained at the facility available for review by NWCAA or Ecology inspectors.

7.1.5. Visible emissions observation records are to be retained at the facility for at least five years.

7.2. For all other BART-eligible emission units

7.2.1. Particulate emissions stack test results shall be submitted to NWCAA and Ecology upon request.

7.2.2. Emissions testing shall use EPA Method 5.

7.2.3. Visual emissions monitoring data shall be recorded and retained at the facility available for review by the NWCAA or Ecology inspectors.

7.2.4. Visible emissions observation records are to be retained at the facility for at least five years.

8. Sulfur Dioxide

8.1. Unit F-103

8.1.1. A record of all hours of operation using fuel oil shall be kept. The record shall record the day and time of the start of use of fuel oil, the day and time fuel oil use ends, and the reason fuel oil is used.

8.1.2. The records are to be retained at the facility for at least five years and be made available to NWCAA or Ecology upon request.

8.2. Unit F-304

8.2.1. A continuous emission monitor system (CEM) shall be installed, calibrated, maintained, and operated to measure oxygen and SO_2 concentrations in the Flue Gas Scrubber stack.

8.2.2. The monitors shall meet the more stringent of the specifications of 40 CFR Part 60 Appendices B and F, or the NWCAA Regulation 367 and Appendix A.

8.2.3. SO_2 emissions data from the CEM shall be maintained as calendar day average concentrations (ppmdv). The daily averages shall be used to calculate and record 7-day and 365-day rolling averages. The daily average SO_2 concentrations and calculations of the 7-day and 365-day averages shall be retained at the facility for at least five years and made available to NWCAA or Ecology on request.

8.3. Refinery fuel gas system

8.3.1. A continuous emissions monitoring system (CEMS) for hydrogen sulfide concentration shall be installed, calibrated, maintained, and operated measuring the outlet stream of the fuel gas blend drum subsequent to all unmonitored incoming sources of sulfur compounds to the system and prior to any fuel gas combustion device. The monitor shall be certified in accordance with 40 CFR Part 60 Appendix B and operated in accordance with 40 CFR Part 60 Appendix F and the NWCAA Regulation 367 and Appendix A.

8.3.2. Record the calendar day average H_2S concentration of the refinery fuel gas as measured by the CEM required in Condition 8.3.1. The daily averages shall be used to calculate the 365-day rolling average. Records of the daily average H_2S concentration and 365-day rolling averages are to be retained at the facility for at least five years and be made available to NWCAA or Ecology upon request.

9. Nitrogen Dioxide Emissions

9.1. Unit F-103

9.1.1. Nitrogen dioxide emissions are to be quantified by means of a continuous emission monitoring system, consisting of a continuous nitrogen oxides monitor and a continuous flow rate monitor meeting the requirements of Condition 9.3, or

9.1.2. Development of a unit-specific emissions factor. The method to develop and update the emission factor is described in Conditions 9.4 and 9.5 below.

9.2. All other BART-eligible units

9.2.1. No monitoring and recordkeeping requirements.

9.3. Nitrogen oxides and flow continuous monitor requirements

9.3.1. The monitor shall meet the more stringent of the specifications of 40 CFR Part 60 Appendices B and F, or the NWCAA Regulation 367 and Appendix A.

9.3.2. Each calendar day's average nitrogen oxides emissions will be calculated and recorded daily.

9.3.3. The rolling annual total nitrogen oxides emissions shall be recalculated and recorded daily.

9.4. If used, a unit-specific emissions factor, expressed as lb/MMBTU of fuel fired shall be based on the following:

9.4.1. Minimum of four discrete NO_X stack tests utilizing the emission test method given in 40 CFR Part 60, Appendix A, Method 7E.

9.4.2. Each of the four tests is to be no closer than three weeks apart or as specified in the source testing plant submitted to NWCAA and Ecology and approved by both agencies.

9.4.3. The first test is the initial compliance test specified in Condition 2.1.3.

9.4.4. Each source test must include information on production rate through the unit, fuel firing rate, specific gravity of the refinery fuel gas, and heat content of the refinery fuel gas. For Unit F-103, the information recorded will include whether fuel oil was used during the test and the nitrogen and sulfur content of the fuel oil.

9.4.5. Each stack test shall be conducted at normal operating rate.

9.4.6. The supporting information and the emission factor (or factors if multiple operating rates have been tested) developed shall be submitted to NWCAA and Ecology within 60 days of the last of the emission tests. Ecology and NWCAA must concur with the appropriateness of the factor proposed.

9.5. If the NO_X emissions from Unit F-103 are determined by a unit-specific emission factor, nitrogen oxide emissions shall be tested at least once each calendar year utilizing 40 CFR Part 60, Appendix A, Method 7E. The information specified in Condition 9.4.4 shall be collected as part of each emission test, and with all previous emissions and process information collected, is used to recalculate the unit-specific emission factor for use in the following calendar year.

REPORTING REQUIREMENTS

10. The test report for the initial NO_X emission control system performance testing required by Condition 2.1 shall be submitted to Ecology and to NWCAA within 45 days of completion.

11. Documentation of completion of each milestone in Condition 6 will be provided by Tesoro by certified mail to Ecology and to NWCAA within 30 days of completion.

12. Continuous emission monitoring data and/or emission factor based emissions shall be submitted to Ecology and to NWCAA on a semiannual basis, January through June and July through December. The semiannual report shall be provided within 45 days of completion of the reporting period. The submittal shall be electronically in a format acceptable to NWCAA. Reporting to Ecology will end when Tesoro has demonstrated compliance with the BART emission limits in this order applicable to a specific unit for a continuous 36-month period.

13. Continuous Emission Monitoring Quality Control Testing

    13.1. Data quality control testing shall be performed at least once per calendar quarter. This entails Cylinder Gas Audits and Relative Accuracy Audits.

    13.2. A Relative Accuracy Test Audit (RATA) test shall be performed at least once per year on every CEM system required by this Order.

    13.3. All RATA tests shall assess the ability of the entire system from stack probe to data acquisition system output.

    13.4. Tesoro shall notify Ecology and NWCAA when annual RATA testing is scheduled to occur, no later than 30 days prior to the testing date.

    13.5. Tesoro shall provide Ecology and NWCAA a copy of the RATA test results in an electronic format within 45 days of completion of the RATA test.

    13.6. Tesoro shall provide NWCAA the results of all quarterly cylinder gas audits performed with the next quarterly data assessment report submitted to NWCAA.

OTHER CONDITIONS

14. If after installation, operational adjustments, and testing, the BART control technology for NO_X specified for Unit F-103 is unable to meet the emission limitation for the unit, Tesoro may submit a written request to Ecology (with a copy sent to NWCAA) that the BART emission limitation for that unit be modified. The request must at a minimum provide the following:

    14.1. If the request is submitted before installation of the control technology:

14.1.1. Tesoro documents the technical difficulties and reasons why the limit cannot be achieved.

14.1.2. Tesoro provides documentation of all work with the equipment vendor and installer, if one is involved, to achieve the emission limitation.

14.1.3. Tesoro proposes an alternative control technology and emission limitation as BART for this unit, including an evaluation of the visibility improvement achievable through implementation of the proposed limitation compared to the effect of the limitation currently in this Order.

14.2. If the request is submitted after the unit has been in operation, but no sooner than 12 months after the start of operation, Tesoro's request must contain:

14.2.1. All information collected by Tesoro and its vendor or equipment installer to determine reasons for failure to meet the emission limitation, including but not limited to:

14.2.2. A listing of the actions to comply attempted, results, and reasons for failure.

14.2.3. Copies of all continuous emission monitor results or emissions tests performed.

14.2.4. Documentation of operating conditions during each test.

14.2.5. Fuels used and fuel ultimate analysis information to be provided for at least one emissions test.

14.2.6. Tesoro proposes as BART an emission limitation based on the capabilities of the control equipment as installed on the unit (including basis for it) for the revised emission limitation. The request shall include an evaluation of the visibility improvement achievable through implementation of the proposed limitation compared to the improvement provided by the limitation currently in this Order.

15. Tesoro may request this compliance Order be rescinded after all of the following occur:

15.1. All BART units at the plant have continuously complied with the emissions limitations in Conditions 1, 2, and 3 for a period of three years after the date in Condition 6.

15.2. The emission limitations in this Order have been incorporated into one or more enforceable orders or permits issued under the criteria of RCW 70.94.152 or 70.94.153 and NWCAA regulations implementing these provisions.

15.3. The emission limitations in the enforceable orders or permits have been incorporated into the Air Operating Permit issued by NWCAA to Tesoro.

16. By issuance of this order, the requirements of Order 5071 have been complied with and it is rescinded.

Within 20 days of receipt of this Order, you may request a delay in the submittal date. Any such request must be accompanied by a written justification for the delay.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.

- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal, you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:

The Pollution Control Hearings Board
P.O. Box 40903
Olympia, WA 98504-0903

OR

Deliver your appeal in person to:

The Pollution Control Hearings Board
4224–6th Avenue SE Rowe Six, Bldg 2
Lacey, WA 98503

To serve your appeal on the Department of Ecology:

Mail appeal to:

Department of Ecology
Appeals Coordinator
P.O. Box 47608
Olympia, WA 98504-7608

OR

Deliver your appeal in person to:

Department of Ecology
Appeals Coordinator
300 Desmond Drive SE
Lacey, WA 98503

And send a copy of your appeal packet to:

Alan Newman
Department of Ecology
Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600

For additional information, go to the Environmental Hearings Office website at http://www.eho.wa.gov.

To find laws and agency rules, go to the Washington State Legislator website at http://www1.leg.wa.gov/CodeReviser.

Your appeal alone will not stay the effectiveness of this Order. Stay requests must be submitted in accordance with RCW 43.21B.320. These procedures are consistent with Chapter 43.21B RCW.

DATED this 7 day of July, 2010 at Olympia, Washington.

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Department of Ecology
Air Quality Program

BART DETERMINATION
SUPPORT DOCUMENT FOR
PORT TOWNSEND PAPER CORPORATION
PORT TOWNSEND, WASHINGTON

Prepared by

Washington State Department of Ecology
Air Quality Program

August 24, 2009
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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 (CAA) 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 of one or more visibility impairing compounds.
4. Cause or contribute to visibility impairment within at least one mandatory federal Class I area.

The Port Townsend Paper Corporation (PTPC) operates a kraft pulp and paper mill that manufacturers unbleached kraft pulp, kraft papers, and lightweight linerboard. The mill is located in Port Townsend, Washington. The mill produces emissions of particulate matter (PM), sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NO_X), and hydrocarbons. The pollutants considered to be visibility impairing are PM, SO_2, and NO_X.

Kraft pulp mills such as the PTPC facility are one of the 26 listed BART source categories. The PTPC mill was first constructed in the late 1920s, but it has had many modifications since then. The mill's potential emissions exceed 250 tons per year (tpy) for at least one of NO_X, SO_2, or PM_{10}. Four units are BART-eligible by construction date. They are the Recovery Furnace, Smelt Dissolving Tank, No. 10 Power Boiler, and the Lime Kiln.

Modeling of visibility impairment was done following the Oregon/Idaho/Washington/EPA-Region 10 BART modeling protocol.[1] Modeled visibility impacts of baseline emissions show impacts on the 8th highest day in any year (the 98th percentile value) of greater than 0.5 deciviews (dv) at only one Class 1 area, the Olympic National Park. The visibility impairment of the highest 98th percentile day was 1.50 dv. NO_X and SO_2 emissions from the Recovery Furnace and No. 10 Power Boiler were responsible for most of the visibility impact.

PTPC prepared a BART technical analysis using Washington State's BART Guidance.[2]

The Washington State Department of Ecology (Ecology) determined that the current level of emissions control is BART for the four applicable units. A wide variety of additional controls were investigated for each unit, but all were determined to be either technically or economically infeasible.

[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.

1. INTRODUCTION

1.1 The BART Program and 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 Best Available Retrofit Technology (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 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:

Step 1 – Identify all available retrofit control technologies.
Step 2 – Eliminate technically infeasible control technologies.
Step 3 – Evaluate the control effectiveness of remaining control technologies.
Step 4 – Evaluate impacts and document the results.
Step 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. This decision is issued to the source owner as an enforceable Order, and included in the State's Regional Haze State Implementation Plan (SIP).

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

As allowed by the EPA BART guidance, Ecology has chosen to consider all 5 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 Port Townsend Paper Corporation Mill

The Port Townsend Paper Corporation (PTPC) operates a kraft pulp and paper mill (PTPC Mill) in Port Townsend, Washington. It is located in the northeast corner of the Olympic peninsula where Puget Sound meets the Strait of Juan de Fuca. The facility produces a variety of unbleached pulp and paper products including market pulp, converting paper, and containerboard. It was originally constructed in 1927. The PTPC Mill is a Title V source operating under Air Operating Permit WA 000092-2. Kraft mills are one of the 26 BART-eligible source categories. The Washington State Department of Ecology (Ecology) received a BART Analysis and Determination Report from PTPC on December 20, 2007.

1.3 BART-Eligible Units at the PTPC Mill

A review of the PTPC Mill emission sources found that:

1. Four of the plant's individual emission units were BART-eligible by construction date. The four are the Recovery Furnace, the Smelt Dissolving Tank, the No. 10 Power Boiler, and the Lime Kiln.
2. The four individual emission units in total have a combined potential to emit at least 250 tpy of nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM).

A Class I area visibility impact analysis was performed using the maximum daily emissions during the 2003-2005 time period and the CALPUFF model. Model results indicate visibility impacts from the BART-eligible units exceeded the 0.5 deciview (dv) contribution threshold in at least one Class I area. This confirmed that PTPC was required to continue in the BART process and prepare a BART determination.

1.3.1 Existing Recovery Furnace Emissions Control

PTPC operates a non-direct contact evaporator (NDCE) Recovery Furnace with an electrostatic precipitator (ESP). The Recovery Furnace fires predominantly black liquor solids (BLS) and some recycled fuel oil (RFO).

A chemical recovery furnace is not simply a "boiler" designed to burn fuel and produce steam. It is a complex device which serves as a chemical reactor, a chemical recovery unit, an internal high efficiency SO_2 scrubber, and an energy recovery unit. The Recovery Furnace recovers

sufficient energy to supply a major portion of the PTCP Mill's steam load and electrical power needs. The Recovery Furnace operates by spraying spent pulping chemical liquids (black liquor) from the digester into the furnace. The organic chemicals in the black liquor (mostly lignins) are combusted. Combustion provides the energy to recover the inorganic pulping chemicals (reduce sodium sulfate to sodium sulfide) for reuse.

The major pollutants emitted from the Recovery Furnace are SO_2, NO_X, and PM_{10}. SO_2 comes from the oxidation of organic sulfur compounds known as total reduced sulfur (TRS) present in the black liquor and losses of sulfur from the chemical recovery section of the furnace. Additional SO_2 emissions result from the oxidation of sulfur in fuel oil which may be used during the combustion process. The chemical recovery process scrubs out most of the SO_2 generated in the chemical recovery/combustion process in the furnace. The scrubbing action is through the reaction of sodium oxide with the SO_2. SO_2 emissions from the furnace represent a loss of process chemical and are not desirable, so the furnace operation is optimized to minimize sulfur loss.

NO_X may form as fuel NO_X and thermal NO_X. Technical literature suggests that NO_X formation from the chemical recovery process is primarily fuel NO_X since recovery furnace temperatures are not high enough for significant thermal NO_X formation.[4] NO_X emissions from recovery furnaces are typically low due to the low nitrogen (N) concentration in the black liquor solids (approximately 0.1 percent), the low overall conversion of liquor N to NO_X (10-25 percent), and the existence of sodium fumes that can participate in "in-furnace" NO_X reduction or removal.[5]

The majority of PM_{10} emissions from the Recovery Furnace are sodium salts with about 80 percent of the PM_{10} being sodium sulfate and smaller amounts of potassium sulfate, sodium carbonate, and sodium chloride.[6] These salts primarily result from the carryover of solids from the combustion process plus sublimation and condensation of inorganic chemicals.[7] Some PM_{10} emissions can also be attributed to the combustion of fossil fuel. Filterable PM_{10} emissions from recycled fuel oil combustion depend not only on the completeness of combustion but also on the sulfur and metals content of the oil.

The particulate collected by the ESP is sent to the Smelt Dissolving Tank for chemical recovery.

The most restrictive emission limits that the Recovery Furnace is currently subject to are in 40 CFR 63 Subpart MM and PSD 1. The applicable PM, NO_X, and SO_2 emission limits are shown in Table 1-1.

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[4] NCASI Special Report 99-01, *A Review of NO_X Emission Control Strategies for Industrial Boilers, Kraft Recovery Furnaces, and Lime Kilns,* April 1999.
[5] NCASI Special Report No. 03-06, *Effect of Kraft Recovery Furnace Operations on NOX Emissions: Literature Review and Summary of Industry Experience,* October 2003.
[6] NCASI Technical Bulletin No. 725, *Particulate Matter Emissions From Kraft Mill Recovery Furnaces, Lime Kilns, and Smelt Dissolving Tanks,* November 1996.
[7] AP-42, Section 10.2, Chemical Wood Pulping, dated September 1990.

Table 1-1. RECOVERY FURNACE CURRENT EMISSION LIMITS

Pollutant	Emission Limit	Regulatory Basis
PM/PM_{10}[a]	0.044 gr/dscf @ 8% O_2	NESHAP Subpart MM, 40 CFR 63.862(a)(1)(i)(A)
NO_X[b]	N/A	N/A
SO_2[c]	200 ppm @ 8% O_2	Permit Limit PSD-I (Condition 2)

[a] PM limits of 0.08 gr/dscf and 0.10 gr/dscf both at 8% O_2 also apply to the Recovery Furnace per Order DE 05AQIS-2892 and WAC 173-405-040(1)(a), respectively. Since the MACT limit of 0.044 gr/dscf at 8% O_2 is also applicable, only the most stringent standard is presented in the table.
[b] There are no NO_X limits that apply to PTPC's Recovery Furnace.
[c] An SO_2 limit of 500 ppm at 8% O_2 also applies to the Recovery Furnace per WAC 173-405-040(11)(a). Since the 200 ppm at 8% O_2 from the PSD-I permit limit is on the same basis, the more stringent of the two limits is presented in the table.

The PTPC Mill's Recovery Furnace is equipped with three electrostatic precipitators (ESPs) to reduce PM/PM_{10}. Each ESP is a parallel single chamber, dry bottom ESP. Two of the ESP units, manufactured by Research Cottrell, were rebuilt in 1993. The third ESP, manufactured by Environmental Elements, was installed as part of a Prevention of Significant Deterioration (PSD) permitting effort in approximately 1986 to 1987. No other add-on control devices are used for the Recovery Furnace.

1.3.2 Existing Smelt Dissolving Tank Emissions Control

A smelt dissolving tank is a part of the kraft pulping chemical recovery process. Smelt, the molten chemicals collected in the bottom of a recovery furnace, is continuously withdrawn from the furnace into a smelt dissolving tank. The smelt is then dissolved with weak wash[8] in the Smelt Dissolving Tank to produce green liquor, which is processed in the causticizing area to produce white liquor for use in the chip digestion process.[9] PM emissions are primarily composed of inorganic components such as sodium sulfate and sodium carbonate. NO_X emissions are minimal since no combustion occurs in these units. SO_2 emissions are from the oxidation of Total Reduced Sulfur (TRS) in the smelt.

The most restrictive emission limitation for the Smelt Dissolving Tank is in 40 CFR 63 Subpart MM. The applicable PM, NO_X, and SO_2 emission limits are shown in Table 1-2.

[8] This process water, also known as weak white liquor, is composed of all liquors used to wash lime mud and green liquor precipitates.
[9] The names of the various liquors denote their actual color.

Table 1-2. SMELT DISSOLVING TANK CURRENT EMISSION LIMITS

Pollutant	Emission Limit	Regulatory Basis
PM/PM_{10}[a]	0.20 lb/ton BLS	NESHAP Subpart MM, 40 CFR 63.862(a)(1)(i)(b)
NO_X[b]	N/A	N/A
SO_2[c]	N/A	N/A

[a] A PM limit of 0.3 lb/ton BLS also applies to the Smelt Dissolving Tank per WAC 173-405-040(2). Since the MACT limit of 0.20 lb/ton BLS is also applicable, only the most stringent standard is presented in the table.
[b] There are no NO_X limits that apply to PTPC's Smelt Dissolving Tank.
[c] There are no SO_2 limits that apply to PTPC's Smelt Dissolving Tank.

The Smelt Dissolving Tank is controlled with a Ducon UW4 Model 4 scrubber. The scrubber was originally installed during the 1970s and was modified by APTech in 2003. The modification in 2003 included the installation of new spray header and nozzles, spin breakers, and chevrons in order to further reduce particulate matter emissions and allow for compliance with MACT II requirements. No other control devices are used on the Smelt Dissolving Tank.

1.3.3 Existing No. 10 Power Boiler Emissions Control

The No. 10 Power Boiler operates by combusting wood waste, primary clarifier sludge, old corrugated container (OCC) rejects, and recycled fuel oil (RFO) to produce steam for use in the kraft pulping process. The boiler is a spreader stoker-type boiler with horizontally opposed overfire air ports and tangential oil burners downstream (above) the grate. While it primarily fires wood waste on the grates, the RFO fired at the tangential burners contributes approximately 30 percent of the heat input.

PM_{10} emissions from wood-fired boilers result from inorganic materials contained in the wood waste and unburned carbon resulting from incomplete combustion.[10] NO_X emissions from boilers are formed by two mechanisms, fuel NO_X and thermal NO_X. Fuel NO_X is the dominant mechanism for NO_X formation during wood waste combustion.[11] SO_2 emissions from combination wood residue and oil boilers are formed as the sulfur contained in the oil oxidizes during the combustion process. PTPC's RFO contains 0.45 to 0.75 percent sulfur, approximately 30 percent[12] of which oxidizes and exits the stack as SO_2. The remaining sulfur is captured by the alkaline wood ash and minimal amounts may exhaust as other sulfur compounds.[13]

[10] NCASI Technical Bulletin No. 884, *Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers,* August 2004.
[11] NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NOx, SO_2 and PM Emissions*, June 2006.
[12] Average percentage of the sulfur burned that is emitted as SO_2, calculated based on the correlation for sulfur capture in combination bark boilers developed by NCASI. NCASI Technical Bulletin No. 884, *Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers,* August 2004, pp. 40 and 41.
[13] NCASI Technical Bulletin No. 884, *Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers*, August 2004.

The most restrictive emission limitations on emissions from the No. 10 Power Boiler are in 40 CFR 60 Subpart D NSPS. The applicable PM, NO_X, and SO_2 emission limits are shown in Table 1-3.

Table 1-3. NO. 10 POWER BOILER'S CURRENT EMISSION LIMITS

Pollutant	Emission Limit	Regulatory Basis
PM/PM_{10}	0.10 lb/MMBtu	NSPS Subpart D, 40 CFR 60.42(a)(1)
NO_X	0.30 lb/MMBtu	NSPS Subpart D, 40 CFR 60.44(2)
SO_2	0.80 lb/MMBtu	NSPS Subpart D, 40 CFR 60.43(a)(1)
Note: NESHAP Subpart DDDDD, Boiler MACT, limits may have applied to the No. 10 Power Boiler. However, the Boiler MACT rule was vacated by the United States Court of Appeals decision on June 8, 2007.		

The No. 10 Power Boiler employs multiclones followed by a Turbotak scrubber to control particulate matter emissions. The multiclones remove the coarse particulate using centrifugal action. The Turbotak was installed in 1988 as a replacement of an existing venturi scrubber. The Turbotak scrubber is a wet scrubber that exposes the exhaust gas stream to a series of atomized water sprays. The multiple water sprays allow for optimizing the ratio between the water droplet diameter and the particulate matter diameter. The Turbotak also employs removal equipment including a knockout chamber, a fan, and chevrons.

1.3.4 Existing Lime Kiln Emissions Control

In the PTPC Mill's Lime Kiln, calcium oxide (CaO) is regenerated from lime mud, which consists primarily of calcium carbonate ($CaCO_3$). The heat required to convert the calcium carbonate to calcium oxide is provided by the combustion of RFO. Lime kilns are generally long, rotating cylindrical units installed on a slope (one end of the lime kiln is at a higher elevation than the other). Lime mud enters the kiln at the "higher" end and makes its way down to the "lower" end of the kiln. The heat, provided by the fuel oil burner, is generated at the "lower" end of the kiln. This counter-current flow of lime mud and hot combustion gases provides an efficient environment for the conversion to CaO.

PM/PM_{10} emissions from lime kilns primarily result from combustion gases picking up dust from lime mud and other particulate matter from alkali vaporization. Sodium sulfate and sodium carbonate primarily comprise the smaller PM with aerodynamic diameter less than 10 µm. NO_X formation in PTPC Mill's Lime Kiln occurs as both "thermal NO_X" and "fuel NO_X." The kiln reaches temperatures high enough for the direct oxidation of atmospheric nitrogen to NO_X. Thermal NO_X formation increases with temperature, oxygen and nitrogen concentrations, and residence time. Additionally, the nitrogen in the fuel oil fired by the Lime Kiln can convert to NO, forming "fuel NO_X." SO_2 emissions from PTPC Mill's Lime Kiln results from the oxidation of sulfur in the fuel oil and, to a lesser extent, sulfur in the lime mud. While the potential for SO_2 emissions from some lime kilns may be high based on the sulfur content of the fuel, most lime kilns emit very low levels of SO_2 due to the regenerated quicklime in the kiln acting as an inherent scrubbing agent. PTPC's particulate control venturi scrubber following the

kiln further augments this SO_2 removal process since the scrubbing solution becomes alkaline as it captures the lime dust.[14]

The most restrictive emission limitations on the Lime Kiln are in 40 CFR 63 Subpart MM and WAC 173-400-040(11)(a). The applicable PM, NO_X, and SO_2 emission limits are shown in Table 1-4.

Table 1-4. LIME KILN CURRENT EMISSION LIMITS

Pollutant	Emission Limit	Regulatory Basis
PM/PM_{10}[a]	0.064 gr/dscf @ 10% O_2	NESHAP Subpart MM, 40 CFR 63.862(a)(1)(i)(c)
NO_X[b]	N/A	N/A
SO_2[c]	500 ppm @ 10% O_2	WAC 173-405-040(11)(a)

[a] A PM limit of 0.13 gr/dscf at 10% O_2 also applies to the Lime Kiln per WAC 173-405-040(3)(a). Since the MACT limit of 0.064 gr/dscf @ 10% O_2 is also applicable, only the most stringent standard is presented in the table.
[b] There are no NO_X limits that apply to PTPC's Lime Kiln.
[c] A TRS limit of 8 ppm at 10% O_2 also applies to the Lime Kiln per 40 CFR 60.283 (a)(5).

The Lime Kiln employs a venturi scrubber to control particulate matter emissions. The showers of the Lime Kiln's venturi scrubber were modified in 2003 for MACT II compliance. No other control devices are used for the Lime Kiln.

1.4 Visibility Impact of the PTPC Mill's BART-Eligible Units

Class I area visibility impairment and improvement modeling was performed by PTPC using the BART modeling protocol developed by Oregon, Idaho, Washington, and EPA Region 10.[15] This protocol uses three years of metrological information to evaluate visibility impacts. As directed in the protocol, PTPC used the highest 24-hour emission rates that occurred in the 3-year period to model its impacts on Class I areas. The modeling indicates that the emissions from this plant caused visibility impairment to Olympic National Park on both the 8th highest impacted day in any one year and the 22nd highest day over the three years that were modeled.[16] For more information on visibility impacts of this facility, see Section 3.

[14] Ibid.
[15] A copy of the modeling protocol is available at **http://www.deq.state.or.us/aq/haze/docs/bartprotocol.pdf**.
[16] 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.

2. BART TECHNOLOGY ANALYSIS

The PTPC BART technology analysis was based on the 5-step process defined in BART guidance and listed in Section 1.1 of this report.

The following three tables identify and summarize possible control options considered in the BART determination analysis for PM_{10}, NO_X, and SO_2 emissions from the PTPC Mill. Sections 2.1 through 2.4 discuss emissions from each BART emissions unit. A more complete description of each control option is provided in Appendix A. Longer discussions of why technologies were considered infeasible were placed in Appendices B through E to make the main body of this report shorter.

Table 2-1. PM_{10} CONTROL TECHNOLOGIES EVALUATED

Control Technology	Available for Emission Unit (Yes/No)[a,b]			
	NDCE Recovery Furnace	Smelt Dissolving Tank	No. 10 Power Boiler	Lime Kiln
Fabric Filters (baghouse)	N/A	N/A	YES	N/A
Cyclone Separator	N/A	N/A	YES	N/A
Wet Scrubber	N/A	Currently used	Currently used	N/A
ESP	Currently used	N/A	YES	N/A
Proper Operating Practices	N/A	N/A	YES	N/A

[a] Availability based on whether control technology can be considered for each.

[b] Availability of PM_{10} control on all units except the No. 10 Power Boiler is not applicable (N/A) because the remaining units comply with MACT standards for PM. Per Section IV of EPA's "Guidelines for BART Determinations under the Regional Haze Rules" [40 CFR Part 51, Appendix Y], "Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, [state agencies] may rely on the MACT standards for purposes of BART."

Table 2-2. NO_X CONTROL TECHNOLOGIES EVALUATED

Control Technology	Available for Emission Unit (Yes/No)[a]			
	NDCE Recovery Furnace	Smelt Dissolving Tank[b]	No. 10 Power Boiler	Lime Kiln
Low Excess Air (LEA)	Yes	N/A	Yes	No
Staged Combustion	Currently used	N/A	Currently used	Yes
Flue Gas Recirculation (FGR)	Yes	N/A	Yes	Yes
Low NO_X Burners (LNB)	Yes	N/A	Yes	Yes
Fuel Staging/Reburning	Yes	N/A	Yes	Yes
Water/Steam Injection	No	N/A	No	Yes
Mid-Kiln Firing	No	N/A	No	Yes
Mixing Air Fan	No	N/A	No	Yes
Good Operating Practices and Proper Design	Yes	N/A	Yes	Yes
Selective Non-Catalytic Reduction (SNCR)	Yes	N/A	Yes	Yes
Selective Catalytic Reduction (SCR)	Yes	N/A	Yes	Yes
Oxidation/Reduction Scrubbing	Yes	N/A	Yes	Yes

[a] Availability based on whether control technology can be considered for each emission unit, not on technical feasibility.

[b] NO_X control technologies are not evaluated for the Smelt Dissolving Tank since this unit is not a source of NO_X emissions.

Table 2-3. SO_2 CONTROL TECHNOLOGIES EVALUATED

Control Technology	Available for Emission Unit (Yes/No)[a]			
	NDCE Recovery Furnace	Smelt Dissolving Tank	No. 10 Power Boiler	Lime Kiln
Flue Gas Desulfurization (FGD) with Wet Scrubber	Yes	Yes[b]	Yes	Yes
FGD – Semi-Dry Lime Hydrate Slurry Injection (semi-dry slurry injection) with ESP or Baghouse	Yes	Yes[b]	Yes	Yes
FGD – Semi-Dry Lime Hydrate Powder Injection (semi-dry powder injection) with ESP or Baghouse	Yes	Yes[b]	Yes	Yes
FGD – Spray Drying with ESP or Baghouse	Yes	Yes[b]	Yes	Yes
Inherent Dry Scrubbing	Currently used	No	No	Currently used
Low Sulfur Fuel Selection	Yes	No	Yes	Yes
Increased Oxygen Levels at the Burners	No	No	No	Yes
Good Operating Practices	Yes	Yes	Currently used	Yes

[a] Availability based on whether control technology can be considered for each emission unit, not on technical feasibility.
[b] Ecology recognizes that the Smelt Dissolving Tank vent system has very little flow, so emission control using these technologies is questionable. PTPC chose to evaluate them, so those evaluations are presented in this report.

2.1 NDCE Recovery Furnace Control Options

2.1.1 PM/PM_{10} Control Options

As noted in Section 1.3, the Recovery Furnace is subject to the NESHAP (MACT) standard for PM (as a surrogate for HAP metals) contained in 40 CFR Part 63 Subpart MM, *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills.*

Particulate emissions from the Recovery Furnace are controlled by an ESP. The ESP control on the Recovery Furnace reduces particulate emissions to less than the MACT limit of 0.044 gr/dscf at eight percent O_2. Actual emissions average about 50 percent of the MACT standard.

The date the PTCP Mill was required to comply with the particulate emission requirements of 40 CFR Part 63 Subpart MM by March 13, 2004. They met that standard without the need to add

any new particulate controls. No new technologies for controlling PM have subsequently become available after this date. Therefore, PTPC proposed the current dry ESP and meeting the MACT limits for PM/PM_{10} for the Recovery Furnace as BART and did not analyze other options for PM emissions control from the Recovery Furnace.[17]

2.1.2 NO_X Control Options

Recovery furnaces inherently use staged combustion. The design of the kraft Recovery Furnace at the PTPC Mill uses multiple levels of air admission into the furnace to control the kraft recovery sodium sulfate reactions and to assure complete combustion of organic compounds. The process control system that regulates this staged combustion process helps minimize the formation of NO_X.

Recovery furnaces have special safety systems to preclude fuel/air explosions and steam explosions if steam pressure ratings are exceeded. Chemical recovery furnaces can experience other unique types of explosions such as pyrolysis gas (CO, methane, hydrogen, and others) explosions and smelt/water explosions. If a recovery furnace experiences a "black out" where the flame extinguishes and the hot char bed continues to produce pyrolysis gases, then a spark or flame can reignite the gases and produce a fuel/air explosion. If a boiler tube develops a leak and water comes into contact with the molten salt at the bottom of the furnace, a very forceful explosion may take place. These hazards pose a significant danger to employees and equipment. These special safety issues and the chemical reactions noted in Section 1.3.1 are what make a chemical recovery furnace unique and explain why some emission technologies that may work for ordinary boilers are technically infeasible and even dangerous for a chemical recovery furnace.

In a 2003 special report, the National Council for Air and Stream Improvement (NCASI) specifically addressed options for reducing NO_X emissions from recovery furnaces, indicating that no operating kraft recovery furnace currently utilizes post-combustion control (such as SCR or SNCR) and limited pollution prevention techniques for NO_X are available.[18] A subsequent NCASI Corporate Correspondence Memorandum states:[19]

> *Optimization of the staged combustion principle within large, existing kraft recovery furnaces to achieve lower NO_X emissions might be the only technologically feasible option at the present time for NO_X reduction . . . Ultimately, the liquor nitrogen content, which is dependent on the types of wood pulped, is the dominant factor affecting the level of NO_X emissions*

[17] Per Section IV of EPA's "*Guidelines for BART Determinations under the Regional Haze Rules*" [40 CFR Part 51, Appendix Y], "Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, [state agencies] may rely on the MACT standards for purposes of BART."
[18] NCASI Special Report No. 03-06, *Effect of Kraft Recovery Furnace Operations on NOx Emissions: Literature Review and Summary of Industry Experience,* October 2003.
[19] NCASI Corporate Correspondent Memorandum No. 06-014, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NOx, SO_2 and PM Emissions*, June 2006.

from black liquor combustion in a recovery furnace. Unfortunately, this factor is beyond the control of pulp mill operators.

NO_X control technologies determined to be technically infeasible are discussed in Appendix B.

As described in the NCASI publication quoted above, and as found in a search of the EPA RBLC database, good combustion practices optimizing the staged combustion inherent in the design of a kraft recovery furnace is the only NO_X control that is both available technology and has been installed on recovery furnaces in the U.S.

2.1.3 SO_2 Control Options

The following table and the following text describe possible SO_2 control options and why PTPC proposed them to be either technically or economically infeasible for the Recovery Furnace.

Table 2-4. TECHNICALLY INFEASIBLE RECOVERY FURNACE SO_2 CONTROL OPTIONS

Technology	Description
FGD with Wet Scrubber	NCASI reports that the use of add-on control equipment specifically installed to reduce of SO_2 from recovery furnaces has not been demonstrated anywhere in the United States and is considered prohibitive from a cost perspective.[20] There are several reasons that a wet scrubber has not been applied for the control of SO_2 from a kraft recovery furnace. A well designed and properly operated recovery furnace emits little SO_2 during normal operation. The majority of SO_2 emissions occur during highly sporadic, unpredictable, and short duration "spikes" in SO_2 emissions. These spikes can be theoretically traced back to dozens of potential culprits, the best characterized and understood of which is variations in black liquor sulfidity and solids content. Thus, a scrubber would not actually remove much SO_2 on an annual basis. Based on the technical difficulties described and the lack of successful implementation, PTPC has also proposed that this technology be considered technically infeasible for control of SO_2 and was not considered further.
FGD – Semi-Dry Slurry or Powder Injection or Spray Drying with ESP or Baghouse	The spray dryer system operation is based on the injection of a sorbent such as lime or sodium bicarbonate into the flue gas. For a kraft recovery furnace, such injection is not reasonable. Dust captured by the ESP is returned to the kraft recovery process via the Smelt Dissolving Tank. Introduction of lime or sodium bicarbonate into the

[20] NCASI, *Corporate Correspondence Memo CC-06-14: Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NOx, SO2, and PM Emissions*, June 4, 2006.

Technology	Description
	flue gas will disrupt the chemical balance of the kraft process. Also, as with wet FGD systems, there is a lack of existing installations for this process. The sulfur content of the gas stream is too low for effective operation of the control technology. For these reasons, PTPC proposed that this technology be considered technically infeasible and eliminated from BART consideration.
Low Sulfur Fuel Selection	The fuel of a recovery furnace is primarily the black liquor processed by the furnace, supplemented with fuel oil. The furnace is operated as a high efficiency SO_2 scrubber in order to recover process chemicals. The sulfur content of the black liquor solids cannot be controlled by the PTPC Mill, but is efficiently recovered by proper operation of the Recovery Furnace. SO_2 emissions primarily come from supplemental fuel. At the PTPC Mill, RFO is the fuel oil used plantwide. It has sulfur content typically between 0.45 and 0.75% sulfur, with a guaranteed maximum of 0.76%. As discussed in Section 2.3.3, switching to the next lower sulfur content of RFO would cost $15,702 per ton of SO_2 emissions avoided. PTPC proposed that this is not cost effective for BART. For these reasons, PTPC did not consider low-sulfur fuel selection any further for the Recovery Furnace.

2.1.4 PTPC's BART Proposal for the Recovery Furnace

For PM/PM_{10} control, PTPC proposed to continue to use the existing ESP as BART. Actual emissions from use of the current ESP average less than 50 percent of the NESHAP Subpart MM limit of 0.044 gr/dscf at eight percent O_2.

For NO_X control, PTPC proposed to continue to properly operate the existing staged combustion system as BART for control of NO_X emissions from the Recovery Furnace.

For SO_2 control, PTPC proposed that Good Operating Practices, as currently in place, should be determined to be BART for the Recovery Furnace. Good Operating Practices entail minimizing fuel oil firing and maintaining the char bed resulting from black liquor solids combustion.

2.2 Smelt Dissolving Tank Control Options

As discussed in Section 1.3.2, a wet scrubber is currently used to reduce PM/PM_{10} emissions. This wet scrubber also provides some reduction of sulfur emissions. The Smelt Dissolving Tank is not a combustion source and has very low emissions as shown in Table 3-3 in Section 3.

2.2.1 PM/PM_{10} Control Options

As noted in Section 1.3, the Smelt Dissolving Tank is subject to the NESHAP (MACT) standard for PM (as a surrogate for HAP metals) contained in 40 CFR Part 63 Subpart MM, *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills.* The date the PTPC Mill was to be in compliance with the requirements of 40 CFR Part 63 Subpart MM was March 13, 2004. No new technologies for controlling smelt dissolving tank PM have subsequently become available after this date. As a result, no additional engineering analyses were conducted by PTPC.

2.2.2 NO_X Control Options

NO_X control technologies are not evaluated for the Smelt Dissolving Tank. It is not a combustion source and the materials processed are not a source of NO_X.

2.2.3 SO_2 Control Options

A possible alternative SO_2 control (to the currently used wet scrubber) might be FGD using either a semi-dry or dry process with addition of either an ESP or baghouse. Operation of either of these spray-dryer-type systems is based on the feasibility of injecting lime into the flue gas followed by a dry ESP or baghouse downstream of the dryer to capture the dry particles. The Smelt Dissolving Tank's exhaust stream has high moisture content (typically 25 to 40 percent) and almost no flowrate, making usage of a spray dryer with a dry ESP system technically infeasible.[21]

The addition of an alkaline solution to the existing wet scrubber could theoretically provide as much as 90 percent reduction of potential annual SO_2 emissions. The annual cost effectiveness for implementing this control technology on the low airflow and low emissions from the Smelt Dissolving Tank was estimated to be $16,247 per ton of SO_2 removed to remove 1.03 tons per year. PTPC proposed that the option of reducing SO_2 emissions by adding alkaline solution to the existing scrubber be considered economically infeasible.

2.2.4 PTPC's BART Proposal for the Smelt Dissolving Tank

For PM/PM_{10} control, PTPC proposes to continue to use the Smelt Dissolving Tank's existing scrubber in lieu of additional add-on control or replacement of the existing scrubber. PTPC will continue to operate the existing scrubber to comply with the existing NESHAP (MACT) Subpart MM limit of 0.20 lb PM_{10} per ton BLS.

For NO_X control, PTPC proposes no additional controls as BART. There is no combustion occurring in the Smelt Dissolving Tank, and the unit is not considered a source of NO_X emissions.

[21] Ibid.

For SO_2 control, PTPC proposes to continue to properly operate the Smelt Dissolving Tank's existing wet scrubber as BART.

2.3 No. 10 Power Boiler Control Options

As discussed in Section 1.3.3, the No. 10 Power Boiler has an overfire air system. A multiclone followed by a wet scrubber are currently used to reduce PM/PM10 emissions.

2.3.1 PM/PM_{10} Control Options

Table 2-1 and Appendix A list five identified PM/PM_{10} control technologies along with proper operating practices. Since the power boiler currently uses a multiclone and wet scrubber, only the two alternative PM control technologies, discussed in the following table, were investigated further.

Table 2-5. NO. 10 POWER BOILER PM/PM_{10} CONTROL OPTIONS EVALUATED

Technology	Description
Fabric Filters (baghouse)	The use of fabric filters to control particulate matter emissions from wood-fired boilers results in a fire hazard due to the potential of burning cinders escaping the multiclone, temperature excursions, and/or operating upsets combined with fabric flammability causing the fabric filters to ignite or melt, depending on the fabric used. Because of this, fabric filters are rarely used on wood-fired boilers. Fabric filters have been successfully used on some wood-fired boilers that burn wood residue or bark stored in salt water because the salt reduces the fire hazard. PTPC's Title V Operating Permit specifically prohibits burning salty hog fuel in the No. 10 Power Boiler as part of the opacity limit. The use of fabric filters to control particulate matter emissions from the No. 10 Power Boiler is proposed to be technically infeasible due to fire hazard.
Wet ESP (addition)	Addition of a wet ESP following the existing scrubber and multiclone system was considered technically feasible. A cost control evaluation was done to evaluate economic feasibility. The control level for the addition of a wet ESP was based on a vendor guarantee of 0.01 gr/dscf. This guarantee represents a removal efficiency of approximately 69% based on the current limit of 0.10 lb/MMBtu at maximum capacity.[22] The cost per ton of PM_{10} removed for the installation of a wet ESP to further control the No. 10 Power Boiler was estimated to be $11,294. PTPC proposed this value as not cost effective.

[22] Percent control rate determined by the current emissions rate using a boiler firing rate of 360 MMBtu/hr, producing 250,000 pounds steam per hour compared to the potential emissions at the 0.01 gr/dscf vendor guarantee and the design exhaust flow rate of 200,000 acfm.

Technology	Description
Wet ESP (substitution)	A wet ESP could be completely substituted for the wet scrubber to get the improved particulate removal discussed in the previous paragraph, but a wet ESP would remove less SO_2 than the existing wet scrubber does. The economic analysis would be based on the same particulate emissions reduction as when the unit was being considered in series with the existing scrubber. Since SO_2 contributes to visibility impact, and the particulate reduction would be the same for either option, the complete substitution of the existing wet scrubber with a wet ESP option was not considered further.

2.3.2 NO_X Control Options

The No. 10 Power Boiler is a load-following spreader stoker combination fuel boiler with tangentially fired oil burners. It combusts wood waste, sludge, OCC rejects, and oil. The spreader stoker design inherently uses a form of staged combustion. In the PTPC Mill's No. 10 Power Boiler, the fuel-rich combustion of the wood waste on the grates results in incomplete combustion and lower flame temperatures. Downstream of the primary flame, the horizontally opposed overfire air ports supply excess air to complete the combustion. Further downstream, the tangential oil burners supply additional heat without increasing the primary flame temperature. This firing configuration results in low peak flame temperatures, and minimal thermal-NO_X formation. As a result, the majority of the NO_X from wood-fired boilers is fuel NO_X.[23] Table 2-2 lists the control technologies considered for the No. 10 Power Boiler. Appendix C contains a discussion of the reasons why each of these additional control options was proposed to be technically infeasible for NO_X control. The discussion was put into an appendix because of its length.

2.3.3 SO_2 Control Options

Implementation of **FGD technology using wet injection with a wet scrubber** on the No. 10 Power Boiler could reduce SO_2 emissions. This technology would involve adding additional alkaline chemicals such as lime or sodium hydroxide to the existing wet scrubber solution. This addition would further increase the pH of the scrubber effluent, which would in turn increase the pH of the ash clarifier into which the scrubber effluent empties. The ash clarifier's pH currently ranges from 11 to 12.2 as a result of the alkaline nature of the fly ash removed by the wet scrubber. The clarifier has a pH limit of 12.45 to ensure that the sludge and scrubbing liquor are not classified as a dangerous waste under Washington State Dangerous Waste regulations and a hazardous waste under federal Resource Conservation and Recovery Act (RCRA) regulations. Increasing the pH of the ash clarifier to a pH of 12.5 or greater would result in generation of a sludge characterized as a state dangerous or RCRA hazardous waste. Such characterization would increase the cost and complexity of ash disposal significantly.

[23] NCASI Special Report 03-04, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience,* August 2003.

Aside from making the sludge into a state dangerous waste and RCRA hazardous waste, the implementation of wet FGD is unlikely to provide significant additional control of SO_2. The alkaline fly ash currently absorbs the SO_2 in the flue gas in the same manner as a FGD alkaline reagent. The calcium and sodium oxides in the fly ash captured by the existing wet scrubber causes the scrubber water to become alkaline, allowing for absorption of SO_2 in the scrubber water. Addition of more alkaline solution to the existing scrubber would provide only an incremental increase in SO_2 absorption.

Because of the above described issues of small increase in performance and significant problems with sludge disposal, PTPC proposed that the implementation of wet FGD technology for control of SO_2 from the No. 10 Power Boiler be considered technically infeasible.

Reducing sulfur content of the fuel is a common approach to reduce SO_2 emissions. This option is considered technically feasible, so a cost estimate to implement it was done. The cost of switching from the recycled fuel oil (RFO) currently fired in the No. 10 Power Boiler (and all other PTPC Mill oil-fired units) to 'High Spec' RFO with guaranteed maximum sulfur content of 0.5 percent ($43.53/barrel) is approximately $15,702 per ton of SO_2 emissions avoided. Switching from RFO to 500 ppm or 15 ppm sulfur diesel ($92.67/barrel) would cost approximately $19,650 per ton of SO_2 emissions avoided. Both 500 ppm and 15 ppm sulfur diesel fuel have essentially the same price per barrel. This estimate calculates the current SO_2 emissions based on the guaranteed maximum sulfur content of 0.76 percent in the RFO. The estimate also assumes that all sulfur in the fuel oil is emitted as SO_2[24] and none is absorbed in the fly ash. It does not include costs of any changes in plant equipment required to store or burn the new fuel.

PTPC proposed that this cost is too high for BART.

2.3.4 PTPC's BART Proposal for the No. 10 Power Boiler

For PM/PM_{10} control, PTPC proposed continued use of the existing wet scrubber as BART.

For NO_X control, PTPC proposed to continue using good operation of the boiler's inherent staged combustion system as BART.

For SO_2 control, PTPC proposed continued operation of the existing wet scrubber and continued good operation of the boiler aimed at minimizing fuel oil firing as BART.

2.4 Lime Kiln Control Options

As discussed in Section 1.3.4 the Lime Kiln currently uses a wet venturi scrubber to reduce PM/PM_{10} emissions. The calcium oxide particulates create alkalinity that enhances SO_2 scrubbing.

[24] For the cost analysis, SO_2 emissions are based on AP-42 Table 1.3-1 emission factor (157*S% lb $SO_2/10^3$ gallons), which assumes 100% of the sulfur in the oil is emitted as SO_2.

2.4.1 PM_{10} Control Options

The Lime Kiln's particulate emissions are currently regulated under 40 CFR 63 Subpart MM. The Lime Kiln meets these emissions requirements. The compliance date for Subpart MM was March 13, 2004. No new technologies for controlling PM have subsequently become available after this recent date. Therefore, PTPC considered the MACT limits for PM from the Lime Kiln as BART and did not analyze further options for PM emissions control.

2.4.2 NO_X Control Options

For purposes of product quality and process economics, PTPC operates its Lime Kiln using a minimum of excess air. This practice contributes to minimizing NO_X emissions.

A RACT/BACT/LAER Clearinghouse (RBLC) search results reveal that no add-on controls or combustion modifications have been required to meet RACT, BACT, or LAER. The database lists only requirements such as "good combustion" or "proper kiln design" as BACT for control of NO_X from a lime kiln.

Ten possible control options were investigated. PTPC proposed all were technically infeasible. A discussion of each of these technologies is found in Appendix D.

2.4.3 SO_2 Control Options

In addition to the SO_2 removal that occurs from the lime produced in the Lime Kiln, the current wet venturi scrubber captures lime dust making the scrubber solution more alkaline and promoting additional SO_2 reduction.

As listed in Table 2-3, several additional technologies were investigated for technical feasibility. After investigation, all were determined to be technically infeasible except for selection of a lower sulfur fuel oil and improved FGD within the existing wet scrubber. A discussion of each technically infeasible category is contained in Appendix E.

Lower sulfur fuel was rejected previously (see Section 2.3.3), because it was not economically justifiable. That analysis is valid throughout the plant, including the Lime Kiln, because it is based on the purchase price of the fuels alone and not installation or operation of equipment.

PTPC included the option of adding more alkali to the wet scrubber to attempt to provide an additional 90 percent control efficiency as the BART 102 modeling scenario described in Section 3. The visibility impact reduction as described in Section 3 was estimated to be 0.004 dv. This small change is understandable considering that existing SO_2 emissions from the Lime Kiln are only about one percent of the total SO_2 emissions of PTPC's BART units. The minimal emissions reduction and visibility impact reduction indicated this option is not BART.

2.4.4 PTPC's BART Proposal for the Lime Kiln

For PM_{10} control, PTPC proposed continued use of the existing wet venturi scrubber as BART. PTPC will continue to operate the current scrubber to comply with the existing NESHAP Subpart MM limit of 0.064 gr/dscf at 10 percent O_2.

For NO_X control, PTPC proposes that proper kiln design and operation as BART for NO_X emissions.

For SO_2 control, PTPC proposes continued operation of the Lime Kiln wet venturi scrubber as BART.

2.5 PTPC's Proposed BART

Table 2-6. SUMMARY OF PTPC'S PROPOSED BART

Pollutant	Emission Unit	Proposed BART Control Option	Control Option Emissions Level or Control Efficiency
PM_{10}	No.10 Power Boiler	Existing Wet Scrubber[a]	0.10 lb/MMBtu[b] (current NSPS Subpart D limit)
	Recovery Furnace	Existing ESP	0.044 gr/dscf[b] (current MACT Subpart MM limit)
	Smelt Dissolving Tank	Existing Wet Scrubber	0.200 lb/BLS[b] (current MACT Subpart MM limit)
	Lime Kiln	Existing Venturi Scrubber	0.064 gr/dscf[b] (current MACT Subpart MM limit)
NO_X	No. 10 Power Boiler	Existing Staged Combustion System	0.80 lb/MMBtu[b] (current NSPS Subpart D limit)
	Recovery Furnace	Existing Staged Combustion System	N/A[c]
	Smelt Dissolving Tank	N/A	N/A[c]
	Lime Kiln	Good Operating Practices	N/A[c]
SO_2[e]	No. 10 Power Boiler	Good Operating Practices	0.30 lb/MMBtu[b]
	Recovery Furnace	Good Operating Practices	200 ppm @ 8% O_2[b] (current PSD limit)
	Smelt Dissolving Tank	Good Operating Practices	N/A[b,c]
	Lime Kiln	Existing Venturi Scrubber[d]	Continued use of wet scrubber with inherently alkaline scrubber solution 500 ppm @ 10% O_2[b] (current WAC limit)

[a] The addition of a wet ESP to the existing wet scrubber on the No. 10 Power Boiler is determined to not be cost effective. However, the visibility impact of implementing this control technology is evaluated as BART 101 for informational purposes to further support the ineffectiveness of implementing this control technology.

[b] For the purposes of presenting this BART emissions limit summary, for the baseline case (where no controls are applied), the existing emissions limits proposed as BART are listed in this table. However, the baseline emission rates used for the BART determination visibility modeling analysis are the maximum actual daily emission rates as presented and modeled for the BART applicability analysis rather than these maximum emissions limits.

[c] There are no current limits that apply to the emission unit for the specified pollutant.

[d] The addition of alkaline solution to the scrubber was found to be cost ineffective. However, the visibility impact of implementing this control technology is evaluated as BART 102 for informational purposes to further support the ineffectiveness of implementing this control technology.

[e] Switching to a lower sulfur content recycled fuel oil (RFO) was determined to be economically infeasible as discussed in Section 2.3.3.

3. VISIBILITY IMPACTS AND DEGREE OF IMPROVEMENT

A baseline Class I Area visibility impact analysis was performed on the BART-eligible emission units at the PTPC Mill using the CALPUFF model with four kilometer grid spacing as recommended by Oregon/Idaho/Washington/EPA Region 10 BART modeling protocol. The 98th percentile modeled 24-hour average visibility impacts modeled for the BART eligible units at the PTPC Mill at each Class I area within 300 km and in the Columbian River Gorge National Scenic Area are shown in Table 3-1.

Table 3-1. BART APPLICABILITY VISIBILITY MODELING RESULTS

Class I Area	22nd highest Δdv, 2003-5 (98th %ile)	8th High 2003 Δdv	8th High 2004 Δdv	8th High 2005 Δdv
Alpine Lakes Wilderness Area	0.284	0.264	0.281	0.313
Glacier Peak Wilderness Area	0.251	0.226	0.238	0.258
Goat Rocks Wilderness Area	0.137	0.137	0.128	0.134
Mount Adams Wilderness Area	0.124	0.128	0.124	0.105
Mount Rainier National Park	0.244	0.272	0.231	0.211
North Cascades National Park	0.236	0.196	0.248	0.236
Olympic National Park	**1.919**	**1.767**	**1.983**	**1.919**
Pasayten Wilderness Area	0.125	0.120	0.147	0.123
Columbia River Gorge National Scenic Area (not a Class I area)	0.060	0.064	0.069	0.043

The BART applicability modeling results presented in Table 3-1 indicates that the 98th percentile visibility impact exceeds the 0.5 dv contribution threshold at only one of the eight Class I areas, Olympic National Park.

After modeling visibility impacts of the BART eligible units at the plant, PTPC proposed three modifications to the initial scenario, to better model the impacts at Olympic National Park:

1) Refinements to the unit emissions used for modeling, applicable to both baseline and control technology modeling
2) Use a different background ammonia concentration (0.5 ppb) from the one specified in the modeling protocol (17 ppb)
3) Use of the new IMPROVE equation.

Ecology did not accept the latter two changes, as they deviated from the modeling protocol. Modeling files submitted by the company were used to extract the visibility impairment based on the old IMPROVE equation. PTPC was requested to rerun some of the post processing steps, so as to revert back to using the 17 ppb ammonia background.

Specific emission changes between the initial BART screening modeling and the final modeling presented in this BART analysis are discussed in Section 6.3 of the BEST AVAILABLE

RETROFIT TECHNOLOGY APPLICABILITY ANALYSIS AND DETERMINATION REPORT, PORT TOWNSEND PAPER CORPORATION, December 2007. These changes, which affected all emissions from the No. 10 Power Boiler and the particulate emissions from the Smelt Dissolving Tank and the Lime Kiln, were accepted by Ecology.

The revised emission rates are summarized in Table 3-2. They result in a modeled 98th percentile visibility impact of 1.614 ΔDV at Olympic National Park. This final baseline modeling result is used as the basis for comparing changes in the remainder of the modeled impacts discussion.

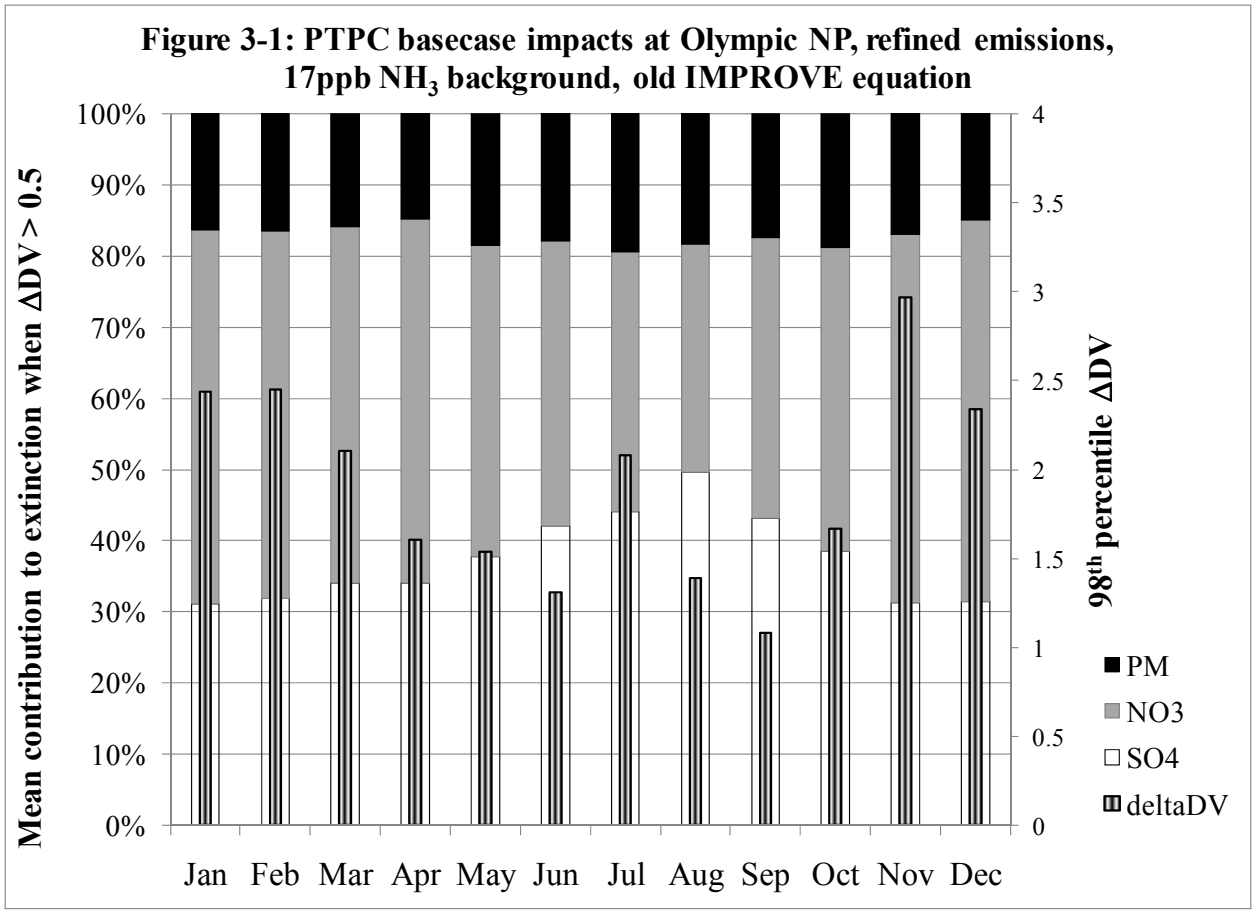
Table 3-2. MAXIMUM 24-HOUR AVERAGE ACTUAL EMISSION RATES

Emission Unit	NO_X (lb/hr)	SO_2 (lb/hr)	H_2SO_4 (lb/hr)	Filterable PM_{10}[a] (lb/hr)	Total PM_{10}[b] (lb/hr)
Recovery Boiler	78.76	105.76	1.66	19.53	24.25
Smelt Dissolving Tank	1.05	0.26	0.11	9.55	9.94
No. 10 Power Boiler	82.61	71.39	8.09	31.59	56.62
Lime Kiln	9.98	1.61	0.78	6.35	7.69

[a] Filterable PM_{10} represents the sum of the modeled filterable PM speciation groups of PMC, PMF, and EC.
[b] Total PM_{10} (TPM_{10}) represents the sum of the modeled filterable and condensable PM, including sulfuric acid (H_2SO_4).

An evaluation of the modeling results show that on an annual basis, NO_X and SO_2 emissions from PTPC each contribute about 40 percent of PTPC's total visibility impact on Olympic National Park. The particulate emissions contribute about 20 percent to visibility impact on the park. Seasonally, the contribution of NO_X, SO_2, and particulate to the modeled visibility impairment varies.

Total visibility impacts are lower during the summer. In the summer, SO_2 from the PCTP Mill can contribute up to about a 50 percent of the visibility impairment caused by the plant, while in the winter NO_X can contribute up to about 50 percent of the visibility impairment caused by the PTPC Mill. The relative contribution of particulate emissions is fairly stable year round at about 18 percent. Figure 3-1 shows the monthly distribution of the days with high impacts (i.e. ΔDV > 0.5) and the breakdown by species.



Net Visibility Improvement

PTPC evaluated the potential visibility improvement that could occur if two of the emissions reduction options were implemented individually. Table 3-4 outlines these modeling scenarios.

Table 3-4. NET VISIBILITY IMPROVEMENT ANALYSIS CONTROL SCENARIOS

Modeling Scenario	Scenario Description
BART100	**Baseline Scenario**
BART101	With Power Boiler No. 10 PM_{10} reductions from the addition of a wet ESP (reduction of PM_{10} emissions to 0.01 gr/dscf vendor guarantee)
BART102	With Lime Kiln SO_2 emissions control from addition of alkaline solution to the existing wet venturi scrubber (assumed 90% emissions reduction of SO_2)

Table 3-5 summarizes the visibility impacts and potential improvement at Olympic National Park for the baseline scenario and the two control option scenarios. The impacts are expressed in terms of the maximum 98th percentile (22nd highest day) 24-hour average visibility impact over the three years of meteorological data modeled.

Table 3-5. BART DETERMINATION VISIBILITY IMPACTS AT

OLYMPIC NATIONAL PARK

Modeling Scenario	98th Percentile Δdv (22nd high in 3 years)	Net Visibility Improvement over Baseline
BART100 (baseline)	1.614	
BART101(PB#10)	1.355	-0.259
BART102 (Lime Kiln)	1.610	-0.004

The modeling results indicate a visibility improvement of 0.259 dv could result from the addition of a wet ESP to further reduce PM_{10} emissions from the No. 10 Power Boiler. The visibility improvement which could result from a 90 percent reduction of SO_2 from the Lime Kiln scrubber is 0.004 dv. PTPC proposed that both emission reduction options were economically infeasible.

4. ECOLOGY'S BART DETERMINATION

Ecology has reviewed the information submitted by PTPC. Ecology agrees with the analyses performed by PTPC and has determined that the current levels of control are BART for the four BART-eligible process units. The controls and emission limitations are summarized in Table 4-1 below.

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

Emission Unit	Pollutant	BART Control Technology	Emission Limitation
NDCE Recovery Furnace	PM_{10}	Existing ESP	NESHAP Subpart MM limit of 0.044 gr/dscf at 8% O_2
	NO_X	Existing staged combustion system	No limit
	SO_2	Good Operating Practices	PSD permit limit of 200 ppm @ 8% O_2
Smelt Dissolving Tank	PM_{10}	Existing wet scrubber	NESHAP Subpart MM limit of 0.20 lb PM10 per ton BLS
	NO_X	No controls	No limit
	SO_2	Existing wet scrubber	No limit
No. 10 Power Boiler	PM_{10}	Existing multiclone and wet scrubber	NSPS Subpart D limit of 0.10 lb/MMBtu
	NO_X	Existing staged combustion system	NSPS Subpart D limit of 0.30 lb/MMBtu
	SO_2	Good Operating Practices	NSPS Subpart D limit of 0.80 lb/MMBtu
Lime Kiln	PM_{10}	Existing venturi wet scrubber	NESHAP Subpart MM limit of 0.064 gr/dscf @ 10% O_2
	NO_X	Good Operating Practices	No limit
	SO_2	Existing wet scrubber	500 ppm @ 10% O_2

4.1 Recovery Furnace BART Determination

For PM/PM_{10} emissions control, Ecology determined that BART is the current level of control provided by the existing ESP. Actual emissions from use of the current ESP average less than 50 percent of the NESHAP (MACT) Subpart MM limit of 0.044 gr/dscf at eight percent O_2. The compliance date for the MACT was March 13, 2004. No new technologies for controlling PM

have become available since then, and the MACT limitation is the strictest limitation currently existing for PM/PM_{10} applicable to this Recovery Furnace.

Since the Recovery Furnace currently utilizes a dry ESP system to control particulate emissions, Ecology made a planning level estimate of the cost to reduce particulate emissions further using cost estimating tools available from EPA's OAQPS.[25] The estimate showed that improvements to the ESP to reduce the BART modeled 106 tpy of particulate emissions in half could cost about $5,100 dollars per ton of particulate removed. As shown in Table 3-2, a reduction of 50% of the recovery furnace particulate emissions would result in approximately a 12% reduction in total particulate emissions from the PTPC plant site. Scaling this from Figure 3-1, this would indicate a small visibility improvement of about 0.07 dv. Ecology considers this improvement to the ESP performance to not be cost effective.

For NO_X control, Ecology has determined that BART is the current level of control provided by the existing staged combustion system. Good combustion practices that optimize the staged combustion inherent in the design of the furnace are the only available technology for control of NO_X that has been demonstrated on recovery boilers. Ecology agrees that the available alternative NO_X control technologies are technically infeasible.[26]

Ecology evaluated the use of a wet scrubbing system to reduce SO_2 from the recovery furnace. Ecology is aware of three recovery furnaces in the Northwest using a wet scrubber to reduce SO_2 emissions, the oldest having been in operation since at least the mid 1980s. Two units are still operational (at Georgia Pacific Camas), but one was shut down in the early 2000s (Longview Fibre). These scrubbers were originally installed to recover waste heat for use in the plant by making hot water by directly contacting the water stream with the hot stack gases. In order to use the hot water produced in this process, the flue gas concentrations of particulate and SO_2 needs to be significantly reduced prior to making the hot water. As a result, this heat recovery process provides some ancillary control of sulfur and particulate emissions.

Ecology's review of recent EPA RBLC recovery furnace entries generally confirms that for most recovery furnaces, installing a scrubber was not considered Best Available Control Technology (BACT). However, one wet scrubber was listed.[27]

Examination of 1997-2007 stack tests on the PTPC recovery furnace showed that SO_2 emissions are typically very low, with most tests showing less than 20 ppm (which was the limit on the GP Camas plant scrubbers). Emissions from a few of the tests were higher than 20 ppm, with the highest near 160 ppm. This testing history indicates that the recovery furnace routinely operates at low SO_2 emission rates, but periodically experiences sporadic short term "spikes" in SO_2 emissions.

[25] EPA Control Cost manual methods were used to calculated costs which were inflated to 2007 dollars.
[26] See Appendix B of this report for further discussions of these technologies.
[27] Meadwestvaco Kentucky, Inc, RBLC entry KY-0085

The EPA scrubber fact sheet indicates[28] that scrubbers with inlet concentrations of 250 to 10,000 ppm can have scrubbing efficiencies of 80 to 99 percent. A scrubber operating at 20 ppm would be expected to be less efficient.

At Ecology's request, PTPC provided a rough estimate of the cost of installing a scrubber to remove SO_2 from the recovery furnace emissions. PTPC assumed a cost of $34 per scfm airflow for this type of wet scrubber.[29] At 250,000 scfm (wet basis) with an assumed 90 percent scrubbing efficiency that removed 417 tpy SO_2, the cost would be $20,383 per ton of SO_2 removed. If the scrubber could not achieve 90 percent efficiency, the cost would be higher. This cost estimate did not consider any site specific retrofit costs.

PTPC concluded the installation of a scrubber to control SO_2 emissions from their recovery furnace to not be cost effective.

For SO_2 control, Ecology has determined that BART is the current level of control provided by the existing staged combustion system operated to minimize loss of sulfur chemicals from the furnace.

4.2 Smelt Dissolving Tank BART Determination

For PM/PM_{10} emissions control, Ecology has determined that BART is the current level of control provided by the existing scrubber and meeting the emission limitation in 40 CFR 63, Subpart MM of 0.20 lb PM_{10} per ton BLS.

For SO_2 control, Ecology has determined that BART is the current level of control provided by the Smelt Dissolving Tank's existing wet scrubber.

4.3 No. 10 Power Boiler BART Determination

For PM_{10} control, Ecology evaluated the controls proposed by PTPC and also looked at the potential to modify the existing wet scrubbing system to provide additional particulate removal.

As discussed in Section 1.3.3, the existing Turbotak wet scrubber was installed in 1988, replacing a venturi scrubber. It is continuously maintained. Routine testing has shown it has consistently operated at between 1/3 and 1/2 of its NSPS based limit of 0.1 gr/dscf since its installation. The emission rate for this unit used in the BART visibility impact modeling reflects this low actual emission rate. BART modeling (see Figure 3-1) indicates that particulate emissions contributed the smallest part of PTPC's visibility impacts. Ecology determined that the small visibility improvement potential from upgrading the scrubber did not justify a full engineering study of the scrubber to determine possible particulate scrubbing improvements.

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[28] US EPA CATC, *Air Pollution Control Technology Fact Sheet – Spray Tower Wet Scrubber,* EPA-451/F-03-016, July 2003. Available at **www.epa.gov/ttn/catc/dir1/fsprytwr.pdf**.

[29] Cost derived from data in US EPA CATC, *Air Pollution Control Technology Fact Sheet – Spray Tower Wet Scrubber,* EPA-451/F-03-016, July 2003. Available at **www.epa.gov/ttn/catc/dir1/fsprytwr.pdf**.

As noted previously, the cost effectiveness of installing a wet ESP is $11,294 per ton of PM_{10} reduced for approximately 109 tpy of emissions reductions. Modeling indicates a definite visibility improvement could occur. However, Ecology determines that the cost of the improved particulate control is too high to justify as BART.

For PM_{10} control, Ecology has determined that BART is the current level of control provided by the existing wet scrubber.

For NO_X control, Ecology has determined that BART is the current level of control provided by proper operation of the boiler's staged combustion system as BART. Ecology could not find a technically feasible NO_X control technology available for retrofit on this boiler. The spreader-stoker design of the No. 10 Power Boiler inherently uses staged combustion, resulting in lower flame temperatures and minimal thermal NO_X formation.

Ecology reviewed BART and further progress evaluations proposed by other states where switching to lower sulfur content fuel oils was considered. Many of the States in the NESCAUM region are considering mandating low sulfur fuel oils for further progress requirements to reduce visibility impairment. NESCAUM evaluated the cost differential of lower sulfur fuels compared to the current fuel oils and determined a range of expected cost effectiveness. For the NE states the cost of this measure was expected to be $500 – 750/ton SO2 reduced. Well below the costs predicted for PTPC.

New Hampshire evaluated the costs for lower sulfur residual oils for the Newton Station and determined that BART for SO_2 is a change from 2% sulfur residual oil to 1% sulfur residual oil for a cost effectiveness of $1900 per ton SO_2 reduced, a value considerably less than the costs for PTPC.

For SO_2 control, Ecology has determined that BART is continued operation of the existing wet scrubber, continued use of the current low sulfur fuels, and implementing good combustion practices aimed at minimizing recycled fuel oil firing as BART.

4.4 Lime Kiln BART Determination

For PM_{10} control, Ecology has determined that BART is the current level of control provided by the existing wet venturi scrubber and compliance with the 40 CFR Part 63, Subpart MM limit of 0.064 gr/dscf at 10 percent O_2.

For NO_X control, Ecology has determined that BART is proper kiln design and Good Operating Practices. Operation using a minimum of excess air minimizes NO_X emissions as well as promoting product quality and process economics.

For SO_2 control, Ecology has determined that BART is the current level of control provided by the Lime Kiln wet venturi scrubber as BART.

APPENDIX A. COMPILATION OF AVAILABLE PM, NO_X, AND SO_2 CONTROL OPTIONS FOR ALL UNITS

Available PM Control Technologies	
Technology	**Description**
Fabric Filter (baghouse)	A fabric filter (baghouse) consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Dirty gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the baghouse. A variety of fabrics is available to cover fuel gas temperatures up to about 650°F. Baghouses are unsuitable for use on water saturated gas streams.
Cyclone Separators	Cyclone separators remove solids from the air stream by application of centrifugal force. In solid fuel combustion devices like hog fuel boilers, they are commonly used to remove large particles prior to the flue gas entering a baghouse or ESP.
Wet Scrubbers	Wet scrubbers intercept dust particles using droplets of liquid (usually water). The larger, particle-enclosing water droplets are separated from the remaining droplets by gravity. The solid particulates are then separated from the water.
Electrostatic Precipitator (ESP)	An electrostatic precipitator (ESP) removes particles from an air stream by electrically charging the particles, then passing them through a force field that causes them to migrate to an oppositely charged collector plate. The dust from the collector plates falls into a collection hopper at the bottom of the ESP. The collection efficiency of an ESP depends on particle diameter, electrical field strength, gas flowrate, and plate dimensions. ESPs can be designed for both dry and wet applications.
Electrified Gravel Bed Filters (EGFs)	Electrified gravel bed filters (EGFs) are a technique that is no longer implemented in Washington State. It used electricity to generate an electrostatic charge on a moving bed of gravel to collect particulate from a wood-fired boiler. The last unit operating in Washington was recently replaced with a baghouse.
Proper Operating Practices	A properly operated emission unit will minimize the formation of PM_{10} emissions. Proper design of combustion units (e.g., boiler and recovery furnaces) concerns features such as the fuel and combustion air delivery system and the shape and size of the combustion chamber. Good operating practices for combustion units typically consist of controlling parameters such as fuel feed rates and air/fuel ratios.

Available NO_X Control Technologies	
Technology	**Description**
Low Excess Air (LEA)	Low excess air (LEA) is a technique where combustion is optimized by reducing the excess air introduced to the unit to the minimum necessary for stable, efficient combustion. Excess air is the air supplied in addition to the quantity required for stoichiometric combustion.
Staged Combustion Technologies	Staged combustion technologies such as overfire air (OFA) reduce NO_X emissions by creating a "fuel-rich" zone via air staging (diverting a portion of the total amount of air required through separate ports). For typical staged combustion, there is a slight excess of air in the initial burn zone. The highest temperatures are reached here, generating thermal NO_X. In the secondary burn zone, a secondary burner injects additional fuel into the marginally lean air, creating strongly rich air (i.e., more fuel is present than oxygen available to oxidize the fuel). In this reducing atmosphere, NO is reacted to N as the hydrocarbons and CO scavenge oxygen. For proper operation, the secondary burn zone must be between 1,800 and 2,200°F. Following this section is the final burn zone, where secondary air (from the cooler) provides sufficient oxygen to oxidize the remaining combustibles.
Flue Gas Recirculation (FGR)	Flue gas recirculation (FGR) reduces peak flame temperature by recirculating a portion of the flue gas back into the combustion zone as a replacement for combustion air. The recirculated gasses have a lower oxygen content that reduces the peak flame temperature in the combustion zone.[30]
Low NO_X Burners (LNB)	Low NO_X burners (LNB) are a technique with limited applicability to pile burning wood-fired boilers and recovery furnaces. Low NO_X burners modify the initial combustion conditions to reduce the peak flame temperature and are often used in conjunction with modifications to overfire air systems. They are most useful when using fuels like natural gas or distillate oil.
Fuel Stating (regurning)	Fuel stating (Regurning) is also known as "reburning" or "off-stoichiometric combustion." Fuel staging is a technique where ten to twenty percent of the total fuel input is diverted to a second combustion zone downstream of the primary zone. Again, this is a technique to reduce the peak flame temperature during combustion
Water/ Steam Injection	Water/steam injection into the main flame can reduce the flame temperature and the generation of NO_X. It is an older technique most often used on older burner designs in natural gas and oil-fired boilers and gas turbines. If the flame temperature is sufficiently quenched, the

[30] Prasad, Arbind, "Air Pollution Control Technologies for Nitrogen Oxides," *The National Environmental Journal*, May/June 1995.

Available NO_X Control Technologies	
Technology	**Description**
	generation of CO can increase and the process efficiency will decrease.
Mid-Kiln Firing	Mid-kiln firing is a form of staged fuel combustion specifically applied to cement and lime kilns. A specially designed fuel injection system introduces a second fuel source at a midpoint in the kiln.[31]
Mixing Air Fan (mid-kiln air lances)	For lime kilns, this technology is a method of staging combustion air through the use of a fan that is mounted on the rotating kiln shell. This can reduce NO_X formation by decreasing peak flame temperatures.
Good Operating Practices and Proper Design	The formation of NO_X can be minimized by proper operation and design practices. Operators can control the combustion stoichiometry to minimize NO_X formation while achieving efficient fuel combustion. This is the most basic combustion modification technique available.
Selective Non-Catalytic Reduction (SNCR)	Selective non-catalytic reduction (SNCR) is an exhaust gas treatment process in which urea or ammonia is injected into the exhaust gas. High temperatures, normally between 1,600 and 1,900°F, promote the reaction between urea or ammonia (NH_3) and NO_X to form N_2 and water.[32] The effectiveness of SNCR systems depends upon six main factors: (1) inlet NO_X concentration, (2) temperature, (3) mixing, (4) residence time, (5) reagent-to-NO_X ratio, and (6) fuel sulfur content.[33]
Selective Catalytic Reduction (SCR)	Selective catalytic reduction (SCR) is an exhaust gas treatment process in which NH_3 or urea is injected into the exhaust gas upstream of a catalyst bed for exhaust temperatures between 450 and 750°F.[34] In the SCR process, the urea or NH_3 injected into the exhaust is stored in a liquid storage tank and vaporized before injection. The exhaust/ammonia mixture then passes over the catalyst. The function of the catalyst is to lower the activation energy of the NO decomposition reaction, therefore, lowering the temperature necessary to carry out the reaction. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) reacts to form diatomic nitrogen (N_2) and water. When operated within the optimum temperature range, the reaction can result in removal efficiencies between 70 and 90 percent.[35] The rate of NO_X removal increases with temperature up to a maximum removal rate at a temperature between 700 and 750°F. As the temperature increases

[31] Battye et al., EC/R Incorporated, *"NOx Control Technology for the Cement Industry"* Final report prepared for EPA, September 19, 2000, Page 65.
[32] NCASI Special Report 03-04, *NOxNOX Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.
[33] Ibid.
[34] Ibid.
[35] 65Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NO_X Controls, EPA/452/B-02-001, pp. 2-9.

Available NO_X Control Technologies	
Technology	**Description**
	above the optimum temperature, or decreases below the optimum range for a conventional vanadium pentoxide catalyst, the NO_X removal efficiency begins to decrease.[36] Depending on the temperatures involved, low temperature and higher temperature catalyst formulations are available. The effectiveness of an SCR system depends upon the same factors as the SNCR system and the condition of the catalyst. The catalyst can degrade over time due to poisoning, fouling, thermal stress, and erosion by particulates, reducing the NO_X removal efficiency of the SCR system.[37]
Oxidation/ Reduction (O/R) Scrubbing	Several proprietary oxidation/reduction (O/R) scrubbing NO_X removal processes are commercially available. The basic elements of a typical process include cooling of the combustion gas stream below its dew point to condense water, treat with ozone or sodium chlorite to oxidize NO_X and SO_2 to their highest oxidized forms, then absorb these oxides as acids in a scrubber. It has been reported that O/R scrubbing has a theoretical NO_X removal efficiency of 95 percent.[38]

SO_2 controls can be placed into three groups: (1) wet flue gas desulphurization systems, (2) dry or semi-dry flue gas desulphurization systems, and (3) low sulfur fuels.

Available SO_2 Control Technologies	
Technology	**Description**
Flue Gas Desulfurization (FGD) with a Wet Scrubber	In flue gas desulfurization (FGD) with a wet scrubber**,** a solution of sodium or calcium hydroxide absorbs SO_2 from the flue gas forming sodium or calcium sulfite. The collected sulfite can be further oxidized to sulfate or left as the sulfite. Typically, large quantities of liquid or solid wastes are generated requiring disposal.[39]
Semi-Dry Lime Hydrate Slurry Injection FGD	For lime hydrate slurry injection, calcium hydroxide in the form of lime slurry is injected into the gas stream. Calcium hydroxide and SO_2 will react to form calcium sulfite. A fabric filter or ESP will be needed to remove the dry solid reaction products from the gas stream.

[36] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NOx Controls, EPA/452/B-02-001, pp. 2-10.
[37] NCASI Special Report 03-04, NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience, August 2003.
[38] Ibid.
[39] Cooper, C. David and Alley, F.C. *Air Pollution Control – A Design Approach, 2nd Edition*. Waveland Press: Prospectus Height, Illinois, 1994.

Available SO_2 Control Technologies	
Technology	**Description**
Dry Lime Powder Injection FGD	Dry lime powder injection FGD controls SO_2 using the same methods as lime hydrate slurry injection and depends on most of the same parameters. As with the lime slurry, a fabric filter or ESP is needed to remove the solid reaction products from the gas stream.[40]
Spray Dryer with an ESP FGD	Spray dryer with an ESP FGD requires installation of a spray dryer and an ESP. Dry lime is injected by a spray dryer into the flue gas in the form of fine droplets under well controlled conditions such that the droplets will absorb SO_2 from the flue gas and then become dry particles because of the evaporation of water. The dry particles are captured by the ESP downstream of the dryer. The captured particles are then removed from the system and disposed.[41]
Low Sulfur Fuel Selection	SO_2 emissions are influenced by the sulfur content of the fuel as well as the sulfur content of the process material. For the Recovery Furnace, the black liquor solids are both the fuel and the material being processed. In the case of the Smelt Dissolving Tank, there is no fuel burning, and in the case of the No. 10 Power Boiler, there is no process material. For the Lime Kiln, the fuel is the dominant source of sulfur rather than the lime feed.
Increased Oxygen Levels at the Burner	Increased oxygen levels at the burner have been shown to decrease SO_2 emissions from lime kilns. The increase in oxygen drives the SO_2 to SO_3 allowing the SO_3 to react with lime to produce $CaSO_4$.
Good Operating Practices	Good operating practices imply that the emission unit is operated within parameters that minimize emissions of air pollutants and maximize combustion efficiency.

[40] Chemical Lime Company Material Safety Data Sheet, Calcium Hydroxide.
[41] Cooper, C. David and Alley, F.C. *Air Pollution Control – A Design Approach, 2nd Edition.* Waveland Press: Prospectus Height, Illinois, 1994.

APPENDIX B. TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES FOR THE RECOVERY FURNACE

Technique	Feasibility Issues/Problems/Limitations
Low Excess Air	Results in the production of smoke, increased CO emissions, and other problems associated with the furnace operation, such as increased corrosion and fouling.[42]
Flue Gas Recirculation	Does not significantly reduce NO_X emissions when firing black liquor solids in a recovery furnace since the majority of NO_X emissions arise from fuel nitrogen. The corrosive conditions inherent in the firing of black liquor solids prevents the use of FGR as the fly ash in the flue gas stream would accumulate in the ductwork required for FGR and absorb moisture, resulting in duct pluggage and severe corrosion. Additionally, the reduced oxygen concentration formed in the furnace by FGR would result in an unacceptable increase in CO emissions. The increased flue gas volume would increase gas velocity in the super heaters and furnace bank, which can cause additional pluggage and lost capacity.
Low NO_X Burners (LNB)	The fireside conditions in a kraft recovery furnace do not accommodate LNB; usage of LNB would prohibit use of multi-stage air feeds and multiple small fuel nozzles, compromising the burners' intended purpose of chemical recovery and impacting their ability to support liquor burning and hearth bed control. The use of low NO_X burners has not been successfully demonstrated for a kraft recovery furnace application.[43]
Fuel Staging	Usage of fuel staging is generally limited to natural gas or distillate oil combustion. Under normal operation, the furnace combusts mostly black liquor solids. The black liquor solids cannot be diverted to a second combustion zone without negatively impacting the delicate balance of the kraft recovery process.
Water/Steam Injection	When firing black liquor solids in a recovery furnace, the majority of NO_X emissions arise from fuel nitrogen. Water/steam injection controls primarily thermal NO_X.
Selective Non-Catalytic Reduction (SNCR)	SNCR for control of NO_X emissions from a kraft recovery furnace has never been demonstrated on a long-term basis and is not listed on the RBLC for any recovery furnace.[44] The Recovery Furnace's complex chemical reaction balance can be upset by the SNCR usage, potentially damaging the furnace and negatively impacting product quality. Optimum NH_3/NO_X molar ratio and correct reaction temperatures would be difficult to monitor and maintain due to fluctuations in furnace load and exhaust gas temperatures. This would cause loss of efficiency

[42] NCASI Special Report 03-04, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.
[43] NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions,* June 2006.
[44] NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions,* June 2006.

Technique	Feasibility Issues/Problems/Limitations
	and result in the release of NH_3 into the atmosphere. It is likely that formation of NH_3 salts would occur which could result in an increase of process downtime. The Recovery Furnace may operate at temperatures above 2,000°F. At temperatures exceeding 2,000°F, the NH_3 injected with the SNCR begins to oxidize, creating additional NO_X. While SNCR has been demonstrated during a short trial on a recovery furnace (which was decommissioned shortly after the trial concluded), long-term use of an SNCR system on a recovery furnace has never been evaluated.
Selective Catalytic Reduction	SCR technology for control of NO_X emissions from a kraft recovery furnace has never been demonstrated even on a short-term basis and is not listed on the RBLC for any recovery furnace.[45] The Recovery Furnace heat input and black liquor solids characteristics vary continuously. This causes temperature swings that would make efficient SCR operation difficult. Efficient operation requires constant exhaust temperatures within a defined range, usually ± 50°F. A low temperature results in slow reaction rates which lead to low nitrogen oxides conversion and unreacted NH_3 passing through the reactor bed (ammonia slip). A high temperature results in shortened catalyst life and can lead to the oxidation of NH_3 and the formation of additional NO_X. Controlling the feed rate of the SCR NH_3 reagent would also present unique technical considerations. NH_3 injection rates must be closely track the varying NO_X rate from the furnace to maintain a given level of NO_X control while simultaneously avoiding excess ammonia slip.
Oxidation/Reduction Scrubbing (including LoTOx)	The ability of an O/R scrubbing system (like LoTOx) to perform efficiently on a recovery furnace has not been demonstrated on a recovery furnace. There are about 10 installations of LoTOx technology on oil refinery FCCUs and 4 other installations of the technology. The principle operating cost is consumption of pure oxygen to produce ozone. A telephone call with the technology supplier indicated that they were focusing on the refining applications at this time.[46] An O/R scrubbing system is designed to complement control systems that already include a caustic scrubber, which PTPC's Recovery Furnace does not have (it has an ESP). If a caustic scrubber were installed on the Recovery Furnace, other technical difficulties would arise. The high moisture content of black liquor solids results in a flue gas dew point temperature that is expected to exceed 300°F, the maximum temperature for effective oxidation/reduction scrubbing. If the flue gas temperature is lowered to below 300°F where these processes work best, condensation liquids with high corrosion potential and disposal issues result. Bleed air or a water spray cooling tower are the technologies typically used to cool the stack gas stream. Increased air flow requires an increase in the size of the induced draft (ID) fan and its power consumption.

[45] Ibid.
[46] By Al Newman in March 2008.

APPENDIX C. TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES FOR THE NO. 10 POWER BOILER

Technique	Feasibility Issues/Problems/Limitations
Low Excess Air (LEA)	LEA is difficult to employ in spreader stoker boilers because high excess air levels are needed for proper fuel burning.[47] LEA is not anticipated to produce NO_X reductions beyond those already achieved by the staged combustion inherently practiced in the boiler. LEA can result in the production of smoke, increased CO emissions, and other problems associated with the boiler operation including increased corrosion and fouling.[48] Due to fluctuations in the fuel properties, a low level of overall excess air would likely cause incomplete combustion, resulting in increased CO emissions.
Flue Gas Recirculation (FGR)	FGR primarily reduces thermal NO_X. FGR would not significantly reduce NO_X emissions when firing a wood waste spreader stoker boiler since the majority of NO_X emissions arise from fuel nitrogen. The use of FGR would also result in soot fouling.
Low NO_X Burners (LNB)	LNB primarily reduce thermal NO_X. As with FGR, is not expected to significantly reduce NO_X emissions when firing a wood-waste spreader stoker boiler since the majority of NO_X emissions arise from fuel nitrogen. A combustion engineering (CE) representative stated that there is no commercially available low NO_X oil burner that can be retrofitted into a tangential type burner like those used in PTPC's No. 10 Power Boiler.
Fuel Staging (Reburning)	Traditional fuel staging (reburning) requires the use of natural gas or distillate oil in a secondary combustion zone downstream of the primary zone. The No. 10 Power Boiler does not use these fuels. Fuel staging often employs FGR, which is considered infeasible for hogfuel boilers due to its inability to minimize fuel NO_X, the primary component of NO_X from wood waste combustion.[49] PTPC's No. 10 Power Boiler inherently uses a process similar to fuel staging by design. The tangential oil burners, which typically supply approximately 30% of the heat to the boiler, are located downstream of the primary wood-fired flame.
Selective Non-Catalytic Reduction (SNCR)	SNCR technology has never been successfully demonstrated for wood-fired boilers with changing loads.[50] The No. 10 Power Boiler firing rate varies to meet the PTPC Mill's steam demand. It has been used on many wood-fired boilers where loads are steadier, like at sawmills.

[47] Washington State Department of Ecology Publication No. 03-02-009, *Hog Fuel Boiler RACT Determination*, April 2003, downloaded June 25, 2007, http://www.ecy.wa.gov/biblio/0302009.html.
[48] NCASI Special Report 03-04, *NOx Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience,* August 2003.
[49] NCASI Special Report 03-04, *NOx Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience,* August 2003.
[50] NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions,* June 2006.

Technique	Feasibility Issues/Problems/Limitations
	There are several reasons why SNCR technology has not been successfully implemented on load-following wood-fired boilers. The injection of the reagent must be applied in a narrow temperature window in order for the reduction reaction to successfully complete. In a load-following boiler, the region of the boiler where this temperature is located varies depending on the firing rate, making it difficult to control the SNCR reaction temperature. Another factor preventing proper implementation of SNCR technology in wood-fired boilers is inadequate reagent dispersion in the injection region, which can lead to significant amounts of unreacted ammonia exhausted to the atmosphere (i.e., large ammonia slip). At least one pulp mill wood-fired boiler had to abandon their SNCR system due to problems caused by poor dispersion of the reagent within the boiler.[51]
Selective Catalytic Reduction (SCR)	SCR technology has never been successfully demonstrated for a spreader stoker boiler.[52] There are several reasons. Size constraints often make locating an SCR system near the boiler impossible in retrofit situations. Most hogfuel boiler temperature profiles are not appropriate for SCR, and the SCR system pressure drop requirements result in sizing concerns related to existing boiler fans. NCASI notes that the high PM concentrations upstream of the PM control equipment would impede catalyst effectiveness and could result in deactivation or poisoning of the catalyst, while installation of SCR downstream of the PM control equipment would render the gas stream too cold for effective reaction with the catalyst to reduce NO_X. The desired temperature range for SCR application is 450 to 750°F, while the outlet temperature of the No. 10 Power Boiler's wet scrubber is less than 150°F. Reheating the flue gas would result in significant energy penalties.
Oxidation/ Reduction (O/R) Scrubbing	O/R scrubbing is not listed as a successfully demonstrated option in any RBLC determination. This technology is not considered readily available or proven for industrial boiler retrofit operations.[53] Even if such technology were to be considered proven and technically feasible for retrofit operations, it is unlikely to be cost feasible.[54]

[51] Ibid.
[52] Ibid.
[53] This technology is not evaluated as a readily available BART option in the BART guidance documents for industrial boilers issued by the Midwest RPO (*Midwest RPO Candidate Control Measures for Industrial, Commercial, and Institutional Boilers*, March 2005) or MANE-VU (*Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants, and Paper and Pulp Facilities*, March 2005).
[54] NCASI Special Report 03-04, *NOx Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience,* August 2003.

APPENDIX D. TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES FOR THE LIME KILN

Technique	Feasibility Issues/Problems/Limitations
Staged Combustion	Staged combustion, also known as staged air combustion or non-selective noncatalytic reduction (NSNCR), is comprised of an initial burn zone (oxidizing), a secondary burn zone (reducing), and a final burn zone (oxidizing). Although staged combustion can theoretically result in NO_X reductions of 20 to 50 percent, the technology is not listed as a control for NO_X in the RBLC database, and PTPC is aware of no lime kilns and only a few cement kilns using this technology. To date, PTPC is aware of only one full-scale industrial operation (a cement kiln in Brevik, Norway) using NSNCR that has reported on its experience. A recent paper reviews six years of operation of the Brevik plant. The Brevik plant included a low NO_X burner in addition to NSNCR. While positive results were initially reported, the averaged results over the six years show little improvement as compared to prior operation with a conventional burner and no NSNCR. In addition, long-term testing showed increases in CO and SO_2 concentrations.[55] Process differences between cement and lime production are the reason this technology has not been applied to the lime industry. A multi-stage pre-heater and cyclones, which a lime kiln does not have, are necessary for the staged combustion required for this control technology.
Mid-Kiln Firing	Although mid-kiln firing (MKF) can reduce NO_X emissions in cement kilns, the longer, lower temperature flame and the addition of fuel to the lime would negatively affect the quality of the lime produced. Introduction of fuel at mid-kiln will increase carryover of unburned carbon to the product. This unburned fuel will prevent the lime product from being used in many applications.[56] MKF is not listed for control of NO_X from a lime kiln in the RBLC.
Mixing Air Fan (mid-kiln air lances)	Mixing air fan (mid-kiln air lances) is a method of staging combustion air to reduce NO_X formation through the use of a fan that is mounted on the rotating kiln shell. However, a mixing air fan can create an oxidizing environment in the kiln in a location that may increase the sulfur content of the product to an unacceptable concentration. There has been no application of a mixing air fan on a lime kiln in the U.S.
Flue Gas Recirculation (FGR)	FGR involves routing a portion of the flue gas to the combustion area for the purpose of reducing the maximum flame temperature (and thus lowering thermal NO_X). Achieving high flame temperatures is critical in the lime production process. The flame temperature achieved using FGR would be below the temperature necessary for proper lime formation. In addition, a

[55] *NO_X Emission Control Technologies for Cement and Lime Kilns,* (Draft, 1995). Radian Canada, Inc.
[56] National Lime Association letter to Ms. Rosalina Rodriguez, North Carolina Department of Natural Resources, *Re: Comments on VISTA's Draft Regional Haze Modeling Protocol*, Ocotober 21, 2005.

Technique	Feasibility Issues/Problems/Limitations
	long and lazy flame will be produced, which is not acceptable for ensuring lime quality. FGR would also require an excessive amount of ducting from the stack to the kiln inlet. FGR has never been demonstrated on a lime kiln and is not listed in the RBLC.
Low NO_X Burners (LNB)	The RBLC does not indicate that LNB has been considered for a lime kiln. There is no commercially available low NO_X burner on the market for implementation in a lime kiln. A 2006 NCASI Corporate Correspondent Memorandum states that "[t]he concept of 'low NO_X burner' is considered a misnomer in the rotary kiln industry. . . In rotary kilns, it is not possible to stage the mixing in the same way [as low NO_X burners in a boiler]."[57] A LNB by design lowers the flame temperature of the burner and changes the flame shape. This is negative for quality control and the calcining process needed to convert a high percentage of $CaCO_3$ mud to CaO reburn lime in the Lime Kiln.
Fuel Staging	The major requirements for fuel staging are to have the fuel feed rate to the main combustion zone be reduced and have an equivalent amount of fuel being fed to the reburn burners in the reburn zone, located downstream of the main combustion zone. Reburning would require major changes for a lime kiln, which could impact the quality of the lime being produced. A lime kiln does not have an area that could be used as a "reburn zone," and additional heat is not needed for a lime kiln pre-heater. Due to these difficulties, this technology has not been previously applied to lime kilns.
Water/Steam Injection	The effectiveness of water/steam injection on lime kiln NO_X emissions is unproven, and this technology is not listed in the RBLC for lime kilns. Water or steam injection into a burner flame will reduce the flame temperature and the generation of NO_X, and is an old, well documented technology for NO_X reduction in boilers and gas turbines. As discussed earlier in the FGR section, the Lime Kiln requires high temperature operation to properly calcine lime. Water/steam injection decreases process efficiency along with flame temperature, and can increase CO generation.
Selective Catalytic Reduction (SCR)	SCR is not listed in the RBLC database for control of NO_X from a lime kiln. To avoid fouling the catalyst bed with the PM in the exhaust stream, an SCR unit would need to be located downstream of the particulate matter control device (PMCD). However, due to the low exhaust gas temperature exiting the PTPC Lime Kiln's wet scrubber PMCD (approximately 156°F); a heat exchanger system would be required to reheat the exhaust stream to the desired reaction temperature range of 450 to 750°F. The source of heat for the heat exchanger would be the combustion of fuel oil, which would

[57] NCASI Corporate Correspondent Memorandum No. 06-0142006, Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions, June 2006.

Technique	Feasibility Issues/Problems/Limitations
	generate additional NO_X and SO_2.
Selective Non-Catalytic Reduction (SNCR)	SNCR has never been demonstrated on a lime kiln and is not listed on the RBLC. Several difficulties preclude use of an SNCR for control of NO_X emissions from lime kilns. If burner temperatures exceed 2,000°F, the NH_3 injected with the SNCR will begin to oxidize, creating additional NO_X. It is also difficult to maintain the correct NH_3/NO_X ratio during load fluctuations. Excess NH_3 will be released into the atmosphere, creating NH_3 slip. NH_3 slip can form ammonium salts which form a visible plume.
Oxidation/ Reduction (O/R) Scrubbing	While O/R scrubbing has a high theoretical NO_X removal efficiency, the technology has never been installed for lime kilns or cement kilns.[58] Additionally, this technology is not listed in the RBLC database for lime kilns.

[58] Telephone conversation between Mr. Darryl Haley (Tri-Mer Corporation) and Mr. David Wilson (Trinity Consultants), October 18, 2001.

APPENDIX E. TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES FOR THE LIME KILN

Technique	Feasibility Issues/Problems/Limitations
Semi-Dry Lime Hydrate Slurry Injection FGD	For lime hydrate slurry injection, calcium hydroxide in the form of lime slurry is injected into the gas stream. A fabric filter or ESP would need to be installed on the kiln to remove the solid reaction products from the gas stream. After the calcium hydrate is injected into the gas stream, the slurry droplets will dry and the particulate matter will be removed from the stream by the fabric filter or ESP. The only possible location to inject the lime hydrate is in the feed chute, which is between the kiln and the pre-heater chamber. The gas residence time in the feed chute is approximately 0.9 seconds, the saturation temperature is approximately 350°F, the actual temperature in the chute is approximately 2000°F, and the SO_2 concentration is relatively low. The injection of lime hydrate slurry at this location will not be effective because the ΔTsat temperature is too large (1650°F), the residence time is too short, and the SO_2 concentration is low. Another possible location for injection would be after the kiln and pre-heater, but before the fabric filter or ESP. However, the kiln already has excess reactive lime available and providing additional lime will not have an appreciable contribution to reducing emissions. In addition, injection at this location is not effective due to the low temperature and low SO_2 concentration.
Dry Lime Hydrate Powder Injection	For lime hydrate powder injection, calcium hydroxide in the form of a lime powder is injected into the gas stream. As with the lime slurry, a fabric filter or ESP would need to be installed on the kiln to remove the solid reaction products from the gas stream. The dry lime hydrate can be also be injected in either the feed chute or prior to the fabric filter or ESP. Hydrated lime decomposes to CaO at a temperature of 1076°F.[59] Since the temperature in the feed chute is 1900 to 2000°F, the hydrated lime will decompose at this location. There is already an abundance of CaO dust at this point in the process, so any additional dry lime will not absorb additional SO_2. Prior to the fabric filter or ESP, the temperature is less than 500°F, which is too low for any substantial reaction between dry $Ca(OH)_2$ and SO_2 to occur.
Lime Spray Drying FGD	Lime spray drying FGD would spray lime in addition to that inherently present in the exhaust stream, so that the lime could absorb the SO_2 in the exhaust. There is already an abundance of lime product in the process. Additional dry lime will not absorb additional SO_2. Injecting additional lime in the transfer chute to control SO_2 is redundant with control already achieved through inherent dry scrubbing of SO_2 and the lime product.
Increased Oxygen Levels at the Burner	The required increase in O_2 levels for implementation of this technology results in additional sulfur being deposited in the lime product, which can potentially compromise product quality. Further, increased O_2 levels near the burner would lead to additional fuel and thermal NO_X formation.

[59] Chemical Lime Company Material Safety Data Sheet, Calcium Hydroxide

APPENDIX F. ACRONYMS/ABBREVIATIONS

BART	Best Available Retrofit Technology
CaO	Calcium Oxide
CO	Carbon Monoxide
dv	Deciview(s)
Ecology	Washington State Department of Ecology
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
F	Fahrenheit
FGD	Flue Gas Desulfurization
MACT	Maximum Available Control Technology
NDCE	Non-Direct Contact Evaporator
NO_X	Nitrogen Oxides
O_2	Sulfur Dioxide
OCC	Old Corrugated Container
PM	Particulate Matter
ppm	Parts per million
PTPC	Port Townsend Paper Corporation
PTPC Mill	Port Townsend Paper Corporation Kraft Pulp and Paper Mill
PSD	Prevention of Significant Deterioration
RFO	Recycled Fuel Oil
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
tpy	Tons per year
TRS	Total Reduced Sulfur
VOCs	Volatile Organic Compounds

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600 • Olympia, WA 98504-7600 • 360-407-6000
711 for Washington Relay Service • Persons with a speech disability can call 877-833-6341

July 7, 2010

Mr. Roger Loney
Port Townsend Paper Corporation
P.O. Box 3170
100 Mill Road
Port Townsend, WA 98368

Dear Mr. Loney:

Regional Haze Best Available Retrofit Technology (BART) Determination

Best Available Retrofit Technology (BART) is required to reduce the regional haze impacts of emissions of your facility. The enclosed Order #7839 contains our BART determination for your facility including a schedule for compliance.

If you have questions or requests relating to this order, please contact Alan Newman at (360) 407-6810 or alan.newman@ecy.wa.gov.

Sincerely,

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Air Quality Program

jj/te

Enclosure

By certified mail

cc: Marc Heffner, Industrial Section
Eveleen Muehlethaler, Port Townsend Paper
Alan Newman, Ecology

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN ADMINISTRATIVE ORDER AGAINST: Port Townsend Paper Corporation	]	ORDER NO. 7839

TO: Mr. Roger Loney
Port Townsend Paper Corporation
P.O. Box 3170
100 Mill Road
Port Townsend, WA 98368

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions that are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the federal and state visibility protection program (WAC 173-400-151 and 40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitutes Best Available Retrofit Technology (BART) for the eligible emission units at your facility.

FINDINGS

A. The Port Townsend Paper Corporation (PTPC) is a Kraft pulp and paper mill subject to BART.

B. The BART-eligible emission units at PTPC are the Recovery Furnace, the Smelt Dissolving Tank, the No. 10 Power Boiler, and the Lime Kiln.

C. Emissions from BART units are controlled by:

   a. Use of an electrostatic precipitator (ESP) to control PM/PM_{10} emissions from the non-direct contact evaporator (NDCE) Recovery Furnace.

   b. Use of a wet scrubber to control PM/PM_{10} and SO_2 emissions from the Smelt Dissolving Tank.

   c. Use of a multiclone and wet scrubber for control of PM/PM_{10} emissions from the No. 10 Power Boiler.

d. Use of a wet venturi scrubber to control PM/PM_{10} and SO_2 emissions from the Lime Kiln.

D. Ecology has determined that the emission controls currently installed at PTPC meet the requirements of BART.

E. Ecology has determined that PTPC has met the requirements of Administrative Order No. #5072, First Amendment, which required submittal of a BART Technical Analysis for the PTPC facility.

Additional information and analysis is available in the BART Determination Support Document for Port Townsend Paper Corporation, Port Townsend, Washington, prepared by the Washington State Department of Ecology, October 2008, and the Best Available Retrofit Technology Applicability Analysis and Determination Report for Port Townsend Paper Corporation, Port Townsend, Washington, prepared by Trinity Consultants on behalf of Port Townsend Paper Corporation, December 2007.

YOU ARE ORDERED: To operate existing emission control equipment for the Recovery Furnace, Smelt Dissolver Tank, Lime Kiln, and No. 10 Power Boiler in accordance with the following conditions:

1. BART Emission Limitations

   1.1. Meet the emission limitations for particulate matter, nitrogen oxides, and sulfur dioxide found in Order DE 05AQIS-2892, issued to the Port Townsend Paper Corporation on August 10, 2006, by the Washington State Department of Ecology's Industrial Section.

   1.2. Meet the SO_2 and NO_X limitations in PSD-I issued June 1, 1984.

   1.3. Compliance will be determined as specified in Order DE 05AQIS-2892.

2. Schedule for Compliance

   2.1. Compliance with the emission limitations for particulate matter, nitrogen oxides, and sulfur dioxide is required upon the effective date of this Order.

3. Monitoring and Recordkeeping Requirements

   3.1. Monitoring and recordkeeping requirements for particulate matter, nitrogen oxides, and sulfur dioxide are contained in Order No. DE 05AQIS-2892.

4. Reporting Requirements

4.1. Reporting requirements for particulate matter, nitrogen oxides, and sulfur dioxide are contained in Order No. DE 05AQIS-2892.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.

- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:		Deliver your appeal in person to:
The Pollution Control Hearings Board P.O. Box 40903 Olympia, WA 98504-0903	OR	The Pollution Control Hearings Board 4224–6th Avenue SE Rowe Six, Bldg 2 Lacey, WA 98503

To serve your appeal on the Department of Ecology:

Mail appeal to:		Deliver your appeal in person to:
The Department of Ecology Appeals Coordinator P.O. Box 47608 Olympia, WA 98504-7608	OR	The Department of Ecology Appeals Coordinator 300 Desmond Drive SE Lacey, WA 98503

And send a copy of your appeal packet to:

Alan Newman
Department of Ecology
Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600

For additional information, go to the Environmental Hearings Office website at http://www.eho.wa.gov.

To find laws and agency rules, go to the Washington State Legislator website at http://www1.leg.wa.gov/CodeReviser.

Your appeal alone will not stay the effectiveness of this Order. Stay requests must be submitted in accordance with RCW 43.21B.320. These procedures are consistent with Chapter 43.21B RCW.

DATED this 7 day of July, 2010 at Olympia, Washington.

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Department of Ecology
Air Quality Program

BART DETERMINATION SUPPORT DOCUMENT FOR LAFARGE NORTH AMERICA SEATTLE PLANT

Prepared by

Washington State Department of Ecology
Air Quality Program

October 21, 2008

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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 of one or more visibility impairing compounds.
4. Cause or contribute to visibility impairment within at least one mandatory federal Class I area.

Lafarge North America (Lafarge) operates a Portland cement plant in Seattle, Washington. The cement production process results in the emissions of particulate matter (PM), sulfur dioxide (SO_2) and nitrogen oxides (NO_X). All of these pollutants are visibility impairing.

Cement plants such as the Lafarge facility are one of the 26 listed source categories. The Lafarge plant began commercial operation in March of 1967 and has the potential to emit more than 250 tons per year of SO_2, NO_X, and PM. Sixteen of the 18 processing areas at the plant are BART-eligible. Lafarge's major sources of visibility impairing pollutants are clinker cooling system and the wet process rotary cement kiln.

Modeling of visibility impairment was done following the Oregon/Idaho/Washington/EPA-Region 10 BART modeling protocol.[1] Modeled visibility impacts of baseline emissions show impacts on the eighth highest day in any year (the 98th percentile value) of greater than 0.5 deciviews (dv) at seven Class 1 areas. The highest impact was 3.16 dv on Olympic National Park. Modeling showed that NO_X and SO_2 emissions from the kiln are responsible for the facility's visibility impact.

Lafarge prepared a BART technical analysis following Washington State's BART Guidance.[2]

The Washington State Department of Ecology (Ecology) determined that BART for PM emissions is the current system of baghouses and electrostatic precipitators at the facility. BART for NO_X is selective non-catalytic reduction (SNCR). BART for SO_2 emissions from the kiln is the current level of control provided by the cement kiln process plus the addition of a dry sorbent injection system using lime. The BART controls selected by Ecology will result in a visibility improvement at Olympic National Park of approximately 1.1 dv with improvements of 0.2 to 0.8 dv at other affected Class I areas.

---

[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.

1. INTRODUCTION

This document is to support Ecology's determination of the Best Available Retrofit Technology (BART) for the Lafarge cement plant located in Seattle, Washington.

The Lafarge plant produces Portland cement using the wet process. Sixteen of the 18 emission units at the plant are subject to BART. The primary emission units of concern are the rotary kiln and the clinker cooler. The rotary kiln is the source of the SO_2 and NO_X produced by the plant. The clinker cooler system is the largest particulate source. All other units are particulate sources controlled by baghouses with low individual emission rates resulting from low airflow rates and intermittent operations. These units collectively have the potential to emit less than 10 percent of the potential particulate emissions from the plant. Currently, an electrostatic precipitator controls particulate matter emissions from the kiln. Particulate matter emissions from the clinker cooler are controlled by a baghouse and a backup baghouse.

1.1 The BART Analysis Process

Lafarge and Ecology used the U.S. Environmental Protection Agency's (EPA's) BART guidelines contained in Appendix Y to 40 CFR Part 51, as annotated by Ecology, to determine BART for the kiln and clinker cooler. The BART analysis protocol reflects utilization of a 5-step analysis to determine BART for SO_2, NO_X, and PM_{10}. 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.

The BART guidance limits the types of control technologies that need to be evaluated in the BART process to available control technologies. Available control technologies are those that have been applied in practice in the industry. The state can consider additional control techniques beyond those that are 'available', but is not required to do so. This limitation to available control technologies contrasts to the Best Available Control Technology (BACT) process where innovative technologies and techniques that have been applied to similar flue gasses must be considered.

As allowed by the EPA BART guidance, Ecology has chosen to consider all 5 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 Basic Description of the Lafarge Plant

The Lafarge plant produces 465,000 tons of Portland cement clinker per year using the wet process. In this process, the raw materials are fed into the rotary kiln as slurry. In the kiln, the slurry is heated to approximately 2700ºF so that the water in the slurry is evaporated and the ground material is converted to metal oxides, the active component of cement.

The primary minerals in Portland cement are calcium oxide, aluminum oxides, iron oxides, and silica. These minerals are derived from limestone, sand, clay, iron ore, iron bearing byproducts, aluminum silicates, natural soils, petroleum contaminated soils, natural gravel, fly ash, boiler slag, lime, gypsum, fluid catalytic cracking unit catalyst, and Vactor wastes (street grit removed from storm drains and pipes), blast furnace and foundry sands, and other material containing calcium, silica, iron, and alumna.

The heat input to the kiln is limited to 282 MMBtu/hr by regulatory order.[3] Fuels that are currently permitted to be used in the rotary kiln are petroleum coke, coal, natural gas, tire derived fuel (TDF), waste oil, and tank bottom oil (TBO).

The raw materials are crushed, mixed with water to form slurry, and pumped into the kiln. In the rotary kiln, heat from combustion is used to dry the slurry and calcine the clinker to remove the carbon dioxide and sulfur dioxide from the minerals to produce cement clinker. The clinker is quickly cooled prior to being pulverized into cement powder. Clinker cooling produces some particulates, which are vented to a baghouse. The final cement powder is mixed with a variety of other materials such as gypsum to produce cements with specific properties.

The principle air pollution control authority for this facility is the Puget Sound Clean Air Agency (PSCAA).

1.3 BART-Eligible Units at Lafarge

Sixteen of the 18 emission units at the Lafarge plant are BART eligible. This means that these 16 emission units have the collective potential to emit more than 250 tons per year of SO_2, NO_X, and PM/PM_{10} and they all commenced operation within the 15-year BART period.[4] Specifically, the plant was constructed during 1966 and is reported to have begun commercial operation in March of 1967.

Table 1-1 gives an overview of the potential emissions from the facility and identifies the primary BART-eligible units. The Potential to Emit is based on permitted emission rates for the

[3] PSCAA Order No. 6202.
[4] The 15-year period ending with August 7, 1977, the date of passage of the Clean Air Act amendments of 1977.

BART-eligible units as listed in the Air Operating Permit issued to Lafarge and the supporting documents for the permit.

Table 1-1. POTENTIAL TO EMIT BY EMISSION UNITS AND WHETHER A BART ANALYSIS WAS PERFORMED BY LAFARGE

Emission Unit	Potential to Emit Tons/year			BART Analysis Performed? (Yes or No)
	NO_X	SO_2	PM_{10}	
Rotary, wet process cement kiln	1720	1650	71	Yes
Clinker cooler primary and backup baghouses	N/A	N/A	2816[5]	Yes
Raw material, finished product storage bins, finish mill conveying system, bagging system, bulk loading/unloading system baghouses	N/A	N/A	480	No

Ecology reviewed the current controls for all emission units at the plant. Lafarge's review focused on the largest emitting units, the wet process kiln, and the primary and backup clinker cooler baghouses. The primary clinker cooler baghouses are designed to operate all the time, while the backup baghouses are intended to operate in the event of failure of one or more of the primary baghouses.

The rotary kiln is the stationary combustion source at the plant. Its emissions of NO_X and SO_2 have been periodically evaluated as part of permitting projects to add new fuels to the list of fuels approved for use in this rotary kiln.

The remaining BART-eligible emission units at the facility are sources of particulate. These units are devoted to handling raw materials, intermediate materials (such as crushed rock or partially crushed clinker), or finished cement. PSCAA has previously subjected these units to a Reasonably Available Control Technology (RACT) analysis as part of bringing the Duwamish Industrial area into attainment with the PM_{10} ambient standards. The RACT analysis for these particulate sources imposed a PM_{10} emission limit of 0.005 g/dscf on all the BART-eligible units. The clinker cooler primary baghouse is the exception to this PM_{10} emission limit.

1.4 Visibility Impact of BART-Eligible Units at Lafarge Plant

Class I area visibility impairment and improvement modeling was performed by Lafarge using the BART modeling protocol developed by Oregon, Idaho, Washington, and EPA Region 10.[6]

[5] Primary baghouse system. The backup baghouse system is smaller than the primary system, but could emit 1408 tons per year if it were to operate for a full year.
[6] A copy of the modeling protocol is available at http://www.deq.state.or.us/aq/haze/docs/bartprotocol.pdf.

This protocol uses three years of metrological information to evaluate visibility impacts. As directed in the protocol, Lafarge used the highest 24-hour emission rates that occurred in the 3-year period to model its impacts on Class I areas. The modeling indicates that the emission from this plant causes visibility impairment on the eighth highest day in any one year and the 22nd highest day over the three years that were modeled.[7] For more information on visibility impacts of this facility, see Section 3 below.

2. BART TECHNOLOGY ANALYSIS

The Lafarge BART technology analysis was based on the 5-step process defined in BART guidance and listed in Section 1.1 of this report.

2.1 Clinker Cooler

Emissions from the clinker cooler are particulates formed during the cooling of the hot clinker and initial handling of the brittle clinkers in the clinker cooler. The existing clinker cooler baghouses and backup baghouses were upgraded in 1994. RACT emission limits were established for these units by PSCAA in order for the area around the plant to return to compliance with the PM_{10} ambient air quality standard. The RACT emission limit for the primary clinker cooler baghouses is 0.025 grain/dry standard cubic foot (g/dscf). For the backup clinker cooler baghouses and all other baghouses at the facility, the emission limitation is 0.005 g/dscf.[8]

2.1.1 PM/PM_{10}

There are many PM/PM_{10} emission controls available for use at this facility. Only those that are capable of meeting the existing emission limitation on the units were evaluated by Lafarge. Controls for particulate emissions from the clinker cooler that were evaluated are given in Table 2-1.

Table 2-1. PM /PM_{10} CONTROLS EVALUATED

Control	Removal Efficiency, % Removal	Typical Emission Limitation, Grains/Dry Standard Cubic Foot (g/dscf)
Baghouse	99.8–99.9	0.004–0.2
Electrostatic precipitator	99.7	0.004–0.2

[7] 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.
[8] PSCAA Order 5627.

The existing baghouses provide for 99.8 percent control of particulate. This is equal or superior to an electrostatic precipitator. Other controls such as wet scrubbers and wet venture scrubbers are available but do not control PM emissions control as well as the currently installed baghouses.

2.1.2 Proposed BART

The currently installed baghouses are the highest level of particulate control available for the clinker cooler system. Lafarge has proposed that the existing baghouses are BART for particulate matter from this clinker cooling processing area.

2.2 Wet Process Rotary Kiln

This unit is a source of sulfur dioxide resulting from the combustion of sulfur containing fuels like coal and petroleum coke and from calcining sulfur minerals in the raw materials, forming SO_2. NO_X is formed in the combustion process through either oxidation of fuel bound nitrogen or oxidation of nitrogen gas in the high temperature flame zone of the kiln (prompt NOx). Particulates are formed in the dryer sections of the kiln through the rotary action of the kiln causing the brittle clinker to fall and fracture, forming smaller clinkers and dust.

2.2.1 SO_2 Control

Currently there is no specific SO_2 control installed on the Lafarge facility. The alkaline nature of the cement clinker formed in the kiln ensures that the process alone provides a considerable amount of sulfur dioxide control. EPA has evaluated this and reports that between 70 and 95 percent SO_2 control is provided by the cement clinker itself.[9] In spite of this much 'native' SO_2 removal in the cement process, Lafarge evaluated the efficacy of a number of add-on SO_2 control technologies that could be applied to their facility.

Table 2-2. SO_2 CONTROL TECHNOLOGIES EVALUATED

Control Technology	Control Efficiency
Dry sorbent injection with lime or sodium	25–35% with an ESP, up to 50% with baghouse
Spray dryer (semi-dry FGD)	Up to 90% with baghouse, up to 70% with ESP
Wet limestone forced oxidation	Up to 95%
Wet lime	Up to 95%
Ammonia forced oxidation	Up to 95%
Alternative fuels and raw materials	< 25%

[9] AP-42 5th Edition–Compilation of Air Pollutant Emission Factors; Chapter 11.6–Portland Cement Manufacturing, U. S. EPA, OAQPS.

Dry sorbent injection involves injecting a dry powder such as sodium carbonate or bicarbonate, calcium oxide, magnesium hydroxide, or calcium hydroxide. The dry reagent reacts with the SO_2 and any SO_3 in the flue gas to convert the carbonates, oxides, or hydroxides to sulfites and sulfates. Injected sorbent (unreacted and reacted) is removed from the flue gas by the particulate control device. Due to the nature of the reaction between lime and the SO_2 in the flue gas, higher SO_2 removal rates and lower lime injection rates can be achieved with the use of a baghouse compared to the use of an electrostatic precipitator (ESP). The cost to replace the existing ESPs with a new baghouse was not evaluated by Lafarge. The addition of duct sorbent injection to cement kiln exhaust is a relatively new concept in the industry, but has been used at a number of kilns around the world.

Lafarge has determined that dry sorbent injection using lime to control SO_2 from the kiln is technically available and analyzed the cost and other environmental impacts of its use at their facility. Their analysis indicates that there is:

- An appropriate location for injection of the dry sorbent.
- Recovered reacted dry sorbent can be beneficially utilized in the cement product.
- This location provides adequate contact time between the flue gas and the dry sorbent to provide a level of emissions control.
- No new ductwork, reactor vessels, or replacement particulate control device is required.
- That this location in conjunction with the existing ESPs will provide a SO_2 removal rate 25 percent (based on a design 7.5 percent control effectiveness and a 90 percent availability of the control system) of the SO_2 leaving the kiln.

A **spray dryer** injects a slurry of recycled solids from the particulate control mixed with lime limestone, or sodium carbonate into the flue gases to react with SO_2 and SO_3 within the droplets containing the reagent chemical. The reaction rate slows as the droplets dry out. The reagent may be sprayed into a duct or a special reactor vessel. The dried reagent is commonly collected in a baghouse located downstream of the injection site, though there are boiler installations using an ESP. The presence of a baghouse increases the removal efficiency of the technique compared to use of an ESP.

Lafarge has proposed that installation of a spray dryer system is technically infeasible at this time. Use of this control would require the addition of the following:

- A new reactor tank since duct length provides insufficient detention time for the spray dryer process.
- Significant modifications to the existing ductwork at the exit of the kiln.
- Disposal costs for the sulfite waste product.
- Higher removal rates than the duct sorbent injection process would require replacement of the ESPs with a baghouse.

Wet Scrubbers for SO_2 control come in a variety of configurations differing most importantly in the chemistry used. Lafarge evaluated the use of a wet limestone forced oxidation and a wet

lime scrubbing systems. Ecology requested an evaluation of the use of an ammonia forced oxidation scrubber that is discussed below.

In a **wet limestone forced oxidation** scrubber, limestone is pulverized and mixed into slurry, which is injected into a reactor vessel. The SO_2 reacts with the limestone slurry to form calcium sulfite. The calcium sulfite in solution is mixed with air to force the reaction of the calcium sulfite to the calcium sulfate (gypsum) form. The calcium sulfate is removed from the scrubbing liquor via a belt or filter press. Lafarge would use the resulting gypsum by mixing it with the cement clinker produced by the kiln.

The plant already uses limestone as one of its major raw materials. Due to this use, the wet limestone forced oxidation process would not require additional or new raw material storage or handling equipment. The gypsum produced would offset purchased gypsum currently used by the plant.

In industrial boiler and coal fired electric utility boiler applications, the wet limestone forced oxidation process has demonstrated removal efficiencies of over 95 percent. There is limited application of this process to cement kilns. At a Lafarge facility in Europe, the process has been able to routinely achieve 81 percent control.[10]

Lafarge has determined that installation of a wet limestone forced oxidation scrubbing system is a feasible control option for this facility. The wet scrubber system would be located between the existing ESPs and the stack. At this location, it would provide about 90 percent removal efficiency. Lafarge estimates that such a system would only be available for 90 percent of the operating time for an annual SO_2 removal efficiency of 81 percent. Experience with this technology on coal-fired power plants indicates that the availability of the control system will be much higher than 90 percent.

The **ammonia forced oxidation** process has been used on a few industrial and coal-fired boilers, but not on cement kilns. The process is similar to the wet limestone process with ammonia replacing the calcium carbonate of the limestone and the final product being ammonium sulfate. The ammonium sulfate can be sold as a fertilizer.

In Lafarge's evaluation of this technology, they focused on the additional space necessary for ammonia storage, the incompatibility of ammonia with the cement product, and the perceived difficulty of selling the resulting ammonium sulfate.

While this technology provides essentially identical emissions control as the wet limestone forced oxidation process, Lafarge has determined the technology is not technically feasible for their facility.

[10] RTP Environmental Associates, "Proposed Best Available Retrofit Technology (BART) for the Lafarge Plant in Seattle, Washington," December 2007, pp. 3-6.

Wet lime scrubbing is similar to the wet limestone forced oxidation process with a few notable differences. First, instead of limestone (calcium carbonate) being used as the reagent, lime (calcium oxide) is used. Second, the wet lime process does not normally take the calcium sulfite formed and further oxidize it to calcium sulfate. Lime is considerably more expensive than limestone and without the inclusion of forced oxidation, the scrubber wastes (primarily calcium sulfite) must be landfilled. Lafarge did not propose to include the forced oxidation step.

Lafarge considers this process technically feasible to implement at their facility.

Cost analysis of the available SO_2 control options

Lafarge estimated the costs of the various control options that are considered technically feasible. The costs and emission reduction provided by each control option evaluated is in Table 2-3. Note that Lafarge did not provide a cost analysis for dry sorbent injection that included the costs of O&M or lime. The cost effectiveness value shown in the table is solely for the capital cost.

Table 2-3. COST AND COST EFFECTIVENESS ANALYSIS SUMMARY

Control Option	Capital Cost	Annualized Cost	Current Emissions, Tons/Year	Tons Per Year Reduced, Tons/Year	Cost Effectiveness, $/Ton Reduced
Dry sorbent injection	$6,090,000	$574,896[11]	570	142.5	$4,034[11]
Wet limestone forced oxidation	$77,064,944	$15,198,999[12]	570	462	$32,920
Wet lime scrubbing	Not calculated		570	399	

2.2.2 NO_X Control

Currently, the NO_X emissions on the rotary kiln are controlled via combustion controls only. This provides a minimal amount of control, and is included in the baseline emissions condition. A number of controls were evaluated in Table 2-4 below.

[11] Does not include annual O&M costs. Based on seven percent interest rate and 20-year equipment lifetime.
[12] Based on seven percent interest rate and 20-year equipment lifetime.

Table 2-4. NO_X CONTROLS EVALUATED

Control Technology	Control Efficiency	Technically Feasible?
Low NO_X burners/indirect firing	15% reduction	Yes
Mid-kiln firing of whole tires	40% reduction	Yes
SCR	Up to 95% reduction	No
SNCR	30-40% reduction	Yes
Low NO_X burners/indirect firing/SNCR	45-85% reduction	Yes
Low NO_X burners/indirect firing/mid-kiln firing	55% reduction	Yes

Low NO_X burners are a common control technique applied to many different combustion sources. Low NO_X burners reduce the emissions of NO_X by reducing the peak temperature of the flame area of the burner. Low NO_X burners have been retrofitted on other wet process kilns in the U.S. According to Lafarge, the use of low NO_X burners would require the replacement of the existing direct firing burner system (the burner fires directly into the rotary kiln) with an indirect firing system (where the burner fires into a smaller primary combustion chamber prior to being ducted to the kiln). The indirect firing component allows better control of the combustion conditions that lead to the formation of NO_X. Lafarge determined that even though the conversion to an indirect firing system with low NO_X burners may be a challenging construction project, the conversion is a technically feasible emission control option. The only significant adverse impact that they identified to this process was that it could result in a limitation on the volatility of the coals used. The systems are apparently adversely impacted when high volatility coals are used. Sub-bituminous coals from the Wyoming/Montana Powder River Basin are considered high volatility coals.

Low NO_X burners are estimated to reduce NO_X emissions by about 15 percent. This technology is compatible with mid-kiln firing, SCR, and SNCR since it is implemented at the fuel feed end of the kiln. Lafarge has estimated that installation of Low NO_X burners and indirect firing would have a capital cost of $15,000,000, and a cost effectiveness of $19,246/ton NO_X reduced.[13]

Mid-kiln firing is a process where a small part of the fuel needs to the kiln is introduced at approximately the middle of the kiln's total length. The process is also known as 'reburning' when applied to fossil fuel fired boiler systems. Whole tires are an attractive, available, and relatively low cost fuel that has been proven in practice to reduce NO_X emissions from long wet

[13] The cost effectiveness is based on a 10 percent interest and a 15-year capital recovery period. Using the Ecology standard of seven percent interest rate and a 20-year period changes the cost effectiveness to $2,921/ton reduced.

kilns such as this one. This technology is expected to reduce NO_X emissions by about 40 percent.[14]

While the literature indicates that any fuel can be added at this point, Lafarge indicates that a quick burning fuel such as wood chips or natural gas would not be effective at reducing NO_X. Preferably, the fuel used would have a relatively long burning time. Whole vehicle tires are the common fuel to meet this criteria, though dewatered wastewater sludge (biosolids) would meet this criterion. Lafarge considers this technology technically infeasible since they do not believe they can guarantee a long-term supply of whole tires. Lafarge currently has the capability to feed whole tires at the mid-kiln location, and did not estimate the cost of this control technique as part of this evaluation.

Selective Catalytic Reduction (**SCR**) is a NO_X control technology that is commonly applied to combustion sources in both new construction and retrofit installations. It involves the use of a base or precious metal catalyst and the injection of ammonia or urea into the flue gas stream. The ammonia reacts with the NO_X to form nitrogen gas and water. Some excess ammonia escapes the process and is emitted. Worldwide, there are only two reported uses of SCR on a cement kiln, and neither of these was on a wet process kiln. The Solnhofen cement plant is a preheater (dry process) type kiln and the SCR process is reported by the cement industry to have operated for a limited period of time before being shutdown. The other installation is on a dry kiln at Cementeria de Monselice in Italy and is still in operation at this time. Dry cement kilns and wet process kilns differ in how and where the fuel is combusted. This difference is significant enough to remove SCR from consideration as an available emission control technology for a wet process kiln.

Selective Noncatalytic Reduction (SNCR) is a NO_X control technology often used where lower rates of NO_X reduction are required or SCR is not feasible. In SNCR process, ammonia, an ammonia water solution, or a urea water solution is sprayed into the combustion zone at a location where the temperature is in the range of 1600–1800ºF. At the Lafarge plant, this temperature window occurs at the same location where mid-kiln firing might occur. According to the company, mid-kiln firing and SNCR are incompatible technologies due to the location of this temperature window.[15] To date, there are two wet kiln plants operating with SNCR, one is the Ash Grove Cement plant in Midlothian, Texas; the other facility is in Europe. When used on boilers, SNCR has exhibited a range of control efficiency from 30–70 percent. The higher levels of control effectiveness have not been demonstrated at the few wet process cement kilns using this control. Lafarge estimates that implementation of SNCR on their wet kiln would result in a reduction of NO_X of 40 percent. They consider the process technically feasible.

Low NO_X burners with indirect firing and SNCR can feasibly be combined at this facility. Lafarge has noted that implementation of low NO_X burners/indirect firing and SNCR would increase the NO_X control efficiency to 55 percent. Lafarge considers that the combination is

[14] Texas Cement Kiln Report (FINAL–7/14/2006), pp. 4-42.
[15] RTP Environmental Associates, "Proposed Best Available Retrofit Technology (BART) for the Lafarge Plant in Seattle, Washington," December 2007, pp. 12-14 of Section 3 and letter of March 11, 2008.

technically feasible to implement, though they did not estimate the costs to implement this process.

Table 2-5 is a summary of the cost analysis and emissions reduction anticipated from use of the control technologies evaluated for NO_X control.

Table 2-5. COSTS AND COST EFFECTIVENESS ANALYSIS SUMMARY

Control Option	Annualized Cost	Uncontrolled Emissions, Tons/Year	Tons Per Year Reduced, Tons/Year	Cost Effectiveness, $/Ton Reduced
Low NO_X Burners/Indirect Firing	$2,738,547	2172.5	325.9	$19,246
SNCR	Not Calculated	2172.5	869	
Mid-kiln firing	Not Calculated	2172.5	869	

2.2.3 PM/PM_{10} Control

Currently particulate control on the rotary kiln is provided by parallel electrostatic precipitators. The plant design anticipated building a second rotary kiln and included as part of the initial construction one electrostatic precipitator for each kiln. Since only one kiln has been constructed, both precipitators are used on the one kiln. Each of the two ESPs was sized to control emissions from one rotary kiln. Each ESP has three stages designed to handle an exhaust flow rate of 400,000 actual cubic feet per minute (acfm) with a space velocity of five feet/second. The one existing kiln operates with an exhaust flow rate under 200,000 acfm. Lafarge has ducted their two ESPs to their one kiln. As a result, each existing ESP has a space velocity of about two feet/second. Because of the low velocities through the ESPs, actual removal efficiency is 99.95 percent or higher, which is equal to or exceeds the capability of a baghouse. The current emission limitation for the kiln/ESP stack is 0.05 g/dscf as required by PSCAA regulation.[16]

Lafarge proposes that the existing ESP system is BART for their cement kiln.

Lafarge's analysis of the visibility impact modeling indicates that the PM_{10} emissions do not contribute a significant amount to the plant's modeled visibility impact.

[16] Regulation I, Section 9.09.

2.2.4 Proposed BART

Lafarge has proposed that the controls listed in Table 2-6 be determined to be BART for the rotary kiln.

Table 2-6. LAFARGE'S PROPOSED BART CONTROLS

Parameter	Control Technology	Proposed BART Control Efficiency, % Reduction	Baseline 30-Day Average Emissions	Proposed 30-Day Average Emission Limit
SO_2	Duct sorbent injection with lime	25	5.74 ton/day	4.31 ton/day
NO_X	SNCR	40	19.1 ton/day	11.5 ton/day
$PM/PM_{10}/PM_{2.5}$	Existing ESP system	0	0.05 g/dscf	0.05 g/dscf

3. VISIBILITY IMPACTS AND DEGREE OF IMPROVEMENT

Lafarge modeled their current visibility impairment and the potential improvement from the two control scenarios that they evaluated as potential BART controls for their facility. In modeling the emissions, they followed the BART modeling guidance prepared for use by sources in Washington, Oregon, and Idaho. In accordance with the EPA BART guidance, this modeling protocol utilizes the CALPUFF modeling system and the 'old' IMPROVE equation to convert modeled concentrations to visual impairment. This approach is consistent with most of the states included in the Western Regional Air Partnership for modeling individual source visibility impairment. The 'old' IMPROVE equation is used because it is included within the CALPUFF modeling system and is part of the EPA accepted version of the model per 40 CFR Part 51, Appendix W. A new equation is available, but is not included within the version of the CALPUFF modeling system specified in the modeling protocol.

The results of the Lafarge modeling are shown in Table 3-1 for all Class I areas within 300 km of the plant plus the Columbia River Gorge National Scenic Area. The table shows the maximum day impairment due to Lafarge, the highest of the three 98th percentile days of each year modeled, and the 98th percentile day of all three years modeled. Also shown is the modeled visibility impairment resulting from the two control scenarios modeled by Lafarge. The modeled emissions for the baseline condition and the two control scenarios are included in Table 3-1. The shaded areas indicate values above the 0.5 dv threshold used to determine if a source contributes to visibility impairment.

The emission rates modeled were derived from operating records of the rotary kiln and reflect the highest 24-hour emission rate within the three years that were modeled. The emission reduction percentages (see table above) were applied to this maximum 24-hour emission rate and those rates were then used for modeling the visibility impairment/improvement that could be achieved using the proposed controls. The maximum day SO_2 emissions during the three years of modeling were not used as that day was reported to be in an abnormal, upset operating condition. In reviewing the emission information, it is also unusually high compared to all other monitored days in the 3-year period. The modeled emission rates are shown in Table 3-1.

Ecology modelers have reviewed the modeling performed by Lafarge and have found that the modeling complies with the Modeling Protocol and produces a reasonable result.

The modeled emission reductions result in substantial reduction in the visibility impairment caused by Lafarge in all Class I areas modeled and in the Columbia River Gorge NSA. At the three most heavily impacted Class I areas, Olympic National Park, Mt. Rainier National Park, and the Alpine Lakes Wilderness, Lafarge's proposed BART controls would provide 0.8 to 1 dv reduction in visibility impairment in each of these areas.

Table 3-1. THREE YEAR DELTA DECIVIEW RANKING SUMMARY

Class I Area	Visibility Criterion	Baseline Emissions	Control Scenario 1: SNCR & DAA	Control Scenario 2: SNCR & Wet Scrubbing
Alpine Lakes Wilderness	Max delta deciview	4.93	3.342	2.779
	Max 98% value (8th high)	2.07	1.335	1.232
	3-yrs Combined 98% value (22nd high)	2.06	1.318	1.182
Glacier Peak Wilderness	Max delta deciview	3.34	2.234	1.754
	Max 98% value (8th high)	1.62	1.05	0.866
	3-yrs Combined 98% value (22nd high)	1.43	0.901	0.769
Goat Rocks Wilderness	Max delta deciview	1.56	0.979	0.859
	Max 98% value (8th high)	0.92	0.581	0.457
	3-yrs Combined 98% value (22nd high)	0.85	0.529	0.448
Mt. Adams Wilderness	Max delta deciview	1.49	0.934	0.812
	Max 98% value (8th high)	0.78	0.491	0.389
	3-yrs Combined 98% value (22nd high)	0.76	0.48	0.389
Mt. Hood Wilderness	Max delta deciview	1.72	1.097	0.874
	Max 98% value (8th high)	0.65	0.412	0.339
	3-yrs Combined 98% value (22nd high)	0.62	0.383	0.307
Mt. Rainier National Park	Max delta deciview	4.47	2.98	2.631
	Max 98% value (8th high)	2.04	1.261	1.092
	3-yrs Combined 98% value (22nd high)	1.78	1.131	0.959
North Cascades National Park	Max delta deciview	2.76	1.8	1.577
	Max 98% value (8th high)	1.48	0.947	0.754
	3-yrs Combined 98% value (22nd high)	1.27	0.798	0.693
Olympic National Park	Max delta deciview	6.99	4.893	4.25
	Max 98% value (8th high)	3.16	2.072	1.81
	3-yrs Combined 98% value (22nd high)	2.96	1.937	1.678
Pasayten Wilderness	Max delta deciview	1.37	0.876	0.736
	Max 98% value (8th high)	0.82	0.513	0.429
	3-yrs Combined 98% value (22nd high)	0.72	0.461	0.393
Class II area modeled per the Modeling Protocol				
Columbia River Gorge National Scenic Area	Max delta deciview	1.41	0.881	0.758
	Max 98% value (8th high)	0.59	0.371	0.336
	3-yrs Combined 98% value (22nd high)	0.51	0.316	0.265
Modeled Rates (lb/hr)				
	NO_X -->	1595	957	957
	SO_2 -->	479	359	48
Modeled Rates (ton/day)				
	NO_X -->	19.1	11.5	11.5
	SO_2 -->	5.7	4.3	0.6

The 8th day in any year or the 22nd day over the 2-year period is the 98th percentile days.

4. ECOLOGY'S BART DETERMINATION

Ecology has reviewed the information submitted by Lafarge. In general, we agree with Lafarge's BART technology evaluation.

While the other particulate sources at the plant that are BART-eligible were not evaluated, we note that the particulate emission limit on these units is based on the use of baghouses meeting an emission limitation of 0.005 g/dscf.

Ecology does not agree with Lafarge's proposed BART emission limitations for NO_X and SO_2 emissions from the rotary kiln.

4.1 Clinker Cooler Baghouses

These units are already well controlled with baghouses. Only an ESP could provide an equivalent level of control, and this would require removal and replacement of the existing baghouses, increase the electrical needs of the facility, and not produce a reduction in emissions. The current emission limitations on the clinker cooler baghouses are reflective of current BACT levels of control imposed on dry material handling equipment.

BART for the clinker cooler baghouses is the existing primary and backup baghouses and the emission limitations for these units contained in Regulation 1, Section 9.09 (in effect on June 30, 2008), and Order of Approval Number 5627. The emission limitations reflecting BART is provided in Table 4-1 below.

4.2 Wet Process Rotary Kiln

4.2.1 SO2 Control

We performed additional cost and technology evaluations for SO_2 controls available for the facility. Those evaluations were specifically oriented to the use of a lime spray dryer or dry sorbent injection. Lafarge has proposed dry sorbent injection as BART for SO_2 control, but did not provide any cost information in their original analysis. At our request, they have supplemented that information and reported the capital cost of a dry sorbent injection system as $6,090,000. We have used this capital cost and estimated its annual operating costs to determine the cost effectiveness of this control. We estimate the annual costs of this control to be $1,116,571, for a cost effectiveness of $7,123/ton SO_2 removed. This is comparable to the applicant's estimated cost of $4,034/ton SO_2 removed, which does not include O&M and reagent costs.

The average cost effectiveness of this control is relatively high compared to other cost effective determinations by Ecology and other agencies. However, the visibility improvement resulting from the implementation of this control technology is substantial. Using the impacts on Olympic National Park, as an example, indicates that on the days where Lafarge has its highest adverse

visibility impact, the SO_2 emissions account for approximately 20 percent of the total visibility impairment. On the worst 98th percentile day in 2004 of 2.072 dv, this indicates that approximately 0.8 dv is due entirely to the SO_2 emissions from the plant. We believe that this is a significant visibility improvement that comes at a reasonable cost of $1.4 million/dv.

Ecology has determined that BART for SO_2 at the Lafarge plant is the current level of SO_2 control afforded by the cement process plus addition of a duct sorbent injection system using lime with an additional removal effectiveness of 25 percent. Emission limitations resulting from use of this technology are shown in Table 4-1 below.

4.2.2 NO_X Control

In response to our review comments, Lafarge evaluated the inclusion of low NO_X burners at their facility. As noted by Lafarge, low NO_X burner technology is compatible with both SNCR and mid-kiln firing of whole tires, additional technologies that are technically feasible and provide approximately the same level of NO_X control in long wet kilns. The cost effectiveness of SNCR with a 40 percent removal rate is estimated by Ecology to be $1,409/ton reduced.[17] The cost effectiveness of SNCR plus low NO_X burners is estimated to be $6,274/ton[18] reduced. The incremental cost of adding low NO_X burners to the SNCR process is $14,900/ton reduced. We find the average and incremental cost effectiveness of the SNCR and low NO_X burners are not cost effective.

Ecology disagrees with Lafarge's conclusion that the mid-kiln firing with whole tires is not technically feasible due to a lack of a long-term tire supply. We see used tires being produced for many years into the future. According to the Department of Ecology's publication, Solid Waste in Washington, Fifteenth Annual Status Report,[19] there are approximately five million waste vehicle tires produced in Washington each year and about 26 percent of those tires are not reused in any way, but are disposed of in landfills. This Ecology report indicates that over 22 thousand tons of used tires are disposed of in landfills each year. According to the State of Texas,[20] tires have a heat content of 14,000 Btu/lb and a sulfur content equivalent to the coal commonly used in Texas kilns. The steel in the tires makes a beneficial contribution to the iron oxide component of the finished cement.

With 22,000 tons of tires per year being disposed of in landfills in Washington, we believe that there is an adequate supply of tires for the foreseeable future. We have determined that the use of mid-kiln firing with whole tires is technically feasible.

While the heat content of tires makes it an attractive fuel source, other industrial operations in Washington that have tried using tires as part of their fuel find significant handling and operational difficulties with their use. The steel component has proven to be a major ash

[17] Based on a seven percent interest rate and a 20-year lifetime for the emission control installed.
[18] Based on a seven percent interest rate and a 20-year lifetime for the emission control installed.
[19] Ecology Publication 06-07-024, December 2006.
[20] Texas Cement Kiln Report (FINAL–7/14/2006), pp. 4-39.

handling issue for these facilities along with the increased particulate emissions due to the filler compounds (such as zinc oxide) in the tires. Neither the steel portion of tires nor the zinc oxide has been a problem for cement plants using whole tires for fuel. The steel is fully oxidized to iron oxides and with the zinc oxide is incorporated within the cement clinker.

Lafarge has already installed the equipment necessary to feed whole tires to their kiln. This installation was costly to the plant and full use of that capability has not yet been realized or permitted. We believe that since the cost of the modifications to allow mid-kiln firing of whole tires has already been completed, the use of this technique, instead of SNCR, would result in reduced annual costs. We would anticipate the annual cost would be reduced to the costs necessary to purchase, store and feed whole used and discarded tires to the existing mid-kiln firing apparatus. While not evaluated in detail, we are of the opinion that implementation of mid-kiln firing of whole tires should be even more cost effective than the use of SNCR since most of the physical equipment is already in place at the plant.

Ecology considers the use of SNCR or mid-kiln firing of whole tires to be equivalent NO_X control techniques for the Lafarge wet process cement kiln. Both techniques are anticipated to provide a 40 percent reduction in NO_X emissions. Which technology is actually implemented is Lafarge's decision and will reflect many other considerations than the amount of NO_X reduction provided.

Ecology has determined that BART for NO_X control at the Lafarge cement kiln is the use of SNCR or mid-kiln firing of whole tires. The emission limitation reflecting BART is provided in Table 4-1 below.

4.2.3 PM/PM_{10} Control

Ecology agrees with Lafarge's analysis that the existing ESPs provide a BART level of particulate control. The BART emission limitations for these ESPs are contained in Regulation 1, Section 9.09 (in effect on June 30, 2008), and Order of Approval Number 5627 of the Puget Sound Clean Air Agency. The emission limitation reflecting BART is provided in Table 4-1 below.

4.3 All Other PM_{10} Sources at the Plant

Ecology agrees with Lafarge's analysis that the existing ESPs provide a BART level of particulate control. The BART emission limitations for these ESPs is contained in Air Operating Permit Number 14046, issued to the Lafarge North America, Seattle Plant on May 15, 2004, and modified July 28, 2004 by the Puget Sound Clean Air Agency. The emission limitation reflecting BART is provided in Table 4-1 below.

4.4 Averaging Period for NO_X and SO_2 Limitations

Ecology has evaluated the BART emission limitations for NO_X and SO_2 and determined that the limit is to be a single day, not to exceed value. Lafarge proposed that the emission limitations be 30-day rolling averages.
The rationale for the not-to-exceed form of the BART emission limitations is as follows:

Lafarge was found to be subject to BART based on visibility impairment modeled from the 24-hour maximum rates for NO_X and SO_2 over a specific 3-year period. The impact of controls on visibility impairment was determined by reducing these maximum 24-hour rates according to the control effectiveness of the selected controls.

Lafarge proposed the maximum day emission rates after control be used as a 30-day average limitation. If these rates were used as rolling 30-day average, then maximum emissions could exceed the observed 30-day maximum rates used in the analysis. Further, if the 30-day average value were met continuously year around, the resulting annual emissions would be higher than the plant's current annual emission rate Consequently, Ecology has determined that to limit the maximum daily impact on visibility and preserve the annual emission rate, the BART limitations should be the SO_2 and NO_X limitations proposed by Lafarge but in a daily not-to-exceed form. This determination is depicted in Table 4-1.

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

	BART Control Technology	Emission Limitation
Clinker Cooling		
$PM/PM_{10}/PM_{2.5}$	Existing baghouses	0.025 g/dscf for the primary baghouse 0.005 g/dscf for backup baghouse
Rotary Kiln		
$PM/PM_{10}/PM_{2.5}$	Existing electrostatic precipitators	0.05 g/dscf
NO_X	SNCR or Mid-kiln firing of whole tires	Not to exceed 22960 lb/day
SO_2	Duct sorbent injection with lime plus currently permitted fuels and the cement kiln process	Not to exceed 8620 lb/day
All Other PM_{10} Sources at Plant		
	Existing baghouses	0.005 g/dscf

APPENDIX A. PRINCIPLE REFERENCES USED

RTP Environmental Associates, "Proposed Best Available Retrofit Technology (BART) for the Lafarge Plant in Seattle, Washington," December 2007. Amended by letters of March 11, 2008 and June 5, 2008.

Travis Weide to Alan Newman, e-mail message, April 8, 2008 and June 5, 2008.

ERG, Inc., "Assessment of NO_X Emissions Reduction Strategies for Cement Kilns – Ellis County Final Report," July 14, 2006, ERG No. 0195.00.002, TECQ Contract No. 582-04-65589, Work Order No. 05-06.

Albert R. Axe, Jr. on behalf of the Portland Cement Association, Comments on report "NO_X Emission Reductions from Ellis County Cement Kilns," letter, addressed to David Shanbacher, Chief Engineer, Texas Commission on Environmental Quality, June 9, 2006. Includes report "The Experience of SCR at Solnhofen and its Applicability to U.S. Cement Plants."

Portland Cement Association, Comments on the final report "Assessment of NO_X Emissions Reduction Strategies for Cement Kilns – Ellis County," November 20, 2006.

Raytheon Engineers and Constructors, Inc. and Easter Research Group, Inc., "Coal Utility Environmental Cost (CUECost) Workbook Users Manual and Excel spreadsheet, Version 1.0," Provided by EPA, 1998.

CEMBUREAU, "Best Available Techniques for the Cement Industry," 1999.

European Commission, Institute for Prospective Technological Studies, Integrated Pollution Prevention and Control, "Reference Document on the Best Available Techniques in the Cement and Lime Manufacturing Industries," Draft September 2007.

Trinity Consultants, "Five Factor BART Analysis for Ash Grove Cement," Montana City, MT, June 2007, plus EPA comment letter of January 9, 2008 to Joe Scheeler, Ash Grove Cement Company from Callie A. Videtich, Director, Air and Radiation Program.

Bison Engineering, Inc., "Best Available Retrofit Technology Analysis," Holcim (US) Inc., Three Forks, MT, July 2007, plus EPA comment letter of January 9, 2008 to Ned Pettit, Environmental Manager, Holcim, Inc. from Callie A. Videtich, Director, Air and Radiation Program.

A. A. Linero, P.E., "What's Up With Cement Plant Permitting?" Florida Department of Environmental Protection, 2002.

Nicholas Confuorto, Belco Technologies Corp & Jeffrey Sexton, Marathon Petroleum Company LL, "Wet Scrubbing Based NO_X Control Using Lotox™ Technology – First Commercial FCC Start-up Experience," Paper given at NPRA Environmental Conference, Austin, TX, September 24-25, 2007.

Air and Waste Management Association, Editors, Anthony Buonicore and Wayne Davis, "Air Pollution Engineering Manual," Von Nostrand Reinhold, 1992.

Sargent & Lundy, "Dry Flue Gas Desulfurization Technology Evaluation," Prepared for National Lime Association, Project Number 11311-000, September 2002.

APPENDIX B. SUMMARY OF ECOLOGY'S COST ANALYSIS

Equipment Life	20 years
Capital Cost Recovery Period	7%
CR Factor	0.0944

	Uncontrolled tpy	% Reduction	Tons Reduced	Capital Cost (CUECost)	Annualized Capital Cost	Annual O&M Cost	Total Annual Cost	$/Ton	Source of Cost Information
Mid-Kiln Firing	2172.5	0.5	1086.25	$ -	$ -	$ -	$ -	$ -	
SNCR	2172.5	0.4	869	1,499,410	141,544	1,082,997	1,224,541	1,409	CUECost
SNCR+LNB/IDF	2172.5	0.55	1194.9	16,499,410	1,557,544	5,938,737	7,496,281	6,274	CUECost + applicant
LNB/IDF	2172.5	0.15	325.9	15,000,000	1,416,000	4,855,740	6,271,740	19,246	Applicant, from 2000 Cement ACT
LSFO	570	0.9	513	64,139,934	6,054,810	4,875,339	10,930,149	21,306	CUECost
LSD	570	0.7	399	42,313,879	3,994,430	3,135,824	7,130,254	17,870	CUECost
Dry Sorbent Injection	570	0.275	156.75	6,090,000	574,896	541,675	1,116,571	7,123	Applicant supplied capital costs information, April 2008. Annual costs derived by ARN utilizing CUECost analysis factors and accounting for already existing equipment and staff. Operating staff reduced from CUECost to 0.5 FTE/shift from 1 FTE/shift based on observation of operating control systems.

APPENDIX C. ACRONYMS/ABBREVIATIONS

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
dv	deciview(s)
Ecology	Washington State Department of Ecology
EPA	United States Environmental Protection Agency
ESP	Electrostatic Precipitator
Lafarge	Lafarge North America
NO_X	Nitrogen Oxides
O&M	Operation & Maintenance
PM	Particulate Matter
PSCAA	Puget Sound Clean Air Agency
RACT	Reasonably Available Control Technology
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
TBO	Tank Bottom Oil
TDF	Tire Derived Fuel

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600 • Olympia, WA 98504-7600 • 360-407-6000
711 for Washington Relay Service • Persons with a speech disability can call 877-833-6341

July 28, 2010

Mr. Richard Sebastianelli
Lafarge North America, Inc.
5400 West Marginal Way Southwest
Seattle, WA 98106-1517

Dear Mr. Sebastianelli :

Regional Haze Best Available Retrofit Technology (BART) Determination

Best Available Retrofit Technology (BART) is required to reduce the regional haze impacts of emissions of your facility. The enclosed Revised Order #7841 contains our BART determination for your facility including a schedule for compliance. This revision replaces Order No. 7841 dated July 7, 2010.

If you have questions or requests relating to this order, please contact Alan Newman at (360) 407-6810 or alan.newman@ecy.wa.gov.

Sincerely,

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Air Quality Program

jj/te

Enclosure

By certified mail

cc: Alan Newman, Ecology
Steve Van Slyke, PSCAA

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN ADMINISTRATIVE ORDER AGAINST: Lafarge North America, Inc.	]	REVISED ORDER NO. 7841

TO: Mr. Richard Sebastianelli
Lafarge North America, Inc.
5400 West Marginal Way Southwest
Seattle, WA 98106-1517

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions that are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the federal and state visibility protection program (WAC 173-400-151 and 40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitutes Best Available Retrofit Technology (BART) for the eligible emission units at your facility. The rules also require the installation and use of those emission controls on the BART-eligible emission units. The emission controls are to be installed as expeditiously as possible, but in no event can the State allow them to start operation later than five years after the State's Regional Haze SIP amendment is approved by the United States Environmental Protection Agency (EPA).

FINDINGS

A. The Lafarge North America, Inc., Seattle Plant (Lafarge) is a wet process cement plant subject to BART.

B. BART emission limitations for the plant are based on:

   a. Use of existing baghouses and electrostatic precipitators for the control of particulate matter.

   b. Use of SNCR or mid-kiln firing of whole tires for control of nitrogen oxides.

   c. Use of the existing wet process rotary kiln process plus dry sorbent injection for control of sulfur dioxide (SO_2) emissions.

C. The Lafarge North America Seattle Cement plant is included in federal Consent Decree resolving Case 3:10-cv-00044-JPG-CJP, Filed 03/18/10 in United States District Court for

the Southern District of Illinois. This Consent Decree establishes compliance schedules and emission limitations for a number of cement kilns owned and operated by Lafarge North America. In addition to emission limitations and dates to achieve compliance with those limitations, the Consent Decree contains provisions related to temporary cessation of operation of a kiln. These provisions require that a kiln comply with the emission limits applicable to it when the kiln is restarted (provided the restart is after the date established to comply with the new emission limitations) or if the kiln is not operated for more than two years, a restart of the kiln is to be treated as a new emissions source.

D. On July 27, 2010, Lafarge North America requested the BART Compliance Order be revised primarily to reflect specific criteria included in the federal Consent Decree, eliminate some initial stack testing performance requirements, and to eliminate compliance schedule dates that occurred prior to issuance of the Order. No emission limitation is being changed as part of this request, nor is the performance test using EPA reference methods being deleted. The request also included several administrative changes such as the name of the plant manager, which have been made.

Additional information and analysis is available in the BART Determination Support Document for Lafarge North America, Seattle Plant, prepared by the Washington State Department of Ecology, October 2008, and the Proposed Best Available Retrofit Technology (BART) for the Lafarge Plant in Seattle, Washington, prepared by RTP Environmental Associates on behalf of Lafarge North America, December 2007.

YOU ARE ORDERED: To install and operate emission control equipment in accordance with the following conditions:

BART EMISSION LIMITATIONS

1. Particulate Matter Emissions

   1.1. Meet the emission limitations for particulate matter found in Puget Sound Clean Air Agency's (PSCAA) Regulation 1, Section 9.09 (in effect on June 30, 2008), and Order of Approval Number 5627.

   1.2. Compliance will be determined as specified in Air Operating Permit Number 14046.

2. Nitrogen Dioxide Emissions

   2.1. Starting no later than the date in Condition 5, emissions of nitrogen dioxide from the wet process rotary cement kiln are limited to a maximum of:

      2.1.1. 22,960 lb/calendar day, except during periods of control system malfunction.

2.1.2. During documented periods of emission control system malfunction (as defined in 40 CFR 60.2), Lafarge shall utilize good operating practices to minimize nitrogen dioxide emissions.

2.2. Compliance will be determined by use of a continuous emission monitoring system.

2.3. An initial performance test utilizing EPA Reference Method 7E will be performed within 180 days of the start of operation of the NO_X control system.

3. Sulfur Dioxide Emissions

3.1. Starting no later than the date in Condition 5, emissions of sulfur dioxide from the wet process rotary cement kiln are limited to a maximum of:

3.1.1. 8,620 lb/calendar day, except during periods of emission control system malfunction.

3.1.2. 1000 ppmdv, 1-hour average.

3.1.3. During documented periods of emission control system malfunction (as defined in 40 CFR 60.2), Lafarge shall utilize good operating practices to minimize sulfur dioxide emissions.

3.2. Compliance will be determined by use of a continuous emission monitoring system.

3.3. An initial performance test utilizing EPA Reference Method 6C will be performed within 180 days of the start of operation of the SO_2 control system.

SCHEDULE FOR COMPLIANCE

4. Particulate Matter Emissions

4.1. Compliance with the emission limitations is required upon the effective date of this Order.

5. Schedule for Compliance with Sulfur Dioxide and Nitrogen Dioxide Emissions

5.1. Compliance with the sulfur dioxide and nitrogen dioxide emission limitations is required. Compliance will be assured by meeting the following milestones:

5.1.1. Installation and operation of SO_2 and NO_X controls no later than February 1, 2011, unless the kiln is in temporary cessation on that date per Section VII of the federal Consent Decree.

5.1.2. If the kiln is in temporary cessation on February 1, 2011, then installation and operation of SO_2 and NO_X controls no later than the date that the kiln is restarted after February 1, 2011.

5.2. Operate in compliance with the SO_2 emission limitations no later than April 30, 2011, or 90 days after the kiln is restarted if the kiln is in temporary cessation on February 1, 2011.

5.3. Operate in compliance with the NO_X emission limitation no later than the date Lafarge completes optimization of the NO_X control system per the criteria in paragraph 10 of the Appendix to the Consent Decree.

MONITORING AND RECORDKEEPING REQUIREMENTS

6. Particulate Matter

6.1. Monitoring and recordkeeping requirements are contained in Air Operating Permit Number 14046, issued to Lafarge North America, Seattle Plant on May 15, 2004, and modified July 28, 2004, by the PSCAA.

7. Sulfur Dioxide

7.1. Sulfur dioxide emissions are to be quantified by means of a continuous emission monitoring system, consisting of a continuous sulfur dioxide monitor, and a continuous flow rate monitor.

7.2. The sulfur dioxide monitor must meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 2.

7.3. The flow rate monitor must meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 6, except for location of the flow rate monitor. The flow rate monitor may be collocated with the nitrogen dioxide or sulfur dioxide monitor's probe, provided that location is demonstrated to meet the other requirements in Performance Specification 6 and the quality assurance requirements referenced in Condition 7.4.

7.4. As a minimum, the continuous emission monitors must meet the annual quality assurance requirement of 40 CFR Part 60, Appendix F.

7.5. Each calendar day's sulfur dioxide emissions will be calculated and recorded daily.

8. Nitrogen Dioxide Emissions

8.1. Nitrogen dioxide emissions are to be quantified by means of a continuous emission monitoring system, consisting of a continuous nitrogen oxides monitor, and a continuous flow rate monitor.

8.2. The nitrogen oxides monitor must meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 2.

8.3. The flow rate monitor must meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 6, except for location of the flow rate monitor. The flow rate monitor may be collocated with the nitrogen dioxide or the sulfur dioxide monitor's probe, provided that location is demonstrated to meet the other requirements in Performance Specification 6 and the quality assurance requirements referenced in Condition 8.4.

8.4. As a minimum, the continuous emission monitors must meet the annual quality assurance requirement of 40 CFR Part 60, Appendix F.

8.5. Each calendar day's nitrogen oxides emissions will be calculated and recorded daily.

REPORTING REQUIREMENTS

9. Initial performance testing of the NO_X emission control system required by Condition 2.3 and the SO_2 control system required by Condition 3.3 shall be submitted to Ecology and to PSCAA within 30 days of completion.

10. Documentation of each action or activity listed in Condition 5, including notification of the start and end of temporary cessation of kiln operation, will be provided by Lafarge by certified mail to Ecology and to PSCAA within 30 days of completion.

11. Malfunction of the emission control system must, at a minimum, be documented in writing and submitted to PSCAA and Ecology with the emissions monitoring data per Condition 12. Additional recordkeeping and notifications related to excess emissions may also be required by Ecology rule or PSCAA regulation.

12. Continuous emission monitoring data shall be submitted to Ecology and to PSCAA in accordance with PSCAA's Regulation 1, Section 12.03 (effective June 30, 2008). The submittal shall be sent electronically in a format acceptable to PSCAA. Reporting to Ecology will end when Lafarge has demonstrated compliance with the BART emission limits in this order for a continuous 36-month period.

13. Lafarge may request this compliance Order be rescinded after all of the following occur:

13.1. The plant has continuously complied with the emissions limitations in Conditions 1, 2, and 3 for a period of three years after the date in Condition 5.2.

13.2. The emission limitations in this Order have been incorporated into an enforceable order or permit issued under the criteria of RCW 70.94.152 or 70.94.153 and PSCAA regulations implementing these provisions.

13.3. The emission limitations in the enforceable order or permit have been incorporated into the Air Operating Permit issued by PSCAA to Lafarge.

This revision replaces Order No. 7841 dated July 7, 2010.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.

- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal, you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:

The Pollution Control Hearings Board
P.O. Box 40903
Olympia, WA 98504-0903

OR

Deliver your appeal in person to:

The Pollution Control Hearings Board
4224–6th Avenue SE Rowe Six, Bldg 2
Lacey, WA 98503

To serve your appeal on the Department of Ecology:

Mail appeal to:

Department of Ecology
Appeals Coordinator
P.O. Box 47608
Olympia, WA 98504-7608

OR

Deliver your appeal in person to:

Department of Ecology
Appeals Coordinator
300 Desmond Drive SE
Lacey, WA 98503

And send a copy of your appeal packet to:

Alan Newman
Department of Ecology
Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600

For additional information, go to the Environmental Hearings Office website at http://www.eho.wa.gov.

To find laws and agency rules, go to the Washington State Legislature website at http://www1.leg.wa.gov/CodeReviser.

Your appeal alone will not stay the effectiveness of this Order. Stay requests must be submitted in accordance with RCW 43.21B.320. These procedures are consistent with Chapter 43.21B RCW.

DATED this 28 day of July, 2010 at Olympia, Washington.

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Department of Ecology
Air Quality Program

BART DETERMINATION
SUPPORT DOCUMENT FOR
TRANSALTA CENTRALIA GENERATION, LLC POWER PLANT
CENTRALIA, WASHINGTON

by
WASHINGTON STATE DEPARTMENT OF ECOLOGY
AIR QUALITY PROGRAM
August 2009
Revised April 2010

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Executive Summary

The Best Available Retrofit Technology (BART) program is part of the larger effort under the Clean Air Act Amendments of 1977 to eliminate human-caused visibility impairment in all mandatory 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 of one or more visibility impairing compounds;
4. Cause or contribute to visibility impairment within at least one mandatory Class I area.

TransAlta Centralia Generation LLC Power Plant (TransAlta) operates a two unit, pulverized coal fired plant near Centralia Washington. Each unit of the plant is rated at 702.5 MW net output. Operation of a coal fired power plant results in the emissions of Particulate Matter (PM), Sulfur Dioxide (SO_2) and Nitrogen Oxides (NO_x). All of these pollutants are visibility impairing.

Pulverized coal plants such as the TransAlta facility are one of the 26 listed source categories. The units at the plant began commercial operation in 1971 and 1972. The units have the potential to emit more than 250 tons per year of SO_2, NO_x, and PM. As part of an approval of the Washington State Visibility State Implementation Plan (SIP) in 2002, Environmental Protection Agency (EPA) Region 10 determined that particulate and SO_2 controls installed as part of a 1997 Reasonably Available Control Technology (RACT) determination[1] issued by the Southwest Clean Air Agency (SWCAA)[2] met the requirements for BART and constituted BART for those pollutants. EPA specifically did not adopt the NO_x controls in the RACT order as BART.

Modeling of visibility impairment was done following the Oregon/Idaho/Washington/EPA-Region 10 BART modeling protocol.[3] Modeled visibility impacts of baseline emissions show impacts on the 8th highest day in any year (the 98th percentile value) of greater than 0.5 Deciviews (dv) at the twelve Class 1 areas within 300 km of the plant. The highest impact was 5.55 dv at Mt. Rainier National Park. Modeling showed that NO_x and SO_2 emissions from the power plant are responsible for the facility's visibility impact.

TransAlta prepared a BART technical analysis following Washington State's BART Guidance.[4]

The TransAlta facility is specifically addressed in Executive Order 09-05 issued by the Governor of Washington. Under that Executive Order, Ecology is to work with the company on the development

[1] SWAPCA Order No. 97- 2057R1 issued December 26, 1998
[2] Previously known as the Southwest Air Pollution Control Authority (SWAPCA)
[3] Modeling protocol available at http://www.deq.state.or.us/aq/haze/docs/bartprotocol.pdf
[4] "Best Available Retrofit Technology Determinations Under the Federal Regional Haze Rule," Washington State Department of Ecology, June 12, 2007

of an order which will result in the plant's greenhouse gas emissions meeting the state's greenhouse gas emission performance standard[5] by 2025.

The Washington State Department of Ecology (Ecology) determined that BART for NO_x emissions is the current combustion controls combined with the completion of the Flex Fuels project and the use of a sub-bituminous coal from the Powder River Basin (PRB) or other coal that will achieve similar emission rates. This change results in a 20% reduction of NO_x emissions from the baseline period emission rate. The use of low sulfur PRB coal also reduces SO_2 emission by about 60% from the same period. The NO_x reduction from the BART controls selected by Ecology will result in a visibility improvement from the baseline impacts at Mt. Rainier National Park of approximately 1.13 dv, with improvements of 0.67 to 1.45 dv at other affected Class I areas. The controls have been installed and have met the emission limitation since October 1, 2009.

[5] The standard is in Chapter 80.80, RCW. Currently the standard is 1100 lb/MWh and is required to be updated in 2012 and every 5 years thereafter. The current standard is less than half of the plant current emission rate of about 2300 lb/MWh.

1.0 INTRODUCTION

This document is to support Ecology's determination of the BART for the TransAlta coal fired power plant located near Centralia, Washington.

The TransAlta plant is a coal fired power plant rated to produce a net of 702.5 MW per unit. The plant has 2 tangentially fired pulverized coal units currently using PRB sub-bituminous coals for fuel.

In a letter dated October 16, 1995, the National Park Service (NPS) notified Ecology certified that there was uniform visibility haze visibility impairment at Mt. Rainier National Park. The Park Service expressed their belief that some or all of the haze was attributable to emissions from the Centralia coal fired power plant.

In 1998, the SWCAA issued a RACT, Order No. 97-2057R1, for compliance with the requirements of Chapter 70.94.153 Revised Code of Washington. This order established emission reductions for SO_2 and NO_x emissions from the coal fired boilers at the plant. The emission limitations in the Order were the results of a negotiation process involving SWCAA, the plant's ownership group, the NPS, US Forest Service, Ecology and EPA, Region 10.

On June 11, 2003, EPA Region 10 approved the Ecology Visibility SIP submitted on November 9, 1999[6]. Ecology included the RACT emission reductions for Centralia as evidence of further progress in meeting the national visibility goals, but not as BART since no determination of attribution had been made as was required by the visibility rules in place in 1997. The Federal Register notice approving this 1999 submittal notes that while the NPS had certified visibility impairment at Mt Rainier National Park "The State of Washington has not determined that this visibility impairment is reasonably attributable to the Centralia Power Plant (CPP)."

The EPA approval of Ecology's 1999 visibility SIP submittal included a determination by EPA that the SO_2 and PM limits and controls required by the 1997 RACT order issued by SWCAA met the requirements of BART. EPA's determination that SO_2 and PM emissions were BART level of control were based on an analysis performed by Region 10 staff and an example analysis in the Technical Support Document issued by SWCAA.

In the Federal Register notice, the EPA specifically did not include the NO_x emission limit in the RACT Order as BART stating "while the NO_x emission limitation may have represented BART when the emission limits in the RACT Order were negotiated, recent technology advancements have been made. EPA cannot say that the emission limitations in the SWAPCA[7] RACT Order for NO_x represent BART."

As a result of the June 11, 2003 approval of the Washington State Visibility SIP, the TransAlta plant is subject to BART under the Regional Haze (RH) program only for its NO_x emissions[8].

[6] 68 *Federal Register* 34821, June 11, 2003.
[7] At the time, SWCAA was known as the Southwest Air Pollution Control Agency (SWAPCA).
[8] Letter from Mahbubul Islam, EPA Region 10, to Robert Elliott, SWCAA, and Phyllis Baas, Ecology, on Best Available Retrofit Technology Applicability for the TransAlta Centralia Power Plant (September 18, 2007).

1.1 The Best Available Retrofit Technology Analysis Process

TransAlta and Ecology used EPA's BART guidance contained in Appendix Y to 40 CFR Part 51, as annotated by Ecology, to determine BART. The BART determination for coal fired power plants greater than 750 MW of total output must follow the process in BART guidance. The BART analysis protocol reflects utilization of a five-step analysis to determine BART. The 5 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.

The BART guidance limits the types of control technologies that need to be evaluated in the BART process to available control technologies. Available control technologies are those which have been applied in practice in the industry. The state can consider additional control techniques beyond those that are "available," but is not required to do so. This limitation to available control technologies contrasts to the Best Available Control Technology (BACT) process where innovative technologies and techniques that have been applied to similar flue gasses must be considered.

In accordance with the EPA BART guidance, Ecology weighs all 5 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 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 in the determination of BART.

1.2 Basic Description of the TransAlta Centralia Generation LLC Power Plant

The TransAlta plant is a 2 unit, pulverized coal boiler based power plant that currently uses PRB coal. The boilers were initially commissioned in 1971 and 1972. Each unit is currently rated at 702.5 MW (net) output capacity. The units are physically identical, tangentially fired, wet bottom units designed by Combustion Engineering.

TransAlta also operates 2 other generating resources that are part of the Centralia power plant complex. Operating under the name of Centralia Gas is a group of 4 combined cycle combustion turbines producing 248 MW. The combustion turbines were built in 2002 and were subject to Prevention of Significant Deterioration (PSD) permitting requirements. They are currently operated as peaking units. The combined cycle turbines are electrically and physically separate from the coal units. There is also a 1 MW hydropower facility located at TransAlta's Skookumchuck River Dam and Reservoir.

In addition to the above electricity generating units, the plant includes numerous other units, including an oil fired auxiliary boiler used for cold starting of the coal fired boilers and steam turbines. The auxiliary boiler is a 170 MMBtu/hr, oil-fired unit permitted to operate on #2 distillate oil

(with less than 0.5% sulfur by weight) for a maximum of 600,000 gallons per year. The SO_2 emissions from fuel oil combustion in this unit are included in the coal boiler SO_2 emission limitation. The potential to emit of NOx from this unit is 7.2 ton/year and SO_2 of 77 ton/year.

SO_2 control on the 2 coal fired boilers is provided by a wet limestone, forced oxidation wet scrubber system. This system removes over 95% of SO_2 in the flue gas from the boilers. The SO_2 controls were installed in the 1999 – 2002 time period.

Particulate control is provided by 2 electrostatic precipitators in series followed by the wet scrubber system. The first electrostatic precipitators were part of the original construction of the plant. The second precipitators date from the late 1970's.

Current NO_x control is provided by combustion modifications incorporating Alstom concentric firing, low NO_x burners with close-coupled and separated over-fire air[9]. These combustion modifications are collectively known as Low NO_x Combustion, Level 3 (LNC3)." The controls were installed in the 2000 – 2002 time period in response to the RACT Order. The combustion controls were designed and optimized to suit Centralia mine coal.

For a variety of reasons, TransAlta stopped active mining at the Centralia coal mine and now purchases all coal from PRB coal fields. To accommodate the change, the company has modified the rail car unloading system to handle up to 10 coal unit trains per week. Additional modifications are focused on the boilers. The boilers have been modified to reduce temperatures in the flue gas to accommodate the higher Btu coal now being combusted. Additional changes include the reinstallation of specific soot blowers and installation of new soot blowing equipment (steam lances) necessary to accommodate the different ash characteristics of the PRB coals. Improved fire suppression equipment has been installed to accommodate the increased potential of PRB coals to catch fire spontaneously.

TransAlta anticipates operating the plant until at least 2030. They acknowledge that to operate beyond 2025 will require significant plant upgrades to assure safe and reliable operation into the future.

On May 21, 2009, the Governor of Washington issued Executive Order 09-05, Washington's Leadership on Climate Change. One specific action in the Executive Order requires the Director of the Department of Ecology to:

> (1)(d) Work with the existing coal-fired plant within Washington that burns over one million tons of coal per year, TransAlta Centralia Generation, LLC, to establish an agreed order that will apply the Greenhouse gas emissions performance standards in RCW 80.80.040(1) to the facility by no later than December 31, 2025. The agreed order shall include a schedule of major decision making and resource investment milestones;

[9] This set of combustion controls are the basis of the presumptive BART limits of 0.15 lb NOx/MMBtu in Section 4.E of EPA's BART Guideline

The power plant is subject to the federal Clean Air Act's Title V permitting program. The plant operations are covered by air operating Permit No. SW98-8-R2-B, issued March 25, 2008 by SWCAA.

Ecology received a BART analysis from TransAlta in February, 2008, which was revised and resubmitted in July 2008 and supplemented in December 2008 and March 2010.

1.3 Best Available Retrofit Technology Eligible Units and Pollutant at TransAlta Centralia Power Plant

The TransAlta facility located near Centralia Washington includes a number of different operations and units. Emissions from the plant are primarily generated and emitted by the 2 coal fired boilers of the main power plant. The oil fired auxiliary boiler is operated infrequently and is permitted to use a limited number of gallons of diesel fuel oil each year. The auxiliary boiler is used during cold start-up of the coal boilers to heat the boiler water to prevent thermal shock and failure of cold boiler tubes and for preheating of the steam turbines. Emissions from the auxiliary boiler were not evaluated for BART.

As noted above, NO_x is the only pollutant addressed in this BART analysis. As required by the BART guidance and modeling protocol, the maximum day emission rate in the calendar 2003 to 2005 period was determined. The hourly NO_x emissions on the day with maximum emissions during the baseline period (2003-2005) were 2,474 lb/hr (0.302 lb/MMBtu) for Unit 1 and 2,510 lb/hr (0.306 lb/MMBtu) for Unit 2.

1.4 Visibility Impact of Best Available Retrofit Technology Eligible Units at TransAlta Centralia Power Plant

Class I area visibility impairment and improvement modeling was performed by TransAlta using the BART modeling protocol developed by Oregon, Idaho, Washington, and EPA Region 10[10]. This protocol uses 3 years of metrological information to evaluate visibility impacts. As directed in the protocol, TransAlta used the highest 24 hour emission rates for NO_x, SO_2, and PM/PM_{10} that occurred in the 3 year period to model its impacts on Class I areas. The modeled SO_2 and PM/ Coarse Particle Matter (PM_{10}) emission rates complied with their respective emission limits. The modeling indicates that the emissions from this plant cause visibility impairment on the 8th highest day in any one year and the 22nd highest day as all mandatory federal Class I areas within 300 km of the power plant [11]. For more information on visibility impacts of this facility, see Section 3 below.

1.5 Relationship of this Best Available Retrofit Technology Analysis to the 1997 Reasonable Available Control Technology Analysis and Determination

As noted previously, in 1997 the SWCAA finalized a determination of RACT for the Centralia Power Plant. As part of the technical analysis that led to the determination of RACT for NO_x emissions

[10] A copy of the modeling protocol is available at http://www.deq.state.or.us/aq/haze/docs/bartprotocol.pdf
[11] A source causes visibility impairment if its modeled visibility impact is above 1 dv, and contributes to visibility impairment if its modeled visibility impact is above 0.5 dv.

from this plant, 37 different emission control alternatives were evaluated (see Appendix B for the list). The analysis documents produced by the plant's owners reviewed many alternative techniques potentially applicable to the facility. The list of controls reviewed ranged from proven methods of combustion control to methods that had only been proven to work in the laboratory. The alternate technologies evaluated at that time included methods such as natural gas reburn, Selective Non-Catalytic Reduction, Selective Catalytic Reduction, and several options which could control NO_x and SO_2 with the same control system.

As discussed in the company's analysis and the SWCAA support document, these technologies were not selected as RACT for NO_x emissions in favor of the installation of the package of combustion modifications that are now recognized as LNC3.

Since the 1997 RACT Determination, Ecology has tracked development and installations of NO_x control technologies. Based on the large list of emission controls that had been reviewed to support the RACT determination, the relatively slow development of some techniques, and disappearance of some other techniques, Ecology allowed TransAlta to use the evaluation from the 1997 RACT determination to narrow the list of potential control technologies appropriate for this BART review.

The BART analysis by TransAlta focused on those controls that are available and have been implemented on coal fired boilers of the general size of the plant. For more details on the control options evaluated for the RACT analysis, please refer to the RACT report by PacifiCorp for the Centralia Power Plant and the SWCAA Technical Support Document supporting the RACT determination.

2.0 SUMMARY OF TRANSALTA CENTRALIA POWER PLANT'S BART TECHNOLOGY ANALYSIS

The TransAlta's BART technology analysis was based on the five step process defined in BART guidance and listed in Section 1.1 of this report. This section is an overview of TransAlta's BART analysis and supplemental material provided by the plant's owner.

2.1 Nitrogen Oxides Controls Evaluated

The plant already has installed combustion controls to reduce NO_x emissions from thermal NO_x. The controls currently installed are considered the base case from which the effects of other controls are evaluated.

Table 2-1 Nitrogen Oxides Controls Evaluated

Control technology	Control Efficiency	Technically feasible?
Low NOx burners with close coupled and separated overfire air (LNC3)	--	Yes, already installed under RACT
Flex Fuel Project – Existing LNC3 combustion controls plus change in fuel to PRB coal and boiler modifications to accommodate use of PRB type coals		Yes, LNC3 already installed, Unit 2 Flex Fuel modifications completed in 2008, Unit 1 were completed Summer 2009
SCR	Up to 95% reduction	Yes
SNCR	20 - 40% reduction	Yes
ROFA/RotaMix	Unknown	No
Neural net controls	Up to 15%	Yes

Low NO_x Combustion, Level 3

As noted above, the **combustion controls** known as LNC3 are currently installed on each of the coal fired boilers at the plant. These controls have demonstrated an ability to meet the current NO_x emission limit of 0.30 lb. NO_x/MMBtu using Centralia mine coal and PRB coals.

The Centralia Plant's implementation of the LNC3 technology was included in EPA's control effectiveness evaluations leading to its determination of the presumptive BART limits of 0.15 lb NO_x/MMBtu in Section 4.E of EPA's BART Guideline. In 2004 in connection with its adoption of the final BART Guidelines, EPA found that of the 17 boilers in the U.S. with the boiler design of the Centralia Plant's (tangential-fired) that burn sub-bituminous coal, two of the units with LNC3 installed prior to 1997 did not meet the presumptive BART limit. Seven of the units with pre-1997 design did meet the presumptive limit. Of the remaining eight units with LNC3 technology installed in 1997 or after, the two Centralia boilers were the only two that did not meet the presumptive limit. (EPA-HQ-OAQ-2002-076-0446(1) TSD).

Subsequent to the public comment period on the proposed BART determination, TransAlta was requested to supply additional information on the installation of LNC3 at this facility. This additional detail is contained in a March 31, 2010 report from CH2MHill to Mr. Richard Griffith (Appendix G).

The LNC3 system installed met its original design intent of a 1/3 reduction in NO_x from the boiler.

Subsequent to the initial burner installation, the company reports no additional analyses or boiler tuning operations beyond what is done in the normal course of operating the boilers.

Flex Fuel project

TransAlta has proposed its Flex Fuel project as an addition to the currently installed LNC3 combustion controls for consideration as BART emission control. The Flex Fuel project is a series of actions being undertaken by the company to accommodate the exclusive use of sub-bituminous coals with ash, nitrogen and sulfur contents similar to PRB sub-bituminous coals. Combustion modeling of the boilers performed by Black & Veatch using EPRI's Vista model using a representative PRB coal has indicated that the proposed changes will result in a reduction of the hourly and annual emission rate for NO_x.

TransAlta decided to rely on PRB coal after suspending mining operations for Centralia sub-bituminous coal at the end of 2006. PRB coals have a number of characteristics that differ significantly from the Centralia coal the plant was designed to use. Important characteristics that affect the boilers' operation are the net heat content, the quantity of ash, and the abundance of sodium. Appendix A contains tables showing the important characteristics of typical PRB coals and the Centralia coal.

The most important differences between the coals is the heat content British Thermal Units Per Pound (Btu/lb), lower fuel nitrogen, lower sulfur content, the moisture content, and the concentration of sodium. Centralia coal is very low in sodium, higher in fuel nitrogen and sulfur content, and much higher in water content than the PRB coals. The difference in sodium content changes the ash that deposits on the boiler tubes from light and fluffy (Centralia) to glassy and sticky (PRB).

The boiler tube slagging and fouling characteristics of PRB coal increase the heat rates of the boilers compared with Centralia Mine coal. The Flex Fuel Project incorporates physical changes to the pressure parts in each boiler's convective pass that improve heat transfer by reducing the boiler's susceptibility to ash deposition. The major individual pressure part changes include: (a) reheater replacement to maximize soot blower cleaning effectiveness on the tube assembly surface areas, and (b) additional low temperature superheater and economizer heat transfer surface area to result in higher boiler efficiency and a lower flue gas exit temperature. Other significant changes associated with this project are reinstallation of some of the original soot blowers and installation of new 'soot blowing' equipment specifically designed to remove the now sticky and glassy soot from the boiler tubes. These changes allow for more efficient heat transfer within the boiler. Additional discussion of this project's effects and the combustion thermodynamic modeling performed to estimate the emissions decrease from the project can be found in the *BART Analysis Supplement* by TransAlta dated December 2008 and the *TransAlta Centralia Boiler Emissions Modeling Study* by Black & Veatch, dated Sept. 2007.

No changes to the fuel delivery equipment (other than adding fire suppression equipment), burners, combustion air system, or steam turbine are being made. The Flex Fuel Project allows the boilers to burn PRB coal more efficiently, but does not increase the boilers' potential steam generating capacity.

The lower nitrogen content of the PRB coals combined with the lower total quantity of fuel required to produce the same heat input rate to the boilers after the project has been completed on both units. The reduction in total fuel combusted will reduce the emissions of NO_x by approximately 20% from the rates during the 2003 – 2005 period. The emission rates during that baseline period averaged 0.304 lb NO_x/MMBtu and at the completion of the Flex Fuel project are expected to be below 0.24 lb/MMBtu.

Annual average NO_x emissions from December 1, 2003 through November 31, 2005 were 15,695 tons. Based on the proposed BART rate of 0.24 lb/MMBtu, the BART limit would reduce emissions by 3,139 tons/year to 12,556 tons/year.

The estimated capital to implement Flex Fuels on both units is $101,808,663, based on the actual costs to implement the Flex Fuels project on Unit 2 and the expected costs of installation on Unit 1. The annualized cost of the Flex Fuel Project is $11,184,197. Based on the estimated NO_x reductions of 3,139 tons/yr, the cost-effectiveness of the Flex Fuel Project is $3,563/ton of NO_x reduced. Since the Flex Fuel Project also reduces SO_2 emissions by an estimated 1,287 tons/year, TransAlta has calculated that the overall cost-effectiveness of the Flex Fuel Project as $2,526/ton of NO_x plus SO_2 reduced[12].

Neural net controls

Neural net controls for boilers are a relatively new technique. It is based on using a number of different boiler operational information and using that information to continuously optimize the combustion efficiency of the boiler. While numerous venders will provide this technology, TransAlta received detailed information from NeuCo, Inc. (NeuCo). NeuCo offers several neural net optimization products. Two of their products, CombustionOpt and SootOpt, provide the potential for NO_x reduction at some facilities. Both CombustionOpt and SootOpt are control-system-based products. CombustionOpt provides for optimized control of fuel and air to reduce NO_x and improve fuel efficiency. SootOpt improves boiler soot blowing by proportioning heat transfer and reducing "hot spots" resulting from ineffective cleaning. NeuCo stated that these products can be used on most boiler control systems and can be effective even in conjunction with other NO_x reduction technologies.

NeuCo predicts that generally CombustionOpt can reduce NO_x by 15 percent, and SootOpt can provide an additional 5 to 10 percent. Expected NO_x reductions are very unit-specific, and actual results may vary greatly. Previously received budgetary prices for CombustionOpt and SootOpt were

[12] Because the Flex Fuel Project is not being implemented for the primary purpose of emissions reduction, these cost effectiveness values are not directly comparable to those for installation of a control technology.

$150,000 and $175,000, respectively, with an additional $200,000 cost for a process link to the unit control system.

Because NeuCo does not guarantee NO_x reduction, the estimated emission reduction levels provided are not considered as reliable projections. In light of the uncertain and unquantifiable emission reductions, TransAlta considers a neural net system as a potential supplementary or polishing technology, but not as an applicable NO_x technology for this BART analysis. Because of the potential NO_x reductions and cost effectiveness, TransAlta is continuing to investigate use of this technique at this plant.

Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction **(**SNCR) is generally used to achieve modest NO_x reductions. It is often chosen to augment combustion controls on older coal fired boiler units which are generally smaller units (units with heat input less than 3,000 MMBtu/hr) and industrial boilers. With SNCR, an ammonia or urea solution is injected into a location in the furnace that provides a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100°F and provides a minimum detention time for the reaction to occur. Within this temperature range the ammonia or urea reduces NO_x to nitrogen and water. NO_x reductions of up to 60 percent have been achieved, although 20 to 40 percent is more realistic for most applications.

Reagent utilization, which is a measure of the efficiency with which the reagent reduces NO_x, can range from 20 to 60 percent, depending on the amount of reduction to be achieved, unit size, operating conditions, and allowable ammonia slip. If the temperature in the boiler at the location of the ammonia injection is too high or too much ammonia is injected, the ammonia or urea is oxidized to NO_x. With low reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create problems downstream.

There are a number of potential adverse impacts due to ammonia slip. Unreacted ammonia can contaminate the fly ash collected in the ESPs that is sold for making concrete. If the ammonia concentration in the fly ash is high enough it will render the fly ash odorous and unsaleable[13]. If the fly ash is unsaleable to make concrete, it would require disposal in a landfill or could be sold to a cement plant as a raw material to make cement. If used to make cement, the heating of the fly ash in a cement kiln will release any mercury that may be contained in the fly ash.

Two additional issues with ammonia slip are that ammonia is listed as a toxic air pollutant by Ecology, and its discharge from the stack may result in additional impacts. The unreacted ammonia may also react with sulfur oxides to generate ammonium sulfate or bisulfate to foul economizer, air preheater, and other duct surfaces. At facilities where there is no wet scrubber system included, excess ammonia may also create a visible stack plume. Since the TransAlta plant has a wet scrubber, no additional plume visibility would be anticipated.

[13] Fly ash is reported to lose its desirability as a concrete admixture if the ammonia content is high enough that detectable levels of ammonia will be volatilized from the fly ash when it is mixed into the wet concrete. Ammonium on /in the fly ash is converted to ammonia when the pH of the mixture rises. At a pH of 12, essentially all the ammonium is converted to ammonia in solution. Based on Ecology's review of the available literature, it is unlikely that a properly controlled SNCR system will cause any adverse impacts to fly ash sales due to ammonia slip.

The control effectiveness of SNCR is a function of many variables, including the uncontrolled emissions concentrations, physical conditions, and operational conditions. A study by Harmon[14] (1998) indicates that a large coal fired, tangentially fired unit equipped with a low NO_x SNCR has the potential to reduce NO_x emissions by only 20 to 25 percent with an ammonia slip of less than 10 ppm. The EPA Office of Air Quality Planning and Standards' *EPA Air Pollution Control Cost Manual* (EPA, 2002) states "SNCR systems applied to large combustion units (greater than 3,000 MMBtu/hr) typically have lower NO_x reduction efficiencies (less than 40 percent), due to mixing limitations." The Centralia Power Plant units have heat input rates of much greater than 3,000 MMBtu/hr (above 7,000 MMBtu/hr[15]). After considering the above factors and a reasonable compliance factor, TransAlta selected a control effectiveness of 25 percent for this evaluation.

TransAlta's cost analysis uses a urea-based SNCR system providing a nominal 25 percent reduction in NO_x levels with a 5 ppm ammonia slip. A 5 ppm ammonia slip is the maximum recommended taking into account the flue gas sulfur levels to avoid problems with ammonium sulfate and bisulfate fouling of the air heater. To achieve the proposed reduction, multiple nozzle lances are proposed to handle load changes from 50 to 100 percent.

Retrofit costs to incorporate SNCR at this facility are included in the cost estimate. These retrofit costs are higher than for other similarly sized facilities due to an extremely tight boiler outlet configuration, limited available space for new equipment, probable modifications to boiler tubes to accommodate the urea injection lances, construction access difficulties to install SNCR injection equipment, and location of urea storage and solution preparation equipment.

TransAlta has estimated that installation of SNCR on their units would consume about 700 kW-h of electricity per unit, or a total of 1.4 MW-h for both units.

The anticipated 25% reduction in emissions from the installation of SNCR would result in an emissions limitation of 0.225 lb/MMBtu and an emission reduction of 3,923 tons/year. TransAlta has estimated that the estimates of capital cost including the retrofit costs, adding SNCR to both units at the plant would cost $33.2 million with a cost effectiveness of $2,258/ton NO_x reduced.

Subsequent to the public comment period on the proposed BART determination, TransAlta was requested to supply additional information on the use and cost of SNCR at this facility. The company had its contractor supply additional information related to the basis of its SNCR cost estimates. This additional detail is contained in a March 31, 2010 report from CH2MHill to Mr. Richard Griffith (Appendix G). The additional detail indicates the cost estimating approach utilized by CH2MHill on this BART analysis.

The March 31, 2010 report indicates that the SNCR cost estimates in the June 2008 BART analysis were "budgetary estimates" supplemented by vendor quote of costs and NO_x removal efficiency from Fuel Tech.

[14] Harmon, A., et al. 1998. Evaluation of SNCR Performance on Large-Scale Coal-Fired Boilers. Institute of Clean Air Companies (ICAC) Forum on Cutting NO_x Emissions, Durham, NC, March 1998
[15] 2008 Acid Rain Program report lists heat input rate at 8500 MMBtu/hr/boiler

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) works on the same chemical principle as SNCR, but SCR uses a catalyst to promote the chemical reaction. Ammonia or urea is injected into the flue-gas stream, where it reduces NO_x to nitrogen and water. Unlike the high temperatures required for SNCR, the SCR reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580°F and 850°F. Due to the catalyst, the SCR process is more efficient than SNCR resulting in lower NO_x and ammonia emissions. Typically an SCR system can provide between 70 and 95% reduction in NO_x emissions.

On coal fired power plants, the most common type of SCR installation is known as the hot-side high-dust configuration, where the catalyst is located downstream from the boiler economizer and upstream of the air heater and particulate control equipment. In this location, the SCR is exposed to the full concentration of fly ash in the flue gas that is leaving the boiler. An alternate location for an SCR system is downstream of the air heater or the particulate control device. In many cases, this location is compatible with use of a low temperature SCR catalyst or is within the low end of the temperature range of a conventional catalyst. Because the temperature of the flue gas leaving the air heaters and the Electrostatic Precipitators (ESPs) is too cool for the low temperature versions of SCR catalyst to operate, the high-dust configuration is assumed for TransAlta.

In a new boiler installation or a retrofit installation where the existing boiler has minimal emission controls installed, the flue gases flow downward through the catalyst to aid in dust removal. In a retrofit situation, the SCR catalyst is often located in the existing gas duct, which may be expanded in the area of the catalyst to reduce flue gas flow velocity and increase flue gas residence time to maximize removal efficiency and minimize ammonia usage. As an alternate location, the catalyst bed in a retrofit situation may be installed in a "loop" of ducting. This loop may be horizontal or vertical in orientation, depending on how the flow in the duct that is intercepted is routed and available space to locate the catalyst bed.

A new installation type SCR costing was used as the basis for analysis at the Centralia Plant because of the limited space to install an SCR catalyst in the existing flue duct and the ability to design for a 90% + reduction catalyst bed. The short distance between the boiler air heater and the entrance to the first ESP does not provide the room required for a catalyst bed with reasonable temperatures or velocities to be inserted in the existing flue gas duct[16]. The ducts from each boiler to the ESP have a relatively high velocity, such that the amount of catalyst that could fit into the unmodified duct would have minimal effectiveness due to the short residence time through the catalyst bed.

As a result of electing to use a design capable of 90+% NO_x reduction, an adjustment was used for SCR cost estimates due to the Centralia Plant's extremely tight boiler outlet ductwork configuration as shown in Figures 3-3, 3-4, and 3-5 of the June, 2008 Revised BART Analysis and March 2010 supplement. As can be seen in the figures, installation of a full-scale SCR system requires reconfiguration of the flue ducts from the boilers, structural modifications of the first ESPs (or

[16] See Figures ES-1, 3.2, 3-4, and 3.5 of the BART Analysis for Centralia Power Plant, Revised July 2008.and supplemented March 2010.

installation of all new structural support to hold the weight of the catalyst beds and ductwork) to accommodate the weight of the SCR catalyst and duct work, and realignment of the duct work from the economizers to the air preheaters. The restricted site layout, support structure needs, intricate duct routing, limited construction space, and complexity of erection increases the capital cost.

Each boiler at the Centralia Plant has two exhaust gas ducts to aid in splitting the flow to the ESPs. As a result each boiler would require two smaller, separate catalyst vessels instead of a single large catalyst vessel. The capital cost of installing dual catalyst vessels for each unit is slightly greater than a single catalyst vessel for units of similar size.

As in the case for SNCR, a potential adverse impact due to unreacted ammonia from the SCR system is that it may render fly ash unsaleable. At facilities where there is no wet scrubber system included, excess ammonia could also create a visible stack plume. Again, TransAlta has a wet scrubber, so a visible stack plume from ammonia is not likely.

As stated in TransAlta's BART analysis, an SCR retrofit increases the electricity consumed by the existing flue gas fan system to overcome the additional pressure drop associated with the new catalyst, typically a 6- to 8-inch water gage increase[17]. The increase in pressure drop results in marginally higher operating costs. Since the BART analysis uses a planning level cost analysis, there has not been a more detailed engineering study of all components that may be affected by adding the SCR system.

TransAlta evaluated 2 options to use SCR at the plant. One option included SCR on only one unit to achieve the Presumptive BART emission limit of 0.15 lb NO_x/ MMBtu, both units averaged together. The other option included SCR on both units.

The emissions reduction for installation of SCR (at a 95% removal rate) on one unit would be 4,364 tons/year. The capital cost for including SCR on only one unit was estimated to be $290.1 million with a cost effectiveness of $8,205/ton NO_x reduced.

The emissions reduction for installation of SCR (at a 95% removal rate) on both units would be 7,855 tons/year. The capital cost for including SCR on both units would be double that for one unit with a cost effectiveness of $9,091/ton NO_x reduced.

Subsequent to the public comment period on the proposed BART determination, TransAlta was requested to supply additional information on the use and cost of SCR at this facility.

In addition to the more readily readable drawings (Appendix F), the company had its contractor supply additional information related to the basis of its SCR cost estimates. This additional detail is contained in a March 31, 2010 report from CH2MHill to Mr. Richard Griffith (Appendix G). The additional detail indicates the cost estimating approach utilized by CH2MHill on this BART analysis. The approach described involved a company re-evaluation of historical information updated with current equipment, material, and constructions costs, including cost estimates based on preliminary engineering sketches. The March 31 submittal indicates that a basic capital cost for an SCR system

[17] Associated with providing a gas velocity through the catalyst beds below 20 ft/sec.

of $200/kW was used as the basis for the cost estimate. This basic cost was then scaled by CH2MHill's engineering judgment of the costs and complexity to install an SCR system on these boilers. As part of this additional analysis, the predicted TransAlta costs were compared to costs for other coal fired power plants in the western US (in Attachment 1 of the March 31, 2010 report). The cost analyses compared were performed by CH2MHill and 4 other consulting firms. Many have been determined to be BART by the various states. The cost for SCR at the Boardman OR plant is listed as $382/kW, versus $413/kW at Centralia. Both costs can be considered to be essentially equivalent since both are well within the +/- 30% cost estimating range of the EPA Control Cost Manual and CH2MHill's +50%/-20% estimate range of each other's cost analyses.

The March 31, 2010 report also contains an improved description of how CH2MHill envisioned the proposed SCR system to be installed and operated. Their proposal would have the SCR system installed in a "hot, dirty" location taking hot flue gas from the economizer and returning it to before the air preheater. The "hot dirty" location in the flow path assures the catalyst bed would be at proper operating temperatures. The catalyst beds would be located above the first ESPs to avoid structural supports in the current access way under the divergent ducting between the air preheater and the ESP inlets. Structural supports would block plant operations and maintenance staff access to equipment and the ESPs. Locating the catalyst above the ESP would also provide the duct length to provide for lower velocities through the catalyst bed. The structural needs to support the weight of the ductwork and the catalyst beds were evaluated qualitatively.

In response to Ecology's questions resulting from public comment, TransAlta had CH2MHill evaluate 2 other locations where SCR catalyst could be installed (Appendix G).

One location evaluated an installation between the ESPs and the wet Flue Gas Desulfurization (FGD) system. The analysis indicates the anticipated difficulties due to changes in flue gas volume and velocity resulting from reheating the flue gas to 700°F and adding aqueous ammonia reagent. The potential adverse impacts of flue gas reheating (even through a regenerative system) on operation of the wet scrubbers were not evaluated.

The other location is in the ESP inlet ducting after the air preheater. The air preheater outlet is 300°F, well below the normal range for SCR catalysts. To increase the temperature of the gas exiting the air preheater would require changes to the plant thermodynamics (by reducing the temperature of combustion air) and would impact the overall plant heat rate and efficiency. In this location, CH2MHill has estimated that the catalyst bed could be no more than 17 feet deep without requiring significant modifications to the ductwork from the economizer to the air heater. CH2MHill presents information that in this location, one layer of catalyst would provide a 5% decrease in NOx with a 5 inch water gauge pressure drop. A 2-layer system would increase removal to 12% at a pressure drop of 15 inches water gauge. The effects of an increased back pressure on the boilers or the ability of the induced fans to accommodate this much increase in pressure drop was outside of the scope of CH2MHill's contract.

Rrotating Overfire Air and Rotamix

Mobotec markets Rotating Overfire Air (ROFA) as an improved second-generation overfire air distribution system. In their system the combustion gases in the boiler are set in rotation with

asymmetrically placed air nozzles. According to Mobotec installation information, the ROFA technology alone has not been installed on any tangentially-fired coal unit greater than 175 MW.

The Mobotec Rotamix technology is a modification of the SNCR process. The ammonia or urea solution is added using lances in conjunction with the ROFA air nozzles to improve both the chemical distribution and lengthen the residence time for the reactions to occur. According to the Mobotec installation list, the largest tangentially-fired coal unit using the Mobotec ROFA/Rotamix combination is 175 MW. The Rotamix SNCR system is anticipated to provide NO_x reductions similar to conventional SNCR systems[18].

Based upon the BART guidance, Mobotec ROFA and Rotamix technologies are 'available' because they have been installed and operated successfully on tangentially fired pulverized coal boilers. TransAlta believes that while the ROFA and Rotamix technology are 'available' control technologies as described in the BART guideline, the use of either ROFA as a replacement or addition to the current overfire air injection system or installation of the Rotamix process are not technically feasible technologies due to unknown difficulties with installation on their boilers. Due to perceived risks of scale-up to their unit size, TransAlta believes that these technologies are not applicable to their facility.

2.2 TransAlta's Proposed Best Available Retrofit Technology

The existing LNC3 combustion controls (low NO_x burners, close coupled and separated overfire air) currently installed at the plant and the Flex Fuels project meeting an emission limitation of 0.24 lb NO_x/MMBtu, 30 day average, is proposed as BART for their facility.

[18] The Mobotec combustion air injection techniques were not evaluated as part of the RACT process. Their development occurred after the RACT determination had been made.

3.0 Visibility Impacts and Degree of Improvement

TransAlta modeled the visibility impairment for the baseline years per the modeling protocol and the potential improvement from the control scenarios that they evaluated as potential BART controls for their facility. In modeling the emissions, they followed the BART modeling guidance prepared for use by sources in Washington, Oregon, and Idaho. In accordance with the EPA BART guidance, this modeling protocol utilizes the CALPUFF modeling system and the 'old' Interagency Monitoring of Protected Visual Environments (IMPROVE) equation to convert modeled concentrations to visual impairment. This approach is consistent with most of the states included in the Western Regional Air Partnership for modeling individual source visibility impairment. The 'old' IMPROVE equation is used because it is included within the CALPUFF modeling system and is part of the EPA accepted version of the model per 40 CFR Part 51, Appendix W. A new equation is available, but is not included within the version of the CALPUFF modeling system specified in the modeling protocol.

The results of the TransAlta modeling are shown in Table 3-1 for all Class I areas within 300 km of the plant plus the Columbia River Gorge National Scenic Area. Table 3-1 shows the maximum day impairment due to TransAlta, the highest of the 3, 98th percentile days of each year modeled, and the 98th percentile day of all 3 years modeled. Also shown is the modeled visibility impairment resulting from the control scenarios modeled by TransAlta. The modeled dv impacts for the baseline condition and the 3 control scenarios for the 98th percentile day (22nd day over the three year period) are included in Table 3-1[19].

The emission rates modeled were derived from operating records for each boiler and reflect the highest 24 hour emission rate within the 3 years that were modeled. The proposed emission rates were applied to this maximum 24 hour operating rate and those rates were then used for modeling the visibility impairment/improvement that could be achieved through the use of the proposed controls. The modeled emission rates are shown in Table 3-1.

The modeled visibility impairment indicates that the plant causes visibility impairment at all Class I areas within 300 km of the plant. The tables include modeled visibility levels for three alternative control scenarios, including the highest level of control considered by TransAlta to be available for the plant, SCR applied to both boilers.

Ecology modelers have reviewed the modeling performed by TransAlta and have found that the modeling complies with the Modeling Protocol and produces a reasonable result.

The modeled emission reductions from the control options modeled by the company result in substantial reduction in the visibility impairment caused by the Centralia Plant in all Class I areas modeled and in the Columbia River Gorge NSA. For example, Table 3-1[20] shows that at the 3 most heavily impacted Class I areas, Olympic National Park, Mt. Rainier National Park, and the Goat Rocks Wilderness, TransAlta's proposed BART controls would provide 1.13 to 1.45 dv reduction in

[19] See the BART Determination Modeling Analysis, TransAlta Centralia Generation Power Plant by Geomatrix Consultants, Inc, June 2008, for additional information on the modeling results for the other control scenarios evaluated. This report is part of the July 2008 BART analysis report.
[20] Revised from the prior version of this document with the modeling results in the March 2010 modeling. This additional modeling was performed in response to public comments on the proposed BART determination.

visibility impairment in each of these areas. All Class I areas within 300 km of the plant are modeled to have visibility improvements of at least 0.2 dv from the NO_x emission reduction from use of SNCR or Flex Fuels. Combined with the effects of the reduction in SO_2 from implementation proposed BART controls, the minimum visibility improvement is 0.67 dv.

The initial modeling for the control scenarios in the table evaluated only the NO_x reduction impacts. Effects of SO_2 reductions which would occur as a result of implementing the Flex Fuels project were not initially evaluated by TransAlta.

The actual SO_2 emission rates from usage of PRB coals are anticipated to result in an additional reduction of about 1,287 tons/yr from the baseline emission rates. Subsequent to the public comment period, Ecology requested and TransAlta remodeled the Flex Fuels project emissions to include the effect of the SO_2 reduction from use of the PRB coals. The results of this remodeling are portrayed in Table 3-1. Control Scenario 3 was not included in the table as presented during the public comment period but was available in TransAlta's July 2008 BART Analysis Revision.

In their review of the initial modeling results, TransAlta's modeling consultant evaluated the modeling results to see if there were any patterns to the modeled impacts, such as season of the year, primary pollutant, or grouping of Class I area. Their review indicated that groups of Class I areas exhibited similar patterns. They found that the 12 Class I areas fell into 4 groups which coincide with both their physical locations and the modeled visibility effects. For their evaluation, see pages 8 and 9 of the June 2008 BART modeling report.

The important points to consider are that for the "East" group (Mt. Rainier N. P. and Goat Rocks and Mt. Adams Wildernesses) most impacts occurred in the summer due to SO_2 emissions. The expected high impacts due to NO_x do not occur because the weather patterns transport the plant's plume to other areas in the winter seasons. The impacts on Olympic NP, (the sole member of the "Northwest" group) occur during wintertime stagnation episodes. While not mentioned in the report, this impact would be dominated by nitrates. For the "South" group (Mt. Hood, Mt. Jefferson, and Three Sisters Wildernesses) there are summertime impacts, but the highest potential visibility changes occur in the winter during wintertime stagnation episodes. Again, the wintertime events are dominated by nitrates. At the remaining 4 Class I areas (the "Northeast group"), there was no obvious seasonality or trends. The figures in Appendix D graphically depict this information for some of the Class I areas.

Overall, the visibility impacts from the plant's emissions on Class I areas are dominated by nitrates. The tables in Appendix D[21] depict the chemical species contributions to visibility impairment for the baseline case, the Scenario 2 Flex Fuels case and the Scenario 1 SNCR case as predicted by CALPUFF. Again, consistent though not identical with the evaluation by TransAlta's modeling consultant, at most nearby Class I areas, the visibility impairment on the 98th percentile worst days is primarily caused by the nitrate resulting from the plant's emissions. These worst days primarily occur in the September through June time period. Conversely, at the more distant Class I areas the visibility impairment is more variable, but the 98th percentile days usually occur in the June through

[21] From Geomatrix BART Modeling Reports, June 2008 and January 2008.

September period and are dominated by sulfates. For more details, please refer to the Modeling Reports supplied by TransAlta.

As noted above, TransAlta was requested to remodel the emissions from the project as a result of public comment on the proposal. They remodeled 2 scenarios using the same modeling protocol as used in the initial modeling. The 2 scenarios were the Flex Fuels and the Flex Fuels plus SNCR control options. The emission rates are consistent between the scenarios, with only the NO_x rate changing to reflect the anticipated 25% reduction in NO_x from the application of SNCR to the emissions from the Flex Fuels Project. The modeling results are contained in a report attached to a March 26, 2010 e-mail from Ken Richmond of Environ to Alan Newman and Clint Bowman of Ecology (Appendix H).

The visibility impacts depicted in Table 3-1 have been updated to reflect the results of the revised modeling. The maximum 24 hour emission rate for SO_2 in the revised Control Scenario 2 and new Control Scenario 3 is based on the ratio of the average sulfur content of Jacobs Ranch PRB coal to the average of the Centralia Mine coal used in the 2003-5 time period. The maximum 24 hour NO_x emission rate used in the Flex Fuels only control scenario is as modeled previously. The NO_x rate for Flex Fuels plus SNCR is a 25% reduction from the Flex Fuels only rate.

Ecology did not request that TransAlta remodel their SCR control scenarios reflecting the use of low sulfur PRB type coals. The modeling results assume that TransAlta would return to using Centralia coal as a primary fuel for the boilers. Based on the modeling performed on Flex Fuels and Flex Fuels plus SNCR, there would be additional visibility improvements were PRB coal continued to be used by the facility and SCR added.

Table 3-1 3-Year Delta Deciview Ranking Summary

Class I Area	Visibility Criterion	Baseline Emissions	Control Scenario 1: SNCR	Control Scenario 2: Flex Fuel	Control Scenario 3: Flex Fuel plus SNCR	Control Scenario 4: SCR on both units
Alpine Lakes Wilderness	Max 98% value (8th high) in any year	4.871	4.393	3.564	2.949	3.057
	3-yrs Combined 98% value (22nd high)	4.346	3.844	2.994	2.598	2.531
Glacier Peak Wilderness	Max 98% value (8th high) in any year	3.615	3.209	2.403	2.049	2.036
	3-yrs Combined 98% value (22nd high)	2.622	2.294	1.905	1.532	1.562
Goat Rocks Wilderness	Max 98% value (8th high) in any year	4.993	4.398	3.676	3.069	3.137
	3-yrs Combined 98% value (22nd high)	4.286	3.708	3.108	2.637	2.385
Mt. Adams Wilderness	Max 98% value (8th high) in any year	3.628	3.118	2.646	2.194	1.984
	3-yrs Combined 98% value (22nd high)	3.628	3.152	2.591	2.147	1.934
Mt. Hood Wilderness	Max 98% value (8th high) in any year	3.471	3.051	2.346	1.978	2.082
	3-yrs Combined 98% value (22nd high)	2.830	2.388	1.997	1.665	1.543
Mt. Jefferson Wilderness	Max 98% value (8th high) in any year	2.079	1.784	1.399	1.150	1.159
	3-yrs Combined 98% value (22nd high)	1.888	1.596	1.267	1.053	1.061
Mt. Rainier National Park	Max 98% value (8th high) in any year	5.447	4.774	4.318	3.606	3.359
	3-yrs Combined 98% value (22nd high)	5.489	4.743	4.225	3.501	3.275
Mt. Washington Wilderness	Max 98% value (8th high) in any year	2.027	1.756	1.323	1.106	1.170
	3-yrs Combined 98% value (22nd high)	1.414	1.248	0.872	0.737	0.855
North Cascades National Park	Max 98% value (8th high) in any year	2.821	2.496	1.852	1.570	1.658
	3-yrs Combined 98% value (22nd high)	2.212	1.887	1.486	1.228	1.183
Olympic National Park	Max 98% value (8th high) in any year	4.645	4.040	3.192	2.695	2.506
	3-yrs Combined 98% value (22nd high)	4.024	3.456	2.991	2.486	2.339
Pasayten Wilderness	Max 98% value (8th high) in any year	1.954	1.701	1.287	1.075	1.160
	3-yrs Combined 98% value (22nd high)	1.482	1.318	0.999	0.822	0.864
Three Sisters Wilderness	Max 98% value (8th high) in any year	2.172	1.910	1.333	1.139	1.172
	3-yrs Combined 98% value (22nd high)	1.538	1.328	0.993	0.819	0.902
Class II area modeled per the Modeling Protocol						
Columbia River Gorge National Scenic Area	Max 98% value (8th high) in any year	2.545	2.193	1.748	1.446	1.347
	3-yrs Combined 98% value (22nd high)	2.353	1.942	1.657	1.378	1.182
Modeled Rates (lb/hr)	**Both units added together**					
	NOx -->	4,984	3,738	3,936	2,952	1148
	SO_2 -->	4,522	4,522	1,854	1,854	4,522

The 8th day in any year or the 22nd day over the 3 year period, are the 98th percentile days.

4.0 The Washington State Department of Ecology's Best Available Retrofit Technology Determination

Ecology has reviewed the information submitted by TransAlta. The following discussions present our rationale for our determination.

4.1 Nitrogen Oxides Control

The BART analysis reports and supplemental material provided by TransAlta indicate that the Flex Fuels project and SNCR are the only feasible controls for use at the Centralia power plant. We concur with their opinion on controls. This concurrence is based on our evaluations of their submittals plus Ecology research on potential controls.

4.1.1 Control options determined not to be feasible

Three available control technologies were evaluated and determined not to be feasible NO_x controls for use at the Centralia plant. In addition, one available control option, natural gas reburning, had been evaluated for the 1997 RACT determination but was not reevaluated by TransAlta in their BART analysis. Ecology has determined that none of these control technologies are feasible controls of NO_x at the Centralia plant.

Rotating Overfire Air /RotaMix

TransAlta did evaluate the installation of the Mobotec ROFA technology. Both Ecology and TransAlta found was that this air injection technique has been neither tested nor demonstrated in tangentially fired coal boilers of this size. Similarly, the Mobotec RotaMix technique for SNCR has not been tested or demonstrated on boilers of this size. For both Mobotec technologies, the largest tangentially fired unit reported to have the equipment is 565 MW[22,23]. This rating is below that of TransAlta's units, which are rated at 700 MW each.

Emissions information on the recent installation is not published. The technology remains untested or demonstrated on units the size of the TransAlta facility. With the current lack of information on the control efficiency on the 565 MW plant, there are questions about the capabilities of scaling the technology up to Centralia size. Under BART, facilities are not expected to assume large risk or expense for installing a new technology or technique on an untried size or type of facility[24]. As a result, Ecology concurs with TransAlta that these techniques are not yet technically feasible for use on this facility.

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[22] As of 2009, The NALCO/Mobotec reports the largest tangentially fired pulverized coal unit using ROFA or Rotamix was 565MW, Minnesota Power's Boswell Unit #4. The next two largest units listed by the company are a 424 MW wall-fired unit and a 577 MW opposed fired unit achieving a 55% reduction to 0.25 lb NOx/MMBtu on bituminous coal. Telephone call with Jay Crilley, Nalco, June 24, 2009

[23] In spite of the limited application of the Mobotec ROFA technology, EPA did evaluate in its analysis of control techniques when evaluating the presumptive BART limitations. Go to the EPA's Regional Haze Rule Docket for EPA-HQ-OAR-2002-0076-0446(1) TSD.xls ,

[24] 40 CFR Part 51, Appendix Y, Section IV. D.

Selective Catalytic Reduction

For new coal fired power plants, SCR is the BACT control technology of choice to reduce NOx emissions. In some cases, the use of SCR is being considered to be the technology to be implemented for BART. There are a number of technical difficulties to implementing SCR at the Centralia plant presented by TransAlta in its reports. The primary difficulties are a lack of space for easy installation of the catalyst beds and ducts, leading to very high construction costs that far surpass ranges of acceptable cost effectiveness.

In response to public comment on the clarity of the plan and profile drawings supplied, Ecology acquired additional layout drawings from TransAlta with dimensions and elevations more readily discernable to reviewers (Appendix F). The drawings indicate that the location proposed for installation of an SCR system is on top of the first ESP bank. This is at an elevation of approximately 80 feet in the air, above the precipitator. This is also the elevation of the air preheaters. The horizontal distance between the outlet of the air preheater and the ESP is 55 feet. As indicated in the drawings, in this 55 ft distance the flue gas has to turn 90 degrees and spread it out across the full width of the ESP inlet.

The earlier BART analyses from TransAlta did not contain an explanation of the flow routing for the proposed SCR installation. As described in CH2MHill's March 31, 2010 report (Appendix G), they envision a "hot, dirty" SCR installation. In other words, the flu gas would be intercepted on leaving the boiler economizer and routed through the SCR unit and returned to the inlet of the air preheater. A "hot, dirty" installation provides flue gas within the normal operating range of an SCR catalyst. A number of additional engineering analyses are identified in the March 2010 report that would be required to improve the construction cost estimate. These additional analyses include the a fluid dynamics evaluation for each possible location, an evaluation of new structures needed to support ductwork and catalyst beds, consideration of maintenance access to the ESPs and other equipment in that area of the plant, and a construction difficulty evaluation. All of these additional analyses were outside the scope of work for CH2MHill's report.

Two other locations for installing an SCR system were evaluated in the March 2010 report. One location is in the diverging ducts between the air preheaters and the ESPs. CH2MHill acquired vendor information about the removal efficiency and head loss of a one and 2 layers of catalyst that could be installed within the duct. Due to velocity and the limited depth of catalyst bed possible in this location, SCR removal seems to be limited to 5% for a single layer system and 12% for a 2 layer system. As a result of the low removal rates that would be provided by a catalyst system in this location, CH2MHill did not evaluate the construction costs of this location. In Ecology's view, there are significant questions if these ducts could support the added weight of the catalyst without additional structural support, or if the company could work around the loss of vehicle access for maintenance purposes to the equipment located on the ground under and around the air preheaters and ESPs.

The other location evaluated is in the ductwork between the ESPs and the wet FGD system. As indicated by the drawings in Appendix F, the ductwork is of different lengths and, what is not clearly obvious from the drawings, they have different cross-sectional dimensions. CH2MHill provided a qualitative analysis of what would be involved in installation of an SCR system between the ESPs

and the wet FGD system (Appendix G). Ecology accepts their qualitative analysis as demonstrating the difficulties in retrofitting an SCR system in this location.

Ecology concurs with TransAlta that the construction costs to overcome the technical difficulties of retrofitting an SCR system on its boilers, given its current configuration and installed emission controls, render this technology economically infeasible for implementation at this time.

Neural Nets

This technique is an available control technology. However, Ecology agrees with TransAlta that the use of this technique at the Centralia plant is not guaranteed to reduce emissions. TransAlta is likely to continue to evaluate the appropriateness of installation and use of a neural net combustion optimization process at the facility and may at a future date choose to include it for polishing and fine-tuning operations beyond what can be achieved by their human operators.

Natural Gas Reburning

Natural gas reburning has the potential to reduce NO_x emissions. Natural gas reburning is a technique where natural gas is injected into the boiler above the last overfire air ports and additional overfire air ports are added above the natural gas injection level. The natural gas has the effect of reducing part of the nitrogen oxides to nitrogen gas, carbon dioxide and water. The technique has an estimated control effectiveness of 40 -50%.

Ecology has looked briefly at the use of natural gas reburning to reduce NO_x from these boilers. A review of the EPA RACT/BACT/LAER Clearinghouse database does not include any listings of this technique being used on any coal fired boiler of any size. The lack of any entries showing use of this technology for coal fired boilers of any size or type, lead us to question whether this control technique is truly available. A review of NO_x control literature from the late 1990's indicates there was a lot of interest and evaluations of various methods to implement reburning, including the use of pulverized coal as the fuel. While there was much experimentation, it appears that low NO_x burner/combustion controls were the dominant technology being implemented at that time.

A 2005 review of NO_x control techniques available for coal fired boilers listed 26 plants that have installed or tested reburning[25]. Of these 26 plants, only 4 were indicated as still using reburning when the review was written. The report's authors express the belief that the reason the control is not used on the plants where it is installed is simple economics; it is costly to operate the reburn process. The 4 largest units listed in the review article, bracket TransAlta in size, but none of them were operating their reburning equipment. The few NO_x emission limitations listed for reburning have higher emission rates than the control level achievable by Flex Fuels or SNCR. Based on the limited published information on installation of reburning on units the size of Centralia, we question the ability of the technology to achieve a level of control comparable to Flex Fuels or SNCR.

Natural gas reburning was not cost effective (compared to the installation of LNC3 combustion controls) in 1997. The cost of natural gas is the primary cost of using this technology. Natural gas

[25] See Reference 5 for details.

costs have increased significantly since 1997, while natural gas pipeline capacity in this part of Washington has not expanded significantly. SWCAA determined in 1997 that this control technique was not cost effective. Ecology is of the opinion that reburning is still not cost effective for implementation at the plant.

4.1.2 Evaluation of controls determined to be feasible

Low Nitrogen Oxides Combustion, Level 3/Flex Fuels

As described in Section 2, the Flex Fuels project is to allow the boilers at this plant to utilize PRB coals and accommodate its potential increased fire hazard. These modifications are relatively simple and well known in the coal combustion industry. Compared to the Centralia mine coal, PRB coal contains less nitrogen and has a higher energy content. These 2 factors work together to reduce the NO_x emissions from the boilers.

The estimated capital cost to TransAlta to implement the Flex Fuels project is $101,808,663. The annualized cost of the Flex Fuel Project is $11,184,197. Based on the estimated NO_x reduction of 3,139 tons/yr, the cost-effectiveness of the Flex Fuel Project is $3,563/ton of NO_x reduced. Since the Flex Fuel Project also reduces SO_2 emissions by an estimated 1,287 tons/year, the cost-effectiveness of the Flex Fuel Project is $2,526/ton of NO_x plus SO_2 reduced.

Selective Catalytic Reduction

SNCR has been commonly selected for BACT determinations on new and modified coal fired power plants where SCR cannot be used, as a method to meet NO_x reductions required to comply with the Clean Air Interstate Rule (CAIR) program, and for seasonal NO_x control requirements. SNCR has been required to meet BART at a few facilities, although the most common BART determinations publically available from states to date is low NO_x burner technology similar to that already installed at the Centralia Plant with SNCR or SCR added later as further progress emission reductions. We evaluated a 25% reduction from the use of SNCR, a level supported in the emission control literature reviewed. When this reduction is applied to the baseline emission rate of 0.304 lb NO_x/MMBtu, the resulting emission limit becomes 0.23 lb NO_x/MMBtu. This is marginally better than the limit of 0.24 lb NO_x/MMBtu limit proposed for the Flex Fuels project.

As can be seen in June 2008 Modeling Report, visibility improvement resulting from the NO_x reductions from SNCR or Flex Fuels (Control Scenario SNCR, and Control Scenario Flex Fuels) provide essentially equal reduction in visibility impacts at all Class I areas within 300 km of the plant. In addition, the use of low sulfur sub-bituminous coals can also reduce SO_2 emissions from the plant by up to 1,300 ton/year[26]. The March 2010 modeling, which includes the effects of the reduced SO2 emissions from use of the Flex Fuels project, indicates that Flex Fuels provides significantly better visibility improvement than SNCR alone.

[26] The effects of the SO_2 reduction was modeled and included in the January 2008 BART report. However the NO_x and SO_2 rates modeled for that report are not identical to those used in the June 2008 report or the December update. The March 2010 remodeling includes the SO_2 reduction from Flex Fuels at the final anticipated reduction rather than the previous differing rates. Ecology is relying on the March 2010 analysis as the most accurate and consistent version for comparison purposes.

As can be seen by looking at Table 3-1, the visibility improvement modeled from the NO_x reduction aspects of the Flex Fuel project (Control Scenario 2) ranges from 1.13 to 1.45 dv at the 3 most heavily impacted Class I areas. This visibility improvement at the most heavily impacted Class I areas is significantly greater than that provided by the use of SNCR (Control Scenario 1). At the least impacted Class I areas the visibility improvement due to NO_x reductions by SNCR is about 0.2 dv while the Flex Fuels project provides about 0.67 dv of visibility improvement.

Ammonia slip from the use of an SNCR system is inevitable. TransAlta based its analyses assuming a 5 ppm slip. An SNCR system of the type contemplated for installation on these boilers normally results in an ammonia slip of 5 - 10 ppm[27]. As noted in Section 2's discussion of SNCR, there are a number of potential adverse impacts that can result from ammonia slip.

Due to the alkaline nature of the FGD system at the Centralia plant, only a small amount of the ammonia entering the FGD system may be removed[28]. Ammonia can be a visibility impairing air pollutant and is a precursor to the formation of secondary Fine Particles ($PM_{2.5}$). The presence of ammonia in the plant's exhaust will tend to increase the total quantity of ammonia available for the formation of ammonium nitrate and sulfate and ultimately in the concentration of $PM_{2.5}$ at downwind locations. This secondary $PM_{2.5}$ and ammonium aerosols increase can lead to lower visibility improvement than would be anticipated based solely on the reduction in NO_x emissions.

Flex Fuels plus Selective Non-Catalytic Reduction

Ecology has also evaluated the impacts of utilizing the Flex Fuels project and adding SNCR to further reduce NO_x emissions. Assuming a 25% reduction in NO_x to occur from adding SNCR to Flex Fuels, the resulting emission limit would be 0.18 lb NO_x/MMBtu. The capital costs to add SNCR to Flex Fuels would increase by about 1/3 above Flex Fuels project costs to an estimated $135 million. The annual costs would increase by $6.2 million to about $17.3 million/year. The cost effectiveness of Flex Fuels plus SNCR is $2,162/ton NO_x for a net reduction of 8,022 tons NO_x per year. The annual cost increase is mostly to cover the cost of ammonia or urea, and to remove ammonium sulfate and bisulfate from boiler tubes and duct work between the ammonia injection point and the first ESP.

Despite the apparent cost effectiveness, it is important to consider the incremental cost of installing SNCR. Given the Centralia Plant has already installed the LNC3 technology and the Flex Fuels project, the cost of adding SNCR now is also an incremental cost. The capital cost to add SNCR to Flex Fuels is the same as SNCR alone since the same equipment needs to be installed. The

[27] For comparison, actual monthly average SO_2 emissions from this plant are currently under 20 ppm.
[28] Ammonia can be removed from air streams with an acidic solution. It can be removed from water solutions by making the solution alkaline. The wet FGD system is alkaline.
At intermediate pHs, the ammonia partitions between ammonium and ammonia in solution according to the following formula: $f = \frac{1}{[10^{(pKa-pH)}+1]}$ Where: f = the decimal fraction of ammonia present in unionized form; pKa = $0.09018 + \frac{2729.92}{T}$; T = water temperature in degrees Kelvin; and pH = the pH of the water solution. The unionized form is what can be emitted.

incremental cost of adding SNCR to both units at the facility is estimated to be $2,145/ton to remove an additional 2,890 tons[29] NO_x over Flex Fuels alone.

The combination of Flex Fuels and SNCR would increase the level of visibility improvement at the 3 most heavily impacted Class I areas due to NO_x reductions by an additional 1.9 dv on the 98th percentile day. At the most distant, least impacted Class I areas, the improvement is 0.8 to 1 dv. The incremental improvement in visibility from adding SNCR to Flex Fuels is at least 0.2 dv compared to Flex Fuels alone.

While this additional project does result in some visibility benefit, we must also weigh the other factors of the BART analysis to determine feasibility. These factors are the

- energy and non-air quality environmental impacts of compliance,
- any existing pollution control technology in use at the source, and the
- remaining useful life of the source.

There are several energy and non –air quality environmental impacts associated with SNCR. The small parasitic load associated with operating an SNCR system would reduce the power the Centralia plant has available for sale by about 1.4 MW. As previously discussed, there is also the potential for ammonia slip with SNCR, which would in turn contribute to visibility impacts. While we believe these impacts to will be manageable, they are additional operational complications resulting from the installation of SNCR.

The Centralia Plant has already installed substantial emissions control technology. SO_2 controls reducing emissions by 95% have been in operation for only 8 years. The LNC3 combination of combustion controls have been in operation for 8 years. This is the same technology used as the basis for EPA's presumptive BART control technology for NO_x. Throughout the western states, this package of combustion controls is being found to be BART or is a component of BART control determinations. As documented by TransAlta, their burner package vendor has confirmed in 2008 that the existing LNC3 package installed in their boilers is the current generation of the package. While the installed LNC3 controls at the Centralia Plant do not meet the presumptive BART limitation defined by EPA, the LNC3 controls installed meet the emission reduction anticipated and required in the 1997 RACT determination. The improvement expected was about a 33% improvement from a 1996/97 average of about 0.45 lb NO_x/MMBtu to the permitted 0.30 lb NO_x/MMBtu.

Further, the wet scrubber system installed on the plant in 2000 – 2002 provides in excess of 95% control of SO_2 emissions. Compared to many other plants of its vintage, the emissions of the Centralia plant are well controlled. This level of control weighs in favor of not requiring installation of significant control technology under BART given the significant NO_x reductions resulting from a project already installed.

There is an issue of the remaining useful life of the Centralia Plant. TransAlta's investor information about its facilities states that continued operation of the Plant beyond 2030 will require a substantial

[29] Based on 78% capacity factor, which is below the company target rate of over 84%

capital investment[30] with decisions to be made by 2025. However, that 20-year lifetime is longer than the BART guidance would consider as a limiting factor for making a BART technology decision on economic grounds.

There are other circumstances that affect the remaining lifetime of this plant in its current configuration. On May 21, 2009, the Governor of Washington issued Executive Order 09-05, Washington's Leadership on Climate Change. One specific action in the Executive Order requires the Director of the Department of Ecology to:

> (1)(d) Work with the existing coal-fired plant within Washington that burns over one million tons of coal per year, TransAlta Centralia Generation, LLC, to establish an agreed order that will apply the Greenhouse gas emissions performance standards in RCW 80.80.040(1) to the facility by no later than December 31, 2025. The agreed order shall include a schedule of major decision making and resource investment milestones;

The current greenhouse gas emission rate for the Plant is about 2,300 lb total greenhouse gases/MW-hour (MWh) of electricity produced for sale. The emission performance standard in the RCW 80.80.040(1) is currently 1,100 lb total greenhouse gases/MWh of electricity produced. Meeting that performance standard would require a greenhouse gas reduction in excess of 50%, on the order of 6-7 million tons of CO_2 per year. The law (Chapter 80.80, RCW) also requires an evaluation of technology every 5 years and a revision to this limitation be established by rule. The revised emission performance standard is based on the capability of new combined cycle natural gas combustion turbines offered for sale and purchase in the United States. Based on current offerings by the combined cycle combustion turbine industry, the first of the revised standards (due in 2012) is anticipated to be 850 – 920 lb/MWh.

TransAlta has a limited number of options to comply with the emission performance standard at the Centralia Plant. Those options include shutting the plant down[31], repowering it with a technology that complies with the performance standard, adding biomass to replace part of the coal supply[32], or addition of CO_2 separation and liquification equipment (along with development of a viable sequestration program). Regardless of the option chosen, each would bring significant further reductions to NO_x, SO_2 and PM emissions from the facility. To meet the requirements of the executive order, the likely economic lifetime of the current configuration of the Centralia Plant and any new emission control equipment would be 15 years or less.

The state has proposed to TransAlta a 3-step process for the plant to comply with the Executive Order. TransAlta is evaluating this proposal. Under the State proposal operation of the coal fired units would be ramped down over a 10-year period. The first action would be to operate the

[30] TransAlta Investor Day 2007, presentations published as PDF file on Nov. 17, 2007, Slide 38 of 101.
[31] Shutting down one unit would not comply with the standard.
[32] We estimate that to reduce emissions to just meet the 1100 lb/MWh standard, the plant would require biomass to replace at least 52% of the heat input to the plant. Assuming that this biomass is dry Douglas fir wood, we have estimated this to be approximately 500 dry tons/hour (over 12,000 tons/day) of biomass (probably wood or a wood derived fuel). Assumptions used in this calculation are, boiler heat input rate 8,554 MMBtu/hr/unit, dry Douglas fir wood at 8,900 Btu/dry lb, coal at 8,800 Btu/lb)

Centralia Gas facility and derate or otherwise limit the ability of one coal unit to produce electricity by the same amount as provided by the gas plant. This first step would start almost immediately after the agreed order was issued. The company would develop renewable energy resources adequate to shut down one coal unit completely about 2020. The second coal unit would be shut down by 2025 and be replaced by a combined cycle combustion turbine plant of about 700 MW size.

4.2 The Washington State Department of Ecology's Determination of Best Available Retrofit Technology

Ecology is proposing BART to be the Flex Fuels project plus use of a sub-bituminous Powder River Basin coal or other coal that will achieve similar emission rates.

Considerations in our decision include:

- When fully installed the Flex Fuel project will provide an emissions rate of 0.24 lbs NO_x/MMBTU, a 20 percent reduction from the current emissions rate. This is slightly higher than the emissions rate that would be achieved by SNCR.
- The Flex Fuels emission reductions are not exclusively NO_x, but include SO_2 reductions from ability to use PRB type coals.
- The NO_x emissions reduction from the use of Flex Fuels, SNCR, or SCR will result in reduced visibility impairment at all Class I areas within 300 km of the plant.
- The visibility improvement due to the use of Flex Fuels is greater than the use of SNCR alone as a result of the SO_2 reduction provided by the use of PRB type coals.
- The NO_x reduction will provide mostly a fall, winter, spring visibility improvement, during lower visitor usage days and periods with cool cloudy or stormy weather.
- The Flex Fuels emission reduction project was completed August 2009 with performance testing completed by the end of September 2009. The facility has met the proposed BART limits since October 2009.
- Additional NO_x reductions from adding SNCR may not occur until 3 to 5 years from when the BART Compliance Order is issued, further reducing the time period to amortize those costs, especially after considering the effects of the Executive Order.
- The Flex Fuels project does not impede any future requirement to impose SNCR (or even SCR) as part of a future reasonable progress determination.
- There will be federal requirements to reduce mercury emissions. The Flex Fuels project does not interfere with any potential mercury control technologies required by a future federal mercury control program.
- In order to meet the requirement of the Governor's Executive Order on Climate Change, TransAlta will be making significant financial and plant viability analyses of how best to comply with the Executive Order directive and the resulting Agreed Order between the company and Ecology.
- Meeting the requirements of the Executive Order on Climate Change will significantly affect the NO_x emissions from the plant and based on the Ecology proposal, change the economic lifetimes of potential NO_x control technologies.

The emission limitation and coal quality limitation reflecting Ecology's determination of BART for NO_x from the Centralia Plant is provided in Table 4-1 below. A coal meeting the nitrogen and sulfur content of the Jacobs Ranch Upper Wyodak coal depicted in Appendix A, Table A-2 is considered to be a PRB coal or equivalent coal.

If the company finds it is unable to comply with the NO_x limitation in the BART order through the use of LNC3 combustion controls and Flex Fuels, it will be required to install SNCR or other NO_x reduction technique that will allow the plant to meet the BART emission limitation.

Table 4-1 Ecology's Determination of the Emission Controls That Constitute Best Available Retrofit Technology

BART Control Technology	Emission Limitation
Flex fuel project	0.24 lb NOx/MMBtu, 30 day rolling average, both units averaged together
Fuel Quality Requirements	Coal used shall be a sub-bituminous coal from the Powder River Basin or other coal that will achieve similar emission rates

Appendix A -- Coal Quality

Table A-1 Summary of Key Centralia mine and Powder River Basin Coal Characteristics

	TransAlta Centralia Mine Coal				Powder River Basin Coal		
	Low Sulfur (<1.2%)		High Sulfur (>1.2%)				
	Mean	Max	Mean	Max	Mean	Max	From
Btu/lb	7,681	8,113	7,930	8,121	8,414	8,800	Jacobs Ranch Upper Wyodak
Sulfur (%)	0.69	0.84	1.89	2.14	0.40	0.88	Jacobs Ranch Upper Wyodak
Ash (%)	15.44	16.44	14.43	16.46	6.21	13.04	Special K Fuel
Carbon (%)	44.95	47.37	45.63	46.45	49.11	51.26	Jacobs Ranch Upper Wyodak
Nitrogen (%)	0.76	0.80	0.71	0.75	0.67	0.8	Jacobs Ranch Upper Wyodak

Coal characteristics on an "as received" basis.

Table A-2 Powder River Basin Coal Characteristics, from *Best Available Retrofit Technology Analysis for the Centralia Power Plant, July 2008*

Coal Sources and Characteristics									
Coal Quality Data	**Units**	**Bucksk in**	**Caballo 8500**	**Cordero Rojo**	**Jacobs Ranch Upper Wyodak**	**Rawhid e**	**Special K Fuel**	**Belle Ayr**	**Eagle Butte**
Proximate Analysis (As-Received Basis)									
Higher Heating Value	Btu/lb	8400.00	8500.00	8456.00	8800.00	8300.00	7907.00	8500.00	8400.00
Moisture	%	29.95	29.90	29.61	26.45	30.50	25.74	30.50	30.50
Volatile Matter	%	30.25	31.40	30.71	32.50	30.40	28.76	30.40	31.92
Fixed Carbon	%	34.65	33.80	34.22	34.35	34.20	32.46	34.20	32.93
Ash	%	5.15	4.90	5.46	6.70	4.90	13.04	4.90	4.65
Fixed Carbon to Volatile Matter (Fuel) Ratio		1.15	1.08	1.11	1.06	1.13	1.13	1.12	1.03
Ultimate Analysis (As-Received Basis)									
Carbon	%	49.00	49.91	49.16	51.26	48.58	45.82	50.01	49.17
Hydrogen	%	3.24	3.56	3.43	3.89	3.34	3.07	3.43	3.42
Nitrogen	%	0.63	0.71	0.71	0.80	0.63	0.56	0.67	0.67
Sulfur	%	0.35	0.36	0.32	0.88	0.37	0.28	0.26	0.38
Ash	%	5.15	4.90	5.46	6.70	4.90	13.04	4.90	4.65
Moisture	%	29.95	29.90	29.61	26.45	30.50	25.74	30.50	30.50
Chlorine	%	0.00	0.00	0.00	0.01	0.01	0.00	0.01	0.01
Oxygen	%	11.68	10.66	11.31	10.01	11.68	11.49	11.12	11.20

Note: Special K Fuel is blend of Spring Creek and Kaolin coals

Appendix B, -- Nitrogen Oxides Controls Evaluated in the 1997 Reasonable Available Control Technology Process

Table B-1 Nitrogen Oxides Controls Evaluated in the 1997 Reasonable Available Control Technology Process

		Screening Criteria used in 1997 Review						
		Technically Feasible	Increase other Emissions	Safety?	Reduce Product Marketability	Cost Competitive compared to LNB?	Mets or Exceeds CDM Emission Level	Comments
	Boiler Modifications							
1	Boiler Tuning					Yes	No	
2	Low Excess Air					Yes	No	Already Optimized
3	Burners-out-of-Service (BOOS)	Constrained by mill capacity						
4	Fuel & Air Tip Replacement					Yes	Meets	New tip developments may provide capability to meet LNB levels of NOx
5	Close Coupled Overfire Air (CCOFA)				Increased UBC potential	Yes	Meets	
6	Separated Overfire Air (SOFA)				Increased UBC potential	Yes	Meets	
7	ABB Advanced TFS-2000 System (2 levels of SOFA)	Furnace height/spacing at Centralia reduces applicability			Increased UBC potential	Yes	Meets	Limited commercial demonstration of this technology, furnace specific
8	CCOFA plus SOFA	May necessitate pressure part modifications			Increased UBC potential	Yes	Exceeds	
9	Selective Noncatalytic Reduction (SNCR)	Not demonstrated on Centralia sized unit	Ammonia slip	Ammonia	Ammonia contamination of fly ash resulting in lost sales	No	Exceeds	High reagent cost/limited reduction capability
10	SNCR plus Air heater SCR (Hybrid)	Only one partial unit coal-fired utility demonstration ; no demonstration s on Centralia sized unit	Ammonia slip	Ammonia	Ammonia contamination of fly ash resulting in lost sales	No	Exceeds	High reagent & O&M cost
11	Selective Catalytic Reduction (SCR)		Ammonia slip	Ammonia	Ammonia contamination of fly ash resulting in lost sales	No	Exceeds	Extremely high capital and O&M cost
12	Natural Gas co-firing				Reduced ash sales	No	Meets	# 14 is a better variation on this option
13	Natural Gas Conversion				No ash to sell	No	Meets	Very High Fuel cost
14	Natural gas	Not			Reduced ash	No	Meets	High variable cost

Screening Criteria used in 1997 Review								
		Technically Feasible	Increase other Emissions	Safety?	Reduce Product Marketability	Cost Competitive compared to LNB?	Mets or Exceeds CDM Emission Level	Comments
	Reburn (1st Generation)	demonstrated on Centralia sized unit			sales			of operation
15	Natural Gas Reburn (2nd Generation)	No Commercial Application			Reduced ash sales	No	Meets	Natural Gas Expensive
	Combined SO_2/NOx Controls							
16	UOP/PETC Fluidized Bed Copper Oxide	Pilot level or limited use				No	Exceeds	
17	Rockwell Moving-Bed Copper Oxide Process	Pilot level or limited use				No	Exceeds	
18	NOXSO Process	Pilot level or limited use				No	Exceeds	
19	Mitsui/BF Activated Process	Pilot level or limited use				No	Exceeds	
20	Sumitomo/EPDC Activated Char Process	Pilot level or limited use				No	Exceeds	
21	Sanitech Nelsorbent SOx-NOx Control Process	Pilot level or limited use				No	Exceeds	
22	NFT Slurry with NOXOUT Process	Pilot level or limited use				No	Exceeds	
23	Ebara E-Beam Process	Pilot level or limited use				No	Exceeds	
24	Karlsruhe Electron Streaming Treatment	Pilot level or limited use				No	Exceeds	
25	ENEL Pulse-Energization Process	Pilot level or limited use				No	Exceeds	
26	California (Berkeley) Ferrous Cysteine Process	Pilot level or limited use				No	Exceeds	
27	Haldor Topsoe WSA-SOX Process	Pilot level or limited use				No	Exceeds	
28	Degussa DESONOX Process	Pilot level or limited use				No	Exceeds	
29	B&W SOx/NOx/ROx/Box (SNRB) Process	Pilot level or limited use				No	Exceeds	
30	Parsons Flue Gas	Pilot level or				No	Exceeds	

Screening Criteria used in 1997 Review								
		Technically Feasible	Increase other Emissions	Safety?	Reduce Product Marketability	Cost Competitive compared to LNB?	Mets or Exceeds CDM Emission Level	Comments
	Cleanup Process	limited use						
31	Lehigh University Low-Temperature SCR Process	Pilot level or limited use				No	Exceeds	
32	IGR/Hellpump Solid-State Electrochemical Cell	Pilot level or limited use				No	Exceeds	
33	Argonne High-Temperature Spray Drying Studies	Pilot level or limited use				No	Exceeds	
34	PETC Mixed Alkali Spray Dryer Studies	Pilot level or limited use				No	Exceeds	
35	Battelle ZnO Spray Dryer Process	Pilot level or limited use				No	Exceeds	
36	Cooper Process	Pilot level or limited use				No	Exceeds	
37	ISCA Process	Pilot level or limited use				No	Exceeds	

Controls Evaluated in Detail as part of 1997 RACT Evaluation

Emission Reduction Technology	1997 Anticipated NO_x Emission Rate (lb/MMBtu)
Boiler Tuning	0.40 to 0.44
Fuel and Air Tip Replacement	0.40 to 0.44
LNB & Close Coupled Overfire Air (CCOFA)	0.38 to 0.42
LNB & Separated Overfire Air (SOFA)	0.30 to 0.34
Selective Noncatalytic Reduction (SNCR)	0.29 to 0.33
LNB with CCOFA plus SOFA	0.26 to 0.30
Hybrid (SNCR plus air heater SCR)	0.24 to 0.28
Gas Reburning	0.20 to 0.25
Selective Catalytic Reduction (SCR)	0.10 to 0.15

Appendix C -- References

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BART Analyses from other states, such as:

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16. CH2MHill, **BART Analysis for Jim Bridger Unit 1** {also Units 2 – 4}, January 2007

17. Black & Veatch, **Portland General Electric Boardman Plant Best Available Retrofit Technology (BART) Analysis**, November, 2007

18. Northern States Power Co. d/b/a Xcel Energy – **Sherburne County Generating Plant Units 1 and 2 Best Available Retrofit Technology Analysis**, October, 2006

19. Pinnacle West, **Arizona Public Services, Four Corners Power Plant**, BART Analysis Conclusions, January, 2008

Appendix D Modeling Results

Modeling Result Information

Table D-1 is copied from the June 2008 BART Modeling Report, Table D-2 is from the Dec. 2008 Flex Fuels Addendum, and Table D-3 is from the January 2008 report.

Tabled D-1, D-2, and D-3 show the % contribution to visibility impairment on the days listed, the specific day and the modeled visibility on those days. The days shown are the 98th %tile for each year and the 3 years modeled. Since the same metrological information is used for each different emission scenario, the only thing that changes is the emission rate and percentage of total visibility attributable to each chemical species.

Table D-1 June 2008 report

BART Determination Analysis Results, Extinction Budgets for Design Days
TransAlta Baseline Case

		98th Percentile Paired By Class I Area		Contribution by Species (%)					
Area of Interest	Year	Delta HI (dv)	Date	SO4	NO3	OC	EC	PMC	PMF
Alpine Lakes Wilderness	2003	3.599	5/22/2003	31.8	67.1	0.3	0.2	0.2	0.4
	2004	4.871	7/18/2004	52.9	46.2	0.3	0.1	0.1	0.3
	2005	3.856	5/4/2005	29.1	70.2	0.2	0.1	0.1	0.3
	2003-2005	4.346	9/28/2005	30.3	68.8	0.3	0.1	0.2	0.4
Glacier Peak Wilderness	2003	2.070	8/15/2003	39.1	60.0	0.3	0.2	0.1	0.4
	2004	3.615	12/24/2004	48.0	51.4	0.2	0.1	0.1	0.3
	2005	2.554	5/4/2005	37.1	62.3	0.2	0.1	0.1	0.2
	2003-2005	2.622	6/10/2003	42.5	56.8	0.2	0.1	0.1	0.3
Goat Rocks Wilderness	2003	4.207	8/7/2003	44.4	55.0	0.2	0.1	0.1	0.2
	2004	4.993	6/11/2004	42.6	55.8	0.5	0.3	0.3	0.6
	2005	3.826	12/3/2005	34.9	64.5	0.2	0.1	0.1	0.3
	2003-2005	4.286	6/25/2005	34.4	64.6	0.3	0.2	0.2	0.4
Mt. Adams Wilderness	2003	3.667	7/5/2003	33.6	65.2	0.4	0.2	0.2	0.5
	2004	3.628	7/3/2004	42.0	57.0	0.3	0.2	0.2	0.4
	2005	3.379	9/2/2005	26.7	71.5	0.5	0.3	0.4	0.6
	2003-2005	3.628	7/3/2004	42.0	57.0	0.3	0.2	0.2	0.4
Mt. Hood Wilderness	2003	2.773	10/4/2003	37.6	61.8	0.2	0.1	0.1	0.3
	2004	3.471	9/25/2004	43.9	55.2	0.3	0.1	0.1	0.4
	2005	2.159	6/29/2005	40.3	58.7	0.3	0.2	0.1	0.4
	2003-2005	2.830	9/23/2004	26.2	72.9	0.3	0.1	0.2	0.4
Mt. Jefferson Wilderness	2003	1.570	10/14/2003	37.0	62.5	0.1	0.1	0.0	0.2
	2004	2.079	8/18/2004	30.6	68.4	0.3	0.2	0.1	0.4
	2005	1.182	4/25/2005	31.5	68.0	0.2	0.1	0.1	0.2
	2003-2005	1.888	7/5/2004	32.7	66.3	0.3	0.2	0.2	0.4
Mt. Rainier National Park	2003	5.552	2/26/2003	23.6	75.9	0.2	0.1	0.1	0.2
	2004	5.447	9/21/2004	17.9	80.5	0.5	0.2	0.3	0.6
	2005	5.373	4/28/2005	26.4	72.7	0.2	0.1	0.2	0.3
	2003-2005	5.489	7/4/2005	35.0	64.1	0.3	0.1	0.2	0.4
Mt. Washington Wilderness	2003	1.374	10/14/2003	36.6	63.0	0.1	0.1	0.0	0.2
	2004	2.027	6/22/2004	43.3	56.0	0.2	0.1	0.1	0.3
	2005	0.945	8/15/2005	57.2	42.0	0.3	0.1	0.1	0.4
	2003-2005	1.414	6/23/2004	51.9	47.5	0.2	0.1	0.1	0.2
N. Cascades National Park	2003	1.557	3/30/2003	22.2	76.6	0.4	0.2	0.2	0.5
	2004	2.821	12/24/2004	47.4	52.0	0.2	0.1	0.1	0.2
	2005	1.811	5/14/2005	45.5	53.6	0.3	0.1	0.1	0.4
	2003-2005	2.212	6/5/2004	40.3	59.1	0.2	0.1	0.1	0.3
Olympic National Park	2003	3.848	12/22/2003	24.4	73.3	0.6	0.3	0.6	0.8
	2004	4.645	10/4/2004	39.3	60.2	0.2	0.1	0.1	0.2
	2005	3.629	11/20/2005	22.4	77.1	0.2	0.1	0.1	0.2
	2003-2005	4.024	3/8/2004	44.0	55.3	0.2	0.1	0.2	0.3
Pasayten Wilderness	2003	1.131	5/24/2003	48.9	50.5	0.2	0.1	0.1	0.2
	2004	1.954	12/24/2004	43.6	55.9	0.1	0.1	0.1	0.2
	2005	1.172	7/5/2005	45.0	54.1	0.3	0.1	0.1	0.4
	2003-2005	1.482	6/25/2004	56.7	42.7	0.2	0.1	0.1	0.3
Three Sisters Wilderness	2003	1.538	5/12/2003	45.7	53.9	0.1	0.1	0.1	0.2
	2004	2.172	7/27/2004	55.3	44.0	0.2	0.1	0.1	0.3
	2005	1.071	9/28/2005	53.8	45.6	0.2	0.1	0.1	0.3
	2003-2005	1.538	5/12/2003	45.7	53.9	0.1	0.1	0.1	0.2
CRGNSA	2003	2.431	9/25/2003	29.8	68.8	0.4	0.2	0.2	0.6
	2004	2.545	5/15/2004	39.2	60.1	0.2	0.1	0.1	0.3
	2005	1.714	12/13/2005	17.4	81.8	0.2	0.1	0.2	0.3
	2003-2005	2.353	1/13/2005	29.8	69.5	0.2	0.1	0.2	0.3
Overall	Min	0.945		17.4	42.0	0.1	0.1	0.0	0.2
	Mean	2.892		38.1	61.1	0.2	0.1	0.1	0.3
	Max	5.552		57.2	81.8	0.6	0.3	0.6	0.8

Table D-2 December 2008 Flex Fuels Addendum

BART Determination Analysis Results, Extinction Budgets for Design Days TransAlta Flex Fuels									
		98th Percentile Paired By Class I Area		Contribution by Species (%)					
Area of Interest	Year	Delta HI (dv)	Date	SO4	NO3	OC	EC	PMC	PMF
Alpine Lakes Wilderness	2003	3.176	5/22/2003	36.8	61.9	0.4	0.2	0.3	0.5
	2004	4.469	7/18/2004	58.9	40.2	0.3	0.2	0.1	0.4
	2005	3.349	5/4/2005	34.4	64.8	0.2	0.1	0.1	0.3
	2003-2005	3.918	2/27/2004	56.7	42.9	0.1	0.1	0.1	0.1
Glacier Peak Wilderness	2003	1.823	11/1/2003	34.5	64.8	0.2	0.1	0.1	0.3
	2004	3.282	12/24/2004	53.8	45.5	0.2	0.1	0.1	0.3
	2005	2.233	5/4/2005	43.1	56.3	0.2	0.1	0.1	0.3
	2003-2005	2.348	7/18/2004	63.4	35.9	0.2	0.1	0.1	0.3
Goat Rocks Wilderness	2003	3.673	8/23/2003	29.4	69.1	0.4	0.2	0.3	0.6
	2004	4.538	9/21/2004	22.5	75.8	0.5	0.3	0.3	0.7
	2005	3.398	12/3/2005	40.1	59.1	0.2	0.1	0.2	0.3
	2003-2005	3.802	6/25/2005	39.7	59.0	0.4	0.2	0.2	0.5
Mt. Adams Wilderness	2003	3.236	7/5/2003	38.9	59.7	0.4	0.2	0.3	0.6
	2004	3.259	7/3/2004	47.6	51.2	0.3	0.2	0.2	0.4
	2005	2.988	5/30/2005	41.5	56.8	0.5	0.3	0.2	0.7
	2003-2005	3.236	7/5/2003	38.9	59.7	0.4	0.2	0.3	0.6
Mt. Hood Wilderness	2003	2.450	10/4/2003	43.3	56.0	0.2	0.1	0.1	0.3
	2004	3.119	9/25/2004	49.8	49.3	0.3	0.2	0.1	0.4
	2005	1.916	6/29/2005	45.9	52.9	0.4	0.2	0.1	0.5
	2003-2005	2.457	9/5/2004	37.6	61.5	0.3	0.2	0.1	0.4
Mt. Jefferson Wilderness	2003	1.376	10/14/2003	42.7	56.8	0.2	0.1	0.0	0.2
	2004	1.832	7/29/2004	45.6	53.4	0.3	0.2	0.1	0.4
	2005	1.014	9/27/2005	36.3	62.9	0.3	0.2	0.1	0.4
	2003-2005	1.643	7/5/2004	38.0	60.8	0.3	0.2	0.2	0.5
Mt. Rainier National Park	2003	4.865	4/17/2003	30.6	67.8	0.4	0.2	0.4	0.6
	2004	4.878	7/13/2004	48.9	50.1	0.3	0.2	0.1	0.4
	2005	4.757	6/3/2005	39.2	58.8	0.6	0.3	0.4	0.8
	2003-2005	4.854	2/28/2003	46.8	51.8	0.4	0.2	0.3	0.5
Mt. Washington Wilderness	2003	1.201	10/14/2003	42.3	57.2	0.2	0.1	0.0	0.2
	2004	1.799	6/22/2004	49.3	49.9	0.3	0.1	0.1	0.4
	2005	0.861	8/15/2005	63.0	36.0	0.3	0.2	0.1	0.4
	2003-2005	1.275	6/23/2004	58.1	41.4	0.2	0.1	0.1	0.3
N. Cascades National Park	2003	1.330	6/14/2003	45.9	53.4	0.2	0.1	0.1	0.3
	2004	2.548	12/24/2004	53.2	46.2	0.2	0.1	0.1	0.3
	2005	1.620	5/14/2005	51.4	47.6	0.3	0.2	0.2	0.4
	2003-2005	1.940	4/13/2004	41.7	57.7	0.2	0.1	0.1	0.2
Olympic National Park	2003	3.433	12/19/2003	24.5	72.2	0.9	0.5	0.8	1.2
	2004	4.130	7/30/2004	56.7	42.3	0.3	0.2	0.2	0.4
	2005	3.124	11/20/2005	26.7	72.6	0.2	0.1	0.1	0.2
	2003-2005	3.546	2/26/2005	39.9	59.2	0.3	0.2	0.1	0.4
Pasayten Wilderness	2003	0.981	6/12/2003	40.9	58.2	0.3	0.2	0.1	0.4
	2004	1.737	9/24/2004	55.0	44.4	0.2	0.1	0.1	0.2
	2005	1.038	7/5/2005	51.2	47.8	0.3	0.2	0.1	0.4
	2003-2005	1.353	10/9/2005	47.1	52.5	0.1	0.1	0.1	0.2
Three Sisters Wilderness	2003	1.361	5/12/2003	52.1	47.5	0.1	0.1	0.1	0.2
	2004	1.956	6/22/2004	50.2	49.0	0.2	0.1	0.1	0.3
	2005	0.921	7/25/2005	33.8	65.1	0.3	0.2	0.2	0.5
	2003-2005	1.361	5/12/2003	52.1	47.5	0.1	0.1	0.1	0.2
CRGNSA	2003	2.111	9/25/2003	34.9	63.4	0.5	0.3	0.3	0.7
	2004	2.250	5/15/2004	45.0	54.2	0.3	0.1	0.2	0.3
	2005	1.439	12/13/2005	21.0	78.0	0.3	0.1	0.2	0.4
	2003-2005	2.008	4/1/2004	22.4	75.9	0.5	0.3	0.4	0.6
Overall	Min	0.861		21.0	35.9	0.1	0.1	0.0	0.1
	Mean	2.562		43.1	55.8	0.3	0.2	0.2	0.4
	Max	4.878		63.4	78.0	0.9	0.5	0.8	1.2

Table D-3 January 2008 Report

BART Determination Analysis Results, Extinction Budgets for Design Days TransAlta SNCR Case									
		98th Percentile Paired By Class I Area		Contribution by Species (%)					
Area of Interest	Year	Delta HI (dv)	Date	SO4	NO3	OC	EC	PMC	PMF
Alpine Lakes Wilderness	2003	3.094	5/22/2003	38.0	60.7	0.4	0.2	0.3	0.5
	2004	4.393	7/18/2004	60.2	38.8	0.3	0.2	0.2	0.4
	2005	3.251	5/4/2005	35.6	63.6	0.3	0.1	0.1	0.3
	2003-2005	3.844	2/27/2004	58.0	41.6	0.1	0.1	0.1	0.1
Glacier Peak Wilderness	2003	1.773	8/15/2003	46.4	52.6	0.3	0.2	0.1	0.5
	2004	3.209	4/12/2004	41.5	57.7	0.2	0.1	0.1	0.3
	2005	2.172	5/4/2005	44.4	54.9	0.2	0.1	0.1	0.3
	2003-2005	2.294	7/9/2005	43.1	55.8	0.3	0.2	0.2	0.4
Goat Rocks Wilderness	2003	3.564	8/23/2003	30.5	68.0	0.4	0.2	0.4	0.6
	2004	4.398	9/21/2004	23.4	74.8	0.5	0.3	0.4	0.7
	2005	3.314	12/3/2005	41.3	57.9	0.2	0.1	0.2	0.3
	2003-2005	3.708	6/25/2005	41.0	57.8	0.4	0.2	0.2	0.5
Mt. Adams Wilderness	2003	3.152	7/5/2003	40.1	58.4	0.4	0.2	0.3	0.6
	2004	3.188	7/3/2004	48.9	49.9	0.3	0.2	0.2	0.4
	2005	2.914	7/1/2005	31.5	66.5	0.6	0.3	0.4	0.8
	2003-2005	3.152	7/5/2003	40.1	58.4	0.4	0.2	0.3	0.6
Mt. Hood Wilderness	2003	2.388	10/4/2003	44.5	54.7	0.2	0.1	0.1	0.3
	2004	3.051	9/25/2004	51.1	47.9	0.3	0.2	0.1	0.4
	2005	1.870	6/29/2005	47.3	51.6	0.4	0.2	0.1	0.5
	2003-2005	2.388	9/5/2004	38.8	60.2	0.3	0.2	0.1	0.4
Mt. Jefferson Wilderness	2003	1.338	10/14/2003	44.0	55.5	0.2	0.1	0.0	0.2
	2004	1.784	7/29/2004	46.9	52.1	0.3	0.2	0.1	0.4
	2005	0.982	9/27/2005	37.5	61.6	0.3	0.2	0.1	0.4
	2003-2005	1.596	7/5/2004	39.2	59.6	0.4	0.2	0.2	0.5
Mt. Rainier National Park	2003	4.754	2/28/2003	48.1	50.5	0.4	0.2	0.3	0.5
	2004	4.774	7/13/2004	50.3	48.7	0.3	0.2	0.1	0.4
	2005	4.613	12/12/2005	21.8	77.4	0.2	0.1	0.2	0.3
	2003-2005	4.743	8/16/2003	64.4	33.3	0.6	0.3	0.5	0.8
Mt. Washington Wilderness	2003	1.168	10/14/2003	43.6	55.9	0.2	0.1	0.1	0.2
	2004	1.756	6/22/2004	50.6	48.5	0.3	0.1	0.1	0.4
	2005	0.845	8/15/2005	64.3	34.8	0.3	0.2	0.1	0.4
	2003-2005	1.248	6/23/2004	59.4	40.0	0.2	0.1	0.1	0.3
N. Cascades National Park	2003	1.296	6/14/2003	47.2	52.1	0.2	0.1	0.1	0.3
	2004	2.496	12/24/2004	54.5	44.9	0.2	0.1	0.1	0.3
	2005	1.583	5/14/2005	52.7	46.3	0.3	0.2	0.2	0.4
	2003-2005	1.887	4/13/2004	43.0	56.4	0.2	0.1	0.1	0.2
Olympic National Park	2003	3.328	12/19/2003	25.4	71.1	0.9	0.5	0.9	1.2
	2004	4.040	10/4/2004	46.7	52.6	0.2	0.1	0.1	0.2
	2005	3.031	6/6/2005	46.8	52.2	0.3	0.1	0.2	0.4
	2003-2005	3.456	2/26/2005	41.1	57.9	0.3	0.2	0.1	0.4
Pasayten Wilderness	2003	0.953	6/12/2003	42.1	56.9	0.3	0.2	0.1	0.4
	2004	1.701	9/24/2004	56.3	43.1	0.2	0.1	0.1	0.2
	2005	1.012	7/5/2005	52.6	46.4	0.3	0.2	0.2	0.4
	2003-2005	1.318	10/9/2005	48.5	51.1	0.1	0.1	0.1	0.2
Three Sisters Wilderness	2003	1.328	5/12/2003	53.5	46.1	0.1	0.1	0.1	0.2
	2004	1.910	6/22/2004	51.6	47.7	0.2	0.1	0.1	0.3
	2005	0.891	7/25/2005	35.0	63.9	0.4	0.2	0.2	0.5
	2003-2005	1.328	5/12/2003	53.5	46.1	0.1	0.1	0.1	0.2
CRGNSA	2003	2.049	9/25/2003	36.1	62.2	0.5	0.3	0.3	0.7
	2004	2.193	5/15/2004	46.3	52.8	0.3	0.1	0.2	0.3
	2005	1.386	12/13/2005	21.9	77.1	0.3	0.1	0.2	0.4
	2003-2005	1.942	9/5/2004	40.1	58.9	0.3	0.2	0.2	0.4
Overall	Min	0.845		21.8	33.3	0.1	0.1	0.0	0.1
	Mean	2.497		44.4	54.5	0.3	0.2	0.2	0.4
	Max	4.774		64.4	77.4	0.9	0.5	0.9	1.2

Figures D-1 through D-5 graphically depict the seasonality of visibility impacts from the TransAlta facility. 5 different Class I areas are depicted in order to indicate how the seasonality of impacts changes somewhat based on season of the year.

Figure D-1

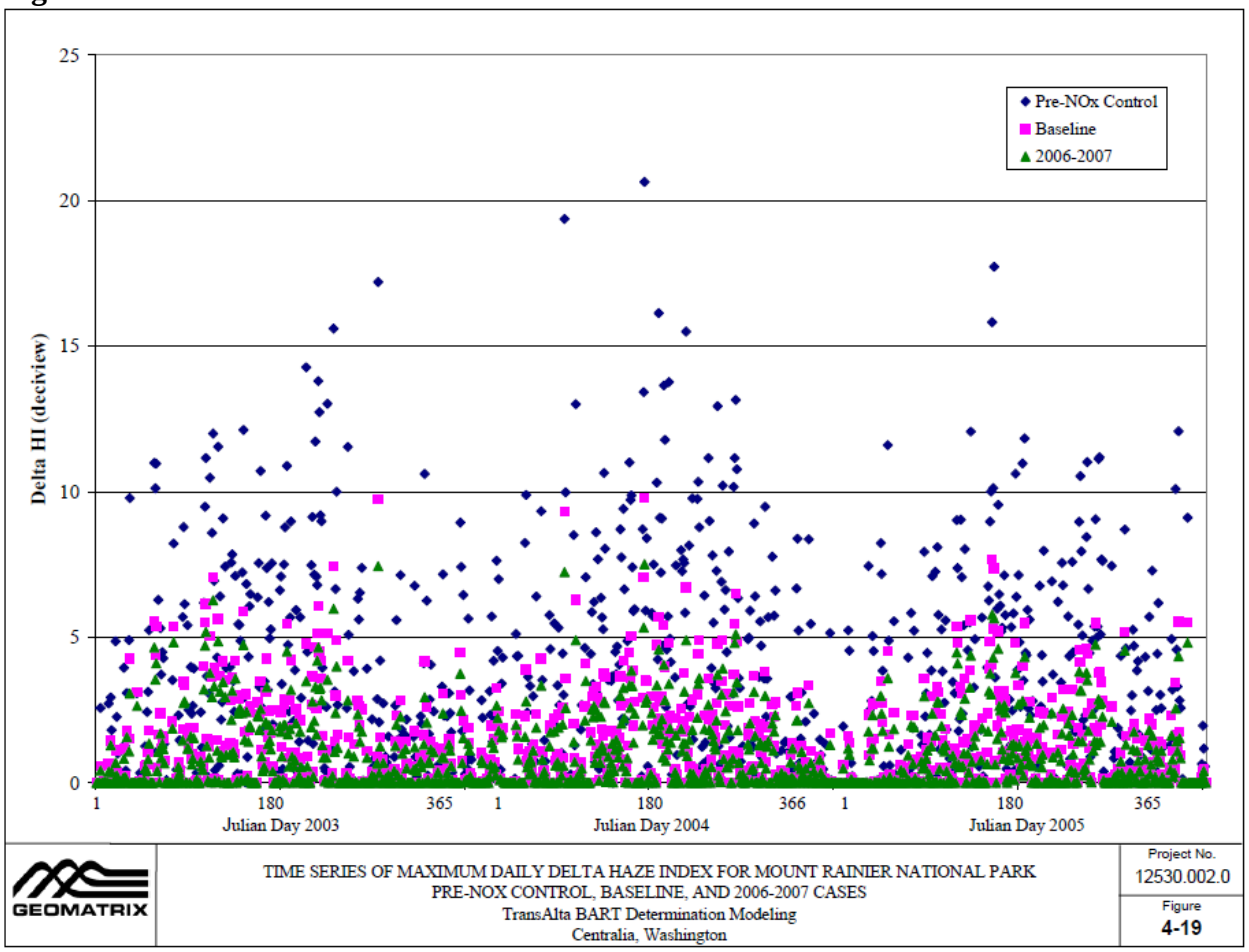
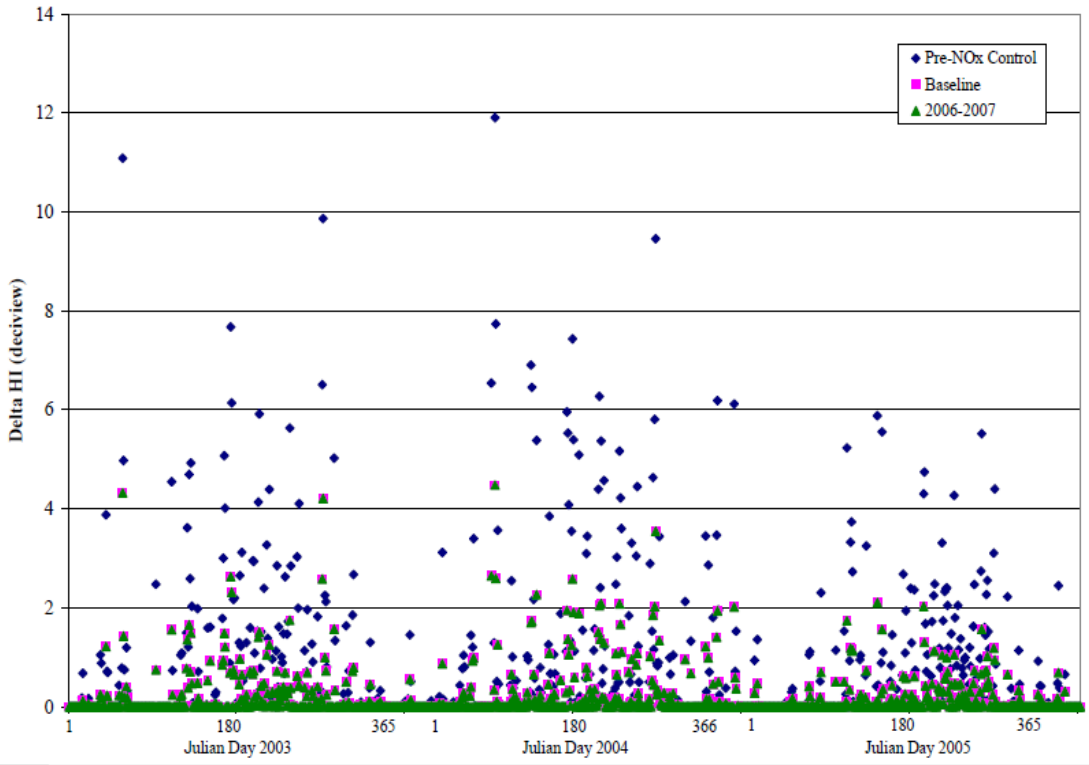


Figure D-2



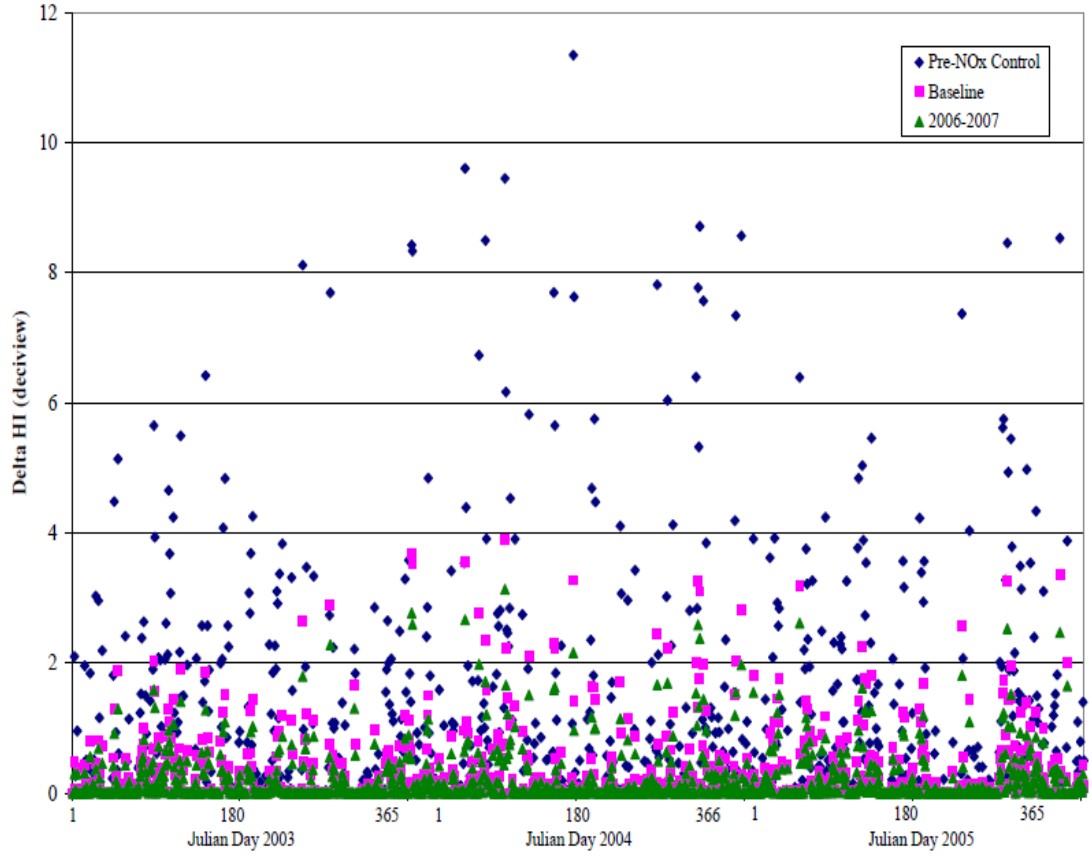
GEOMATRIX

TIME SERIES OF MAXIMUM DAILY DELTA HAZE INDEX FOR MOUNT JEFFERSON WILDERNESS
PRE-NOX CONTROL, BASELINE, AND 2006-2007 CASES
TransAlta BART Determination Modeling
Centralia, Washington

Project No. 12530.002.0

Figure 4-16

Figure D-4



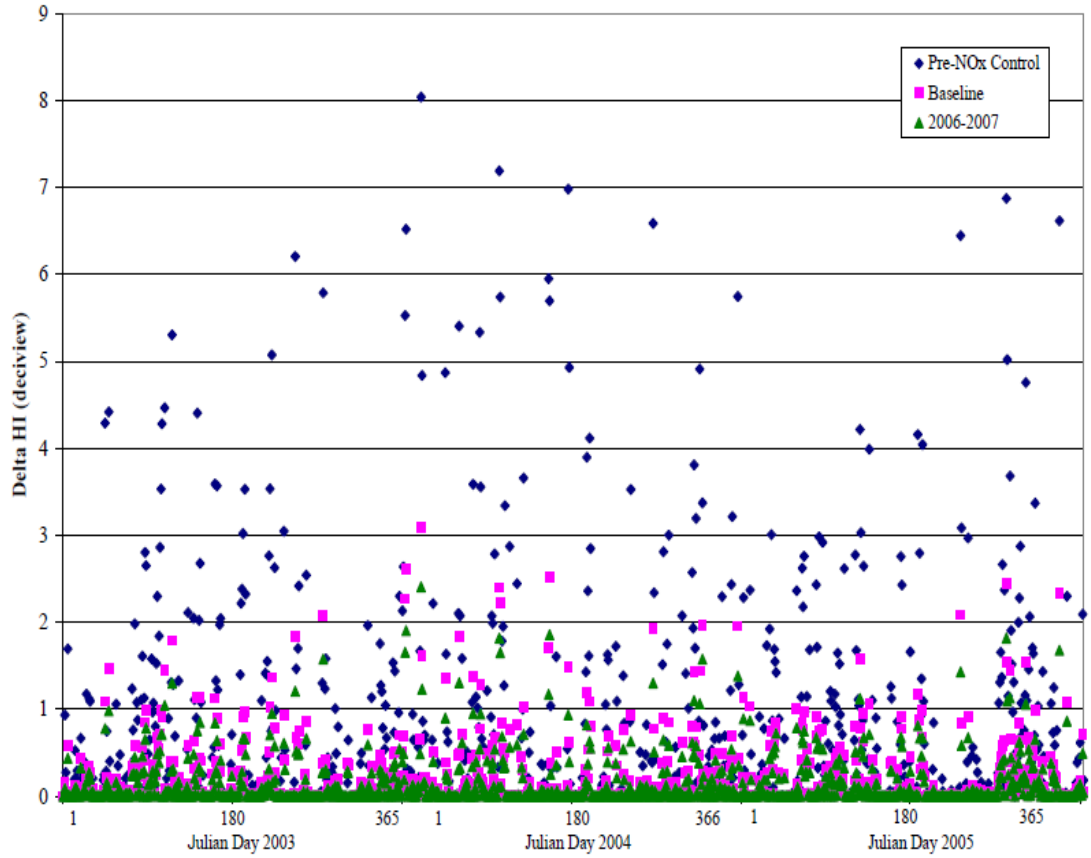
GEOMATRIX

TIME SERIES OF MAXIMUM DAILY DELTA HAZE INDEX FOR NORTH CASCADES NATIONAL PARK
PRE-NOX CONTROL, BASELINE, AND 2006-2007 CASES
TransAlta BART Determination Modeling
Centralia, Washington

Project No. 12530.002.0

Figure 4-25

Figure D-5



GEOMATRIX

TIME SERIES OF MAXIMUM DAILY DELTA HAZE INDEX FOR PASAYTEN WILDERNESS
PRE-NOX CONTROL, BASELINE, AND 2006-2007 CASES
TransAlta BART Determination Modeling
Centralia, Washington

Project No. 12530.002.0

Figure 4-31

Appendix E Coal Fired Electric Generating Unit BART Determinations in Western US

Table of Coal Fired Electric Generating Unit BART Determinations in Western US

All information presented is contained in Regional Haze State Implementation Plans available for public review or that have been submitted to EPA for approval, as of January 2010.

Table E-1

State	Unit	NOx Technology	lb/MMBtu, 30 day avg	Comments
EPA Region 8, Montana	Colstrip			No final Decisions publicly available
EPA Region 9, Navajo Reservation	Navajo			No final Decision publicly available
	Four Corners			No final Decision publicly available
Arkansas	Entergy Arkansas, Inc. White Bluff, Units 1 and 2		0.28 on bituminous coal 0.15 on sub-bituminous coal	Controls not given. Limits in State Regulation 19.1505
	SWEPCO Flint Creek Power Plant Unit 1		0.23	Controls not given. Limits in State Regulation 19.1506
California	No Coal fired Units subject to BART			
Colorado	Martin Drake Units 5 - 7	Install overfire air systems	0.39	Also limited to 0.35 lb/MMBtu, annual Average
	CENC (Trigen) Unit 4	Limited by rule to combustion controls, LNC3	115 lb/hr	
	CENC (Trigen) Unit 5	Limited by rule to combustion controls, LNC3	182 lb/hr	
	Craig Unit 1	Limited by rule to combustion controls, LNC3	0.39	Also limited to 0.30 lb/MMBtu, annual Average
	Craig Unit 2	Limited by rule to combustion controls, LNC3	0.39	Also limited to 0.30 lb/MMBtu, annual Average
	Public Service of Colorado, Comanche Units 1 and 2	Low NOx Burners	0.2	Also limited to 0.15 lb/MMBtu annual average both units combined
	Public Service of Colorado, Cherokee Unit 4	Modify existing Low NOx burner and over fire air or install new burners	0.28	

State	Unit	NOx Technology	lb/MMBtu, 30 day avg	Comments
	Public Service of Colorado, Hayden Unit 1	Modify existing Low NOx burner and over fire air or install new burners	0.39	
	Public Service of Colorado, Hayden Unit 2	Modify existing Low NOx burner and over fire air or install new burners	0.28	
	Public Service of Colorado, Pawnee Unit 1	Modify existing Low NOx burner and over fire air or install new burners	0.23	
	Public Service of Colorado, Valemont Unit 5	Modify existing Low NOx burner and over fire air or install new burners	0.28	
Idaho	No coal fired units			
Kansas	La Cynge Generating Station, Unit 1 and 2	SCR on Unit 1, Controls as needed on Unit 2	0.13, both units averaged together	
	Jeffrey Energy Center, Units 1 and 2	Low NOx Burners	0.15	
Minnesota	MN Power, Taconite Harbor Boiler No. 3	ROFA/Rotamix (Mobotec)	0.13	
	MN Power, Boswell Boiler No. 3	LNB + OFA, SCR	0.07	
	Rochester Public Utilities, Silver Lake, Unit #3 boiler	No additional controls	No Limit	
	Rochester Public Utilities, Silver Lake, Unit #4 boiler	ROFA/Rotamix (existing controls)	0.25	
	Xcel Energy, Sherco, Boiler 1	LNB +SOFA+Combustion Optimization	0.15	
	Xcel Energy, Sherco, Boiler 2	Combustion optimization	0.15	
	Xcel Energy, Allen S. King Boiler 1	SCR (existing controls)	0.1	
	Northshore Mining, Silver Bay, Boiler 1	LNB + OFA	0.41	
	Northshore Mining, Silver Bay, Boiler 2	LNB + OFA	0.4	
Iowa	Used CAIR for BART			
Louisiana	Used CAIR for BART			

State	Unit	NOx Technology	lb/MMBtu, 30 day avg	Comments
Nebraska	Gerald Gentleman, Units 1 and 2	Existing LNC3 on Unit 2 New LNC3 on Unit 1	0.23, both units averaged together	
	Nebraska City Station, Unit 1	LNC3	0.23	
Nevada	No Coal Fired BART units			
New Mexico	San Juan Generating Station	No final Decision publicly available		
North Dakota	Olds Unit 1	SNCR plus overfire air	0.19	
(All Lignite units)	Olds Unit 2	SNCR plus overfire air	0.35	
	Coal Creek Units 1and 2	Additional overfire air plus LNB	0.19	
	Stanton Unit 1	LNC3 plus SNCR for a 1/3 reduction	0.29	a 1/3 reduction
	Milton Young Station Unit 1	Advanced overfire air plus SNCR for a 58% reduction	0.36	
	Milton Young Station Unit 2	Advanced overfire air plus SNCR for a 58% reduction	0.35	
Oregon	Boardman	LNC3	0.28	Note SNCR to be installed by July 2014 @ 0.23 lb/MMBtu and SCR @ 0.07 lb/MMBtu required later. Neither is required as BART
Oklahoma	OG&E Muskogee Generating Station Units 4 and 5		0.15	
	OG&E Sooner Generating Station Units 1 and 2		0.15	
	AEP/PSO Northeastern Power Station Units 3 and 4		0.15	
Texas	No Coal Fired BART units Subject to BART			
Utah	Hunter Power Plant, Units 1 and 2	LNC3	0.26	Replacing LNC1 burners and add 2 levels of overfire air under minor NSR program.
	Huntington Power Plants, Units 1 and 2	LNC3	0.26	Replacing LNC1 burners and add 2 levels of overfire air under minor NSR program.

State	Unit	NOx Technology	lb/MMBtu, 30 day avg	Comments
Wyoming	Naughton Unit 1	LNC3	0.26	Wyoming Long term strategy for this unit requires SCR @ 0.07 lb/MMBtu by 2018.
	Naughton Unit 2	LNC3	0.26	
	Naughton Unit 3	LNC3 plus SCR	0.07	
	Jim Bridger Units 1 - 4	LNC3	0.26	
	Dave Johnston Unit 3	LNC3	0.26	
	Dave Johnston Unit 4	LNC3	0.15	
	Wyodak Unit 1	LNC3	0.23	
	Basin Electric Units 1 - 3	LNC3	0.23	

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600 • Olympia, WA 98504-7600 • 360-407-6000
711 for Washington Relay Service • Persons with a speech disability can call 877-833-6341

June 18, 2010

Mr. Lou Florence,
TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, WA 9853

Dear Mr. Florence:

Regional Haze Best Available Retrofit Technology (BART) Determination
Order No. 6426

Best Available Retrofit Technology (BART) is required to reduce the regional haze impacts of emissions of your facility. The enclosed order #6426 contains our BART determination for your facility including a schedule for compliance.

If you have questions or requests relating to this order, please contact Alan Newman at (360) 407-6810 or by mail at the address above.

Sincerely,

Jeff Johnston, Ph.D.
Science and Engineering Section Manager
Air Quality Program

jj/lb

Enclosure

cc: Clint Lamoreaux, SWCAA
Alan Newman, Ecology
Richard DeBolt, TransAlta

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN ADMINISTRATIVE ORDER AGAINST: TransAlta Centralia Generation LLC	]	ORDER NO. 6426

TO: Mr. Lou Florence,
TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, WA 98531

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions that are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the state visibility protection program (WAC 173-400-151), which is implemented consistent with the requirements of the federal visibility protection program (40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitute Best Available Retrofit Technology (BART) for the eligible emission units at your facility. The rules also require the installation and use of those emission controls on the BART-eligible emission units. The emission controls are to be installed as expeditiously as possible, but in no event may the State allow them to start operation later than five years after the State's Regional Haze SIP amendment is approved by the United States Environmental Protection Agency (EPA).

FINDINGS

A. The TransAlta Centralia Generation LLC ("TransAlta") Centralia Power Plant is a coal fired power plant larger than 750 MW output subject to BART.

B. BART emission limitations for sulfur dioxide and particulate were determined by the Environmental Protection Agency in 2003. The Centralia Power Plant's Operating Permit incorporates the BART emission limitations determined by EPA.

C. BART for nitrogen oxides at the Centralia Power Plant is based on:

   a. Use of low NO_x burners with separated and close coupled over fire air systems (aka LNC3).

   b. Use of a sub-bituminous Powder River Basin coal or other coal that will achieve similar emission rates.

c. Use and installation of additional boiler heat recovery equipment and boiler tube cleaning equipment to maximize the extraction of fuel energy into boiler steam.

Additional information and analysis is available in the BART Determination Support Document for the Centralia Power Plant, by the Washington State Department of Ecology, November 2008, and the BART Analysis for the Centralia Power Plant, June 2008 and the BART Analysis Supplement, December 2008.

YOU ARE ORDERED: To install and operate in accordance with the following conditions:

BART Emission Limitations

1. Nitrogen Dioxide Emissions

   1.1. Starting no later than the date in Condition 2, emissions of nitrogen dioxide from the two coal-fired utility steam generating units at the Centralia Power Plant are limited to a maximum of:

      1.1.1. 0.24 lb/MMBtu, 30 day rolling average, both units averaged together for days (i.e., midnight to midnight) when either unit's generating load is 360 MW gross or greater.

      1.1.2. In the event that during a given 30 day period, only one unit operated, the average of both units will be the 30 day average emission rate for the operating boiler.

   1.2. Compliance will be determined by use of a continuous emission monitoring system.

   1.3. Coal used shall be a sub-bituminous coal from the Powder River Basin or other coal that will achieve similar emission rates.

Schedule for Compliance

2. Compliance with the 30-day rolling average nitrogen dioxide emission limitation begins on the date of issuance of this Order, based on emissions for the prior 30 day period.

3. Determination of compliance with the rolling annual average nitrogen and sulfur coal content limitation will commence at midnight on the 365th day after issuance of this Order, based on coal nitrogen and sulfur content testing during the prior year.

Monitoring and Recordkeeping Requirements

4. Nitrogen Dioxide

   4.1. Nitrogen dioxide emissions are to be quantified by means of a continuous emission monitoring system, consisting of a continuous nitrogen dioxide monitor, and a continuous flow rate monitor.

4.2. The continuous monitoring system shall comply with Condition M9 of the Centralia Power Plant's Air Operating Permit, SW98-8- R3 (issued September 16, 2009) ("Air Operating Permit") and corresponding monitoring conditions in future renewals of the Air Operating Permit.

5. Missing data requirements for nitrogen dioxide emission monitoring required by this order

5.1. For a unit with less than 12 continuous hours of missing CEM data, the substituted hourly emission rate will be the higher of (a) the average of emissions during the hour before and the hour after the period of missing data or (b) the average of emissions from the previous 720 operating hours of quality-assured data.

5.2. For a unit with 12 or more continuous hours of missing CEM data, the substituted hourly emission rate will be based on the 90th percentile of the previous 720 operating hours of quality-assured data.

5.3. Those 30 day periods which include substitute data for calculating 30 day averages shall be indicated in the emissions information reported in Condition 7.

6. Coal Quality Monitoring

6.1. Coal nitrogen and sulfur content shall be determined by taking a sampling coal conveyed by the transfer belt between the coal pile and coal silos. An alternate location that provides a sample representative of the coal fired by the boilers may be proposed to Ecology by TransAlta for approval for use.

6.2. A sample of coal for nitrogen and sulfur content analysis will be taken at least once per week when at least one coal fired boiler is in operation. The sample shall be taken following ASTM Method D2234/D2234M-07.

6.3. Coal nitrogen and sulfur content will be determined using ASTM Method D3176-89 (as reapproved in 2002). Note, other ASTM methods related to sample collection and preparation may need to be followed in order to perform this test.

6.4. As an alternate to coal nitrogen and sulfur content testing at the plant, certified results of testing by the coal mine operator of coal actually sent to the Centralia Power Plant may be used. Testing frequency should be no less frequent than required above.

Reporting Requirements

7. Malfunction of the emission control system must, at a minimum, be documented in writing and submitted to SWCAA and Ecology with the emissions monitoring data per Condition 7. Additional recordkeeping and notifications related to excess emissions may also be required by SWCAA regulation.

8. Continuous emission monitoring data shall be submitted to Ecology and to the SWCAA in accordance with condition R3 of the Centralia Plant's Air Operating Permit; SW98-8- R3 (issued September 16, 2009). In addition to the information required in condition R3, the report will include the 30 day rolling average lb. NOx/MMBtu and tons of NOx emitted during the current calendar year. The submittal shall be sent electronically in a format acceptable to the SWCAA. Reporting to Ecology under this condition will end if the Order has been rescinded as provided in Condition 10, below.

9. Coal nitrogen and sulfur content information shall be submitted to Ecology and to the SWCAA in accordance with schedule in condition R3 of the Centralia Plant's Air Operating Permit; SW98-8-R3 (issued September 16, 2009).

   9.1. Coal nitrogen and sulfur reporting during the first year (Oct. 30, 2009 through Oct. 30, 2010) shall include the date each coal sample is taken, the nitrogen and sulfur content of each coal sample analyzed, the running average content and the maximum and minimum concentrations found.

   9.2. After the first year, the report shall include the rolling annual averages for nitrogen and sulfur content plus the maximum and minimum concentrations in the prior year.

   9.2.1. The weekly coal sample test results shall be retained for at least 5 years and available for review by Ecology or SWWCAA upon request.

10. TransAlta may request this Order be rescinded after all of the following occur:

   10.1. The emission limitations in this Order have been incorporated into an enforceable order or permit issued by SWCAA under the criteria of RCW 70.94.152 or 70.94.153 and SWCAA implementing regulations, provided that BART emission limits for the Centralia Power Plant will not be reanalyzed or reconsidered in connection with SWCAA's issuance of such enforceable order or permit.

   10.2. The emission limitations in the enforceable order or permit have been incorporated into the Air Operating Permit issued by SWCAA for the Centralia Power Plant.

   10.3. EPA has incorporated the Order into the Regional Haze State Implementation Plan.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order. Ecology shall enforce the terms of this Order only until such time as SWCAA incorporates the terms of the Order into the Centralia Power Plant's Air Operating Permit or except as provided by RCW 70.94.785.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.
- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:

The Pollution Control Hearings Board
PO Box 40903
Olympia, WA 98504-0903

OR

Deliver your appeal in person to:

The Pollution Control Hearings Board
4224–6th Avenue SE Rowe Six, Bldg 2
Lacey, WA 98503

To serve your appeal on the Department of Ecology:

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DATED this 18 day of June, 2010 at Olympia, Washington.

Jeff Johnston, Ph.D.
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BART DETERMINATION SUPPORT DOCUMENT FOR WEYERHAEUSER CORPORATION LONGVIEW, WASHINGTON

Prepared by

Washington State Department of Ecology
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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.

The Weyerhaeuser Corporation (Weyerhaeuser) operates an integrated Kraft, thermomechanical, and recycled paper, pulp and paper mill that produces a wide range of paper products, including paperboard, corrugating medium, newsprint, and fine papers. The mill is located in Longview, Washington. The mill produces emissions of particulate matter (PM), sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NO_X), and hydrocarbons. The pollutants considered to be visibility impairing are PM, SO_2, and NO_X.

Kraft pulp mills are one of the 26 listed BART source categories. A pulp mill began operation on the site in 1931. The current mill was constructed in 1948 and expanded in 1956/57, but it has had many modernizations and upgrades since then. The mill's potential emissions exceed 250 tpy for at least one of NO_X, SO_2, or PM_{10}. Three units are BART-eligible by construction or reconstruction date. They are the No. 10 Recovery Furnace, No. 10 Smelt Dissolver Tank, and the No. 11 Power Boiler.

Modeling of visibility impairment was done following the Oregon/Idaho/Washington/EPA-Region 10 BART modeling protocol.[1] Modeled visibility impacts of baseline emissions show impacts on the 8th highest day in any year (the 98th percentile value) of greater than 0.5 deciviews (dv) at five of the 12 Class I areas within 300 kilometers (km) of the plant.

Weyerhaeuser prepared a BART technical analysis using Washington State's BART Guidance.[2]

The Washington State Department of Ecology (Ecology) has determined that the current level of emissions control is BART for the three BART-eligible units. A wide variety of additional controls was investigated for each unit. However, all were determined to be either technically or economically infeasible.

[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.

1. INTRODUCTION

1.1 The BART Program and BART Analysis Process

The federal Clean Air Act Amendments of 1977 (CAA) established a national goal of eliminating human induced visibility impairment in all mandatory federal Class I areas. The CAA requires certain sources to utilize Best Available Retrofit Technology (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 United States Environmental Protection Agency (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. This decision is issued to the source owner as an enforceable Order, and included in the State's Regional Haze State Implementation Plan (SIP).

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

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 Weyerhaeuser Corporation's Longview Mill

Weyerhaeuser operates an integrated timber products facility, including a Kraft pulp and paper mill located on the banks of the Columbia River in Longview, Washington. The facility produces a variety of timber, wood, pulp and paper products, including logs, dimensional lumber, bleached Kraft pulp, liquid packaging board, newsprint, and publication papers. Paper products are produced from bleached Kraft pulp, de-inked recycled paper, and thermomechanical pulp. The Kraft mill was constructed in 1948 and expanded in 1956/57, but it has had many modernizations and upgrades since then, including installation of a new Kraft Fiberline in 1993-1995. The combined Weyerhaeuser and NORPAC pulp and paper operations are regulated as a single facility operating under Air Operating Permit WA 000012-4. Ecology received a BART Analysis and Determination Report from Weyerhaeuser on December 20, 2007, which was revised and resubmitted on June 30, 2008.

1.3 BART-Eligible Units

A review of the emission at the facility found that:

1. Three of the plant's individual emission units are BART-eligible by construction date. They are the No. 10 Recovery Furnace, the No. 10 Smelt Dissolver Tank, and the No. 11 Power Boiler.

2. The three individual emission units in total have a potential to emit at least 250 tons/year of nitrogen oxides (NO_X), and sulfur dioxide (SO_2).

3. A Class I area visibility impact analysis was done using the maximum daily emissions during the 2003-2005 time period and the CALPUFF model. The model results indicated the visibility impact from the BART-eligible units exceeded the 0.5 dv contribution threshold in at least one Class I area.

1.3.1 Existing Recovery Furnace Emissions Control

Weyerhaeuser operates a non-direct contact evaporator (NDCE) recovery furnace with an electrostatic precipitator (ESP). The recovery furnace fires black liquor solids (BLS) and some fuel oil. The furnace is equipped with boiler tubes to recover thermal energy from the

combustion of black liquor. As a result of the continuous operation of the Kraft process, the recovery furnace operates continuously at approximately the same rate all the time (a.k.a. "baseload" operation). The steam generated is used to produce electricity and provide process heat and steam.

A chemical recovery furnace is not simply a "boiler" designed to burn fuel and produce steam. It is a complex device which serves as a chemical reactor, a chemical recovery unit, an internal high efficiency SO_2 scrubber, and an energy recovery unit. Recovery furnaces operate by spraying concentrated spent pulping chemical liquids (black liquor) into the furnace. The organic chemicals in the black liquor (mostly lignins) are combusted. Combustion provides the energy to recover the inorganic pulping chemicals (sodium sulfide) for reuse. As with most recovery furnaces, this furnace is equipped with boiler tubes to generate steam for electrical generation and process needs.

This furnace utilizes tertiary over fire air combustion to maximize chemical recovery and minimize emissions. The black liquor is concentrated prior to introduction into the furnace. Heat energy is recovered as steam used for production of electricity and plant steam needs.

The major pollutants emitted from the furnace are SO_2, NO_X, and PM_{10}. SO_2 is generated in the recovery furnace from the oxidation of inorganic and organic sulfur compounds contained in the black liquor and hydrogen sulfide losses from the chemical recovery portion of the furnace. Additional SO_2 results from the oxidation of sulfur in fuel oil which may be used during the combustion process. The chemical recovery process scrubs out most of the SO_2 generated in the chemical recovery/combustion process in the furnace. SO_2 emissions from the furnace represent a loss of process chemical and are not desirable, so the furnace operation is optimized to minimize the loss of process chemicals, primarily sodium and sulfur.

NO_X may form as fuel NO_X and thermal NO_X. Technical literature suggests that NO_X formation from the chemical recovery process is primarily fuel NO_X since recovery furnace temperatures are not high enough for significant thermal NO_X formation.[4] NO_X emissions from recovery furnaces are typically low due to the low nitrogen concentration in the black liquor solids (approximately 0.1 percent), the low overall conversion of liquor nitrogen to NO_X (10 to 25 percent), and the existence of sodium fumes that can participate in "in-furnace" NO_X reduction or removal.[5]

The majority of particulate emissions are in the form of particulate matter less than 10 microns in size (PM_{10}). The majority of the PM_{10} emissions from the recovery furnace are sodium salts with about 80 percent of the PM_{10} being sodium sulfate and smaller amounts of potassium

[4] NCASI Special Report 99-01, *A Review of NO_X Emission Control Strategies for Industrial Boilers, Kraft Recovery Furnaces, and Lime Kilns,* April 1999.
[5] NCASI Special Report No. 03-06, *Effect of Kraft Recovery Furnace Operations on NO_X Emissions: Literature Review and Summary of Industry Experience,* October 2003.

sulfate, sodium carbonate, and sodium chloride.[6] These salts primarily result from the carryover of solids from the combustion and chemical recovery process plus sublimation and condensation of inorganic chemicals.[7] Some PM_{10} in the recovery furnace flue gas can be attributed to the combustion of fossil fuel. Most of the particulate generated in the furnace falls out in the economizer with the rest captured by the electrostatic precipitator. The particulate (known as "saltcake") captured in the economizer and ESPs, is recycled back to the process by mixing with black liquor before it enters the black liquor concentrators. The concentrated black liquor is then sent to the recovery furnace.

The recovery furnace is equipped with an electrostatic precipitator (ESP) to reduce PM/PM_{10}. The SO_2 and NO_X emissions are controlled through the design and careful operation of the recovery furnace's tertiary air system.

The NO_X, SO_2, and PM_{10} emissions from the No. 10 Recovery Furnace are subject to BACT emission limits in Prevention of Significant Deterioration (PSD) 92-03 and the requirements of 40 CFR 63 Subpart MM, as well as other less stringent limits. The most stringent of the applicable PM, NO_X, and SO_2 emission limits are shown in Table 1-1.

Table 1-1. RECOVERY FURNACE CURRENT EMISSION LIMITS

Pollutant	Emission Limit	Regulatory Basis
PM/PM_{10}	0.027 gr/dscf @ 8% O_2, and 0.020 gr/dscf @ 8% O_2 annual average	PSD 92-03, Amendment 4
NO_X	140 ppm @ 8% O_2	PSD 92-03, Amendment 4
SO_2	75 ppm @ 8% O_2	PSD 92-03, Amendment 4

1.3.2 Existing Smelt Dissolver Tank Emissions Control

A smelt dissolver tank is a part of the Kraft pulping chemical recovery process. Smelt is the molten chemicals collected in the bottom of a recovery furnace. Smelt is continuously withdrawn from the furnace into a smelt dissolver tank where it is dissolved in water and weak wash[8] to produce green liquor. Green liquor is mixed with lime from the lime kiln (not a BART-eligible unit at this plant) to produce white liquor for use in the chip digestion process.[9] During digestion, the white liquor is converted to black liquor.

PM/PM_{10} is the primary emissions from the smelt tank. The particulate is formed when the water solution is introduced to the hot smelt from the furnace. The relatively cooler water causes

[6] NCASI Technical Bulletin No. 725, *Particulate Matter Emissions from Kraft Mill Recovery Furnaces, Lime Kilns, and Smelt Dissolving Tanks,* November 1996.
[7] AP-42, Section 10.2, Chemical Wood Pulping, dated September 1990.
[8] This process water, also known as weak white liquor, is composed of all water used to wash lime mud and green liquor precipitates.
[9] The names of the various liquors denote their actual color.

the smelt to shatter prior to dissolving into solution. The particles that enter the exhaust stream are small; 90 percent by weight are PM_{10} and 50 percent by weight are less than one micrometer in aerodynamic diameter. Chemically the particles are composed of inorganic compounds used to prepare the pulping liquor, principally sodium sulfate and sodium carbonate. Since no combustion occurs in a smelt tank, there are no NO_X emissions and SO_2 emissions are minimal.

The No. 10 Smelt Dissolver Tank is currently controlled with a high-efficiency wet scrubber permitted as BACT in 1993.[10]

The Smelt Dissolver Tank is currently subject to the BACT emission limit in PSD 92-03, Amendment 4 and 40 CFR 63 Subpart MM. The applicable PM, NO_X, and SO_2 emission limits are shown in Table 1-2.

Table 1-2. SMELT DISSOLVER TANK CURRENT EMISSION LIMITS

Pollutant	Emission Limit	Regulatory Basis
PM/PM_{10}	0.20 lb/ton BLS	NESHAP Subpart MM, 40 CFR 63.862(a)(1)(i)(b)
	0.120 lb/ton BLS	PSD 92-03
NO_X	N/A	N/A
SO_2	N/A	N/A

1.3.3 Existing No. 11 Power Boiler Emissions Control

The No. 11 Power Boiler is a spreader-stoker type boiler firing wood-waste, dewatered wastewater treatment plant sludge, and supplemental low sulfur western coal. Low sulfur (< 2 percent by weight) No. 6 fuel oil may be burned during startup, shutdown, and malfunction operations. During 2006, the boiler was upgraded and now has a rated capacity of 575,000 lb steam/hr and 1,016 million British thermal units per hour (MMBtu/hr) heat input. Actual emissions did not increase as a result of the upgrade project due to increased combustion efficiency and the addition of a trona-based SO_2 control. Actual 2007 operating rates are lower than the rated capacity, averaging 413,000 lb steam/hr and 724 MMBtu/hr heat input. Weyerhaeuser operates this boiler in conjunction with No. 10 Recovery Furnace, to provide process steam and steam to generate electricity. The No. 10 Recovery Furnace normally operates at a constant rate and the No. 11 Power Boiler varies its operating rate so the pair matches the steam demand of the rest of the plant. However, when either recovery furnace or the No. 11 Power Boiler is out of operation, the other unit plus other boilers on site must increase operating rate to meet the plant heat needs.

PM/PM_{10} emissions from this boiler results from inorganic materials contained in the fuels and unburned carbon resulting from incomplete combustion.[11] NO_X emissions from boilers are formed by two mechanisms, fuel NO_X and thermal NO_X. In the case of this boiler, both

[10] PSD 92-03, Amendment 4.
[11] NCASI Technical Bulletin No. 884, *Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers,* August 2004.

mechanisms exist, though it is expected that the fuel NO_X is the dominant source of the emissions.[12] SO_2 emissions primarily come from the coal and wastewater sludge. Some of the SO_2 formed is captured by the alkaline wood ash and removed by the ESP.[13]

Emission controls currently in place on the No. 11 Power Boiler are a multiclone to remove cinders and coarse particulate followed by dry trona[14] injection for SO_2, followed by a dry ESP for trona and fine particulates removal. The trona is injected into the flue duct on the boiler side of the ID fan and makes use of the ID fan to mix the trona with the fuel gas. NO_X emissions are controlled through use of good combustion practices to minimize emissions and maximize combustion efficiency.

The ESP was installed as part of a boiler upgrade project in 2006 and replaced the last electrified gravel bed particulate control device remaining in Washington. The trona injection was installed as part of the 2006 boiler upgrade project to assure that the post upgrade SO_2 emissions would not be higher than the pre-project emissions.

The No. 11 Power Boiler is currently subject BACT emission limitations in a state NSR permit and to 40 CFR 60 Subpart D NSPS. The most stringent applicable PM, NO_X, and SO_2 emission limits are shown in Table 1-3.

Table 1-3. NO. 11 POWER BOILER'S CURRENT EMISSION LIMITS

Pollutant	Emission Limit	Regulatory Basis
PM/PM_{10}	0.10 lb/MMBtu	NSPS Subpart D, 40 CFR 60.42(a)(1)
	0.050 gr/dscf @ 7% O_2	Ecology Order 94AQ-I080[15]
NO_X	0.30 – 0.7 lb/MMBtu, depending on fuel mixture	NSPS Subpart D, 40 CFR 60.44(a)
SO_2	0.80–1.2 lb/MMBtu, depending on fuel mix	NSPS Subpart D, 40 CFR 60.43(a)
	1000 ppmv, 1-hr average	WAC 173-400-040(11)(b)

1.4 Visibility Impact of the Weyerhaeuser Mill's BART-Eligible Units

Class I area visibility impairment and improvement modeling was performed by Weyerhaeuser using the BART modeling protocol developed by Oregon, Idaho, Washington, and EPA Region

[12] NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, June 2006.
[13] NCASI Technical Bulletin No. 884, *Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and PaperMills Including Boilers*, August 2004.
[14] Trona is a natural mineral primarily composed of sodium carbonates.
[15] Weyerhaeuser requested a numerical limit be established under WAC 173-400-091 to replace a narrative limit in the original NOC approval. To assure clear limitations and enforceability within the AOP, the regulatory order established this numerical limitation.

10.[16] This protocol uses three years of metrological information to evaluate visibility impacts. As directed in the protocol, Weyerhaeuser used the highest 24-hour emission rates that occurred in the 3-year period to model its impacts on Class I areas. The modeling indicates that the emissions from the three BART-eligible units at this plant cause visibility impairment on the 8th highest day in any one year and the 22nd highest day over the three years that were modeled.[17] For more information on visibility impacts of this facility, see Section 3.

2. BART TECHNOLOGY ANALYSIS

The Weyerhaeuser BART technology analysis was based on the five step process defined in BART guidance and listed in Section 1.1 of this report.

The following three tables identify and summarize control options considered in the BART Determination analysis for PM_{10}, NO_X, and SO_2 emissions from the Weyerhaeuser Mill. Sections 2.1 through 2.4 discuss emissions from each BART emissions unit.

Table 2-1. PM/PM_{10} CONTROL TECHNOLOGIES EVALUATED

Control Technology	Available for Emission Unit (Yes/No)[18]		
	No. 10 Recovery Furnace	Smelt Dissolver Tank	No. 11 Power Boiler
Fabric Filters (baghouse)	No	N/A[a]	Yes
Cyclone Separator (multiclone)	N/A	N/A	Currently used
Wet Scrubber	Yes	Currently used	Yes
Wet ESP	Yes	N/A	Yes
Dry ESP	Currently used	N/A	Currently used
Venturi Scrubber	Yes	Yes	Yes
[a] Not Applicable or Not Available			

Table 2-2. NO_X CONTROL TECHNOLOGIES EVALUATED

Control Technology	Available for Emission Unit (Yes/No)		
	No. 10 Recovery Furnace	Smelt Dissolver Tank	No. 11 Power Boiler
Staged Combustion	Currently used	N/A	Currently used
Good Operating Practices and Proper Design	Currently used	N/A	Currently used
Selective Non-Catalytic Reduction (SNCR)	No	N/A	Yes
Selective Catalytic Reduction (SCR)	No	N/A	Yes

[16] A copy of the modeling protocol is available at http://www.deq.state.or.us/aq/haze/docs/bartprotocol.pdf.
[17] 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.
[18] Availability based on whether control technology can be considered for each emission unit and has been applied in practice on this type of unit, not on technical feasibility.

Table 2-3. SO_2 CONTROL TECHNOLOGIES EVALUATED

Control Technology	Available for Emission Unit (Yes/No)		
	No. 10 Recovery Furnace	Smelt Dissolver Tank	No. 11 Power Boiler
Flue Gas Desulfurization (FGD) with Wet Scrubber	Yes	No	Yes
FGD – Semi-Dry Lime Hydrate Slurry Injection with ESP or Baghouse	Yes	No	Yes
FGD – Semi-Dry Lime Hydrate Powder Injection with ESP or Baghouse	Yes	No	Yes
FGD – Spray Drying with ESP or Baghouse	Yes	No	Yes
FGD Dry Trona Injection with ESP	No	No	Currently used
Good Operating Practices/Inherent Dry Scrubbing	Currently used	No	N/A
High efficiency wet scrubber	N/A	Currently used	No

2.1 No. 10 Recovery Furnace Control Options

2.1.1 PM/PM_{10} Control Options

As discussed in Section 1.3.1, particulate emissions from the No. 10 Recovery Furnace are controlled by an ESP.

As noted in Section 1.3, the No. 10 Recovery Furnace is subject to BACT emission limitations that are more stringent than the standard for PM (used by EPA as a surrogate for hazardous air pollutant (HAP) metals) contained in 40 CFR Part 63 Subpart MM, *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills*. Compliance with the BACT limitation is achieved by the inclusion of a dry ESP for particulate control.

Of the available particulate emission controls for the recovery furnace, Weyerhaeuser was unable to locate an existing recovery furnace with either a wet ESP or a baghouse as the particulate control technology. They noted that the use of a fabric filter would not work due to the "sticky" nature of the particulate that would be collected; removing it from a fabric filter would be extremely difficult compared to the proven technique of an ESP.

Use of a **wet ESP** is feasible, but would not provide any greater particulate removal than is provided by the dry ESP currently installed. Weyerhaeuser was unable to locate an installation of a wet ESP on a Kraft recovery furnace.

Similarly, the EPA's BACT/RACT LAER Clearinghouse shows that over the last 15 years, no U.S. recovery furnace has had a **venture scrubber or other wet scrubber** installed as the

particulate control device as the result of new source permitting requirements. The primary reason is that wet scrubbers are not as effective at particulate removal as an ESP.

Weyerhaeuser did evaluate two options to further reduce particulate emissions from the recovery boiler. They evaluated **adding a venturi scrubber after the ESP** to further reduce condensable particulate and adding an additional field to the ESP to further enhance removal efficiency of primary particulate.

Adding a venturi scrubber to remove about 27 lb/hr (118.3 tpy) of condensable and additional solid particulate at an estimated cost effectiveness of $28,000/ton of PM reduced. The cost analysis did not include an evaluation of the potential impacts to the wastewater treatment system of receiving water from this scrubber.

Adding an **additional field to the ESP** is a more involved project than adding the venturi scrubber. Additional details on this option are given in Weyerhaeuser's BART Analysis Report. This alternative is estimated to reduce emissions by an additional 50 percent, or about 7.5 lb/hr (32.8 tpy) at a cost effectiveness of $122,000/ton PM reduced.

Weyerhaeuser considers the current BACT emission limit and dry ESP on the No. 10 Recovery Furnace PM as BART.

2.1.2 NO_X Control Options

To control NO_X from a recovery furnace, there are a limited number of options. The recovery furnace process utilizes staged combustion in order to maximize the recovery of the expensive pulping chemicals. As part of this chemical recovery process, the thermal NO_X emissions are minimized. In the Kraft process, the black liquor is already low in fuel nitrogen, further limiting the quantity of NO_X emitted.

Weyerhaeuser currently utilizes **"tertiary" staged combustion t**o maximize chemical recovery and minimize NO_X emissions. The addition of tertiary air in 1995 required extensive modification of the fire box. The modification required removal and lengthening the lower section of the furnace to increasing the volume of the primary combustion zone and allow space to add a third level of over fire air. Tertiary over fire air is considered the normal design for the best performing existing and most new recovery furnaces.

There are a few new recovery furnaces that have included a 4th stage of over fire air. This 4th stage has been shown to further increase chemical recovery and quality while reducing emissions of SO_2, NO_X and carbon monoxide. In order for Weyerhaeuser to add a 4th stage of combustion air would require the furnace to be rebuilt again to lengthen the fire box. The company believes such a project may also require the overall height of the recovery furnace building to be increased to accommodate a taller furnace. Whether the added height is provided at the top or bottom of the furnace, this would be a significant construction project, and put the Kraft portion

of the plant out of operation for the duration of the construction project. The cost and potential emission reduction of this change was not determined.

"Boiler tuning" was briefly evaluated, but the potential effectiveness of this option to reduce NO_X is unknown. In "boiler tuning," the quantity of air supplied at each stage is adjusted to optimize the chemical recovery efficiency and minimize the NO_X and SO_2 emissions. At the conclusion of the project to add tertiary over fire air, boiler tuning was performed as part of the project. As a result, additional significant reductions are not anticipated.

SCR and SNCR have been reviewed for applicability on this recovery furnace. Weyerhaeuser and National Council for Air and Stream Improvement (NCASI) have both been unable to find a current installation of SCR or SNCR on a Kraft recovery furnace. A major impediment to the inclusion of SNCR on a recovery furnace is the effect of introducing ammonia into the chemical recovery process through addition of the ammonia contaminated fly ash to the smelt dissolver tank. The use of SCR on a recovery furnace results with questions about the potential of catalyst poisoning or blinding from the alkaline particulate from the furnace and difficulties in removing that particulate from the catalyst material. Since no known installation of SCR exists on a Kraft recovery furnace, to what degree the potential for the adverse affects would actually occur is unknown.

In 2003, NCASI specifically evaluated the options for reducing NO_X emissions from recovery furnaces. Their evaluation indicated that no operating Kraft recovery furnace currently utilized post-combustion control (such as SCR or SNCR) and there a very limited number of other NO_X reduction techniques are available.[19] A subsequent NCASI Corporate Correspondence Memorandum states:[20]

> Optimization of the staged combustion principle within large, existing Kraft recovery furnaces to achieve lower NOx emissions might be the only technologically feasible option at the present time for NOx reduction . . . Ultimately, the liquor nitrogen content, which is dependent on the types of wood pulped, is the dominant factor affecting the level of NOx emissions from black liquor combustion in a recovery furnace. Unfortunately, this factor is beyond the control of pulp mill operators.

Weyerhaeuser concluded that the current NO_X emission limitation and currently installed system of staged combustion is BART for this furnace.

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[19] NCASI Special Report No. 03-06, *Effect of Kraft Recovery Furnace Operations on NO_X Emissions: Literature Review and Summary of Industry Experience,* October 2003.

[20] NCASI Corporate Correspondent Memorandum No. 06-014, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, June 2006.

2.1.3 SO_2 Control Options

Weyerhaeuser considered the addition of wet and dry SO_2 control options along with the possibility of combustion controls to further reduce the SO_2 emissions from the recovery furnace. Recovery furnaces are by definition chemical recovery units since sodium and sulfur are the major chemicals recovered from the used black liquor sent to the furnace. As a result of their primary purpose, a well designed and properly operated recovery furnace emits little SO_2 under normal, steady state operation. New recovery furnaces can be expected to have essentially no SO_2 emissions during steady state operations while existing recovery furnaces have continuous low rate SO_2 emissions. All recovery furnaces experience uncontrolled, highly sporadic, unpredictable, and short duration "spikes" in SO_2 emissions. The steady-state emissions occur most operating hours of the year. As a result, a wet lime or limestone scrubber would not actually remove much SO_2.

NCASI reports that neither a **wet lime nor a limestone scrubber** has been successfully demonstrated on a recovery furnace in the United States.[21] As a result, the ability of such a scrubber to reduce SO_2 emissions is theoretical, not demonstrated.

While the addition of a **Semi-Dry or Dry sorbent injection** system preceding the existing ESP is available technology, Weyerhaeuser did not evaluate this option in depth since this would not provide a substantial emission reduction compared to the existing system. A spray dryer system removes SO_2 by injecting a sorbent such as lime or sodium bicarbonate into the flue gas. The existing recovery boiler flue gas handling system inherently acts like and achieves comparable results to an add-on sorbent injection system. As noted earlier, the particulate collected emitted by the recovery furnace is composed largely of sodium carbonate and bicarbonate. These sodium salts are present in excess of the quantity of SO_2 in the flue gas and act as an acid gas sorbent scrubbing agent. The reacted flue gas particulate is then collected by the recovery furnace economizer and ESP and returned to the Kraft chemical recovery process. The addition of an external sodium based dry sorbent injection system or injection of sodium based sorbent into the furnace would be redundant to the sodium based scrubbing system existing in the recovery furnace.

Injection of calcium based sorbent in the flue gas would render the recovered saltcake unusable. The presence of calcium would cause unmanageable scaling and plugging in the black liquor mix tanks, black liquor concentrators, furnace feed lines, boiler tubes, and economizer passages, saltcake collection hopers, the smelt dissolving tank and associated piping. The contaminated saltcake is anticipated to become a waste requiring disposal rather than a recovered byproduct. The ash disposal costs have not been evaluated in detail, but Weyerhaeuser believes the costs would be considerable due to the large volume of material involved.

[21] Ibid.

At this time, there are no known installations of semi-dry or dry sorbent injection to control SO_2 from a recovery furnace. Weyerhaeuser does not consider these technologies as technically feasible.

Weyerhaeuser proposes that the existing operations of the recovery furnace including tertiary air deliver and black liquor concentrators be considered as BACT for SO_2 from this furnace.

2.1.4 Weyerhaeuser's BART Proposal for the Recovery Furnace

For PM/PM_{10} control, Weyerhaeuser proposed BART is the existing ESP with an emission limit of 0.02 grain/dscf as BART.

For NO_X control, Weyerhaeuser proposed proper operation BACT of the existing tertiary, staged combustion system meeting the BACT emission limitation of 140 ppm NO_X as BART for control of NO_X emissions from the Recovery Furnace.

For SO_2 control, Weyerhaeuser proposed proper operation of the existing tertiary, staged combustion system meeting the BACT emission limitation of 75 ppm SO_2 as BART for control of NO_X emissions from the Recovery Furnace.

2.2 No. 10 Smelt Dissolver Tank Control Options

As discussed in Section 1.3.2, a wet scrubber is currently used to reduce PM/PM_{10} emissions. This wet scrubber also provides some reduction of sulfur compound emissions. A smelt dissolver tank's exhaust stream has high moisture content (typically 25 to 40 percent) and almost no flow rate, eliminating many control options that require a positive air flow for operation.

2.2.1 PM_{10} Control Options

For smelt dissolver tanks, various wet scrubbing systems are considered BACT level of control. The current BACT emission control system is a high efficiency wet scrubber. The No. 10 Smelt Dissolver Tank has a BACT emission limitation of 0.120 lb/ton black liquor solids. This is the most stringent BACT limitation in the EPA RACT/BACT/LAER database of permitted and constructed emission controls in the U.S. and is more stringent than the federal MACT standard of 0.20 lb/ton black liquor solids.

Weyerhaeuser did not evaluate improvements to or replacement of the current particulate control technology on the No. 10 Smelt Dissolver Tank.

Weyerhaeuser proposed the current particulate control system meeting the BACT emission limit of 0.12 lb/ton black liquor solids as BART for particulate emissions from the No. 10 Smelt Dissolver Tank.

2.2.2 NO_X Control Options

NO_X control technologies are not evaluated for the Smelt Dissolver Tank. It is not a combustion source, and the materials processed are not a source of NO_X.

2.2.3 SO_2 Control Options

Smelt dissolver tanks are a negligible source of SO_2. As such, Weyerhaeuser did not evaluate additional controls in detail; though they note that adding a wet ESP could be technically feasible, but would likely result in an increase in reduced sulfur compound (odor) emissions. A smelt dissolver tank's exhaust stream has high moisture content (typically 25 to 40 percent) and almost no flow rate, making usage of a spray dryer/dry ESP system technically infeasible.[22]

2.2.4 Weyerhaeuser's BART Proposal for the No. 10 Smelt Dissolver Tank

For PM/PM_{10} control, Weyerhaeuser proposed to continue using the existing high efficiency scrubber meeting the BACT emission limitation of 0.120 lb PM/ton black liquor solids fired as BART. Weyerhaeuser proposes no additional controls for SO_2 or NO_X, as the No. 10 Smelt Dissolver Tank is not a source of those pollutants.

2.3 No. 11 Power Boiler Control Options

As discussed in Section 1.3.3, the No. 11 Power Boiler has an over fire air system to provide for efficient combustion. A multiclone followed by an ESP is currently used to reduce PM/PM_{10} emissions. Trona injection after the multiclone and before the ESP is used for SO_2 reductions and combustion control is used to achieve NO_X control.

2.3.1 PM/PM_{10} Control Options

Table 2-1 lists six identified PM/PM_{10} control technologies along with Good Operating Practices. Since the No. 11 Power Boiler currently uses a multiclone and an ESP, only those controls that provide at least as much control as the multiclone/ESP combination were considered in detail.

The use of **fabric filters** to control particulate matter emissions from wood-fired and combination fuel boilers has rarely been implemented. Their use on pulverized coal-fired utility boilers is relatively common, but there are operational and boiler exhaust temperature differences that reduce the comparability of these two uses. The use of fabric filters on wood-fired units is a potential fire hazard due to the potential of burning cinders escaping the multiclone, temperature excursions, and/or operating upsets. In pulverized coal boilers, there are no cinders as combustion is complete and there are exhaust gas cooling operations (economizers, air

[22] NCASI, *Corporate Correspondence Memo CC-06-14: Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2, and PM Emissions*, June 4, 2006.

preheaters, feed water heaters) that may not exist on wood-fired units. Fabric filters can ignite or melt depending on the fabric used and the quantity of combustible particulate on the filters. Because of this, fabric filters are rarely used on wood-fired and combination fuel boilers.

Fabric filters have been successfully used on some wood-fired boilers that burn wood residue or bark stored in salt water because the salt reduces the fire hazard. Weyerhaeuser does not use significant amounts of wood waste that has been stored in salt water. Therefore, the use of fabric filters to control particulate matter emissions from the No. 11 Power Boiler is proposed to be technically infeasible due to fire hazard.

The existing **dry ESP** was permitted in 2003/04 and began operation in 2006 as a RACT control technology. This new ESP installation replaced an old electrified gravel bed system. As part of this BART evaluation, Weyerhaeuser did evaluate adding an additional field to the new ESP system. Prior to looking at costs, Weyerhaeuser discounted the option due to the lack of space to install an additional field to the ESP. The site in the area of the ESP is very constrained due to underground and overhead utilities, the new stack, vehicle turning areas, and rail lines. More details are available in Weyerhaeuser's BART Analysis Report.

While replacing the current dry ESP with a **wet ESP** is an available approach in some cases, Weyerhaeuser did not evaluate that option. Wet ESPs work well in situations with large amounts of condensable particulate or high resistivity ashes. The removal efficiency of a wet ESP is the same as a dry ESP. This boiler with its multiclone system and the use of multiple fuels does not generate a high resistivity ash or a lot of condensable particulate matter. A wet ESP has a wastewater discharge that must be addressed. There is no advantage to the use of a wet ESP in this situation or increase in particulate removal to be achieved.

Weyerhaeuser proposed their current multiclone/dry ESP system, meeting an emission limit of 0.050gr/dscf, as BART for the No. 11 Power Boiler.

2.3.2 NO_X Control Options

As noted before, the No. 11 Power Boiler is a load-following spreader-stoker combination fuel boiler. It combusts wood-waste, sludge, western sub-bituminous coal, and No. 6 fuel oil. The spreader-stoker design uses a simple form of staged combustion, providing under fire air (air supplied under the fire grate), a small amount of air to spread the fuel in the boiler and one stage of over fire air above the elevation of the spreaders. Most combustion occurs on the fire grate at temperatures that favor fuel bound NO_X formation over thermal NO_X.

As part of the 2006 boiler upgrade project that resulted in installation of the new ESP, Weyerhaeuser also **replaced the air distribution system** in the No. 11 Power Boiler. The size and location of over fire air ports changed as well as the total quantity of air delivered to the firebox. The previous over fire air distribution system was undersized and provided little mixing of the over fire air with combusting fuel in the boiler. The revised over fire air system uses

fewer air ports, and higher velocity air to allow the over fire air to penetrate to the center of the combustion zone and improve overall combustion efficiency.

As a follow-up to the over fire air system changes, Weyerhaeuser implemented a program to optimize the distribution of combustion air between the new over fire air system, the under fire air system, and the air used to spread the fuel on the grate. The optimization focused on reduction of emissions and maximizing fuel combustion efficiency. This has lead to a moderate reduction in NO_X emissions (10 to 20 percent) from the boiler compared to the pre-modification condition. Weyerhaeuser did not evaluate any additional combustion modifications that might reduce NO_X concluding it would be technically infeasible to implement any of the remaining available combustion modifications.

As part of their BART evaluation, Weyerhaeuser looked closely at the installation of **SCR and SNCR** on this boiler. They evaluated installation of an SCR unit between the boiler and the ESP and the addition of SNCR to the boiler.

SCR involves the injection of an ammonia or urea solution into the hot fuel gases prior to a catalyst. The catalyst reduces the temperature at which the reaction of nitrogen oxides and ammonia occurs. The nitrogen oxides and ammonia react to form nitrogen gas and water. Standard NO_X catalysts operate at approximately 850ºF while low temperature catalysts operate at about 450ºF.

Weyerhaeuser's evaluation of SCR indicated that to obtain the correct temperature for the standard catalyst to operate would require removal of some of the current boiler tubes. This would have the effect of reducing the maximum quantity of steam produced by this boiler requiring a non-BART boiler to be operated to replace the missing steam. There are construction and difficulties as well as issues related to installation location for an SCR unit placed immediately after the boiler. This area of the plant is very congested with underground utilities, overhead conveyors, and truck and rail routes. A cost evaluation of an SCR system in the boiler that would provide 75 percent reduction in NO_X would have a cost effectiveness of about $13,000/ton NO_X reduced, for a reduction of 1,146 tons/year.

They did evaluate installation of the SCR unit after the ESP, but noted that the temperature at this location is below the optimum range for a low temperature catalyst and would require the combustion of fuel (probably natural gas) to reheat the flue gas to the necessary temperatures. Weyerhaeuser does not consider an SCR in this location to be technically feasible. As noted before, space in this area of the plant is limited.

SNCR was also evaluated for this boiler. In SNCR process, ammonia, an ammonia water solution, or a urea water solution is sprayed into the combustion zone at a location where the temperature is in the range of 1600 to 1800ºF. Since this boiler is a load-following boiler (while the recovery furnace is operated as a base load boiler), there will need to be several levels of ammonia injection into the flue gases.

To date, there are no installations of SNCR on boilers of this type in the pulp and paper industry. There are load-following boilers in other industries that utilize SNCR. Their experience has provided the operational and design information necessary to successfully implement SNCR on load-following boilers. In spite of potential operational difficulties, Weyerhaeuser did evaluate the cost effectiveness of installing SNCR on this boiler. At an estimated removal efficiency of 25 percent, the cost effectiveness is estimated to be $6,686/ton NO_X reduced. The reduction in NO_X would be 382 ton/year.

Weyerhaeuser proposed to utilize its existing combustion control system as BART for NO_X emissions.

2.3.3 SO_2 Control Options

Weyerhaeuser currently operates a **dry sorbent (trona) injection system** on the No. 11 Power Boiler. This was installed as part of the boiler upgrade project and provides a small removal of SO_2 from the flue gas.

The current trona-based system is designed to remove 25 percent of the SO_2 from the boiler. The uncontrolled concentration of SO_2 in the boiler exhaust is 80 ppm. Trials after installation were made and the trona injection rate optimized to meet the removal guarantee. Trona was selected as the preferred sorbent due to cost and simplicity of equipment required compared to use of sodium bicarbonate or calcium based sorbents.

In addition to the SO_2 control provided by the trona system, boilers utilizing wood plus other fuels exhibit lower SO_2 emissions than a boiler burning only coal or fuel oil. This is due to the production and presence of calcium and sodium oxide from the minerals in the wood and dirt on the wood. The calcium and sodium oxides react with the SO_2 in the flue gas and produce sulfites and sulfate particulates that are removed by the particulate system.[23]

Continuous emission monitoring indicates the trona system and the fly ash SO_2 removal result in a controlled SO_2 emission rate of about 164 lb/hour or about 0.23 lb/MMBtu. Weyerhaeuser evaluated use of **low sulfur fuels** and the installation of a wet calcium scrubber instead of the current dry sorbent injection.

The primary fuels used in this boiler are waste wood, pulp mill sludges, low sulfur western coal, and No. 6 fuel oil. As a result of the sulfur content of the No. 6 oil and coal, Weyerhaeuser looked at the feasibility of replacement with lower sulfur fuel.

Weyerhaeuser is a small purchaser of coal. As a result, it is unable to negotiate for lower, preferred pricing or easily dictate coal contract terms. This limits its ability to acquire the lowest sulfur coal available on the market. The current coal they use is a Powder River Basin sub-

[23] National Council for Air and Stream Improvement, Technical Bulletin 640, Sulfur Capture in Combination Bark Boilers.

bituminous coal with 0.4 to 0.5 percent sulfur by weight. The coal used during the baseline emissions period was also a Powder River Basin coal from a different mine with a sulfur content of 0.5 to 0.9 percent.

All other boilers at the mill are equipped to utilize either natural gas or No. 6 fuel oil supplied by a single 30,000 gallon fuel tank. The No. 6 oil is used in the No. 10 Recovery Furnace for startup and flame stabilization when needed and for startup of the No. 11 Power Boiler. For the No. 11 Power Boiler, fuel oil supplies less than 0.5 percent of the annual heat input to the boiler. The current No. 6 oil is specified to contain less than two percent sulfur by weight. Any changes to the fuel oil supply to reduce SO_2 from the No. 11 Power Boiler would also affect the SO_2 emissions from all other boilers. Conversion of the system to use a lighter, lower sulfur fuel oil such as No. 2 oil would entail extensive replacement and upgrading of pumps, burners, and fittings to accommodate the less viscous, lighter fuel oil. Due to the low usage rate of fuel oil plant-wide, Weyerhaeuser concluded that converting the fuel oil system to handle a lighter, lower sulfur fuel oil would provide negligible SO_2 reductions from this boiler (and all other boilers capable of using fuel oil at the plant). As a result, Weyerhaeuser did not pursue this option further.

The opportunity to **replace the existing trona system** was evaluated. The primary option considered would substitute the dry trona injection system with a hydrated lime injection system. The damp lime dries quickly in the hot flue gases and is effective in removing SO_2 from the flue gas. Weyerhaeuser determined that the injection of hydrated lime would present some technical difficulties. If they were to utilize the available space for a hydrated lime system where the trona system currently exists, the hydrated lime would be injected upstream of the induced draft (ID) fan and utilize the ID fan for mixing of the sorbent with the flue gas.

The primary difficulty anticipated to occur would be the dried and drying lime collecting on the ID fan blades causing the ID fan to fail or be prone to significantly increased maintenance needs. Loss of the ID fan would cause the boiler to shutdown to prevent unsafe or explosive conditions from occurring in the boiler. Loss of the ID fan would result in the boiler being taken out of service until the fan was repaired. Catastrophic loss of the ID fan could cause boiler to explode or require emergency shutdown of the boiler so the fan blades could be cleaned or replaced. Such a shutdown would require other fossil fueled boilers at the plant be started up and used to provide necessary steam at the plant, adding significant costs to plant operations. These operational and cost difficulties caused Weyerhaeuser to conclude this option is not technically feasible.

Two **wet lime/limestone technologies** were evaluated for cost effectiveness using the EPA CUECost emission control cost model. A wet limestone/forced oxidation and a lime spray dryer system were evaluated for cost effectiveness. The wet limestone/forced oxidation system was based on using a conventional wet scrubber such as a spray tower with limestone slurry as the scrubbing liquor. In a lime spray dryer, the wet scrubber is replaced with a slurry injection into the flue duct and the resulting dry material is collected in the ESP. The capital cost to add a wet

scrubber/forced oxidation system on the No. 11 Power Boiler is estimated to be about $75 million. The lime spray dryer technology is estimated to be at about $55 million.

In both cases, the cost effectiveness is above $17,000/ton and is not considered cost effective by Weyerhaeuser. One additional constraint not entirely accounted for in the CUECost model is the amount of existing new and old equipment that would need to be demolished to provide adequate space for the new wet scrubber and particulate control. Due to the location of this boiler, its support equipment and other plant process structures and underground piping, Weyerhaeuser has concerns if there is adequate space to install additional emission controls on this boiler.

Weyerhaeuser also evaluated installation of a wet lime/limestone scrubber after the ESP. Using a cost estimate for another Weyerhaeuser facility, scaling it to this boiler's size, but not including costs to relocate existing equipment and above and underground structures, indicates a cost effectiveness of $24,000/ton.

After considering the available control options, Weyerhaeuser proposed that the existing trona system combined with the existing low sulfur fuel mix as BART for SO_2 from this boiler.

2.3.4 Weyerhaeuser's BART Proposal for the No. 11 Power Boiler

For PM/PM_{10} control, Weyerhaeuser proposed continued use of the existing multiclone/ESP system meeting a limit of 0.050 grain/dscf as BART.

For NO_X control, Weyerhaeuser proposed continued operation of the boiler's current staged combustion system and fuel mix as BART.

For SO_2 control, Weyerhaeuser proposed continued use of low sulfur fuels and operation of the existing trona dry sorbent injection system as BART.

2.4 Weyerhaeuser's Proposed BART

A summary of the emission controls and emission limitations proposed as BART by Weyerhaeuser is shown in Table 2-4.

Table 2-4. SUMMARY OF WEYERHAEUSER'S PROPOSED BART

Pollutant	Emission Unit	Proposed BART Control Option	Control Option Emissions Level or Control Efficiency
PM_{10}	No. 11 Power Boiler	Existing ESP	0.050 grain/dscf @ 7% O_2 (current limit)
	No. 10 Recovery Furnace	Existing ESP	0.027 gr/dscf, per test, and 0.020 grain/dscf, annual average (current BACT limits in PSD 92-03, Amendment 4)
	Smelt Dissolver Tank	Existing High Efficiency Wet Scrubber	0.120 lb/BLS (current BACT limit in PSD 92-03, Amendment 4)
NO_X	No. 11 Power Boiler	Existing Combustion System	(0.30x + 0.70y)/(x + y) lb per MMBtu (derived from solid fossil fuel, liquid fossil fuel and wood residue) (40 CFR 60.44(b) which also defines the variables)
	No. 10 Recovery Furnace	Existing Staged Combustion System	140 ppm @ 8% O_2 (current BACT limit in PSD 92-03, Amendment 4)
	Smelt Dissolver Tank	N/A	No limit required
SO_2	No. 11 Power Boiler	Fuel mix and trona injection system	1000 ppm @ 7% O_2, 1-hour average, (0.8y +1.2z)/(y +z) lb per MMBtu. (derived from burning a mixture of liquid and solid fossil fuel) (40 CFR 60.43(b) which also defines the variables)
	No. 10 Recovery Furnace	Good Operating Practices	75 PPM @ 8% O_2 (current BACT limit in PSD 92-03, Amendment 4
	Smelt Dissolver Tank	N/A	No limit required

3. VISIBILITY IMPACTS AND DEGREE OF IMPROVEMENT

A Class I area visibility impact analysis was performed on the BART-eligible emission units at Weyerhaeuser using the CALPUFF model with four kilometer grid spacing as recommended by Washington's BART modeling protocol. The modeled 24-hour average visibility impacts at each Class I area within 300 km of the Weyerhaeuser Mill and the Columbia River Gorge National Scenic Area are shown in Table 3-1.

Table 3-1. BASELINE VISIBILITY MODELING RESULTS

Class I Area	8th High 2003 Δdv	8th High 2004 Δdv	8th High 2005 Δdv	2003/05 22nd High Δdv
North Cascades National Park	0.127	0.223	0.227	0.218
Glacier Peak Wilderness Area	0.214	0.287	0.206	0.248
Olympic National Park	0.470	0.654	0.638	0.583
Alpine Lakes Wilderness Area	0.274	0.513	0.398	0.400
Mount Rainier National Park	0.540	0.973	0.572	0.595
Goat Rocks Wilderness Area	0.384	0.535	0.457	0.457
Mount Adams Wilderness Area	0.433	0.440	0.436	0.440
Mount Hood Wilderness Area	0.725	0.677	0.628	0.689
Mount Jefferson Wilderness Area	0.440	0.375	0.287	0.367
Mount Washington Wilderness Area	0.303	0.345	0.229	0.289
Three Sisters Wilderness Area	0.340	0.361	0.257	0.291
Diamond Peak Wilderness Area	0.203	0.224	0.148	0.192
Class II Area Evaluated				
Columbia River Gorge National Scenic Area	0.809	0.662	0.637	0.675

The results presented in Table 3-1 indicate that the 98th percentile visibility impact calculated exceeds the 0.5 dv contribution threshold for five of the 12 Class I areas within 300 km of the plant (the shaded cells). The maximum 98th percentile visibility impact occurs at Mt. Rainier National Park.

The maximum 24-hour emission rates that were modeled are shown in Table 3-2. These are the maximum rates during the 2003-2005 time period and do not reflect any reductions that may have been achieved at the No. 11 Power Boiler through the replacement of the electrified gravel bed particulate control with the current ESP and trona injection system in 2006. This project occurred after the period of time modeled for visibility impacts, but did not result in the imposition of any new or lower emission limitations. As a result, no emission reduction was modeled to reflect this replacement control equipment.

Table 3-2. MAXIMUM 24-HOUR AVERAGE ACTUAL EMISSION RATES

Emission Unit	NO_X (lb/hr)	SO_2 (lb/hr)	H_2SO_4 (lb/hr)	Filterable PM_{10}[a] (lb/hr)	Total PM_{10}[b] (lb/hr)
Recovery Boiler	222	2	4	10	22
Smelt Dissolver Tank	0	0	0	4	6
No. 11 Power Boiler	426	344	3	48	63

[a] Filterable PM_{10} represents the sum of the modeled filterable PM speciation groups of PMC, PMF, and EC.
[b] Total PM_{10} (TPM_{10}) represents the sum of the modeled filterable and condensable PM, including sulfuric acid (H_2SO_4).

Net Visibility Improvement

Weyerhaeuser did not evaluate the potential visibility reductions that could accrue from the emission controls evaluated. None of the controls evaluated were technically or economically feasible in Weyerhaeuser's opinion. As explained above, the actual emission reductions from the upgrades and modifications completed in 2006 to the No. 11 Power Boiler were also not modeled.

4. ECOLOGY'S BART DETERMINATION

Ecology has reviewed the information submitted by Weyerhaeuser. Ecology agrees with the analyses performed by Weyerhaeuser and has determined that the current levels of control are BART for the three BART-eligible process units. The controls and emission limitations are summarized in Table 2-4 and repeated in Table 4-1 below.

As noted above, Weyerhaeuser has noted a lack of physical space to install certain controls such as additional controls on the No. 11 Power Boiler. In February 2008, Ecology made a site inspection of all the BART eligible units at the Weyerhaeuser facility. Based on that inspection, we agree that there are site constraints on the No. 11 Power Boiler that prevent or would require costly modifications to existing infrastructure to provide space for upgrades and modifications to the particulate and SO_2 controls currently installed.

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

Pollutant	Emission Unit	Proposed BART Control Option	Control Option Emissions Level or Control Efficiency
PM_{10}	No. 11 Power Boiler	Existing ESP	0.050 grain/dscf @ 7% O_2 (current limit)
	No. 10 Recovery Furnace	Existing ESP	0.027 gr/dscf, per test, and 0.020 grain/dscf, annual average (current BACT limits in PSD 92-03, Amendment 4)
	Smelt Dissolver Tank	Existing High Efficiency Wet Scrubber	0.120 lb/BLS (current BACT limit in PSD 92-03, Amendment 4)
NO_X	No. 11 Power Boiler	Existing Combustion System	(0.30x + 0.70y)/(x + y) lb per MMBtu (derived from solid fossil fuel, liquid fossil fuel and wood residue) (40 CFR 60.44(b) which also defines the variables)
	No. 10 Recovery Furnace	Existing Staged Combustion System	140 ppm @ 8% O_2 (current BACT limit in PSD 92-03, Amendment 4)
	Smelt Dissolver Tank	N/A	No limit required
SO_2	No. 11 Power Boiler	Fuel mix and trona injection system	1000 ppm @ 7% O_2, 1-hour average, (0.8y +1.2z)/(y +z) lb per MMBtu. (derived from burning a mixture of liquid and solid fossil fuel) (40 CFR 60.43(b) which also defines the variables)
	No. 10 Recovery Furnace	Good Operating Practices	75 PPM @ 8% O_2 (current BACT limit in PSD 92-03, Amendment 4
	Smelt Dissolver Tank	N/A	No limit required

4.1 No. 10 Recovery Furnace BART Determination

For PM_{10} emissions control, Ecology determined that BART is the current level of control provided by the existing ESP and BACT established emission limitation. No new technologies

for controlling PM have become available since the BACT limitation was established, so Ecology accepts this BACT limit as BART.

For NO_X control, Ecology determined that BART is the current level of control established in PSD 92-03, which is proper operation of the existing tertiary, staged combustion system to both promote optimum combustion and control the Kraft recovery sodium sulfate reactions. Good combustion practices that optimize the staged combustion inherent in the design of the furnace are the only available technology for control of NO_X. All alternative NO_X control technologies were found to be technically or financially infeasible.

While not evaluated by Weyerhaeuser, the potential to install a LoTOx® system on the recovery furnace was evaluated by Ecology using information acquired through evaluations for its potential use at an oil refinery. To date, Ecology has been unable to find any other location that uses the LoTOx system on any combustion unit outside of the oil refining industry except for one lead smelter.

The principle problems with the use of the LoTOx technology on the Weyerhaeuser recovery furnace is the retrofit costs, determining where to locate the equipment, and what impacts may occur on the wastewater treatment system resulting from the new stream of nitrates being added. LoTOx operates best at a maximum temperature below 300°F. The installation of LoTOx on the recovery furnace would entail at a minimum rerouting of the ducting from the ESPs to the stack to the location of the new unit, installation of water supply, oxygen/ozone supply equipment, installation of the LoTOx reactor/scrubber and either a new stack or routing the wet scrubber exhaust to the existing stack. It is more likely that a new stack would be needed to handle the corrosion issues resulting from the "wet stack" conditions that will occur after the wet scrubber portion of the LoTOx system.

Ecology has not done an exhaustive cost analysis for installation of LoTOx on this furnace. We have reviewed the cost analysis performed for the CO boiler at the Tesoro Refinery and cost analyses performed in Texas as part of their cement kiln study and other reviews of the technology. Based on that review, we have found that given an equivalent "new" installation or where LoTOx is not required to add to or replace an existing control system that LoTOx and SNCR are approximately equal in cost effectiveness in $/ton removed. However, the much more extensive retrofit costs associated with this installation lead us to the conclusion that the cost will be much higher. We agree with Weyerhaeuser that the cost to install and use SNCR of $6,600/ton removed not cost effective for SNCR. With the cost for LoTOx anticipated to be higher yet, we conclude the technology while available and technically feasible is not financially feasible.

Again, for add-on SO_2 control, Ecology has also evaluated the opportunity to add a new wet scrubber to the recovery furnace system. Unlike the statements by NCASI that there are no SO_2 scrubbing systems operating on Kraft recovery furnaces, Ecology is aware that there are at least

two such units operating in Washington.[24] In one case, an SO_2 emission limitation of 10 ppm was imposed by Ecology in permitting. In the other case, no emission removal credit was given to the unit, establishing an emission limit of 150 ppm based on capability of the recovery furnace. As with the LoTOx system, this would require extensive rerouting of fuel ducts from the existing dry ESPs to a new wet scrubber (or even to insert a wet scrubber between the furnace and the ESPs). As noted above, the existing stack is designed for "dry" conditions and is unlikely to be able to sustain continuous operation with a saturated flue gas before suffering corrosion failure. As a result, we do not believe that adding a "water only" wet scrubber for additional SO_2 control is an option.

For SO_2 control, Ecology has determined that BART is operation of the furnace using a tertiary air system, use of "good operating practices" and meeting the emission limitation in PSD 92-03, Amendment 4. Good operating practices entail promoting the efficient recovery of sulfur by maintaining the char bed at a level that results in maximum retention of sulfur in the smelt, and minimize emissions of SO_2. No add on SO_2 control technology was found to be technically or financially feasible for installation on this recovery furnace.

4.2 No. 10 Smelt Dissolver Tank BART Determination

For PM_{10} control, Ecology determined that BART is the current level of control provided by the existing wet scrubber to comply with the existing BACT limit of 0.120 lb PM_{10} per ton BLS. Since the No. 10 Smelt Dissolver Tank is not a source of NO_X and a negligible source of SO_2 no additional controls are required for those pollutants.

4.3 No. 11 Power Boiler BART Determination

For PM/PM_{10} control, Ecology determined that BART is the current level of control provided by the recently installed dry ESP. Ecology agrees with Weyerhaeuser that there are no new emission controls available that will remove more particulate matter than the current system. For NO_X control, Ecology determines that BART is to continue using good operation of the boiler's staged combustion system BART as optimized in 2006/07. Ecology agrees with Weyerhaeuser's analysis that no other NO_X reduction technology exists that is both technically and financially feasible for installation on this unit.

We have also evaluated the option to install a LoTOx system on this boiler. We believe that this technology is available and technically feasible for use on this power boiler. However, we could find no installation of the technology on a boiler using solid fuels. This then brings the technology transfer of this technique into question.

[24] The units are advertised as heat recovery systems (heat recovery scrubbers) intended to provide hot water at about 140 to 150°F for use in plant processes. Prior to the hot water production, an alkaline scrubbing section is included to remove SO_2 and any particulates remaining after the particulate control system. In one case, Ecology recognized that the process removed SO_2 and issued a permit reflecting that situation. In another case, Ecology accepted the company's proposal that no additional removal was provided by the heat recovery scrubber system.

The area where a LoTOx system could be installed is already highly constructed with underground and overhead utilities and structures. The wet, potentially acidic nature of the exhaust gas from the control is incompatible with a dry ESP system. There is no opportunity on this boiler to add it to the outlet of the ESP system due to the simple lack of space to install it. For these and the reasons given for the recovery furnace, Ecology does not consider a LoTOx system to be a cost effective emission control system to install on this power boiler.

For SO_2 control, Ecology determines that BART is continued operation of the existing trona dry sorbent injection system, and to continue to practice good operation of the boiler aimed at minimizing fuel oil firing.

APPENDIX A. PRINCIPLE REFERENCES USED

CH2M-Hill, "Best Available Retrofit Technology Analysis Report, Weyerhaeuser Corporation Longview, WA," December 2007, Revised June 2008.

Greg Bean et al. to Alan Newman, letters responding to comments on December 2007 BART report, March 7, 2008 and June 2008.

SNCR Committee, Institute of Clean Air Companies, "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_X Emissions," February 2008.

Arun Someshwar and Ashok Jain, NCASI, "Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience, Special Report No. 03-04," August 2003.

Raytheon Engineers and Constructors, Inc. and Easter Research Group, Inc., "Coal Utility Environmental cost (CUECost) Workbook Users Manual and Excel Spreadsheet," Version 1.0, provided by EPA, 1998.

Air and Waste Management Association, Editors, Anthony Buonicore and Wayne Davis, "Air Pollution Engineering Manual," Von Nostrand Reinhold, 1992.

"EPA Air Pollution Control Cost Manual," Sixth Edition, EPA/452/B-02-001, January 2002.

N. Confuorto and J. Sexton, "Wet Scrubbing Based NO_X Control Using LoTOx™ Technology – First Commercial FCC Start-up Experience," presented at NPRA Environmental Conference, September 24-25, 2007.

Belco Technologies Corp., "Flue Gas Scrubbing of FCCU Regenerator Flue Gas – Performance, Reliability, and Flexibility – A Case History," company report, undated.

William Ellison, P.E., "Simultaneous SO_2, NO_X and HG Removal in Dry/Semi-Dry FGD Operation," presented at 29th International Technical Conference on Coal Utilization & Fuel Systems, April 2004.

BOC Gas Solutions, "Low Temperature Oxidation System Demonstration at RSR Quemetco, Inc, City of Industry California," California Air Resources Board Innovative Clean Air Technology Grant ICAT99-2, report dated June 28, 2001.

APPENDIX B

Cost effectiveness calculation for SO_2 controls at Weyerhaeuser's No. 11 Power Boiler.

The values in the table are copied from the CUECost model output included in the Weyerhaeuser BART Analysis Report and are reformatted and converted into the annualized cost effectiveness value. The CUECost model is a conservative cost analysis model developed for EPA and is suitable for planning level cost analyses.

Interest Rate			0.07	based on annual average lb/hr rate.			
CRF			0.0944				
	Removal rate	Capital Costs (CUECost)	Annualized capital	O&M costs (CUECost)	Total annual cost	Controlled emissions	$/ton Controlled
LSFO	0.95	74193089	7003827.6	6305121	13308949	682.404	$ 19,503
LSD	0.9	55437854	5233333.4	5824429	11057762	646.488	$ 17,104

APPENDIX C. ACRONYMS/ABBREVIATIONS

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BLS	Black Liquor Solids
dv	Deciview(s)
Ecology	Washington State Department of Ecology
EPA	United States Environmental Protection Agency
ESP	Electrostatic Precipitator
FCCU	Fluid Catalytic Cracking Unit
FGR	Flue Gas Recirculation
LAER	Lowest Achievable Emission Rate
LNBs	Low-NO_X Burners
MMBtu	Million British Thermal Units
NCASI	National Council for Air and Stream Improvement
NDCE	Non-Direct Contact Evaporator
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
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SRU	Sulfur Recovery Unit
SWS	Sour Water Stripper
Tesoro	Tesoro Refining and Marketing Company
TGU	Tail Gas Unit
tpy	Tons per Year
ULNBs	Ultra-low-NO_X Burners
VOC(s)	Volatile Organic Compound(s)

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600 • Olympia, WA 98504-7600 • 360-407-6000
711 for Washington Relay Service • Persons with a speech disability can call 877-833-6341

July 7, 2010

Mr. Frank Busch
Weyerhaeuser Corporation
3401 Industrial Way
Longview, WA 98632

Dear Mr. Busch:

Regional Haze Best Available Retrofit Technology (BART) Determination

Best Available Retrofit Technology (BART) is required to reduce the regional haze impacts of emissions of your facility. The enclosed Order #7840 contains our BART determination for your facility.

If you have questions or requests relating to this order, please contact Alan Newman at (360) 407-6810 or alan.newman@ecy.wa.gov.

Sincerely,

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Air Quality Program

jj/te

Enclosure

By certified mail

cc: Greg Bean, Weyerhaeuser Corporation
Marc Crooks, Industrial Section
Alan Newman, Ecology
Brian Wood, Weyerhaeuser Corporation

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN ADMINISTRATIVE ORDER AGAINST: Weyerhaeuser Corporation	]	ORDER NO. 7840

TO: Mr. Frank Busch
Weyerhaeuser Corporation
3401 Industrial Way
Longview, WA 98632

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions that are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the federal and state visibility protection program (WAC 173-400-151 and 40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitutes Best Available Retrofit Technology (BART) for the eligible emission units at your facility.

FINDINGS

A. The Weyerhaeuser Corporation (Weyerhaeuser) operates an integrated pulp and paper mill located in Longview, Washington, which contains three emission units that are subject to BART.

B. The BART-eligible emission units are the No. 10 Recovery Furnace, the No. 10 Smelt Dissolver Tank, and the No. 11 Power Boiler.

C. Emissions from BART units are controlled by:

   a. Use of an electrostatic precipitator (ESP) to control PM/PM_{10} emissions from the non-direct contact evaporator (NDCE) Recovery Furnace.

   b. Use of a tertiary air system for black liquor combustion in the No. 10 Recovery Furnace to control SO_2 and NO_X emissions.

   c. Use of a high efficiency wet scrubber to control PM/PM_{10} and SO_2 emissions from the No. 10 Smelt Dissolver Tank.

   d. Use of an ESP for control of PM/PM_{10} emissions from the No. 11 Power Boiler.

e. Use of a dry trona injection system to control SO_2 from the No. 11 Power Boiler.

D. Ecology has determined that the emission controls currently installed on these units meet the requirements of BART.

E. Ecology has determined that Weyerhaeuser has met the requirements of Administrative Order No. #5074, which required submittal of a BART Technical Analysis for the BART-eligible units at Weyerhaeuser's Longview facility.

Additional information and analysis is available in the BART Determination Support Document for Weyerhaeuser Corporation, Longview, Washington, prepared by the Washington State Department of Ecology, October 2008, and the Best Available Retrofit Technology Analysis Report, Weyerhaeuser Corporation Longview, Washington, December 2007, prepared by CH2M-Hill and revised June 2008.

YOU ARE ORDERED: To operate existing emission control equipment for the No. 11 Power Boiler, No. 10 Recovery Furnace, and No. 10 Smelt Dissolver Tank in accordance with the following conditions:

1. BART Emission Limitations

1.1. No. 11 Power Boiler

1.1.1. Meet the emission limitations for particulate matter found in Order DE 94AQ-I080, issued December 9, 1994.

1.1.2. Meet the emission limitations for nitrogen oxides found in 40 CFR 60.44(b), as published July 1, 2008.

1.1.3. Meet the emission limitations for sulfur dioxide found in 40 CFR 60.43(b), as published July 1, 2008.

1.2. No. 10 Recovery Furnace

1.2.1. Meet the emission limitations for particulate matter found in PSD 92-03, Amendment 4, Condition 3, issued December 7, 1999.

1.2.2. Meet the emission limitations for nitrogen oxides found in PSD 92-03, Amendment 4, Condition 7, issued December 7, 1999.

1.2.3. Meet the emission limitations for sulfur dioxide found in PSD 92-03, Amendment 4, Condition 5, issued December 7, 1999.

1.3. No. 10 Smelt Dissolver Tank

1.3.1. Meet the emission limitations for particulate matter found in PSD 92-03, Amendment 4, Condition 14, issued December 7, 1999.

1.4. Compliance will be determined as specified in Order DE 94AQ-I080, issued December 9, 1994, and PSD 92-03, Amendment 4, issued December 7, 1999, or 40 CFR 60.45(b)(2) or 40 CFR 60.45(b)(3), as published July 1, 2008, as appropriate.

2. Schedule for Compliance

2.1. Compliance with the emission limitations for particulate matter, nitrogen oxides, and sulfur dioxide is required upon the effective date of this Order.

3. Monitoring and Recordkeeping Requirements

3.1. Monitoring and recordkeeping requirements for particulate matter, nitrogen oxides, and sulfur dioxide are contained in Order No. DE 94AQ-I080, issued December 9, 1994, and PSD 92-03, Amendment 4, issued December 7, 1999.

4. Reporting Requirements

4.1. Reporting requirements for particulate matter, nitrogen oxides, and sulfur dioxide are contained in Order No. DE 94AQ-I080, issued December 9, 1994, and PSD 92-03, Amendment 4, issued December 7, 1999.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.

- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal, you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:

The Pollution Control Hearings Board
P.O. Box 40903
Olympia, WA 98504-0903

OR

Deliver your appeal in person to:

The Pollution Control Hearings Board
4224–6th Avenue SE Rowe Six, Bldg 2
Lacey, WA 98503

To serve your appeal on the Department of Ecology:

Mail appeal to:

Department of Ecology
Appeals Coordinator
P.O. Box 47608
Olympia, WA 98504-7608

OR

Deliver your appeal in person to:

Department of Ecology
Appeals Coordinator
300 Desmond Drive SE
Lacey, WA 98503

And send a copy of your appeal packet to:

Alan Newman
Department of Ecology
Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600

For additional information, go to the Environmental Hearings Office website at http://www.eho.wa.gov.

To find laws and agency rules, go to the Washington State Legislator website at http://www1.leg.wa.gov/CodeReviser.

Your appeal alone will not stay the effectiveness of this Order. Stay requests must be submitted in accordance with RCW 43.21B.320. These procedures are consistent with Chapter 43.21B RCW.

DATED this 7 day of July, 2010 at Olympia, Washington.

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Department of Ecology
Air Quality Program

Air Quality Program
Notice of Public Hearing

Reducing Haze-Causing Emissions From Industrial Plants

Ecology will hold a public hearing to receive comments on plans to reduce emissions from six industrial plants in Washington. These plants emit air pollutants that cause or contribute to visibility-limiting haze in national parks and wilderness areas. The federal government has directed states to reduce regional haze. Air pollutants that cause haze include fine particles, sulfur dioxide, and nitrogen oxides.

How will emissions be reduced?

Ecology is working with the owners of six industrial plants:

- The BP Cherry Point refinery in Whatcom County;
- The Alcoa Intalco Works aluminum smelter in Whatcom County;
- The Tesoro refinery in Skagit County;
- The Lafarge cement plant in Seattle;
- The Port Townsend Paper Corporation mill; and
- The Weyerhaeuser Corporation paper mill in Longview.

Each of these plants will reduce their emissions through Best Available Retrofit Technology (BART). BART is used for emission units that never met current emission limits, because they were in use before those limits became effective. BART means the existing equipment is updated with technology to reduce its emissions as much as possible. To be selected as BART, a control technology must be available, technically feasible, cost effective, and improve visibility. It must also have a low chance of causing any other negative environmental effects.

Hearing schedule

A public hearing is scheduled for:

Tuesday, October 27, 2009
6:00 p.m.
Ecology Headquarters Building, Auditorium
300 Desmond Drive
Lacey, WA

How to review and comment

The proposed BART determinations and related documents will be available for review at the following locations:

Bellingham Public Library
210 Central Avenue
CS-9710
Bellingham, WA 98227-9710
360-778-7323

Mount Vernon City Library
315 Snoqualmie Street
Mt. Vernon, WA 98273
360-336-6209

Seattle Public Library – Central Library
1000 Fourth Avenue
Seattle, WA 98104
206-386-4636

Port Townsend Public Library
1220 Lawrence Street
Port Townsend, WA 98368
360-385-3181

Longview Public Library
1600 Louisiana Street
Longview, WA 98632
360-442-5300

Ecology will accept comments from September 15 through November 6, 2009. Send comments to:

Al Newman
Department of Ecology
Air Quality Program
P.O. Box 47600
Lacey, WA 98504-7600
AQcomments@ecy.wa.gov

For more information

For more information, contact:

Al Newman
Department of Ecology
Air Quality Program
(360) 407-6810
alan.newman@ecy.wa.gov

or go to:
http://www.ecy.wa.gov/programs/air/globalwarm_RegHaze/bart/bartinformation.html

If you need this publication in another format, please contact the Air Quality Program at (360) 407-6800. If you have a hearing loss, call 711 for Washington Relay Service. If you have a speech disability, call 877-833-6341.

DEPARTMENT OF ECOLOGY
State of Washington

CORRECTION TO NOTICE PUBLISHED 9/9/09

Air Quality Program
Notice of Public Hearing

Ecology/TransAlta Mediation Agreement – CORRECTED NOTICE

The notice published on September 9, 2009 gave the time of the public hearing as 7:00 p.m. This notice corrects the time to 6:30 p.m. All other information in the previous notice is correct.

Ecology and the owner of TransAlta have reached a proposed agreement for TransAlta's Centralia area coal-fired power plant to reduce its mercury and nitrogen oxide emissions. Ecology is holding a public hearing to receive comments on this agreement, and on Best Available Retrofit Technology for TransAlta.

What's in the agreement?

The agreement focuses on two air pollutants: mercury and nitrogen oxides (NOx).

- **Mercury**: TransAlta will voluntarily purchase and use technologies that will remove up to 50 percent of its mercury emissions by 2012. TransAlta has also voluntarily installed technology for measuring mercury, and will begin self-reporting mercury emissions in 2009.
- **NOx:** Ecology and TransAlta agree that TransAlta's existing emission technologies make up "Best Available Retrofit Technology" (BART) for the Centralia plant. Ecology will issue a regulatory order requiring BART at the plant. See the heading "What is Best Available Retrofit Technology," below, for more information.

What is Best Available Retrofit Technology?

Best Available Retrofit Technology (BART) is set for emission units that were in use before current emission control limits became effective, and therefore never met the current limits. BART means the existing equipment is updated with technology that will reduce its emissions as much as possible. The BART determination for TransAlta is required under the federal Regional Haze rules. Ecology will submit the TransAlta BART determination to EPA for approval as part of the Regional Haze State Implementation Plan. A State Implementation Plan is a plan for meeting air quality standards in a specific area.

Why use a voluntary agreement instead of a regulation or an order?

Right now, neither Washington nor the federal government have regulations that require coal-fired power plants to reduce their mercury emissions. Because there is no regulation, a voluntary agreement is the only way to get mercury reductions from power plants.

Ecology worked on a mercury regulation for nearly two years. Ecology based its regulation on the federal regulation. When a court threw out the federal regulation in February 2008, Ecology was forced to withdraw its state regulation as well.

TransAlta requested mediation to discuss a variety of environmental issues, including NOx emissions. When the mercury regulation was withdrawn, mercury emissions were added to those discussions.

Hearing schedule

A public hearing is scheduled for:

Tuesday, October 13, 2009
6:30 p.m.
Ecology Headquarters Building, Auditorium
300 Desmond Drive
Lacey, WA

How to comment

Ecology will accept comments on the proposed mediation agreement and BART determination from September 14 through November 9, 2009. Send comments to:

AQcomments@ecy.wa.gov

OR

Sarah Rees
Washington State Department of Ecology
Air Quality Program
P.O. Box 47600
Lacey, WA 98504-7600

For more information

For more information, see
http://www.ecy.wa.gov/programs/air/TransAlta/TransAltaAgreement.html or contact:

Sarah Rees
Washington State Department of Ecology
Air Quality Program
(360) 407-6823
Sarah.rees@ecy.wa.gov

If you need this publication in another format, please contact the Air Quality Program at (360) 407-6800. If you have a hearing loss, call 711 for Washington Relay Service. If you have a speech disability, call 877-833-6341.

Ecology's Response to Comments on 6 Draft BART Technical Support Documents and Compliance Orders

Comments received on the proposed BART documents are provided below. There is an index table for written comments received. You can find the responses to each comment by going to the page numbers referenced in the table.

Written Comments	
Name / Organization	**Page #**
James C. Langford	1
US Forest Service	1, 7
National Parks Service	1, 3, 4, 8
Trinity Consultants	3
Tesoro Refining and Marketing	8
Lou Kings	9
Thea Levkotitz	9
Bill Pease	9

Response to general comments:

General comments:

1. James C. Langford
   I believe in emission controls but your group has no business in keeping on pushing for lower and lower limits when you are ignoring China and India and their air pollution that travels here. Seems like the only public you are interested in is destroying the US economy. I am told to test for fraud actions like your group would engender is to follow the money and how much are you asking? Come on!!!

Response:
Protecting the air quality in Washington State is an important component of air pollution control. As you correctly indicate, air pollution has been demonstrated to travel from Asia to North America. While this may be an important source of pollutants, the State of Washington is unable to affect those emissions. As part of the State's Regional Haze State Implementation Plan (RH SIP) we demonstrate that a portion of the visibility impairment on the worst days is due to air pollutants crossing the Pacific Ocean and from Canada. Control of those pollutants is the responsibility of the US National Government. Washington State is required to work to reduce the impacts from those sources of air pollution that we can control and identify the impacts that are out of our control.

A review of our proposed BART decisions would indicate that we have rejected costly emission controls that could be imposed on the various companies if cost were not a factor in the decision process.

2. US Forest Service and National Park Service
   In general both agencies are concerned with the lack of visibility improvement resulting from the BART process in Washington. The USFS recognizes that the federal guidance gives the state latitude in the importance given to the 5 BART decision factors; they are concerned that visibility improvement is not given enough importance. Instead of relying solely on a cost effectiveness

based on $/ ton of pollutants reduced, Ecology should use a measure such as $/dv improved as outlined in a Sept. 2008 memorandum from Scott Copeland of the USFS or as proposed by EPA Region 9 for use in their BART decision process for power plants located on Indian Reservations in Region 9.

For the National Park Service, this concern about evaluating visibility improvement is especially important when multiple Class I areas are affected by a single facility. Their opinion is that the visibility improvement at all affected Class I areas needs to be included in a cost effectiveness evaluation using a method similar to the ones included in the Sept. 2008 memorandum. They advocate for BART determinations to be based on a $/cumulative dv of improvement. Their compilation of proposed BART determinations indicates that the proposed decisions all result in a maximum cost effectiveness of $12 – 19 million/cumulative dv improved (with one exception at $50 million/cumulative dv).

Response:
Ecology is also concerned over the minimal improvement in visibility resulting from the BART process in Washington. We do note that evaluations performed in developing the Regional Haze Implementation Plan indicate that significant amounts of the visibility impairment at Washington's mandatory Class I Areas comes from Asian and Pacific Offshore sources and for some mandatory Class I Areas, Canada.

Ecology has utilized all 5 factors in the BART process in making its proposed BART decisions including the degree of visibility improvement factor. As noted, the state has latitude in determining the relative importance of the various factors. The EPA BART guidance only requires an evaluation of the degree of visibility improvement anticipated by the proposed emission controls[1]. The guidance does not suggest that the state set a minimum visibility improvement criteria or any other measure of visibility improvement as a determining factor in acceptability of any BART decision. Equivalently the guidance document does not suggest or require that visibility impacts and improvements beyond the nearest mandatory Class I Area to be modeled in great detail, indicating EPA expected states to focus modeling resources on the closest mandatory Class I Areas[2].

For cost effectiveness we are relying on a measure that we know and understand, the $/ton reduced. Between July, 2005 when EPA issued the final BART guidelines until the fall of 2008 when the first proposal from the FLMs was developed on how to do a $/dv measure, no state was using this measure and EPA provided no guidance in how to perform the calculation. Ecology has chosen to follow the lead of essentially all other states in evaluating BART control costs on a $/ton reduced.

To complicate matters more, the Sept. 2008 memorandum referenced by the Forest and Park Services proposes 2 variant methods to calculate cumulative deciviews, noting problems with each approach. An

[1] EPA comments to S. Dakota DENR, Nov. 13, 2009, on the Big Stone I BART determination states in Comment #7, "The net visibility change between the pre-control and post-control emission control scenarios is the principal visibility related factor to be considered in determining BART limits." See also 40 CFR Part 51, Appendix Y, Section IV.D, Step 5 How should I determine visibility impacts in the BART determination?

[2] See 40 CFR Part 51, Appendix Y, Section III.A.3 Option 1 Individual source Attribution Approach (Dispersion Modeling) and, Section IV.D, Step 5 How should I determine visibility impacts in the BART determination? In both locations EPA advises to have a dense grid of receptors in the nearest Class I areas and for other Class I areas in close proximity to the source, model a few strategic receptors to determine whether affects may be greater than the nearest Class I area. This approach to modeling does not fit with the cumulative visibility improvement approach advocated by the Park and Forest Services.

EPA Region 9 Federal Register Notice concerning how Region 9 would evaluate visibility impacts from 2 power plants located on Navajo Tribal lands, proposed 2 more very different methods to implement a $/dv improved metric.

National Park Service documents appear to utilize variations on the approaches proposed in the Sept. 2008 memorandum. Which is the correct method to use to determine $/dv improved? What is the cost effectiveness threshold when using this approach? What is the basis for a $/dv cost effectiveness threshold? The approaches proposed by the FLMs and EPA Region 9 do not supply the answers or indicate where they lie. The only source of information on what might be an appropriate $/cumulative dv improved cost value is a compilation of proposed BART determinations by Mr. Shepherd of the National Park Service. While informative, the compilation contains information from BART proposals, not the final determinations by individual states.

Separately, Ecology undertook a review of BART determinations included in SIPs submitted to EPA by Western US states. This review indicates no state has relied on the $/dv improved measure to make a BART determination. The RH SIPs that have been submitted and reviewed by Ecology all utilize the $/ton reduced metric for BART. Two of the SIPs reviewed seem to utilize a $/dv measure to support additional further progress emission reductions volunteered by or imposed on individual plants.

Response to comments on Port Townsend Paper Company BART:

1. Trinity Consultants on behalf of Port Townsend Paper Company
   The consultant indicates that footnote 'a' to Table 2.6 in the Technical Support Document is inconsistent with the text on Page 28 and the company's BART analysis regarding the cost effectiveness of adding or converting the existing dry ESP on the No. 10 boiler to a wet ESP and requests that the footnote be corrected.

Response:
Thank you for pointing out the inconsistency. The document will be corrected.

2. National Park Service
   Ecology should consider the visibility improvements that would occur at all of the Class I areas within 300 km of the BART source.

   Ecology should have included evaluations of upgrading and improving operations of existing control equipment, especially the ESP on the recovery furnace and wet scrubber on the power boiler.

   Ecology should expand its evaluation of the cost effectiveness of switching to a lower sulfur fuel oil as a means to reduce SO_2 emissions. Ecology inappropriately rejected the use of lower sulfur fuel oil on a cost basis without also evaluating the visibility benefit from the resulting lower SO_2 emissions. Since the Massachusetts Department of Environmental Protection has proposed that all residual fuel oil be limited to 0.5% sulfur, we believe that this should become the default presumption for SO_2 BART at PTPC.

Ecology evaluated the visibility impacts of only two options—reductions of PM_{10} from the No. 10 Power Boiler and the Smelt Dissolving Tank. Therefore, the remaining BART determinations are incomplete.

Addition of a wet ESP to control PM_{10} emissions from the Power Boiler #10 is cost-effective and represents BART.

Response:
The initial modeling of the facility covered all Class I Areas within 300 km of the plant. That modeling showed that emissions from the plant exceeded the contribute threshold only at the Olympic National Park. In order to save resources, we focused all subsequent modeling data analyses only on the effects at Olympic National Park, though the modeling domain still contained all the other Class I areas.

Ecology and Port Townsend Paper Company evaluated upgrades and improvements to the existing emission control equipment on the power boiler and recovery furnace as part of the project.

Ecology evaluated the costs of switching to lower sulfur fuel oil in addition to the work done by the company in its analysis. The evaluation is documented in the Technical Support Document and in supporting materials from the company posted on our BART web page, specifically BART Analysis, 2nd Addendum. As demonstrated in our Technical Support Document, the cost of switching to a lower sulfur fuel oil is excessive on a $/ton basis. Since the SO_2 reduction option was not cost effective, we determined that it did not need to have the visibility benefits from using it evaluated.

Based on the lack of information available publically about the Massachusetts Regional Haze SIP, we have reviewed information from Northeast States for Coordinated Air Use Management (NESCAUM) and Mid-Atlantic/Northeast Visibility Union (MANE-VU) about the low sulfur residual fuel proposal and The New Hampshire Regional Haze SIP. This oil sulfur content reduction is not proposed as BART but as a further progress element to achieve SO_2 reductions from all oil combustion (residential, commercial and industrial) sources in the NESCAUM area. There is a schedule of dates to phase in this oil fuel sulfur limitation, with the residual oil limit proposed to be met in 2018. As a result, Ecology cannot accept the NPS proposal that fuel oil with 0.5% sulfur content is presumptive BART for fuel oil used by PT Paper.

Ecology evaluated the visibility of only the 2 options that were possibly cost effective for implementation at the facility. As such, the evaluation is complete in accordance with our understanding of the requirements of the BART guidance.

Ecology respectfully disagrees with the National Park Service that adding a wet electrostatic precipitator to Power Boiler #10 is cost effective.

Response to comments on INTALCO Aluminum Corporation - Ferndale BART:

1. National Park Service
   Sodium based scrubbing systems have been evaluated by Canada and in the US for installation on primary aluminum smelters, including one in Washington. The technology is technically feasible for use, and needs further evaluation here. Ecology notes in its support document that sodium based

scrubbing systems are technically infeasible due to the inability to discharge wastewater. The cost to treat the resulting wastewater is part of the cost analysis step, not the technical feasibility step.

The cost analysis for limestone wet scrubbing appears to overestimate costs. One example is a doubling of the erection costs for the scrubbing system, a cost element present in all BART analyses the NPS has reviewed from Intalco. Other examples are the cost of operating labor and the cost for maintenance materials. Ecology needs to evaluate a one absorber tower configuration for the plant such as was done in Tennessee, but not presented to Ecology by Intalco.

Costs that deviate from the EPA Control Cost Manual approach and factors should be documented and justified by Ecology.

Based on a Rio Tinto–Alcon PSD application in Kentucky and the analysis presented, we believe that a sodium based scrubbing system is cost effective at $4,387/ton SO_2 removed. Ecology should perform a full 5 factor evaluation of the use of a single vessel sodium based scrubbing system.

Intalco and Ecology should provide modeling results for all Class I areas within 300 km for the base case as well as the 95% potline SO_2 removal case. Ecology should explain how it objectively evaluated the resulting visibility benefits to all of those Class I areas. We believe that, when Ecology does so, it will conclude that 95% SO_2 scrubbing of potline emissions is BART at Intalco.

Response:
Ecology does agree that any wet scrubbing system to control SO_2 at INTALCO Aluminum Corporation - Ferndale (INTALCO) is technically feasible. What is in question is the ability to discharge treated wastewater to Puget Sound. The language of the Technical Support Document was in error or unclear in its statement that a sodium based scrubbing system is technically infeasible due to the inability to discharge wastewater. The cost and difficulty in discharging treated wastewater is however a significant cost impediment that exists at this site. The Technical Support Document will be corrected.

The portion of Puget Sound/Strait of Georgia where the INTALCO plant is located is part of an Aquatic Reserve that was established in 2000. The construction of any new intake and/or discharge structures within the Cherry Point Aquatic Reserve would require an impact analysis, assessment, and Washington Department of Natural Resources authorization of any environmental impacts from the new discharge. The Department of Ecology would have to issue a new National Pollutant Discharge Elimination System (NPDES) permit after the environmental impacts of the new discharge were evaluated. Due to issues with protection of spawning and rearing areas for herring (a primary forage fish for salmon) a new wastewater discharge to the Strait of Georgia/Puget Sound in the area of the INTALCO Smelter are effectively impossible to get. This would apply to the ability to discharge wastewater from any wet scrubbing system, sodium or calcium based. Similarly a land discharge of treated wastewater is difficult to get permitted as a result of wetlands issues.

As noted in the BART analysis from the company and reiterated in the Ecology Technical Support Document, there are regulatory hurdles that would need to be overcome to allow discharge of treated scrubber wastewater to the Georgia Strait at the location of the smelter.

The Park Service notes that four aluminum smelters, including the Goldendale Aluminum smelter, in Washington use a sodium based wet scrubbing system. For the Goldendale smelter, the wet scrubber was located after the fluoride and particulate control system. The primary system wet scrubber was

designed to provide a 70% SO_2 reduction and at time of plant closure provided about 80% reduction in SO_2 but the permitting documents in our possession are inadequate to define this as a sodium based wet scrubbing system, only that sodium hydroxide is used for pH control. A clear water scrubber was utilized in the secondary control system, using recirculated water and pH control as needed to keep the pH above 6.0. The addition of the scrubbers to the plant halted its ability to discharge wastewater to the Columbia River. Fortunately, the higher temperatures of the Soderburg smelting process and the plant's location in Eastern Washington allowed it to develop a 'no discharge' wastewater handling system. The plant is currently not operating with 2 of the potlines already dismantled and the last potline is in the process of being dismantled. As a result there is little likelihood of this plant ever operating again. Similarly, another of the facilities identified by the National Park Service, a smelter in The Dalles Oregon, has been converted to a secondary aluminum facility. Based on the available public information on the smelters identified, most are Soderberg facilities, which have a higher gas stream temperature than a prebake facility like INTALCO.

Previously Ecology has evaluated SO_2 controls for the INTALCO facility as part of a PSD permitting exercise that the company abandoned. During that BACT review a number of SO_2 controls were evaluated, including dry and wet scrubbing options utilizing both calcium and sodium based scrubbing systems. These controls were not found to be cost effective at that time either, on both a capital and an annualized basis.

In our analysis of the costs of calcium based wet scrubbing of the potline emissions, INTALCO provided the information on a single vessel option and we did evaluate the effect of all the fine tunings of the cost model advocated by the Park Service. A synopsis of our evaluation of the single vessel option is included in the Technical Support Document. While our costs differ from those presented by the National Park Service, we find that the cost effectiveness of single vessel SO_2 control was higher than what we would require for a new facility, let alone an existing facility. The costs were higher on a $/ton basis than was applied to the coal-fired power plant in Centralia for its limestone based wet scrubbing system. The costs are also higher than what other states have been accepting as cost effective for BART for control of SO_2.

A review of Regional Haze SIPs for states with aluminum smelters and the BART determinations for other aluminum smelters indicates that states have found most smelters are not Subject to BART. Of those that are Subject to BART, the states have determined that the existing emission controls meet the requirements of BART.

We will amend the Technical Support Document to indicate the results of our 'fine tuning' of the LSFO cost effectiveness evaluation.

The applicability of the Rio Tinto-Alcan's analysis of a sodium based scrubbing system on a portion of that facility can only compare the air quality aspects of the installation. However, we have been able to acquire very little information from the State of Kentucky about the project other than to confirm that sodium based scrubbing is being evaluated as one of the SO_2 control options and that BACT has not yet been determined. A sodium based scrubbing system (along with a lime/limestone system) was evaluated as part of a proposed 1998 PSD project at this facility. Based on costs at that time, all wet scrubbing technologies were proposed by INTALCO to not be cost effective. Ecology did not make a BACT decision on this PSD application as the company withdrew their proposal.

The BART process is not focused solely on the air quality benefits of a particular emission control. We are also required under the BART guidelines to look at the non-air quality impacts of the proposed control technology. This is not required of a BACT determination for PSD permitting. As indicated above and in our Technical Support Document[3], Department of Ecology wastewater discharge policies and environmental protection for herring spawning and rearing areas reduces the opportunity for a new or expanded discharge of pollutants into Puget Sound at the INTALCO location. As a result, a no-discharge option for the scrubber wastewater is required. This area is also unable to provide for adequate evaporation to develop a no-discharge system to handle the scrubber wastewater and there are no existing POTWs near and large enough to send the excess scrubber water for treatment.

The visibility impacts at all Class I Areas within 300 km of the INTALCO facility have been modeled and are included in the modeling files. As for the cumulative visibility assessment the National Park Service indicates we should perform, see the general response to this issue given above.

2. <u>The US Forest Service</u>
   We are particularly concerned about the frequency in which this facility is modeled to cause or contribute to visibility impairment at eight Federal Class I areas, primarily due to SO2 emissions from its pot lines. While we recognize that Ecology has evaluated several control technologies and has concluded that none are appropriate to implement as BART, we remain concerned about the lack of improvement in reducing haze caused from this source.

Response:
Thank you for the comment. We have been involved with evaluating SO_2 controls for primary aluminum smelters for a number of years and continue to be concerned with the lack of viable controls for this location and industry as a whole.

Response to comments on Weyerhaeuser Company - Longview BART:

1. <u>The US Forest Service</u>
   The No. 11 Power Boiler at Weyerhaeuser has existing controls (i.e., dry sorbent injection) to reduce SO2 emissions. However that system was originally designed to achieve a 25% reduction in emissions to avoid New Source Review. Dry sorbent injection systems commonly achieve 50 to 90 percent removal. Improved SO2 removal efficiency may be accomplished through use of dry sorbent materials other than Trona, modifications to increase flue gas contact time, or through fine tuning of operational methods.

Response:
The application of dry sorbent injection using Trona at this facility reduces SO_2 at approximately the same level as dry sorbent injection (lime) is anticipated to provide at the Lafarge North America cement plant in Seattle. Alternative approaches were evaluated by the company for SO_2 control; including the use of calcium based sorbents rather than the sodium based Trona. Based on the information submitted by the company and an on-site evaluation of the Trona injection system and the electrostatic precipitator, we believe that there is little opportunity in the current configuration to improve the SO_2 removal efficiency.

[3] INTALCO BART Analysis Technical Support Document, Appendix A, Discussion of sea water scrubbing.

Response to comments on Tesoro Refining and Marketing Company BART:

1. Tesoro Refining and Marketing Company
   The company provided numerous detailed comments related to the internal consistency of the Support Document and one comment to edit proposed emission limitation in the proposed BART Order to be consistent with the requirements of the Order of Approval issued by NWCAA.

Response:
Ecology appreciates the inconsistencies being pointed out and will revise them as appropriate and necessary. The other edits and suggested changes to the Technical Support Document will be evaluated and revised as appropriate.

We also will make the requested correction to the proposed order to be consistent with the underlying regulatory requirement.

Where there are conflicts between the BART Technical Support Document, the comments from the company, and the recently issued (Jan. 26, 2010) Air Operating Permit for the facility, the information in the Air Operating permit will be used to resolve the differences. One example of this is the total heat input rate for heater F6650/6651.

2. National Park Service
   In general, the analyses presented appeared to be reasonable. However, Ecology should have adjusted the costs of plant-wide SO_2 control to account for the values of the additional sulfur recovered from the refinery gas.

   Ecology did not evaluate the visibility improvements that would result from any specific control option. This is especially problematic with respect to Ecology's rejection of plant-wide SO_2 reductions through reductions in the sulfur content of refinery gas.

   We have a fundamental concern with Ecology's decision to not consider the visibility improvements that would occur at all of the Class I areas within 300 km of the BART source.

   We agree that scheduling issues may make it more appropriate to implement the proposed controls under the Reasonable Progress provisions of the WA Regional Haze SIP.

Response:
The value of sulfur is low and the inclusion of an economic benefit from the additional sulfur available for sale is low. Ecology does not consider that its exclusion changes the overall cost effectiveness for implementing a lower refinery fuel gas sulfur level.

Ecology recognized the cost of modeling potentially 3 or 4 control scenarios at between 15 and 30 individual emission units at the 2 Subject-to-BART oil refineries. As a result, we directed the companies to focus modeling resources on the effects of control scenarios that were likely to be implemented.

The visibility impacts at all Class I areas within 300 km of the Tesoro refinery have been modeled and are included in the modeling files and the Support Document. As for a cumulative visibility assessment, see the general response to this issue given above.

Response to comments on Lafarge North America BART:

1. Lou Kings
   Lou Kings submitted a comment in support of the Proposed BART Determination.

Response:
Thank you.

2. Thea Levkotitz
   Request from Thea Levkovitz on behalf of the Duwamish River Cleanup Coalition that the BART hearing covering the Lafarge facility be held closer to the Duwamish Community which is located near the plant.

Response:
The Department held a single public hearing for 6 of the 7 BART determinations that have been proposed. This single hearing was held in Olympia due to the large geographic spread of the facilities involved. The hearing was held at the time and place in the public notice and no one showed up to talk in favor or against the proposals.

3. Bill Pease
   Bill Pease was concerned with holding a single public hearing in Olympia. He was also concerned with the BART process in general focusing on a select few industrial sources while many more are not being evaluated. His BART process concerns specifically are about the focus on the 6 facilities included in the public hearing that included the proposed BART determination for the Lafarge facility and why this made any sense.

Response:
See above response to the single hearing in Olympia comment.

The Best Available Retrofit Technology process is a component of the Regional Haze Program contained in Environmental Protection Agency rules. Those rules require a state to develop a plan for the state to meet the federal goals for visibility in 156 National Parks and large Wilderness areas (mandatory Class I Areas). The BART process is circumscribed in the federal Clean Air Act and Environmental Protection Agency rules to apply to a specific subset of all industrial plants in the country.

There are 7 industrial facilities in Washington that meet all the criteria to be in that group of industrial plants. These facilities all meet 4 criteria to be subject to the BART process. These criteria are:

- One or more sources of emissions initially started operation or began construction between Aug. 7, 1962 and Aug. 7, 1977,
- Is one of 26 specific source types listed in the federal Clean Air Act and EPA regulation,
- Has a potential to emit any visibility causing air pollutant at a rate above 250 tons per year, and

- Has a modeled visibility impact at a mandatory Class I Area that causes or contributes to visibility impairment.

The Lafarge North America facility in Seattle is one of the 7 industrial plants in Washington that meet all of these criteria.

ECOLOGY'S RESPONSE TO COMMENTS ON THE DRAFT TRANSALTA BART TECHNICAL SUPPORT DOCUMENT AND COMPLIANCE ORDER

Comments received on the proposed TransAlta Best Available Retrofit Technology (BART) determination are provided below. There is a separate index table for written comments and for verbal testimony received. You can find the responses to each comment by going to the page numbers referenced in the tables.

Two versions of form letters were received by e-mail from multiple stakeholders through Sierra Club's web site. The total number of e-mails for both form letters received prior to the close of the comment period was 1,896. This number does not account for duplicate e-mails that were sent by the same stakeholders. Ecology has consolidated responses to both versions of these form letters below.

Written comments and the content of the form letters can be accessed at http://www.ecy.wa.gov/programs/air/TransAlta/TransAltaAgreement.html.

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Janette K. Brimmer	Earthjustice (Counsel for National Parks Conservation Association, Sierra Club and NW Environmental Defense Center)	5
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Verbal Testimony		
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Response to comments from Dr. Ranajit Sahu:

1. One overall comment on the BART determination for this facility: a proper top-down BART analysis was not completed due to an inadequate analysis of the Selective Catalytic Reduction (SCR) alternative. The reviewer has specific issues with:

- SCR cost analysis submitted by TransAlta.
- Lack of Ecology investigation of combustion system modifications to reduce Nitrogen Oxides (NO_X) and subsequent size of SCR system required.
- No evaluation of alternative locations to install SCR unit such as after the Electrostatic Precipitators (ESPs) or wet scrubbers.
- Inadequate schematics provided to facilitate 3rd party review–unable to determine scale and subsequently distances between objects on the plot and profile drawings.
- No documentation of source for vender quote(s) in CH2MHill reports.
- SCR cost analysis not scrutinized for extraneous costs such as a 16% cost surcharge, the basis of balance of plant charges, why the cost of two SCRs simply double one SCR, since only one reagent system is needed, etc.
- How much catalyst is assumed in the SCR cost analysis? How many layers, etc.?
- Basis for assuming the NO_X emission rate of 0.07lb/MMBtu when a 90% reduction from 0.30 lb/MMBtu would result in a 0.03 lb/MMBtu emission rate, thus increasing the quantity of emissions used in determining cost-effectiveness.
- Additional similar questions related to details of the Selective Non-Catalytic Reduction (SNCR) control alternative.

Response:

Ecology briefly reviewed the SCR option during our review of the January and July BART analyses submitted by TransAlta. The information presented by TransAlta was consistent with information included in references reviewed in preparation for reviewing all BART analysis submitted in Washington. Familiarity of the Ecology staff and local permitting authority with the physical constraints on adding additional emission controls or reconfiguring exhaust gas flow paths to accommodate new add on emission controls lead us to agree that the costs for inclusion of SCR would have high installation costs.

As a result, we did not investigate the details of the cost analysis. We did use an alternative Environmental Protection Agency (EPA) cost model (CUECost) that EPA issued to replace the use of the Control Cost Manual for coal-fired power plants. The cost estimates from the CUECost model indicate that the SCR costs estimated by TransAlta are in the range expected for that type of facility. Experience in doing BACT cost analyses lead us to the opinion that even the fine tuning of the cost analysis presented by the company would not substantially change the total capital cost, the annual operating cost, or the annualized costs of the project.

At our request after the public hearing, TransAlta submitted more readily readable drawings and information on the basis of its SCR cost estimates (see Draft Support Document for BART Determination for TransAlta Centralia Generation, LLC Power Plant, Centralia, Washington, Washington State Department of Ecology, revised April 2010, p. 15).

We also did not delve into the actual emission limit that would reflect the use of SCR on the boilers at this plant. Such an evaluation might result in a different emission limitation, though a review of most power plant BART determinations in western states indicate that for the few facilities required (or volunteering) to install SCR for BART, none have an emission limitation below 0.07 lb/MMBtu.

Alternately, we did review the costs for SNCR in greater detail. The duplication of some costs such as those for reagent tanks might be reasonable to eliminate, but are not the significant cost for the use of SNCR. At our request after the public hearing, TransAlta supplied more information on the basis of its SNCR cost estimates (see Draft Support Document, p. 15)

2. Improved combustion control not evaluated.

- Literature review of combustion control effectiveness not obviously reviewed.
- No evaluation of why this installation if Low NO_X Combustion, Level 3 (LNC3) combustion controls are unable to meet the presumptive BART emission limitation EPA proposed in the BART guidance for this control on this type of boiler.
- Installation of neural net control/combustion optimization not required as part of BART.

Response:

The literature on combustion control effectiveness was reviewed in the context of all BART analyses performed by Washington. The review was not called out specifically in regard to this facility.

A review of the emission record for this facility indicates that since the combustion controls were first installed and before the company's decision to suspend mining coal at Centralia, the units had been subject to fine tuning for improved effectiveness of the combustion controls.

The change from Centralia to Powder River Basin (PRB) coals results in an immediate decrease in NO_X emissions resulting from a combination of factors including the reduced fuel nitrogen content and the higher heat net content of the PRB coals compared to the Centralia coal.

The neural net process could be installed and might actually result in a decrease in NO_X emissions. However, without the ability to quantify any potential for NO_X reductions, the cost-effectiveness of the installation cannot be evaluated. We do encourage the company to implement the process if their additional analyses indicate that it may provide positive benefits.

3. Numerous unexplained changes between the January 2008, the June 2008, and December 2008 submittals. Changes not explained or obvious to the reviewer. Vendor cost changes for SCR. Baseline emissions change in each of these submittals.

Response:

The June 2008 submittal was intended to replace the January 2008 submittal. Changes in vender costs reflected new information acquired by TransAlta's emission control analysis consultant.

TransAlta's consultant was involved in a number of additional BART analyses in the western U.S. during this period and used information collected for one project in others. At Ecology's request after the public hearing, TransAlta supplied additional information related to the basis of its SCR cost estimates.

We agree the baseline emissions changes between the submittals is troubling and not explained in the company submittals, but analysis of the emissions against data submitted to EPA's Clean Air Markets Division indicate the bases of these changes.

4. The Flex Fuels project might be subject to a New Source Review (NSR) permit as a major modification. Has this been investigated? It is not portrayed as an emission control technique. Not obvious how the use of Flex Fuels results in a 20% decrease in NO_X emissions.

Response:

Ecology has previously analyzed the Flex Fuels project for Prevention of Significant Deterioration (PSD) permit applicability. The review indicated that the project did not qualify as a major modification of a major stationary source.

The Black and Veatch analysis submitted as part of the PSD applicability analysis evaluated methods to restore steam generation capacity lost due to the slagging issues and reduced heat transfer resulting from the use of 100% PRB coals. As the report and the project's minor NSR permitting materials indicate the PRB coal's sodium content changed the fly ash/slag on the boiler tubes from a "light and flakey" ash very amenable to standard soot blowing techniques, to a glassy material requiring a different method of "soot blowing." We agree the Black and Veatch report does not portray this project as an emission control project.

The Flex Fuels project results in a 20% decrease in NO_X as a result of a number of factors including the reduction in fuel bound nitrogen in the coal reduced quantity of coal combusted due to the higher new heat content, and reduced firing rate to accommodate the coal slagging characteristics.

5. The focus of EPA on SNCR in its comments on a preliminary version of the BART determination and support document is premature. Ecology has not defeated SCR as BART for this facility.

Response:

Ecology's view is that EPA's focus on SNCR indicates that they agree with Ecology that SCR is not a feasible control technology for this power plant. The EPA staff involved with the comments was involved in the 1997 Reasonably Available Control Technology (RACT) process and is familiar with the configuration of the facility, difficulty of construction on the site, and the cost analysis methods used in Best Available Control Technology (BACT) determinations.

6. Due to the large visibility impact of the emissions from this facility, SCR cannot be ruled out as BART for the plant.

Response:

We recognize that this plant has a large impact on visibility at a number of mandatory Class I areas in Washington and Oregon. The proposed BART emission limitations will result in substantial reductions in visibility impacts at all mandatory Class I areas within 300 km modeling radius of the plant. The proximity of the plant to numerous mandatory Class I areas magnifies the impacts compared to other power plants of similar size in the U.S.

The Regional Haze program guidance from EPA allows the states to evaluate and balance all benefits and impacts of the installation of emission controls on a particular facility. Visibility impact and potential visibility improvement are only two of the factors to be considered in that determination. As such, the fact that this particular facility has a large visibility impact is not sufficient by itself to justify SCR as BART.

Response to comments from Earthjustice:

Earthjustice provided comment on the proposed settlement agreement on behalf of the National Parks Conservation Association, the Sierra Club, and Northwest Environmental Defense Center (collectively the "Conservation Organizations"). The comments are 17 pages in length. Below, Ecology has attempted to summarize the key points from this comment letter and respond to them instead of engaging in legal argument. The full comment letter from Earthjustice is available on line at http://www.ecy.wa.gov/programs/air/TransAlta/TransAltaAgreement.html.

1. It is extremely unfortunate and puzzling why Ecology feels compelled to reach this lopsided Agreement with TransAlta. This Agreement is not a compromise between two ends of a spectrum, but rather a capitulation. Ecology and the citizens of Washington get nothing from this "bargain" that TransAlta wasn't already going to give them. TransAlta gets exactly everything it wants: it is not subject to BART for NO_x; it is not required to do anything to control NO_X pollution that it's not already doing, and would do regardless of this Agreement; it can do minimal mercury control, well below industry standards, at its sole option with no repercussions if it does not achieve the reductions agreed to. In return, Ecology agrees to "hands-off" treatment for the next 10 years or more for the TransAlta coal plant on a number of pollution issues; the state agrees to become TransAlta's partner in seeking accommodation and/or positive treatment from the EPA on a number of pollution issues; and the state agrees to look kindly on a wide-ranging list of potential TransAlta proposals for dealing with coal ash waste. Conservation Organizations find that the Agreement provides nothing of benefit for the citizens and natural resources of this state and strongly urge the State to reject this Agreement and engage in a full-scale, thorough BART analysis for NO_x, and aggressive case-by-case mercury control in line with industry achievements of over 90% reduction.

Response:

Ecology disagrees with the commenter's characterization of the agreement. The agreement reached a quick and effective resolution of issues related to NO_x and mercury controls without the delay that would otherwise be caused through the regulatory process or potential litigation. Instead of litigating the question of whether TransAlta is subject to BART, Ecology and TransAlta were able to agree and move forward on a BART determination for NO_x that meet the requirements of the federal Regional Haze Rule. Instead of expending much time and resource in establishing a mercury rule for a single facility, Ecology secured an agreement to use state-of-the-art technology to reduce mercury emissions by at least 200 lbs per year beginning in 2012. This achieves substantial mercury reductions well in advance of the EPA action. Regarding ash handling, all Ecology has agreed to do is work with TransAlta to find solutions to potential future ash handling problems (which would be as a result of the new control technology) within the constraints of Ecology's solid waste rules. These results are all at tremendous benefit to Ecology, the state of Washington, and to the environment.

2. The proposed agreement and consent decree include various clauses and constraints that further weaken the agreement.

Response:

Ecology believes that the commenter's have misconstrued these clauses. To implement the mercury reductions, TransAlta is agreeing to install the controls and undergo substantial expenditures to make them work. In fact, TransAlta has already taken major steps in this direction by proceeding with testing and design of the controls. While Ecology has agreed to not require additional NO_X reductions until after 2018, Ecology believes this agreement is reasonable as stated in response to Earthjustice comment 4 below. Finally, Ecology is puzzled by the comment regarding "beneficial uses" of ash. "Beneficial use" is a term clearly defined in Ecology's solid waste rules, WAC 173-350 et seq., and is a well-known term of art. Further, the inference that TransAlta's ash handing could result in a coal ash spill such as that by the Tennessee Valley Authority (TVA) in December 2008 is misleading. TransAlta does not have ash ponds of this nature and its coal ash handling system is disposed in accordance with Ecology's solid waste rules, so such an outcome is not possible.

3. NO_X pollutants from the TransAlta coal plant negatively affect the air quality of at least one Class I area.

Response:

We agree and recognize that this plant has a large impact on visibility at a number of mandatory Class I areas in Washington and Oregon. The proximity of the plant to numerous mandatory Class I areas magnifies the impacts compared to other power plants of similar size in the U.S. The TransAlta coal plant is subject to BART for NO_x emissions.

4. The Flex Fuels project cannot properly be considered BART.

- Flex Fuels is not a NO_X reduction technology or project.
- There is no support in the record for the claimed NO_X reduction from the Flex Fuels boiler efficiency project.
- Even after the application of Flex Fuels, the TransAlta coal plant will cause visibility impairment in 12 Class I areas.

Response:

Ecology does not agree with the commenter's' characterization of the Flex Fuels project. The Flex Fuels project required the installation of boiler modifications to TransAlta's boilers so that they could burn low sulfur coal full-time. The lower sulfur content PRB coals also contains less fuel bound nitrogen and higher net energy content compared to coal from the Centralia coal field. TransAlta's boilers were originally designed to burn coal mined from Centralia, which has lower energy content than low sulfur coal from the PRB. Because the low sulfur coal provides more energy per pound burned, it also generates lower NO_X emissions. Less coal is burned to meet the same boiler energy input requirements, so less NO_X is emitted. As Ecology has explained, the Flex Fuel project will provide at least a 20% reduction in NO_X emissions from currently permitted levels at the facility. The Flex Fuel project is already installed, and Ecology has observed the reduction in NO_X emissions. In combination with the existing combustion controls, the average NO_X emissions for calendar 2008 from the TransAlta facility are approximately 0.21 lbs NO_X/MMBtu, a rate that is more than a 25% reduction from the currently permitted level of 0.30 lb/MMBtu.

TransAlta will still impact visibility at Class I areas from its NO_X emissions even with the Flex Fuel project. In fact, TransAlta will impact these Class I areas from its Sulfur Dioxide (SO_2) and Particulate Matter (PM) emissions, even though TransAlta has been determined by EPA to meet BART for those pollutants due to its existing controls. The evaluation and application of BART under the federal Regional Haze Rule (RHR) does not require that a facility have no residual impact on visibility at Class I areas. BART instead requires a multiple factor analysis of a facility and its attributes as further described in Response 6 below.

5. SCR technology is BART:

- SCR is technically feasible.
- There is no support in the record for the claims regarding physical space limitations.
- The record has no explanation for TransAlta's failure to control the unusually high boiler-out NO_X emissions at the TransAlta coal plant, a fundamental component of considering feasible BART technologies.
- There is no support in the record for TransAlta's high cost claims for the SCR technology.

Response:

Ecology strongly disagrees that SCR technology is BART for the TransAlta Centralia facility. Ecology acknowledges that SCR may represent BART for a different facility. However, the

facts of the TransAlta facility show that SCR is far too expensive for the benefit achieved considering the controls that have already been installed.

It is important to remember that a BART determination is a multi-factor, fact-specific analysis. It does not require that a specific type of control technology be installed for all facilities. To be selected as BART, a control technology has to be available, technically feasible, and cost-effective, provide a visibility benefit, and have minimal potential for adverse non-air quality impacts. All of these factors have to be considered; no single factor is dominant.

As Ecology has more fully explained in the Technical Support Document for its draft BART determination for the TransAlta facility, when SCR is evaluated through the five factor BART analysis, it doesn't fall within acceptable limits for BART. Ecology agrees that SCR technology is available, technically feasible, and if implemented would provide a significant visibility benefit. However, there are several complicating circumstances that impede its application for the TransAlta facility.

First, there is inadequate physical space to locate a SCR control unit. As explained in the Technical Support Document for the TransAlta BART determination, "[t]he short distance between the boiler economizer and the entrance to the first ESP does not provide the room required for a catalyst bed with reasonable velocities to be inserted in the existing flue gas duct." (Draft Support Document for BART Determination for TransAlta Centralia Generation, LLC Power Plant, Centralia, Washington, revised April 2010, p. 15). This conclusion is based on the best professional judgment of the Ecology Air Quality Program's senior engineer, evaluating the space available and the velocities present in the boiler ducts. The modifications, duct rerouting, and structural support work required to install SCR in such a restricted footprint greatly increase the cost of the SCR controls, far exceeding the range of what is considered cost-effective under standard metrics. Ecology investigated these claimed costs for SCR in detail. The costs for the actual SCR equipment, catalyst beds, ammonia storage, injection systems, and operating controls, all fall within the costs expected for an installation on a boiler of this size. Based on this plus our knowledge of the construction difficulties at this facility that do not exist at other power plants, we concluded the costs identified by TransAlta appeared accurate.

As noted above, Ecology received more readily readable site drawings at larger scales for the administrative record. The larger scale allows easier analysis of the layout issues by non-engineers. In addition, in response to several comments, Ecology requested TransAlta to evaluate locating an SCR after the ESPs in the duct from the ESP to the Flue Gas Desulfurization (FGD) scrubber (a cold, clean location) and include the impacts of reheat. We have also requested the company to evaluate the installation of an SCR system in the duct between the boiler and the ESP inlet. The information supplied by TransAlta is discussed in the April 2010 revised draft Technical Support Document.

Section 3 of TransAlta's July 2008 BART analysis discusses the reasons for the higher than normal construction costs to install SCR at the Centralia plant. The discussion in the Company submittal starts on page 3-9. The TransAlta discussion doesn't indicate dimensions, but using the provided drawings in the report and information in the modeling report, indicates that the distance from the boiler outlet to the inlet of the first ESP is approximately 42 feet. This whole

distance is used to evenly distribute the flow from the boilers to the ESP inlet to allow for proper operation of the ESP. The diverging ducts from the boilers to the ESPs are also located between 70 and 100 feet off the ground.

As TransAlta has proposed, the only location to install an SCR unit without having to reheat the flue gas is on top of the first ESP. What is obvious from the proposal drawings (Figures 3-3 and 3-4) is that TransAlta's consultant did not fully consider how to get the boiler exhaust to the SCR units and back into the ESP and still provide for even flow distribution to the ESP. A quick review of Figure 3-3 also indicates other issues of the tight construction site.

Capital costs for SCR systems reflect more than the costs of catalyst, ammonia storage, ammonia supply, and injection control systems. These equipment costs vary based on the flue gas volume and NO_X concentration. As a result, these equipment costs are relatively uniform between installations. The most significant cost factors for this facility are the result of the density of existing emissions controls immediately adjacent to the boilers resulting in:

- The tight construction site.
- Potential difficulty in finding a location for ammonia storage that is safe, does not impede access to other components, or interfere with underground or above ground utilities and ducting.
- Elevated construction location.
- Difficulty in ducting exhaust gas from the boiler through the SCR units to the ESPs while achieving even flue gas distribution across the SCR catalyst beds and within the ESP.

The potential to remove first of the two series ESPs on each boiler and replace it with an SCR unit has been suggested as an alternative method to install SCR. While this seems to be an attractive option, the cost of destroying the existing ESP is part of the capital costs to install a new SCR system. Revising the ductwork for the remaining ESP, potentially having to relocate the induced draft fans, are other cost considerations. Equally, the lost revenue from sales of fly ash from the first ESP is a negative cost in the cost analysis.

Removal of the first ESP coupled with the history of the installation of the two series ESPs also brings into question the ability of the facility to meet its PM emission limitation.[1] Achieving the current PM emission limit is based on both ESPs in operation and does not anticipate any removal through the FGD system. The second ESP was not anticipated to accept the full particulate load from the boiler, only to remove enough of the remaining particulate from the exhaust of the first ESP to meet the particulate limit of 0.010 grain/dscf[2] (filterable PM only).

The lack of the two ESPs removing particulate is anticipated to contaminate the gypsum produced for sale to a level that prevents its resale, resulting in a cost to landfill the gypsum rather than receive compensation for the gypsum as a raw material. The lack of gypsum supply

[1] See Section 1 of the Technical Support Document for the 1997 RACT order for information on the history of the ESPs.
[2] As referenced in the 1997 RACT analysis support document, the series ESPs comply with the permit limit, but neither alone can meet the limit.

to the wall board maker that purchases the gypsum will also adversely affect the price of that company's primary raw material.

Weighing the above factors, Ecology determined that SCR is not BART for the TransAlta facility.

The commenter's further question "the unusually high boiler-out NO_X emissions at the TransAlta coal plant." Ecology disputes this characterization of TransAlta's emissions. TransAlta currently has installed LNC3 low NO_X burners for NO_X control; this technology is the presumptive BART control technology for NO_X designated by EPA. These combustion controls meet their anticipated emission reduction of 0.30 lb/MMBtu, about 1/3 reduction from the pre-installation actual emission rate of 0.45 lb/MMBtu. The emission limitation presumed by EPA for these controls is 0.15 lb NO_X/MMBTU. While the TransAlta facility's permitted emissions are double this amount, it is not an unusually high level. When EPA set the presumptive BART emission level for NO_X, there were relatively few data points. A review of BART determinations in the western U.S. indicate that the TransAlta facility's current emission rate and our BART determination is not out of line with what is being determined to be BART by other states for their coal-fired power plants (see table following the response to Earthjustice Comment 6).

6. Step 5 of the required BART analysis appears almost entirely absent from Ecology's process.

- Ecology did not question TransAlta's calculations that dilute the visibility improvement expected from SCR.
- The record is devoid of evidence describing how Ecology balanced cost and visibility improvement, or any support indicating that Ecology necessarily struck the correct balance.

Response:

Here are the five steps in a BART analysis as outlined by EPA in Appendix Y of 40 CFR Part 51:

Step 1 – Identify All Available Retrofit Control Technologies
Step 2 – Eliminate Technically Infeasible Options
- The identification of available and technically feasible retrofit control options.
- Consideration of any pollution-control equipment in use at the source (which affects the applicability of options and their impacts).

Step 3 – Evaluate Control Effectiveness and Costs of Remaining Control Technologies
Step 4 – Evaluate Energy and Non-Air Quality Impacts
- The remaining useful life of the facility.
- The energy and non-air quality environmental impacts of compliance.

Step 5 – Evaluate Visibility Impacts
- The degree of visibility improvement that may reasonably be anticipated from feasible control options.

Step 5 in the EPA guidance document requires a determination of the visibility improvement that could accrue from the imposition of a control technology. The definition of BART in the regulation lists the 5th factor in determining BART as:

> "The degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology." 40 CFR 51.301, definition of Best Available Retrofit Technology.

The analysis of the 5th factor is provided in Section 3 of the Technical Support Document, and the modeling analysis portion of TransAlta's BART analysis submittals. These analyses indicate that all control technologies evaluated in detail would provide a reduction in visibility impacts if installed and operated.

Under both the definition and the guidance from EPA, Ecology has a great deal of latitude to determine how to address the question of visibility improvement. In Section IV.5 of the BART Guidance Document, the state has "discretion to determine the order in which you should evaluate control options for BART. You should provide a justification for adopting the technology that you select as the "best" level of control, including an explanation of the CAA factors that led you to choose that option over the other control levels." Section 4 Ecology's Technical Support Document includes our analysis and rationale for selecting BART for this facility.

The costs of controls, energy impacts, non-air quality environmental impacts, and the visibility improvement were given equal weight in our analysis. Neither cost nor visibility improvement were given paramount importance in balancing the various factors in determining BART.

The cost calculations are not part of determining the degree of visibility improvement that might result from use of a particular control technology.

COAL-FIRED POWER PLANT BART DETERMINATIONS FOR NO_X IN PUBLICALLY AVAILABLE REGIONAL HAZE SIPS*

*Most states able to utilize CAIR are not represented on this list because they are mostly using CAIR as BART for those power plants.

State	Unit	NO_X Technology	lb/MMBtu 30-day average	Comments
EPA Region 8, Montana	Colstrip			No final decision publicly available
EPA Region 9, Navajo Reservation	Navajo			No final decision publicly available
	Four Corners			No final decision publicly available

State	Unit	NO_X Technology	lb/MMBtu 30-day average	Comments
Arkansas	Enbtergy Arkansas, Inc. White Bluff, Units 1 and 1		0.28 on bituminous coal 0.15 on sub-bituminous coal	Controls not given. Limits in State Regulation 19.1505
	SWEPCO Flint Creek Power Plant Unit 1		0.23	Controls not given. Limits in State Regulation 19.1505
California	No coal fired units subject to BART			
Colorado	Martin Drake Units 5 - 7	Install overfire air systems	0.39	Also limited to 0.35 lb/MMBtu, annual average
	CENC (Trigen) Unit 4	Limited by rule to combustion controls, LNC3	115 lb/hr	
	CENC (Trigen) Unit 5	Limited by rule to combustion controls, LNC3	182 lb/hr	
	Craig Unit 1	Limited by rule to combustion controls, LNC3	0.39	Also limited to 0.30 lb/MMBtu, annual average
	Craig Unit 2	Limited by rule to combustion controls, LNC3	0.39	Also limited to 0.30 lb/MMBtu, annual average
	Public Service of Colorado, Comanche Units 1 and 2	Low NO_X Burners	0.2	Also limited to 0.15 lb/MMBtu, annual average both units combined
	Public Service of Colorado, Cherokee Unit 4	Modify existing low NO_X burner and over fire air or install new burners	0.28	
	Public Service of Colorado, Hayden Unit 1	Modify existing low NO_X burner and over fire air or install new burners	0.39	
	Public Service of Colorado, Hayden Unit 2	Modify existing low NO_X burner and over fire air or install new burners	0.028	

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State	Unit	NO_X Technology	lb/MMBtu 30-day average	Comments
Colorado (cont.)	Public Service of Colorado, Pawnee Unit 1	Modify existing low NO_X burner and over fire air or install new burners	0.23	
	Public Service of Colorado, Valemont Unit 5	Modify existing low NO_X burner and over fire air or install new burners	0.28	
Idaho	No coal-fired units			
Kansas	La Cynge Generating Station, Unit 1 and 2	SCR on Unit 1, Controls as needed on Unit 2	0.13, both units averaged together	
	Jeffrey Energy Center, Unit 1 and 2	Low NO_X Burners	0.15	
Minnesota	MN Power, Taconite Harbor Boiler No. 3	ROFA/Rotamix (Mobotec)	0.13	
	MN Power, Boswell Boiler No. 3	LNB + OFA, SCR	0.07	
	Rochester Public Utilities, Silver Lake, Unit #3 boiler	No additional controls	No Limit	
	Rochester Public Utilities, Silver Lake, Unit #4 boiler	ROFA/Rotamix (existing controls)	0.25	
	Xcel Energy, Sherco, Boiler 1	LNB + SOFA + Combustion Optimization	0.15	
	Xcel Energy, Sherco, Boiler 2	Combustion Optimization	0.15	
	Xcel Energy, Allen S. King, Boiler 1	SCR (existing controls)	0.1	
	Northshore Mining, Silver Bay, Boiler 1	LNB + OFA	0.4	
Minnesota (cont.)	Northshore Mining, Silver Bay, Boiler 2	LNB + OFA	0.4	

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State	Unit	NO_X Technology	lb/MMBtu 30-day average	Comments
Iowa	Used CAIR for BART			
Louisiana	Used CAIR for BART			
Nebraska	Gerald Gentleman, Unit 1 and 2	Existing LNC3 on Unit 2, New LNC3 on Unit 1	0.23, both units averaged together	
	Nebraska City Station, Unit 1	LNC3	0.23	
Nevada	No coal-fired BART units			
New Mexico	San Juan Generating Station	No final decision publicly available		
North Dakota	Olds Unit 1	SNCR plus overfire air	0.19	
(All Lignite units)	Olds Unit 2	SNCR plus overfire air	0.35	
	Coal Creek Unit 1 and 2	Additional overfire air plus LNB	0.19	
	Stanton Unit 1	LNC3 plus SNCR for a 1/3 reduction	0.29	A 1/3 reduction
	Milton Young Station Unit 1	Advanced overfire air plus SNCR for a 58% reduction	0.36	
	Milton Young Station Unit 2	Advanced overfire air plus SNCR for a 58% reduction	0.35	
Oregon	Boardman	LNC3	0.28	Note SNCR to be installed by July 2014 @ 0.23 lb/MMBtu and SCR @ 0.07 lb/MMBtu required later. Neither is required as BART.
Oklahoma	OG&E Muskogee Generating Station Unit 4 and 5		0.15	
	OG&E Sooner		0.15	

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State	Unit	NO_X Technology	lb/MMBtu 30-day average	Comments
	Generating Station Unit 1 and 2			
	AEP/PSO Northeastern Power Station Unit 3 and 4		0.15	
Texas	No coal-fired BART units subject to BART			
Utah	Hunter Power Plant, Unit 1 and 2	LNC3	0.26	Replacing LNC1 burners and add 2 levels of overfire air under minor NSR program.
	Huntington Power Plants, Unit 1 and 2	LNC3	0.26	Replacing LNC1 burners and add 2 levels of overfire air under minor NSR program.
Wyoming	Naughton Unit 1	LNC3	0.26	Wyoming Long-term Strategy requires SCR @ 0.07 lb/MMBtu by 2018.
	Naughton Unit 2	LNC3	0.26	
	Naughton Unit 3	LNC3 plus SCR	0.07	
	Jim Bridger Units 1-4	LNC3	0.26	
	Dave Johnston Unit 3	LNC3	0.26	
	Dave Johnston Unit 4	LNC3	0.15	
	Wyodak Unit 1	LNC3	0.23	
	Basin Electric Units 1-3	LNC3	0.23	

Responses to comments from the United States Department of the Interior, National Parks Service:

1. TransAlta and Ecology did not evaluate alternative locations where SCR system could be installed such as between the ESPs and the wet scrubbers. That location will require reheating the gas stream, though fuel may not be significant as waste heat can be used to reheat the gas stream after the ESPs.

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Response:

As part of the initial review of this BART analysis, Ecology did not consider, or request TransAlta to consider, alternative locations to install an SCR system other than the cold, dirty location evaluated. An alternate location requested to be evaluated previously was in the duct between the boiler and the ESP inlet. To respond to several commenters who wanted this evaluation, Ecology requested TransAlta to evaluate locating an SCR after the ESPs in the duct from the ESP to the FGD scrubber (a cold, clean location) and include the impacts of reheat. The Technical Support Document has been revised to reflect the information supplied by TransAlta.

2. The emission limitation evaluated for SCR is not reflective of the capabilities of the control system. Ninety percent reduction easily accomplished, the emission rate used for cost-effectiveness does not reflect the 90% reduction achievable or the actual seasonal emission rates achieved by eastern power plants subject to seasonal NO_X reduction requirements for the ozone National Ambient Air Quality Standard (NAAQS). Suggest reasonable SCR emission limitations are applicable to this plant.

Response:

See response to Dr. Ranajit Sahu's Comment 1.

3. The SCR costs are overestimated and unsubstantiated. The EPA Control Cost manual has not been used as advised by EPA in the BART guidance. No information on source of vendor quotes. Did not use the methods and default factors included in the EPA Control Cost Manual to estimate costs. Instead used a model based on EPA's CUE Cost model. The NPS version of EPA's Control Cost Manual SCR cost method is provided to Ecology. No explanation of extra expenses and how the estimates were derived.

Response:

See responses to Dr. Ranajit Sahu Comment 1 and Earthjustice Comment 5.

4. Ecology should consider the cumulative effects of improving visibility at all 12 Class I areas affected within 300 km of the plant. Using cumulative visibility improvement results in a cost-effectiveness in line with other BART determinations made in the country.

Response:

The use of cumulative visibility effects is not reflected in the BART guidelines in 40 CFR Part 51, Appendix Y. EPA did not describe a method to utilize cumulative visibility changes as part of a BART determination process. Cost-effectiveness analysis using a metric like $/Deciviews (dv) is only a suggestion to consider in addition to standard $/ton pollutant reduced cost-effectiveness.

For cost-effectiveness, we are relying on a measure that we know and understand, the $/ton reduced. Between July 2005, when EPA issued the final BART guidelines until the fall of 2008 when the first proposal from the Federal Land Managers (FLMs) was developed on how to do a $/dv measure, no state was using this measure and EPA provided no guidance in how to perform the calculation. Ecology has chosen to follow the lead of essentially all other states in evaluating BART control costs on a $/ton reduced.

To complicate matters more, the September 2008 memorandum referenced by the USFS and the NPS proposes two variant methods to calculate cumulative dv, noting problems with each approach. An EPA Region 9 Federal Register notice concerning how Region 9 would evaluate visibility impacts from two power plants located on Navajo Tribal lands, proposed two more very different methods to implement a $/dv improved metric.

NPS documents appear to utilize variations on the approaches proposed in the September 2008 memorandum. Which is the correct method to use to determine $/dv improved? What is the cost-effectiveness threshold when using this approach? What is the basis for a $/dv cost-effectiveness threshold? The approaches proposed by the FLMs and EPA Region 9 do not supply the answers or indicate where they lie. The only source of information on what might be an appropriate $/cumulative dv improved cost value is a compilation of proposed BART determinations by Mr. Don Shepherd of the NPS. While informative, the compilation contains information from BART proposals, not the final determinations by individual states.

Separately, Ecology undertook a review of BART determinations included in regional haze State Implementation Plans (SIPs) submitted to EPA by western states. This review indicates no state has relied on the $/dv improved measure to make a BART determination. The SIPs that have been submitted and reviewed by Ecology all utilize the $/ton reduced metric for BART. Two of the SIPs reviewed seem to utilize a $/dv measure to support additional further progress emission reductions volunteered by or imposed on individual plants.

As a result of our review of the determinations by other states, Ecology is being consistent in using $/ton of pollutant reduced as the primary cost analysis measure to determine BART.

5. Ecology should evaluate cumulative visibility improvement from a control technology. Specifically, EPA Region 9 proposed two methods to consider cumulative visibility improvement methods. Wyoming evaluated cumulative visibility improvement for BART and reasonable progress determinations. Oregon considered cumulative benefits for the Boardman Power Plant SCR addition for reasonable progress.

Response:

See response to NPS Comment 4.
The Wyoming and Oregon SIP submittals do not reflect the use of cumulative visibility improvement as the determining factor for their BART determinations, only for determining reasonable progress. Oregon's BART determination is clearly based on a $/ton pollutant removed analysis.

Response to comments from the United States Department of Agriculture, National Forest Service:

1. Post combustion controls can do a better job of NO_X reduction and visibility improvement than what is proposed. Need to reconsider the value of visibility improvement and require additional controls through SCR or SNCR.

Response:

See responses to comments to NPS and Dr. Ranajit Sahu given above.

2. The proposed BART control does little to improve visibility at USFS Class I areas.

Response:

The proposed controls provide essentially the same degree of visibility improvement at the nearby USFS Class I areas as the adjacent NPS Class I areas. As noted in the Technical Support Document and in the BART analysis by the company, visibility improvements accrue at all Class I areas within 300 km of the plant as a result of implementing the proposed BART emission limits. One of the largest reductions from the proposed BART controls at TransAlta occurs at the Goat Rocks Wilderness, a USFS Class I Area.

3. Actual SO_2 emissions are far less than the permitted emissions. In 2008 reported to be 2318 tons per year compared to the permitted rate of 10,000 tons per year. While 2008 the plant operated only at 80% capacity, if a limit based on the 2008 actual emissions and 100% capacity, an emission limit reflecting 100% capacity would be approximately 2918 ton SO_2 per year. Ecology should establish a new emission limit for SO_2 from this plant.

Response:

The SO_2 emission limit of 10,000 tons per year has been determined by EPA to be BART for SO_2 from this facility. To reduce the SO_2 emission limitation below this level will have to be accomplished outside of the BART Compliance Order.

4. Ecology determined SCR to be technically feasible, but did not select it as BART due to costs on a $/ton removed basis. The SCR cost presented is accurate at a -20% / +50% level in contrast to the expected accuracy of ±30% in the EPA Control Cost Manual.

Response:

Ecology considers the EPA Control Cost Manual, EPA's newer control technology cost analysis software (CUECost), and the cost analysis produced by TransAlta's consultant to be equivalent in level of accuracy. The consultant's cost analysis tool is used on a routine basis by the consultant for other clients and in producing BACT determinations.

5. SCR Costs evaluated on a 15-year period contrasted with the 20-year lifetime in the Control Cost Manual and TransAlta's May 2008 response to comments.

Response:

The 6th edition of the Control Cost manual uses a 20-year lifetime for an SCR system. The 15-year period is reasonable for other reasons and the difference in annual cost from the 5-year difference is small.

State actions outside of the Regional Haze process will have an effect on the expected lifetime of this facility. Most notable is a Governor's Executive Order that requires Ecology to work with TransAlta on an agreed order that would reduce the emissions of greenhouse gases from the plant to meet the requirements of the Greenhouse Gas Emission Performance Standard in Chapter 173-407 WAC by 2025. In order to meet that standard, the plant will have to be functionally replaced by another generation source, have installed ad-on carbon dioxide capture technology, and have started sequestering that collected carbon dioxide. In either case, the lifetime of the facility and any new add-on emission controls are anticipated to be limited.

Since the agreed order required by the Governor's Executive Order has not been developed and signed, we have to assume that the lifetime of the plant is not a consideration in the calculation of cost-effectiveness for this facility.

6. Using $/ton of pollutant reduced offers no consideration of visibility improvement, let alone cumulative impacts at multiple Class I areas. While the BART guideline does not offer specific guidance on how to consider visibility in assessing cost-effectiveness, the guideline does mention the use of a metric such as $/dv. The FLMS developed draft guidance in Sept. 2008 and provided it to Ecology for its consideration. In addition, EPA region 9 developed a different methodology on proposed for consideration of visibility improvement in cost-effectiveness. The NPS has compiled proposed and final BART determinations that they have received. The cumulative cost-effectiveness from those proposed and final BART determinations show cumulative cost-effectiveness of $0.6 million/dv to $15.3 million/dv. Using this background, the cost-effectiveness of SCR is $8.5 million/ dv (sum of 98th percentile across all affected Class I areas) is reasonable and SCR is cost-effective. We advocate that Ecology reconsider the cost-effectiveness of SCR and the potential benefits.

Response:

See our responses to the NPS Comment 4.

7. Ecology should quantify the visibility improvement likely to occur from implementation of the Flex Fuels project both the SO_2 and the NO_X reductions that are proposed. Using only the visibility reductions from the NO_X reduction underestimates the actual visibility improvements anticipated.

Response:

After the public hearing, we requested that TransAlta analyze the expected visibility benefits from use of the Flex Fuels project using both the NO_X reduction and the anticipated SO_2 reduction resulting from use of the Flex Fuels project and PRB low sulfur coals. The use of PRB coals is anticipated to result in a reduction of 1,287 tons/yr from baseline SO_2 emissions rates. With the effect of the SO_2 reduction included in the modeling analysis, the minimum visibility improvement at a mandatory Class I Area is projected to be 0.067 dv. The modeling is discussed in Draft Support Document for BART Determination for TransAlta Centralia Generation, LLC Power Plant, Centralia, Washington, revised April 2010, p. 19.

8. Provisions associated with the BART determination (in the mediation agreement) should be separated from the voluntary mercury reductions to remove the non-enforceability provisions intended to cover the voluntary mercury reductions.

Response:

The BART determination language in the mediation agreement will be superseded by the BART regulatory order to be issued to the facility. As a result, the "non-enforceability" considerations of the BART portions of the mediation agreement go away.

9. Ecology should not limit itself from opportunities to reduce haze-causing emissions at the TransAlta Centralia plant for the next 20 years.

Response:

The mediation agreement does not limit our ability to come back to TransAlta for additional reductions in the context of reasonable progress toward meeting the visibility goal. The agreement only provides that through 2018 we will not impose any new requirements as a result of regional haze requirements. Such requirements could be imposed as part of the long-term strategy included in the 2018 regional haze SIP.

Response to consolidated comments in Form Letter #1, Sierra Club Members:

1. The Clean Air Act requires power plants to reduce haze-causing pollutants, including nitrogen oxides, and toxic chemicals like mercury. Washington should require the most effective pollution controls to reduce TransAlta's nitrogen oxide and mercury emissions. Without these controls, the Centralia coal plant will continue to unnecessarily obscure views and contaminate water and wildlife in our national parks and wilderness areas for decades to come.

Response:

Thank you for your comments on the proposed Settlement Agreement and Consent Decree between the Washington State Department of Ecology and TransAlta regarding the company's coal-fired power plant near Centralia.

Staff members with Ecology's Air Quality Program reviewed your comments and offer these responses:

Sufficiency of nitrogen oxide controls: Staff analysis of the TransAlta facility near Centralia concludes that the terms of the Settlement Agreement satisfy requirements for Best Available Retrofit Technology (BART). BART is the standard that applies to this facility. Under BART, the selection of an emission control technology is based on a multi-factor analysis. These factors include non-air quality impacts, visibility impacts, cost of the equipment, and remaining expected plant life.

It is important to note that many of coal-fired power plants that are reporting 80 to 90 percent emission reductions did not have emission controls prior to the installation of this technology.

In addition, many of the 80 to 90 percent mercury reductions required by jurisdictions outside Washington only apply to new facilities, with lower or no requirements for existing facilities.

Thank you again for your comments and for your interest in helping to protect Washington's air quality and environment.

Response to consolidated comments in Form Letter #2, Sierra Club Members:

1. From health care professionals to park rangers to fishermen, the Washington public has grave concerns about what this plant generates in our communities. As the State's largest polluter for global warming, mercury and haze (from nitrogen oxide pollution), the cumulative impact of this plant affects Washingtonians from every walk of life. The State should not move forward with the Settlement Agreement as proposed until a more substantive review can take place.

There are three main problems with this Settlement Agreement with regard to haze as it now stands:

1. This agreement is insufficient in controlling nitrogen oxide, the main cause of haze in our national parks and wilderness areas.
2. The pollutant-by-pollutant process has distorted the pollution impacts of this plant on public health.
3. The public process has been insufficient.

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Response:

Thank you for your comments on the proposed Settlement Agreement and Consent Decree between the Washington State Department of Ecology and TransAlta regarding the company's coal-fired power plant near Centralia.

Staff members with Ecology's Air Quality Program reviewed your comments and offer these responses:

1. **Sufficiency of nitrogen oxide controls:** Staff analysis of the TransAlta facility near Centralia concludes that the terms of the Settlement Agreement satisfy requirements for Best Available Retrofit Technology (BART). BART is the standard that applies to this facility. Under BART, the selection of an emission control technology is based on a multi-factor analysis. These factors include non-air quality impacts, visibility impacts, cost of the equipment, and remaining expected plant life.

2. **Plant impacts on public health:** A pollutant-by-pollutant approach is the only applicable scientific standard. At this point, no scientific method has been developed to measure combined pollutants' interactions and effects.

3. **Sufficiency of public process:** The State of Washington entered into confidential mediation on these issues at TransAlta's request. Mediation enabled the State to avoid potentially lengthy and costly litigation over these issues. Once the proposed Settlement Agreement was near completion and announced publicly, Ecology began its normal public participation process, which included a formal public comment period and a public hearing.

Thank you again for your comments and for your interest in helping to protect Washington's air quality and environment.

Response to testimony from October 14, 2009, Public Hearing on proposed TransAlta mediation agreement:

Mark Quinn, Washington Wildlife Federation:

Thank you for your views. The Governor's Executive Order, 09-05 plus the program in Chapter 70.235 sets up an approach to reducing our states greenhouse emissions and promoting 'greener' energy sources. One element of the Executive order directs the Department of Ecology to work with TransAlta to establish an agreed order for the company to reduce its emissions to meet the greenhouse gas emission requirement in Chapter 80.80 RCW by 2025.

Randy King, Superintendent Mt. Rainier Natl. Park:

Thank you for your views. As noted in our presentation at the hearing, Ecology is concerned with the mercury emissions from the facility and has worked with the company on a voluntary approach to reduce the emissions on a schedule that is faster than would be accomplished by

waiting for EPA to complete new rules. We have addressed the concerns about the level of NO_X control more thoroughly in our response to written comments.

Johnathan Smith, Maia Face, Adam Fleisher:

We acknowledge your views that the mediation agreement doesn't result in enough mercury control, and that the nitrogen oxides reduction proposal in the BART order is inadequate. Ecology respectfully disagrees with your assessments, as more fully described in the responses to written comments.

Shane Macover:

When issued as final documents, the mediation agreement and BART order will be legally binding and enforceable documents, not listings of voluntary actions.

Janette Brimmer, Earth Justice:

Thank you for your views on nitrogen deposition, and climate change. Your oral comments on the BART determination and mercury control and other aspects of the Mediation Agreement are covered by our responses to written comments.

Donna Albert:

We appreciate your thoughtful views on the subject of coal free electric power and stopping the ongoing climate change.

Doug Howell, Sierra Club:

Thank you for your views on the Confidential Mediation process and your views of what would constitute adequate public involvement. Your direct questions and concerns about the Mediation Agreement and its content and process are covered in response to Earth Justice's written comments.

Your concerns about the Air Operating Permit process are outside of the scope of this hearing. Your concerns about greenhouse gas emissions from the TransAlta facility are outside the scope of this hearing, but are being addressed through the process included in the Governor's Executive Order 09-05.

Ecology's Response to Comments on the Draft TransAlta BART Technical Support Document and Compliance Order

Appendix

Written Comments and Hearing Transcript

Comments on

TransAlta Coal-fired Power Plant, Centralia, Washington

Preliminary BART Determinations for NOx and Proposed Voluntary Mercury Reduction

By

Dr. Ranajit (Ron) Sahu

1. I have been asked by the Sierra Club to review the ongoing assessment of the Washington Department of Ecology of existing and proposed controls of Nitrogen Oxide ("NOx") emissions from the coal-fired power plant located in Centralia, Washington and owned by TransAlta Centralia Generation, L.L.C. ("TransAlta"). I have also provided comments on the proposed voluntary mercury reduction program at Centralia.

2. My background and qualifications are as follows: I have a Bachelor of Technology Degree with Honors from the Indian Institute of Technology, and a Masters of Science in Mechanical Engineering and Ph.D. in Philosophy, both from the California Institute of Technology. I have over 18 years of experience in the fields of environmental, mechanical, and chemical engineering including program and project management services as well as design and specification of pollution control equipment. In that time I have successfully managed and executed numerous projects. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involved the communication of environmental and technical data to the public. I have provided and continue to provide consulting services to numerous private sector, public sector, and public interest clients. My clients over the past 18 years have included steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, various manufacturers of equipment, chemical distribution facilities and various public sector entities such as the Environmental Protection Agency, U.S. Department of Justice, California Toxic Substances Control, municipalities etc. I have performed projects in 45 states. In addition to my consulting work, I have taught and teach numerous courses at several Southern California universities, including University of California at Los Angeles (air pollution), University of California at

Riverside (air pollution and process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management).

3. I have reviewed a number of documents from TransAlta, consultants retained by TransAlta, and from the Department of Ecology, including analysis and reports by CH2M Hill and Black and Veatch. I have also had one telephone conversation with Mr. Al Newman of Ecology. Unfortunately, it appears that a number of documents that are relevant to the consideration of NOx controls have been withheld by the Department of Ecology which has hampered my ability to be sure that I have all the relevant information and it has hampered my ability to fully analyze emissions and control technologies for the TransAlta Centralia facility (the "Plant").

NOx BART

4. The electrical output of each of the two boiler units at the TransAlta coal-fired power plant located in Centralia, Washington, is 702.5 MW net.[1] The units are tangentially fired and currently use Powder River Basin ("PRB") coals. They are anticipated to use PRB coals for the foreseeable future. TransAlta and the Department of Ecology claim that Best Available Retrofit Technology ("BART") for NOx emissions from each boiler is the current set of combustion controls (called the "LNC3" combustion controls) along with the completion of the "Flex Fuels" project (so characterized by TransAlta) and the full use of PRB coals.[2] The expected NOx emissions reduction is around 20% of current (0.3 lb/MMBtu) emissions based on modeling conducted by the applicant. Thus, the expected post-Flex Fuels NOx levels are expected to be approximately 0.24 lb/MMBtu. Since the units already have the set of combustion controls (low NOx burners, close-coupled and separated OFA installed during 2000-2002) and already fire PRB coals, the expected 20% reduction is to accrue from the Flex Fuels project, which appears

[1] While there is no discussion of reduction of the Unit ratings in this matter, the applicant notes in its December 2008 submittal that it evaluated NOx emission rates for the "…maximum potential sustainable load (663 MW)…" It is not clear why the Vista modeling would be limited to this lower net load, nor it is clear if the imputed NOx reductions of 20% would be sustained at the higher and current maximum load of 702 MW. Ecology or the permitting entity should clarify this issue and analyze whether the 20% would actually be sustained at the higher load of 702 MW.

[2] It appears that the facility has been using PRB coal for quite some time and almost exclusively since late 2007.

to be something the Plant already wants to do for other reasons and which appears to have been a project the Plant was working toward since closing the Centralia mine around 2006. Thus, BART is to be met with no additional incremental effort at NOx reduction by TransAlta. Not surprisingly, the Plant collectively has significant visibility impacts for a number of Class I areas, even after implementation of the NOx BART option proposed by TransAlta that Ecology appears ready to accept.

5. From the description provided, it does not appear that the Flex Fuel project is geared towards NOx controls, per se. While combustion modeling may indicate that there may be a 20% reduction in NOx from Flex Fuels, this is incidental to the overall goals of what is essentially an efficiency improvement project. Unfortunately, no technical details for this combustion modeling are available on the record in order to determine the appropriateness of the assumptions made, and the overall usefulness or accuracy of the analysis.[3] It is therefore clear that Ecology has not reviewed the combustion modeling analysis. Even if, contrary to what appears in the file (see detailed discussion of NOx analysis below), the Flex Fuels project could be regarded as a NOx-reduction project, the record is wholly insufficient to know and understand whether a 20% reduction is at all realistic or meaningful.

6. The major error in the BART analysis is the rejection of Selective Catalytic Reduction ("SCR") as the NOx control option for the boilers. Although Ecology erroneously declares SCR to be technically infeasible, it is clear from the applicant's analysis and Ecology's own summary (see Table 2-1) that SCR is a technically feasible option.[4] The only impediment to its installation seems to be "…the lack of room…" at the boilers for an easy SCR installation. Although TransAlta claims that the configuration is tight, there is scant engineering detail regarding the congestion. In response to Ecology's questions regarding SCR as discussed in the initial BART application, the applicant provided three figures (3-3 through 3-5) in its revised BART application purporting to support its contention that space was unavailable for the SCRs. Specifically, see question 14 in Ecology's April 25, 2008 letter to TransAlta. In response, on

[3] Personal communication with Mr. Newman of Ecology, October 2009.

[4] Ecology notes in Section 4.1 of its January 9, 2009 document that "…the Flex Fuels project and SNCR are the only technically feasible controls…."

May 23, 2008, CH2M Hill notes that "the revised BART analysis will provide a more detailed explanation." The additional detail was apparently the three figures 3-3 through 3-5 in the revised July 2008 application, which figures are inadequate to support or assess the assertions regarding physical limitations. Simple examination shows that these figures do not contain anywhere near the level of detail that Ecology asked for or would be needed to make a proper engineering assessment of the space or retrofit difficulty for SCR. These figures, at the scales provided, simply do not make the case that space may or may not be available for SCR. They certainly do not make the case for an engineering assessment of the degree of difficulty of the retrofit. Figure 3-3 is a plan view of the entire facility in which the scale and distances are barely legible. Figure 3-4 is an elevation with illegible details and a SCR box pasted onto the figure. Figure 3-5 is a photograph showing one single side view perspective of the connection between Unit 1 and its ESP. Collectively, they do not provide any details as to where the applicant assumed the one-SCR or two-SCR options would be located, the length of piping runs in the modified configuration, etc. In addition, the application does not discuss the potential for moving or re-configuring existing equipment (such as the ESPs) or piping runs that would render the retrofit less problematic. In order to do a proper evaluation of the SCR option, several details need to be provided as discussed below.

7. A fundamental question is the level of NOx emissions from the boilers themselves, prior to any control. As noted earlier, the current boiler NOx emissions are approximately 0.3 lb/MMBtu, dropping to 0.24 lb/MMBtu or so with the implementation of the Flex Fuels project. However, these emissions are still too high given what we know is happening elsewhere in the industry. Numerous existing PRB-fired coal boilers, currently operating (and operating for at least the last 5 years or more) have much lower boiler out NOx emission rates – generally well below 0.15 lb/MMBtu. A survey of the EPA's acid rain database[5] shows, for example, lower NOx levels from pulverized coal boilers, including Scherer Units 1-4 (Georgia), Labadie Units 1-4 (Missouri), Rush Island Units 1-2 (Missouri), Meramec Units 1-2 (Missouri), Newton Units 1-2 (Illinois), and Deely Units 1-2 (Texas). Each of these older units burns PRB coals, from

[5] www.epa.gov/airmarkets

various mines in the PRB with likely considerable variability in the coal nitrogen content,[6] and none of these units uses SCR or SNCR so their NOx emission levels reflect the use of low NOx burners and other strategies (such as OFA) in the boiler itself – strategies that TranAlta claims it uses effectively at the boilers in question. Tables 1-6 provide the data.

8. It should also be kept in mind that the units referenced above are not subject to stringent NOx permit limits and are therefore not carefully maintaining NOx performance. In other words, likely even lower NOx emissions from the boiler are possible, with careful control or with the use of adaptive combustion controls such as NeuCo. Nonetheless, it is obvious from Tables 1-6 that boiler-out NOx emissions from a well controlled and operated PRB coal combustion unit should be no more than 0.10 to 0.15 lb/MMBtu. Within this range, as the data shows, it should be possible to achieve levels closer to or lower than 0.10 lb/MMBtu.

9. Further support for these levels of boiler-out NOx levels is provided in many recent technical papers that were not discussed in the record and in the development of the BART limits. Examples of these include:

- G.T. Bielawski, et. al., "How Low Can We Go? Controlling Emissions in New Coal Fired Power Plants," U.S. EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Symposium: "The Mega Symposium," August 20-23, 2001 Chicago, Illinois, U.S.A. This paper states that "For PRB coal, emission levels down to 0.008 lb/MMBtu NOx , 0.04 lb/MMBtu SO_2, and 0.006 lb/MMBtu particulate with a high level of mercury capture can be achieved."
- A. Kokkinos et al., "Which is Easier: Reducing NOx from PRB or Bituminous Coal, Power 2003." This paper discusses retrofits at Georgia Power Company's Plant R.W. Scherer Units 3 and 4 (which burn PRB coal) with separated over fire air. The paper shows that Units 3 and 4 achieved 0.13 lb/MMBtu of NOx after the retrofit.
- Robert Lewis, et al., Summary of Recent Achievements with Low NOx Firing Systems and Highly Reactive PRB and Lignite Coal: as Low as 0.10 lb NOx/MMBtu

[6] As such, these NOx levels should also be achievable using the 50:50 blend coals that may be used as the alternate fuel in the proposed unit.

- Patrick L. Jennings, Low NOx Firing Systems and PRB Fuel; Achieving as Low as 0.12 LB NOx/MMBtu, ICAC Forum 2002.
- T. Whitfield, et al., Comparison of NOx Emissions Reductions with PRB and Bituminous Coals in 900 MW Tangentially Fired Boilers, 2003 Mega Symposium.
- Galen Richards, et al., Development of an Ultra Low NOx Integrated System for Pulverized Coal Fired Power Plants. This paper noted that use of the TFS 2000™ firing system achieved NOx emissions of 0.11 for PRB coals or approximately 70-75% reduction over the baseline NOx emissions. Additional NOx reduction of approximately 0.03 lb/MMBtu over the optimized TFS 2000™ levels was achieved using the Ultra-Low NOx firing system technology.

10. None of this was discussed or compared in the development of the BART analysis. It is striking that the Ecology did not review the technical literature above or the performance of other comparable PRB-fired units in assessing the NOx BART emissions levels. It would also appear that when Ecology asked TransAlta as to why their NOx emissions from the boilers was so high (i.e., 0.3 lb/MMBtu), that TransAlta had no technical answer or response.[7] In any case, there is no support for the contention that the boiler out NOx emissions levels should be as high as even 0.24 lb/MMBtu when using the supposed controls that the boilers have, along with firing PRB coals. Rather, it should be closer to 0.10 lb/MMBtu, especially for a well-run, baseload unit. This is a crucial component of NOx control and BART analysis that this plant and Ecology simply have not done.

11. The issue of boiler-out NOx emissions is crucial, not just for understanding and requiring best controls for NOx with existing technology, but also because minimizing boiler NOx emissions will require less NOx control after the boiler using add-on approaches such as SNCR or SCR. In particular, the impact on SCR will be considerable. For example, at a minimum, if the boiler-out NOx emissions are kept to the levels outlined above, it will mean that the subsequent SCR could be smaller in size, obviating or greatly reducing any of the space constraints that are claimed to be a problem at the Centralia facility. For example, there is no

[7] Personal communication with Mr. Newman of Ecology, October 2009.

analysis of how much SCR catalyst would be needed for various levels of NOx reductions, for example 90%, 80%, 70%, or even just 50% more than achieved with the boiler-out control levels discussed above. Even at 50% reduction, which would require the least amount of catalyst, the combined boiler-out NOx level of 0.10 lb/MMBtu and 50% reduction would result in a NOx emissions level of 0.05 lb/MMBtu, which is approximately a fifth of the current BART proposed limit of 0.24 lb/MMBtu. Such a reduction will also reduce NOx-related visibility impacts from Centralia by approximately 80%.The space and weight requirements for a 50% reduction SCR would be far smaller than a 90% or 80% reduction SCR. Yet, this crucial aspect and interconnectivity between boiler-out NOx emissions and SCR size seems to be entirely absent in TransAlta's analysis or Ecology's review. For this reason alone, it is premature to disregard and set aside SCR as has been done in TransAlta's BART analysis and Ecology's approval of it.

12. In fact, all of the arguments or rationales regarding physical space configurations at the existing Plant against a properly-sized SCR are not actually issues associated with the technical feasibility of SCR, but rather issues of how much TransAlta is willing to spend to adequately control NOx emissions. Further, on the issue of cost effectiveness of SCR for the Plant, the cost assumptions in TransAlta's materials do not appear to be tied to the supposed retrofit difficulty, since there is no supporting documentation for the size of the SCR, the physical limitations at the plant, or associated costs. The assertions are unsupported and the connections are not transparent. Yet, Ecology seems to have accepted the applicant's initial and revised cost assessments without question, a failure of Ecology's obligations relative to BART determinations. Numerous questions remain that must be answered and examined in order for Ecology, the permitting entity, and importantly, the public, to assess TransAlta's claims that SCR control technology is not BART, including:

(i) what was the boiler-out NOx emissions and why (especially in view of the discussion presented above)?

(ii) what was the basis for the SCR size used in the analysis?

(iii) what was the basis for the SCR cost estimates in the initial application, where the costs were ascribed to "vendor"?[8]

(iv) Who or what vendors provided data? What type of data were provided by the vendors? Were the vendors provided with engineering drawings (as opposed to Figures 3-3 through 3-5) in order to develop costs estimates?

(v) Why was the capital cost of two SCRs double that of one SCR? Two SCRs would or could share several components such as the reagent storage system, etc., making a simple "doubling" highly unlikely (further demonstrating cursory, as opposed to analytical, review by Ecology.)

(vi) What is the basis of assuming that construction costs and balance-of-plant (items not defined) costs are each an additional 50% of the SCR capital cost?[9]

(vii) What is the basis of the 16% surcharge?[10]

(viii) Finally, what was the basis for assuming that the NOx level with SCR would be 0.07 lb/MMBtu. Even with the current (or pre-Flex Fuel) NOx level of 0.30 lb/MMBtu and an SCR efficiency of 90%, the outlet NOx level would be 0.03 lb/MMBtu. Or, as discussed above, the combination of a boiler-out NOx emissions level to 0.1 lb/MMBtu and use of a 50% reduction SCR would result in a NOx emission level of 0.05 lb/MMBtu. Just dropping the NOx level from 0.07 lb/MMBtu to 0.03 lb/MMBtu or 0.05 lb/MMBtu would lower the calculated cost effectiveness, bringing it down to the range of acceptable cost-effectiveness, all other factors kept constant. Yet, this final NOx level was not examined critically by Ecology. Based upon what is readily known regarding SCR or combined SCR and boiler-out controls, NOx should be lower and therefore visibility more improved, than indicated by TransAlta's analysis, accepted by Ecology. Further, there is no detail or support for why the baseline NOx emissions level of 0.30 lb/MMBtu could not be significantly lower. It appears from what is known, to be wholly inaccurate and/or inflated.

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[8] January 2008 BART Analysis for Centralia Power Plant, pp 43/80 (.pdf version). The SCR capital cost is noted as 204 million dollars and the Factor/Source is listed as 'Vendor," with no further explanation or detail that can be verified.
[9] Ibid.
[10] Ibid.

(ix) While cost is one factor in the BART determination, it must be weighed against visibility and the importance of preserving Class I resources. Ecology should give a detailed explanation of how it balanced these factors, and how it arrived at the final balance of these factors specific for the TransAlta facility at Centralia. In particular Ecology or the permitting entity should also clarify what the acceptable cost-effectiveness limit is for NOx.

(x) Why did the "vendor" basis change in the revised July 2008 application to CH2M Hill? How did the consultant CH2M Hill obtain its base cost estimates for SCR? Why are the form of the costs different than how costs were presented in the January 2008 analysis? Why are the SCR costs higher in the July 2008 analysis? What was or what were the retrofit factors that may have been applied to inflate the base costs for SCR? What was the basis for the retrofit factors? How were they supported by actual field conditions? What was the geometry and location for the single SCR (on one boiler) and two SCR configurations? Also, all of the questions posed earlier regarding the level of NOx after SCR (i.e., 0.07 lb/MMBtu) are also applicable.

(xi) What was the size or sizes of the SCRs assumed in the analysis? How many catalyst layers were assumed to be present? What are the details regarding the reagent and reagent processing or handling? Answers to these and related types of questions affect the physical layout, the degree of retrofit ease, and the costs of the project.

13. There seems to have been much confusion regarding the choice of baseline periods. Even though TransAlta initially accepted 2006-2007 as the proper baseline for cost effectiveness, in its December 2008 submittal, the applicant seems to have backtracked. While noting that the 2006-2007 period was "not representative" because "…emissions….were lower on average…than more representative periods…" and that there was "…emissions variability…" the applicant provides nothing factual or specific. It simply selects 0.30 lb/MMBtu as the baseline. While the actual impact of this may be small, Ecology should provide a thorough discussion regarding baseline in its Determination Document. The January 9, 2009 document does not discuss this issue in any detail.

14. Ecology notes that Transalta "continues to investigate" the use of neural net controls such as by NeuCo or others as a "potential supplementary or polishing" technology. It is not clear if such technologies will be implemented or not. Utilities have routinely expected and obtained 10-15% additional NOx reduction by implementing such techniques. It is not clear why these technologies are any less reliable in predicting NOx reduction than the Flex Fuel project. In the latter, the imputed NOx emissions derive from computational modeling of the project modifications – and do not appear to result from any specific changes to hardware. As such, it is not clear why Ecology would not expect and assume a further 10-15% NOx reduction from the implementation of neural net technology implementation.

15. Without answers to the above and related questions, it is simply impossible to verify the applicant's cost (and resulting cost-effectiveness) assumptions, and it appears that Ecology did not do so. As a result, without much greater detail in the record, it is entirely premature and incorrect to reject SCR as the BART choice for these two units. In combination with the expected 0.24 lb/MMBtu that would result from the existing controls and Flex Fuel, SCR at even 90% efficiency would imply a NOx emission rate of 0.024 lb/MMBtu. Or, in combination with a boiler NOx emissions level of 0.1 lb/MMBtu, a far smaller SCR would still provide a NOx emission level in the same range. These vastly reduced emissions would significantly lessen the adverse visibility impacts of the plant on numerous Class I areas, a key component of BART. As noted earlier, all NOx related visibility impacts from Centralia should be reduced by 80% or so.

16. From my analysis of the file, it is my opinion that SCR cannot be ruled out as BART for the Plant. Given the current very large, adverse impacts from the Plant to numerous Class I areas, Ecology's review and acceptance of the applicant's meager and unsupported analysis regarding SCR is puzzling, and not in keeping with BART and visibility requirements.

17. In view of the fact that SCR has not been properly analyzed, it is premature to focus any significant attention on the next lower control, namely SNCR. While EPA has provided extensive comments to Ecology relating to SNCR, it is improper to focus the control discussion on SNCR as opposed to SCR. Plainly, SNCR will cause greater emissions of ammonia as

opposed to SCR resulting in additional production of secondary nitrate aerosols with attendant visibility impacts. Also, SNCR NOx reduction levels will be far smaller than those which can be obtained from the use of SCR.

18. Ecology acknowledges a 5-step BART process (see January 9, 2009 BART Determination Support Document, Section 1.1). As can be seen above, Ecology has not properly completed that process. Also, as part of the 5-step BART process, Ecology notes that the state can consider additional controls beyond those that are available, but is not required to do so. This one plant has a significant impact on many Class I areas, and therefore Ecology must consider using its authority to consider additional controls. If Ecology does not do so for this Plant, it raises serious question regarding whether Ecology will consider adequate controls to address visibility impacts from any emissions in Washington state.

19. There is a question regarding whether the Flex Fuel project might trigger New Source Review ("NSR") that must be examined by either or both the permitting entity and Ecology. Ecology's summary contains contradictory statements. On page 10 of 25 of the January 9, 2009 document, it states that "[T]he Flex Fuel project….does not increase the boilers' potential steam generating capacity." Yet, later on the same page, it also states that "[T]he lower nitrogen content of the PRB coals combined with the lower total quantity of fuel required to produce the same heat input to the boilers along with the potential for additional steam production after the project has been completed…." TransAlta, the permitting entity and Ecology should clarify whether the Flex Fuel project is a purely efficiency driven project in which heat input and emissions will not increase or if it involves debottlenecking the boiler island in any manner. If the latter is possible, Ecology must examine the NSR aspects of this project.

Proposed Voluntary Mercury Reduction

20. It appears that TransAlta has committed to a voluntary emissions reduction effort with regards to mercury. The entirely voluntary effort also includes significant constraints, such as aiming for a goal of only 50% mercury reduction and a constraint of TransAlta not spending

more than 3 million dollars per year to achieve mercury reductions, regardless of whether the 50% is ultimately achieved.[11]

21. Based on conversations with Ecology,[12] it appears that TransAlta has completed and is in the midst of completing pilot and additional tests involving a variety of sorbents, boiler injection chemicals, and injection strategies in order to determine its path forward with regards to mercury reduction. Since none of the details, including results, of such tests are available, either to the public or to Ecology,[13] comments cannot be provided on any of these aspects.

22. However, it is clear that the stated goal of 50% mercury reduction, to be achieved at TransAlta's "sole discretion"[14] is a travesty. Far greater mercury reduction (over 90%) has been and can be obtained from PRB coals, as discussed below. It is not clear why Ecology feels that a goal of only 50% mercury reduction is acceptable.

23. Greater than 90% mercury removal has been achieved on a long term basis at PRB coal-fired power plants with activated carbon injection. For example, the Holcomb Unit 1 power plant, which burns PRB coal, achieved 93% mercury control in long term testing.[15] In addition, over a year of continuous mercury CEMS data is available for the WE Energies Presque Isle facility in Michigan, which burns PRB coal, and these data demonstrate that over 90% mercury control has been achieved on a continuous basis. This site is a Department of Energy test site, and the data is thus publicly available. Some of this data has been summarized in presentations and published articles[16]. Furthermore, at least two other full-scale, long-term mercury control demonstrations have been reported to continuously achieve 90%+ mercury control: at Rocky Mountain Power (Hardin) in Montana,[17] and at the Comanche Station in Colorado,[18] both of which burn PRB

[11] See Ecology/TransAlta Settlement Agreement, Section B.4.
[12] Personal communication with Mr. Newman, October 2009.
[13] Ibid.
[14] Settlement Agreement, Section B.7.c.
[15] Sjostrom, Sharon, Evaluation of Sorbent Injection for Mercury Control, DoE Report Number 42307R27, December 2008.
[16] TOXECON™ Tests at PIPP Continue Successfully, PRECIP Newsletter No. 397, February 2009.
[17] Amrhein, J., Results of a Long-Term Mercury Control Project for a PRB Unit with an SCR,Spray Dryer and Fabric Filter, 11th Annual EUEC Conference and Expo Tucson, Arizona, January 30, 2008.
[18] Colorado Air Toxics Meeting Comanche 3 Project Update, Pueblo, CO, May 2009.

coal. It would also appear that Ecology was well aware that 90% mercury reduction is being obtained at numerous locations at US coal-fired power plants based on documents obtained from Ecology.[19]

24. The record does not appear to contain details of the current mercury levels in the PRB coal that is burned at the TransAlta boilers. Therefore, there is no discussion of what the expected mercury levels will be after TransAlta's voluntary effort (assuming, given its wholly-voluntary nature, that any reductions occur.) Providing this information (in lb/GW-hr or lb/TBtu) would allow for a direct comparison of the mercury emissions levels at other comparable PRB burning facilities.

25. For comparison purposes, we provide the mercury levels, tested back in 1999, as part of EPA's Information Collection Request (ICR), at various coal-fired power plants.

Unit	**1999 ICR Mercury Emission Rate, lb/TBtu**[20]
Kline Township Cogen, Unit 1	0.0816
Scrubgrass Generating Company, Unit 1	0.0936
Mecklenburg Cogeneration Facility, Unit 1	0.1062
Dwayne Collier Battle Cogen Facility, Unit 2B	0.1074
Valmont, Unit 5	0.1268
Stockton, Unit 1	0.1316
SEI Birchwood Facility – Unit 1	0.2379
Intermountain Power Plant, Unit 2	0.2466
Logan Generating Plant, Unit 1	0.2801
Salem Harbor, Unit 3	0.3348
Clover Power Station, Unit 2	0.3529
AES Hawaii, Unit A	0.4606
Clay Boswell, Unit 2	0.6633
Craig, Unit 3	0.7248
W.H. Sammis, Unit 1	0.8291

[19] See letter from Ms. Carolyn Slaughter, ICAC, to Mr. Jay Manning, Director, Ecology, March 30, 2009. See also the possibility of obtaining 90% mercury reduction at Minnesota Power's Boswell Unit 3, as noted in the exerpt from the Boswell Unit 3 Environmental Improvement Plan. See also the technical paper Cost Effective Mercury Emissions Control at the Newmont TS Power Plant, by Seeliger, J., August 2008.

[20] A copy of the spreadsheet of mercury emission rates measured at these and other electrical generating units as part of the 1999 ICR is available for download at http://www.epa.gov/ttnatw01/combust/utiltox/utoxpg.html.

Charles R. Lowman, Unit 2	0.9706
Shawnee Fossil Plant, Unit 3	1.0507
Cholla, Unit 3	1.2066
Presque Isle, Unit 6	1.2217
Presque Isle, Unit 5	1.2622
Widows Creek Fossil Plant, Unit 6	1.3986

Dated:___November 4, 2009_____

Ranajit Sahu, Ph.D.

EARTHJUSTICE

ALASKA CALIFORNIA FLORIDA MID-PACIFIC NORTHEAST NORTHERN ROCKIES
NORTHWEST ROCKY MOUNTAIN WASHINGTON, DC INTERNATIONAL

November 9, 2009

Via Electronic Mail

Sarah Rees
Washington Department of Ecology
Air Quality Program
P.O. Box 47600
Lacey, WA 98504-7600

Re: Proposed Ecology/TransAlta Settlement Agreement and Consent Decree
TransAlta Centralia Generation, L.L.C., Centralia, Washington

Dear Ms. Rees:

Earthjustice submits these comments on the proposed Settlement Agreement and Consent Decree regarding the coal-fired power plant in Centralia, Washington, between the State of Washington, Department of Ecology ("Ecology") and TransAlta Centralia Generation, L.L.C. ("TransAlta"). These comments are submitted on behalf of the National Parks Conservation Association, the Sierra Club, and Northwest Environmental Defense Center (collectively the "Conservation Organizations").[1]

The National Parks Conservation Association ("NPCA") is a national organization whose mission is to protect and enhance America's National Parks for present and future generations. NPCA performs its work through advocacy and education. NPCA has over 310,000 members nationwide with its main office in Washington, D.C. and 24 regional and field offices. NPCA's regional Northwest office is located in Seattle, where it works on a variety of issues affecting Northwest National Parks such as Mt. Rainier, Olympic, and North Cascades National Parks. NPCA is active in advocating for strong air quality requirements in our parks, including submission of petitions and comments relating to visibility issues, regional haze State Implementation Plans, global warming and mercury impacts on parks, and emissions from individual power plants and other sources of pollutants affecting National Parks. NPCA's members live, work, and recreate in all the National Parks of the Northwest, including those directly affected by the TransAlta coal-fired power plant in Centralia, Washington.

The Sierra Club is a national organization founded in 1892, with more than 60 chapters throughout the U.S., including the Cascade Chapter located in Seattle, Washington. The Cascade Chapter's membership resides and recreates throughout the state. Sierra Club is devoted to the

[1] The Conservation Organizations, with the Washington Wildlife Federation, also filed a Petition to the U.S. Department of Interior, National Park Service, requesting certification to Ecology that visibility impairment in Mt. Rainier and Olympic National Parks is reasonably attributable to nitrogen oxide emissions from the TransAlta Centralia coal plant. The petition is pending.

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Public Review Draft

study and protection of the earth's scenic and ecological resources—mountains, wetlands, woodlands, wild shores and rivers, deserts, plains, and their wild flora and fauna. An important part of Sierra Club's current work at both the national and chapter level, is its Beyond Coal campaign which, among other things, focuses on retiring and reforming old coal-fired power plants that are significant contributors to health-harming soot and smog pollution, global warming pollutants, and hazardous pollutants such as mercury.

The Northwest Environmental Defense Center ("NEDC") is a regional non-profit organization, based in Portland, Oregon. NEDC works to protect the environment and natural resources of the Pacific Northwest, by providing legal support to individuals and grassroots organizations with environmental concerns, and engaging in litigation independently or in conjunction with other environmental groups. NEDC also provides hands-on experience for students to enhance their education in environmental law. NEDC is regularly involved in efforts to maintain or enhance the air quality of the Pacific Northwest by serving as a watchdog over Oregon's Department of Environmental Quality, Washington's Department of Ecology, and each state's respective permitting processes. Student volunteers regularly comment on proposals for new air permits and permit modifications, monitor current permits in search of violations, and monitor major air quality issues, such as changes in administrative regulations.

The Conservation Organizations object to the Settlement Agreement and Consent Decree (the "Agreement") as contrary to the law, not supported by the record or established engineering and science, and because the Agreement is contrary to the public interest.

I. THE NITROGEN OXIDE PROVISIONS OF THE AGREEMENT DO NOT COMPLY WITH THE REQUIREMENTS OF THE CLEAN AIR ACT AND ARE INADEQUATE TO CLEAN UP AND PROTECT THE AIR QUALITY OF WASHINGTON'S NATIONAL PARKS AND WILDERNESS AREAS.

A. Nitrogen Oxide Pollutants From The TransAlta Coal Plant Negatively Affect the Air Quality Of at Least Twelve Class I Areas

On an annual basis, the TransAlta Coal Plant in Centralia, Washington (hereinafter the "TransAlta coal plant") discharges approximately 12,000-16,000 tons of nitrogen oxides ("NOx").[2] NOx is a primary contributor to haze pollution. Haze pollution is adversely affecting the air quality in many of the region's national parks and wilderness areas.[3] The Clean Air Act

[2] EPA emissions database http://camddataandmaps.epa.gov/gdm/index.cfm.

[3] See enclosed extinction analyses and conclusions from National Park Service demonstrating TransAlta coal plant's NOx emissions will be an increasing source of haze pollution in Washington's Class I areas and which provide: "NO_X emissions from Centralia in 2002 were approximately 15,470 tons or approximately 36 percent of all point source NO_X emissions in the State. Based on [Western Regional Air Partnership] WRAP projections, Centralia will be approximately 10 percent of ALL mobile and point source emissions in the State by 2018. 2018 Projections: Nitrate will become more important than sulfate for extinction at Olympic and

("CAA") requires that national parks and wilderness areas, identified in the CAA as "Class I areas," must receive the highest degree of protection from all air pollution. 42 U.S.C. § 7472.

Almost twenty-five years ago, in 1985, the Department of the Interior ("Interior") certified to the Environmental Protection Agency ("EPA") that visibility in Mt. Rainier and Olympic National Parks, as well as all other Class I areas in the region, was impaired. Almost fifteen years ago, in 1995, the National Park Service ("NPS") formally notified the Southwest Air Pollution Control Authority (now known as the Southwest Clean Air Agency or "SWCAA") and Ecology that the impairment of visibility in Class I areas in Washington could reasonably be attributable to sulfur dioxide emissions from the coal plant in Centralia.[4]

The TransAlta coal plant currently employs a combustion control technology commonly-referred to as "Lo-Nox burners" (or "LNC3") to control haze-causing NOx pollutants.[5] At this level of control, the TransAlta coal plant is impairing visibility in at least twelve Class I areas in the region, the second largest cumulative impact of any coal-fired power plant in the nation.[6] According to EPA's Clean Air Markets Database, in 2007, the TransAlta coal plant was in the top 10 percent of worst polluters for NOx.

The CAA requires the clean-up of visibility pollution at Mt. Rainier and Olympic National Parks (as well as all other Class I areas in the region). 42 U.S.C. § 7491(a)(1). Despite some improvements in the TransAlta coal plant's emissions, the air quality at Mt. Rainier and Olympic National Parks, and other Class I areas remains impaired, with haze pollution still primarily caused by the TransAlta coal plant.[7] As part of the requirements to clean-up and protect Class I areas, the CAA and EPA regulations and guidance require states to develop a State Implementation Plan ("SIP") for addressing visibility impairment, 42 U.S.C. § 7491(b)(2) and 40 C.F.R. § 51.302, and as part of that SIP, to ensure that certain major sources of air pollutants, such as the TransAlta coal plant, employ Best Available Retrofit Technology ("BART") to control pollutants that cause or contribute to haze pollution, including NOx. Id. The critical aspect of the visibility protection program is the requirement for each applicable implementation plan in which Class I areas are located to contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal. The SIP and the BART determinations within it are subject to public process and the states must consult with the Federal Land Managers ("FLMs") as part of the process. 42 U.S.C. §§ 7410 and 7491.

Mount Rainier according to the WRAP projections."

[4] See letters dated August 2, 1995 and October 16, 1995, enclosed with these comments.

[5] See Report of Dr. Ranajit Sahu, November 4, 2009, enclosed and incorporated herein.

[6] See enclosed graphs and material from NPS and TransAlta's own extinction analyses in Ecology's files.

[7] See Testimony of Mt. Rainier Acting Superintendent Randy King, October 13, 2009, copy enclosed.

To determine what constitutes BART for a source, Washington must employ a five-step process:

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.

Appendix Y to C.F.R. Part 51, Guidelines for BART Determinations Under the Regional Haze Rule, Section IV. See also 40 C.F.R. § 51.301 and 42 U.S.C. § 7491(g)(2).[8]

The proposed Agreement fails to conform to these BART requirements and processes.

B. The Flex Fuels Project Can Not Properly Be Considered BART.

The Agreement suggests that the TransAlta Coal Plant will be implementing "additional" NOx controls through the "Flex Fuels" project. Conservation Organizations disagree that the Flex Fuels project is an additional NOx control, or a NOx control that can be considered BART.

1. Flex Fuels is not a NOx reduction technology or project.

It is clear from the record that TransAlta has planned and implemented (and would have implemented regardless of any mediated agreement with Ecology), the Flex Fuels project over the course of the last several years.[9] It has been TransAlta's plan and intent for years to move away from burning Centralia coal to the exclusive use of Powder River Basin ("PRB") coal. Flex Fuels is a boiler efficiency project associated with the shift to PRB coal. Specifically, TransAlta, contrary to earlier representations and agreements with the state[10], closed the Centralia mine in late 2006. From that time to the present, TransAlta has been shifting away from Centralia coal to PRB coal. TransAlta's own website noted that the shift was complete at the end of 2007.[11] Any reduction in NOx emissions is entirely incidental to a project that has been proposed for non-NOx reduction reasons. Therefore, as noted in Dr. Sahu's report, the Agreement attempts to satisfy BART requirements with the Flex Fuels project, yet with no

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[8] Visibility and BART requirements have also been incorporated into Washington and SWCAA regulations. See e.g. WAC 173-400-030, 173-400-151, SWCAA 400-030, 400-151.

[9] See e.g. information from Ecology in response to questions by the Conservation Organizations (hereafter "Ecology Answers"), that in September 2007, TransAlta was already referring to the Boiler Efficiency Project. TransAlta later renamed the project "Flex Fuels" in January 2008 BART submissions. http://www.ecy.wa.gov/programs/air/TransAlta/Earthjustice.pdf..

[10] Including agreements that TransAlta would, in exchange for generous tax treatment from the state, keep the mine operating and the jobs associated with it. TransAlta has continued to receive the tax benefits, even after the mine closure.

[11] See also Ecology Answers.

additional incremental effort at NOx reduction by TransAlta beyond what it would be doing anyway.

2. There is no support in the record for the claimed NOx reduction from the Flex Fuels boiler efficiency project.

Even if Flex Fuels were appropriately in the running as a BART technology intended to address NOx and haze pollution in Class I areas, Ecology has not properly analyzed the Flex Fuels project and cannot rely on the claimed 20% NOx reduction. As set forth in Dr. Sahu's report, there are no technical details regarding combustion modeling in Ecology's record and therefore no way for the public to determine the appropriateness of the assumptions made, or the overall usefulness or accuracy of the analysis by either TransAlta or Ecology regarding the NOx reductions that may occur as an incidental benefit of the Flex Fuels boiler efficiency project. It appears that the information was not requested by, or provided to, Ecology.[12] Therefore, it also appears that Ecology did not actually analyze NOx reductions from the Flex Fuel project. Instead, Ecology has relied on a bare assertion by TransAlta. There is no way for Ecology or the public to determine whether a 20% incidental benefit is realistic or even meaningful. Flex Fuels cannot be considered as BART, because Ecology has failed to actually engage in at least steps 3 and 4 of the analysis and as a result, cannot have properly engaged in step 5. See 40 C.F.R. § 51.301.

3. Even after the application of Flex Fuels, the TransAlta coal plant will cause visibility impairments in twelve Class I areas.

Even after implementation of the Flex Fuels boiler efficiency project, the TransAlta coal plant will continue to cause significant visibility impairments at Mt. Rainier and Olympic National Parks as well as other Class I areas in the region and the Columbia River Gorge. As noted above, the TransAlta coal plant's NOx pollution impairs visibility in 12 Class I areas, including Mt. Rainier and Olympic National Parks. Even after application of the Flex Fuels project, the cumulative negative impact is 33 deciviews.[13] EPA considers a 1 deciview impact to be a cause of an impairment (and anything over .5 deciviews to be a contribution to impairment.) The TransAlta coal plant's impact on Mt. Rainier National Park alone will be 5 deciviews even after implementation of the boiler efficiency project—five times the level EPA considers a cause of a negative impact.[14] This indicates that even if Ecology were considering the boiler efficiency project as BART, Ecology has failed to adequately apply Step 5 of the BART analysis regarding improvements to visibility. See 40 C.F.R. § 51.301.

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[12] Sahu Report at paragraph 5.

[13] A deciview is a measure of visibility impairment.

[14] See generally enclosed information and extinction graphs from NPS.

C. Selective Catalytic Reduction Technology Is BART.

The CAA, EPA regulations and guidance, state law, and the record all support Selective Catalytic Reduction technology ("SCR") as BART. As pointed out by Dr. Sahu, rejection of SCR is a "major error" in TransAlta and Ecology's determination of BART for the TransAlta coal plant.

1. SCR is technically feasible.

SCR is technically feasible, despite Ecology's unsupported statement to the contrary. Dr. Sahu notes that while Ecology makes a bald statement that SCR is technically infeasible, such a claim is not actually made in TransAlta's analysis or Ecology's own summary.[15] The only impediment listed is the "lack of room" (i.e. physical space limitations), for easy SCR installation. This does not mean that SCR cannot be installed, but only that it could potentially be costly. Therefore, under the 5-step BART analysis, SCR is technically feasible.

2. There is no support in the record for the claims regarding physical space limitations.

Even if the physical space limitation were to be considered a technical as opposed to cost issue, the record contains no evidence to support TransAlta's assertion. Dr. Sahu notes there is little to no engineering detail regarding the congestion.[16] While Ecology asked questions on this issue early in the process, TransAlta failed to provide information adequate to the task and Ecology apparently never followed up.[17] The figures that TransAlta did provide are barely legible and do not contain the level of engineering detail requested by Ecology or that is necessary to assess the claimed space limitations.[18] The figures provide no support for the claim of physical limitation for SCR and according to Dr. Sahu "certainly do not make the case for an engineering assessment of the degree of difficulty of the [SCR] retrofit."[19] Finally, the information from TransAlta is incomplete in that it contains no discussion of the potential for moving or re-configuring existing equipment, or how that factors into the physical limitation and cost discussions. For example, TransAlta fails to provide any information regarding moving or replacing the electro-static precipitators ("ESPs") or reconfiguring piping runs that would render

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[15] In fact, it appears that Ecology has been imprecise in its language regarding BART and SCR. It appears that Ecology believes that SCR would be technologically feasible at the TransAlta coal plant, but accepts TransAlta's rejection of it based upon cost reasons. See also Ecology's answers to Conservation Organizations' questions that the cost of SCR is "extreme" yet providing no support or detail regarding the claimed cost.

[16] Sahu Report, paragraph 6.

[17] Id.

[18] Id.

[19] Id.

an SCR retrofit less problematic.[20] Therefore, even if cost due to space limitations is properly considered a technical issue for installation of SCR, the analysis and information provided is inadequate to actually assess the problem.

3. The record has no explanation for TransAlta's failure to control the unusually high boiler-out NOx emissions at the TransAlta coal plant, a fundamental component of considering feasible BART technologies.

TransAlta and Ecology have failed to analyze all potential, technically feasible, control technologies because TransAlta and Ecology have not adequately assessed the situation with NOx emissions from the boilers themselves and possible improvements at the boilers. The current boiler-out NOx emissions are approximately 0.3 lb/MMBtu. The emissions are predicted to drop to 0.24 lb/MMBtu with the Flex Fuels project. Dr. Sahu finds that these emissions are very high given operations elsewhere in the industry. Numerous existing PRB-fired boilers are operating with NOx emissions much lower than those reported by the TransAlta coal plant, generally well below 0.15 lb/MMBtu.[21] None of the scientific and engineering literature that is widely-available on the subject nor any of the boiler emissions information available from the EPA database was discussed, compared, or analyzed relative to the BART analysis for the TransAlta coal plant. While Ecology appears to have inquired into why TransAlta's boiler NOx emissions are so high, according to Ecology TransAlta had no technical response.[22] The is no reason that TransAlta's boiler-out NOx emissions should be as high as 0.24 lb/MMBtu when using the claimed controls for the boilers along with PRB coals. Given known information from the industry and the literature, the NOx emissions should be closer to 0.10 lb/MMBtu for a well-run, baseload unit.[23]

The issue with the boiler emissions is fundamental to Ecology's BART analysis and determination. Minimizing boiler-out NOx will require less NOx control from add-on technologies such as SCR. For example, if NOx emissions from the boiler were kept within the industry levels outlined in Dr. Sahu's report, SCR technology could be smaller in size, reducing or obviating physical constraint concerns at the plant. The attendant improvements in visibility in the national parks and wilderness areas of such a combined approach would be huge.[24] TransAlta and Ecology have failed to assess this crucial connection between improved boiler-out

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[20] Id. It should also be noted that the NPS believes there are benefits for both NOx and mercury reductions with the removal of one or both ESPs and the use of baghouses for mercury control. Removal of the ESPs then makes room for the SCR. See King testimony and enclosed email from Bruce Polkowsky, NPS.

[21] See, paragraphs 7-9, Sahu Report and Table 1-6 therein.

[22] See also Ecology Answers where Ecology said it does not know why the boilers and Lo-NOx burners do not meet the level of performance usually attained by this technology.

[23] Sahu report, paragraph 10.

[24] Sahu Report, paragraph 11.

NOx emissions and appropriately-sized SCR. As a result, Ecology has failed to properly complete Steps 1 through 3 of the BART analysis.

4. There is no support in the record for TransAlta's high cost claims for the SCR technology.

Ecology has also not examined TransAlta's arguments regarding cost of SCR technology. The cost assumptions submitted by TransAlta do not appear tied to the claimed physical difficulties as there is no supporting documentation for the size of the SCR (which can vary), the physical limitations at the plant, or how either of those things specifically affect the cost of the retrofit. For example, there is no information regarding cost estimates other than costs ascribed to "vendor". The "vendor" identification is not even disclosed. Further, it is unclear what the vendors might have had at their disposal when the "vendor" rendered the opinion; it is conceivable that the vendor was simply offering something rough and off the cuff.[25] There are also items such as a "surcharge" of 16% with no explanation of what that is or what it's for or why 16% is the proper amount. Or, there is the straight doubling of the cost estimate from one SCR unit to two. As pointed out by Dr. Sahu, that makes no sense on its face as two SCRs would share several components.[26] Overall, the cost assertions are entirely unsupported and opaque. Unfortunately, Ecology appears to have nonetheless accepted them wholesale.

If Ecology is going to reject SCR as BART because it costs "too much", TransAlta and Ecology must produce much more information regarding those costs and consider costs as one step within the context of the five-step BART process. On the current record, there is no support for the rejection of SCR based on "cost".

D. Step 5 Of The Required BART Analysis Appears Almost Entirely Absent From Ecology's Process.

While it is unclear under which step Ecology is actually rejecting SCR, it if is Step 5 of the BART process and based on a claim that the improvement in visibility is not "worth" the cost, far more information and analysis is required before that conclusion can be drawn. Step 5 requires an assessment of the visibility improvement from technically-feasible control technologies. Ecology has given no indication of how it has addressed Step 5 in the BART analysis and it appears that it has not adequately assessed TransAlta's characterization of visibility improvements from SCR. As part of that, Ecology may weigh cost against improvement, but it must document how and why it reaches a particular decision.

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[25] See Sahu Report, paragraph 12. It is also unclear whether and to what extent TransAlta or Ecology used the Control Cost Manual recommended by the EPA BART guidelines in analyzing the cost of SCR at the TransAlta coal plant. EPA recommends use of the Manual in order that cost estimates are transparent and consistent across the nation. The NPS also recommends use of the Manual.

[26] Id.

1. Ecology did not question TransAlta's calculations that dilute the visibility improvement expected from SCR.

TransAlta's assessment of visibility improvement is unsupported and appears to be too small by virtue of two mistakes (or at least questions) in their calculation. First, Dr. Sahu notes an unexplained change in the baseline for calculation of cost-effectiveness of SCR NOx controls. Initially, TransAlta and Ecology were using a 2006-2007 baseline for emissions in order to calculate improvements in NOx emissions and the attendant improvement in visibility in Class I areas. However, later in the process, with the unsupported explanation that the period was "not representative" or "lower than average," TransAlta unilaterally and apparently arbitrarily selected 0.30 lb/MMBtu as the baseline. Ecology provides no discussion regarding the shift in baseline in the proposed Agreement or supporting documents. There is nothing in the record to support the assertions that 2006-2007 was somehow out of the ordinary or otherwise not appropriate for use as the baseline.[27] The shift had the potential effect of making SCR controls look less promising for visibility improvement.

The National Park Service has also identified a way in which TransAlta's accounting of visibility improvement underestimates the potential gains for the Class I areas. TransAlta's assessment focuses solely on improvement in Mt. Rainier National Park. While Mt. Rainier is the most-impacted of the many Class I areas the TransAlta coal plant affects, it is not the only one. TransAlta must take into account its cumulative negative impacts on a large number of Class I areas, all of which must attain and maintain pristine air quality. The cumulative improvement to the many Class I areas negatively affected by TransAlta's coal plant, is significantly larger, improving the cost-effectiveness of the SCR technology option. Again, there is no indication in the record or Ecology's decision document or the Agreement itself that Ecology recognized these issues, assessed them, or what Ecology might have decided about them. Ecology has failed to properly apply Step 5 of the BART analysis.

2. The record is devoid of evidence describing how Ecology balanced cost and visibility improvement, or any support indicating that Ecology necessarily struck the correct balance.

Ecology has provided no explanation of how it balanced the factors in its cost-effectiveness determination. As noted above, Ecology accepted TransAlta's cost figures at face value with no support. Then, Ecology accepted TransAlta's visibility improvement estimates at face value without inquiring into the dilution of the numbers from a changed baselines and/or failure to count all Class I areas. Even accepting these figures, Ecology fails in Step 5 because Ecology does not explain where it strikes the balance between costs and visibility improvement and why. If, in fact, Ecology has disregarded or failed to give sufficient weight to visibility improvements from SCR technology, Ecology has failed to properly apply Step 5 in the BART process. Ecology, in accepting TransAlta's approach, failed to explain its reason for finding that

[27] Sahu Report, paragraph 13.

approach reasonable and consistent with its CAA BART obligations.

The rejection of SCR technology and the apparently unquestioning acceptance of the cost effectiveness argument demonstrates a house of cards in Ecology's decision-making for the TransAlta coal plant. Ecology's decision regarding NOx controls is built upon unsupported assumptions resting on more unsupported assumptions. Even the simplest, most apparent questions do not appear to have been asked or answered. Therefore, the claimed BART determinations set forth in the Agreement are unfinished, unsupported, and inadequate. The Conservation Organizations object to the Agreement and strongly urge Ecology to reexamine the decision based upon the matters raised herein.

II. THE TRANSALTA COAL PLANT IS SUBJECT TO BART FOR NOX EMISSIONS.

Conservation Organizations disagree with Ecology's rationale for entering into an agreement that provides less protection for the State of Washington and the region's Class I areas than is required by federal law. TransAlta's expectation that it is not subject to BART is contrived and contrary to fact. Simple examination of the documents from the negotiations in the late 1990s demonstrates the flaws in TransAlta's position.[28]

First, the February 1998 order issued by SWCAA's predecessor agency is a RACT order, not BART. It says it is a RACT order on its face and each aspect of it provides that SWCAA is setting RACT for various pollutants at the TransAlta coal plant.

Second, also clear on the face of the RACT order, is the fact that the parties to the negotiation did not go through the BART process and did not meet all BART requirements for public process, consultations, and BART determinations. In fact the order itself pointedly states the parties' intentions to avoid the BART process by entering into the agreement and that the process was much more streamlined than a BART process would have been. Therefore, in keeping with its (or its predecessor's) own desired outcome at the time, TransAlta has not been subject to BART.[29]

Third, in approving the RACT order, EPA clearly and unequivocally found that the RACT order was not BART for NOx and that TransAlta would be subject to BART for NOx at

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[28] The Conservation Organizations understand that TransAlta argues it is not subject to BART because it and its immediate predecessor participated in a collaborative process in the late 1990s that resulted in changes to the plant. The Conservation Organizations also understand that TransAlta has set forth its arguments in a "White Paper" dated June 2007. While most of the negotiations on that earlier agreement (if not all) were done by TransAlta's predecessor, it appears that TransAlta is the owner that made the changes to the plant that were required by the negotiated agreement and the resulting RACT order.

[29] It actually appears that TransAlta has not been subject to BART for any of the pollutants at issue in the late 1990s, including sulfur dioxide and particulates. Nonetheless, Conservation Organizations' arguments here will remain focused on NOx.

some point in the future.

Fourth, the NPS was an important and active participant in the negotiations that led up to SWCAA's RACT order for the TransAlta coal plant. It is plain from its submissions in this process, that the NPS did not consider the agreements and the resulting RACT order to constitute a BART process and that the TransAlta plant had not been subject to BART, at least as to NOx pollutants.

TransAlta cannot, based upon these statements and the content of the order, believe that it is not subject to BART for NOx.

III. ECOLOGY SHOULD RETAIN ITS AUTHORITY TO REQUIRE FURTHER NOX REDUCTIONS REGARDLESS OF TRANSALTA'S ARGUMENTS.

Finally, regardless of whether TransAlta is subject to BART, the State, as recognized by Ecology, has the continuing authority and obligation to make reasonable further progress on improving visibility in Class I areas. See e.g. 42 U.S.C. § 7491(b). With TransAlta being the largest source of emissions and cumulative effects in the region, Ecology can and should impose additional controls in order to ensure reasonable further progress by 2018—something that clearly will not happen under the Agreement proposed.

And yet even here, Ecology ties its own hands. The Agreement provides that Ecology will affirmatively waive its reasonable further progress authority, in TransAlta's favor, until 2018.[30] And even then, Ecology has agreed that it will not impose additional controls on TransAlta if, between now and 2018, SWCAA imposes some very minimal additional NOx standards on the coal plant. Those additional NOx standards are truly minimal—they are less than presumptive BART and less than what other plants are achieving with better boiler-out performance as discussed by Dr. Sahu. Ecology fails to use any of the tools at its disposal to address this second largest negative impact on Class I areas in the nation. As a result, the Agreement should be rejected as contrary to the CAA and contrary to the public interest.

IV. THE MERCURY PORTIONS OF THE PROPOSED AGREEMENT AND CONSENT DECREE ARE INADEQUATE AND NOT IN THE PUBLIC INTEREST.

A. The TransAlta Coal Plant Is Washington's Largest Source of Toxic Mercury Emissions.

Reports for 2007 at the TransAlta coal plant show a combined mercury emission (just for the coal-fired units) of a little over 372 pounds for the year, making it the largest emitter of mercury in the state.[31] Mercury is a toxic pollutant which, when released into the atmosphere from coal plants and other sources, deposits into lakes, rivers, streams and the ocean where it

[30] Agreement at III (A)(2).

[31] Mercury Summary for 2007 and Air emissions Inventory for 2007, emissions units 1 and 2. Documents from SWCAA file for TransAlta Centralia Generation, L.L.C Centralia coal plant.

bioaccumulates in fish.[32] Ingestion of fish by humans leads to a variety of health problems, particularly for fetuses or children (whose nervous systems are still developing, making them particularly vulnerable to neurotoxins like mercury).[33] Nationwide, approximately 6-8% of women of childbearing age are at risk of having mercury blood levels that exceed levels associated with a variety of health risks and as a result, hundreds of children are born each year at risk of mercury-caused learning disabilities and other developmental problems.[34]

Recently, the NPS reported that Olympic and Mt. Rainier National Parks show high levels of mercury contamination in snow and in fish in mountain lakes. Some fish sampled exceeded health thresholds for human consumption while all fish from both parks exceeded health thresholds for one or more species of fish-eating wildlife.[35]

Ecology has claimed in public meetings and in their answers to Conservation Organizations' questions, that most of TransAlta's mercury enters the atmosphere, circles the world, and deposits over a large area.[36] Although Ecology summarily claims there is little local deposition, recent studies have shown that some types of mercury can deposit locally.[37] Ecology has not provided adequate analysis in the settlement agreement or supporting documentation that demonstrates that TransAlta mercury emissions do not have a local effect. It takes only a gram

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[32] See generally EPA information regarding mercury, e.g. http://publicaccess.custhelp.com/cgi-bin/publicaccess.cfg/php/enduser/std_adp.php?p_faqid=1824&p_created=1106159090&p_sid=zTcbbuLj&p_accessibility=0&p_redirect=&p_lva=&p_sp=cF9zcmNoPTEmcF9zb3J0X2J5PSZwX2dyaWRzb3J0PSZwX3Jvd19jbnQ9OSw5JnBfcHJvZHM9MjMzJnBfY2F0cz0mcF9wdj0xLjIzMyZwX2N2PSZwX3BhZ2U9MQ**&p_li=&p_topview=1 and http://www.epa.gov/mercury/advisories.htm

[33] Id.

[34] Report to Congress; U.S. Centers for Disease Control, Blood Mercury Levels in Young Children and Childbearing-Aged Women – United States, 1999-2002 (Nov. 5, 2004); Trasande, L., Landrigan, P.J., and Schechter, C., *Public Health and Economic Consequences of Methyl Mercury Toxicity to the Developing Brain.* Environmental Health Perspectives, 113(5), 590-596 (May 2005). See also http://www.epa.gov/ttn/atw/hlthef/mercury.html.

[35] http://www.nps.gov/olym/parknews/airborne-contaminants-study-released.htm. Western Airborne Contaminant Project, Feb. 2008.

[36] As noted by testifiers at the public meeting on October 13, 2009, the fact that a potent neurotoxin will likely affect other countries and their citizens rather than Washington's citizens is a poor reason to decline to strongly regulate the toxin.

[37] See Gerald J. Keeler, M.S. Landis, G.A. Norris, E.M. Christianson, and J.T. Dvonch, "Sources of Mercury Wet Deposition in Eastern Ohio, USA," Environmental Science and Technology (American Chemical Society), Vol. 40 (19), 5874-5881 (2006); Watkins, et al., EPA National Exposure Research Laboratory, Preliminary Results From Steubenville Hg Deposition Source Apportionment Study (April 27, 2005).

of mercury to contaminate a 20 acre lake such that the fish in that lake exceed the consumption standard for human health.[38] Clearly, if even a very small fraction of TransAlta's mercury is being deposited locally, Lewis County's and Washington's citizens are being greatly affected.

B. Contrary To Assertions In The Proposed Agreement, The State Has The Authority And The Obligation To Control Mercury Emissions From the TransAlta Coal Plant.

Ecology incorrectly asserts that it cannot regulate mercury from the TransAlta coal plant because it abandoned its rulemaking effort over a year ago when the federal Clean Air Mercury Rule was overturned by the U.S. Circuit Court of Appeals for the D.C. Circuit.[39] It further claims that now it must sit and wait for EPA to complete a MACT standard for mercury from power plants before Ecology can take any action to limit the large amount of this toxic pollutant from the TransAlta coal plant. Ecology's position on this issue is simply not supported by Washington or federal law.

WAC 173-400-040(5) provides that:

> No person shall cause or permit the emission of any air contaminant from any "source" if it is detrimental to the health, safety, or welfare of any person, or causes damage to property or business.

An air contaminant is defined to include vapor and gas, and air pollution is the presence of one or more air contaminants in such quantities or characteristics as to be or likely to be injurious to human health, plant, or animal life, or property or that unreasonably interferes with the enjoyment thereof. RCW 70.94.030; WAC 173-400-030. Washington law also requires that all emissions units be required to use RACT to control emissions. WAC 173-400-040. Clearly, Ecology has both the authority and the obligation under Washington law to regulate mercury from the TransAlta coal plant.

Moreover, there is no need for Ecology to engage in formal rulemaking in order to address TransAlta's mercury. Washington law provides that for categories where there are fewer than three sources (the case here as the TransAlta coal plant is Washington's only coal-fired power plant), Ecology may proceed to determine and apply RACT on a case by case basis, without rulemaking. RCW 70.94.154. RCW 70.94.154 further provides that Ecology may make a source-specific RACT determination where such a determination is needed to address specific air quality problems for which the source is a significant contributor. As noted above, TransAlta's coal plant is the single largest source of toxic mercury in the state.

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[38] http://www.newmoa.org/prevention/mercury/mercurylake.pdf and http://yosemite.epa.gov/opa/admpress.nsf/d0cf6618525a9efb85257359003fb69d/88c64f9ee84a23e4852574240004276d!OpenDocument

[39] See Agreement at II(17) (citing New Jersey v. EPA, 517 F.3d 574 (D.C. Cir. 2008)).

Nor is there a need to wait for the EPA to regulate mercury before the state takes action to regulate this toxic pollutant. The Clean Air Act clearly provides that states can always regulate air pollutants more stringently than the Clean Air Act and/or federal regulation. 42 U.S.C. § 7416; Exxon Mobil Corp. v. EPA, 217 F.3d 1246, 1255 (9th Cir. 2000) ("Air pollution prevention falls under the broad police powers of the states, which include the power to protect the health of citizens in the state."). In fact, many states are already leading the way and requiring significant mercury reductions, regardless of the status of rules from EPA.[40]

Ecology cannot argue a lack of authority as a reason for entering into this token Agreement regarding mercury.

C. The Industry Is Currently Achieving 90% And Better Reductions In Mercury Emissions, A Standard To Which TransAlta Should Be Held.

The voluntary 50% reductions in mercury emissions from the TransAlta coal plant fall far short of what is being achieved in the industry. Greater than 90% mercury removal has been achieved on a long-term basis at a number of PRB-coal-fired power plants using activated carbon technology.[41] The Government Accountability Office recently made similar findings: that activated carbon technology is allowing a number of coal-fired power plants to remove over 90% of the mercury in their emissions and to do so at a fairly low cost.[42] Finally, Ecology's own files on this matter contain scientific and engineering papers about 80%, 90% and even better mercury reduction at various power plants.[43]

Activated carbon injection technology is the very technology currently being tested at the TransAlta coal plant. Clearly, Ecology should receive more than TransAlta's minimal efforts on this toxic pollutant. It appears TransAlta could achieve much better than the 50% offered in the Agreement and it could do better with fairly minimal additional cost.

Finally, the NPS raised an interesting point, supported by the GAO Report, in Acting

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[40] See Appendix III, U.S. Government Accountability Office, "Mercury Control Technologies at Coal-Fired Power Plants Have Achieved Substantial Emissions Reductions," GAO-10-47 (October 2009) ("GAO Report").

[41] See examples discussed in Sahu Report, paragraphs 23-25.

[42] GAO Report generally.

[43] See e.g. R. Chang, et al., Development and Demonstration of Mercury Control by Dry Technologies: 2005 Update, EPRI Document # 1004263 (Feb. 2005). See also March 30, 2009 Letter from the Institute of Clean Air companies to Director Jay Manning, Ecology, regarding mercury removal technologies and Seeliger, J., Brown, J.H., Jankura, B., Redinger, K., "Cost Effective Mercury Emissions Control At the Newmont TS Power Plant" (2008) (presented at Power Plant Air Pollutant Control "Mega" Symposium, August 2008).

Superintendent King's testimony at the public meeting on October 13, 2009. Superintendent King noted that if the TransAlta coal plant were to install BART—SCR technology—for the control of NOx, the plant would also obtain increased mercury reduction benefits. This finding is echoed by the GAO Report that notes that plants that have installed technologies for the control of other pollutants, such as NOx, have found significant co-benefits for the control of mercury.[44]

Given the state of mercury control technology and the clear authority of the state to regulate mercury, the voluntary 50% mercury reduction at the TransAlta coal plant is far too minimal, not in compliance with Washington's Clean Air Act requirements, and contrary to the public interest.

V. THE PROPOSED AGREEMENT AND CONSENT DECREE INCLUDE VARIOUS CLAUSES AND CONSTRAINTS THAT FURTHER WEAKEN THE AGREEMENT.

In addition to the very weak standards for NOx and mercury control in the Agreement, the Agreement contains a number of other constraints on TransAlta's obligations, constraints on Ecology's enforcement of the Agreement terms, and vaguely-stated additional commitments by Ecology. These additional terms further demonstrate that the Agreement is weak and not in the public interest.

First, as noted above, the commitments by TransAlta regarding mercury are wholly voluntary. Therefore, TransAlta could, for a variety of reasons, choose to do nothing with respect to mercury reduction.[45] The Agreement's terms are clear that in that instance, Ecology cannot enforce even the 50% obligation. The Agreement also provides that, at its sole option, TransAlta could simply choose to spend up to a certain amount on mercury-related tasks, but no more, regardless of whether the 50% reductions are achieved. Further, if TransAlta and Ecology wished to reach a meaningful and enforceable agreement to reduce mercury emissions, they could use the legal mechanism that currently exists under Washington law: WAC 173-400-091 ("Voluntary limits on emissions"). That provision would allow Ecology to issue a regulatory order setting the mercury emission limit at the agreed-to level, and, after appropriate notice and comment, establish a federally-enforceable mercury limit. WAC 173-401-091(4)-(5). Therefore, even the 50% reduction, meager though it is, is in question.

As to NOx, in addition to requiring no additional NOx reduction beyond what the TransAlta coal plant already chooses to do, Ecology agrees to forego any further progress on

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[44] GAO Report, pp. 5-6.

[45] Ecology claims that it could, if TransAlta failed to follow-through on its voluntary commitments, engage in mercury rulemaking to compel mercury reductions. This is curious given Ecology's stated reasons for entering into the Agreement in the first instance. If Ecology has the authority do so, Ecology should exercise that authority to the benefit of the public and the environment and not settle for such a paltry result as represented by TransAlta's commitments in the Agreement. It is unclear at this juncture, just what Ecology believes its authority really is.

NOx reductions from the plant for almost ten years (and possibly longer). Again, Ecology relinquished authority that it could retain in order to ensure that, should the Class I areas remain significantly impaired by the TransAlta coal plant's pollution even after the agreed NOx reductions, it could impose additional reductions to obtain reasonable further progress on the impairment problem. In fact, the Agreement goes a step further in making commitments to TransAlta. Ecology agrees that it will not even require additional reductions in 2018, regardless of the status of the Class I areas, if SWCAA imposes a slightly lower NOx requirement on the TransAlta coal plant than that which is required in the Agreement. Again, the slightly lower NOx requirement would still not achieve the presumptive BART limit of 0.15 lb/MMBtu and would be well above even the boiler-out control of NOx that many PRB-fired plants currently achieve.

The Conservation Organizations further oppose the language of paragraph 11 of the Agreement regarding coal ash waste disposal. Ecology agrees to "support" any future proposal and measures by TransAlta to reduce the cost of dealing with its ash waste or other byproducts that have been contaminated with mercury (or other heavy metals that precipitate out into the ash as a result of pollutant controls.) The Agreement notes that such "support" may include approval of "beneficial uses". Beneficial uses is not defined. Again, this appears to be a provision where Ecology relinquishes regulatory authority for nothing in return. This is particularly troubling in light of recent coal ash disasters such as the TVA coal plant spill in December of 2008, or problems with groundwater contamination in communities that have allowed "beneficial uses" of coal ash in roads and as fill for recreational developments. This kind of advance approval of any and all coal ash projects that might "reduce costs" or be considered "beneficial" by TransAlta is per se arbitrary and capricious decision-making by Ecology. Inadequately disposed coal ash waste may lead to detrimental public health and ecological consequences. It is entirely inappropriate for Ecology to pledge and agree to support proposals without even knowing what those proposals are.

CONCLUSION

It is extremely unfortunate and puzzling why Ecology feels compelled to reach this lopsided Agreement with TransAlta. This Agreement is not a compromise as between two ends of a spectrum, but rather a capitulation. Ecology and the citizens of Washington get nothing from this "bargain" that TransAlta wasn't already going to give them. TransAlta gets exactly everything it wants: it is not subject to BART for NOx; it is not required to do anything to control NOx pollution that is it not already doing and would do regardless of this Agreement; it can do minimal mercury control, well below industry standards, at its sole option with no repercussions if it does not achieve the reductions agreed to. In return, Ecology agrees to "hands-off" treatment for the next ten years or more for the TransAlta coal plant on a number of pollution issues; the state agrees to become TransAlta's partner in seeking accommodation and/or positive treatment from the EPA on a number of pollution issues; and the state agrees to look kindly on a wide-ranging list of potential TransAlta proposals for dealing with coal ash waste. Conservation Organizations find that the Agreement provides nothing of benefit for the citizens and natural resources of this state and strongly urge the State to reject this Agreement and engage in a full-scale, thorough BART analysis for NOx and aggressive case by case

mercury control in line with industry achievements of over 90% reductions.

Sincerely,

Janette K. Brimmer
Earthjustice
Counsel for National Parks Conservation Association, the Sierra Club, and Northwest Environmental Defense Center

cc: Doug Howell, SC
Mark Riskedahl, NEDC
Stephanie Kodish and Sean Smith NPCA
Don Shepherd, NPS
Region 10 EPA

United States Department of the Interior

NATIONAL PARK SERVICE
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P.O. Box 25287
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IN REPLY REFER TO:

November 20, 2009

N3615 (2350)

Mr. Stuart A. Clark
Air Quality Program Manager
Department of Ecology
Air Quality Program
PO Box 47600
Lacey, Washington 98504-7600

Dear Mr. Clark:

Thank you for providing information on the Best Available Retrofit Technology (BART) proposals for facilities in Washington that are subject-to-BART. We recognize that much time and effort went into the analyses conducted by the Department of Ecology (Ecology), and we appreciate the time Ecology has taken to discuss the difficult and important issues inherent in this major effort. These comments supplement the statement made by Randy King, Superintendent of Mount Rainier National Park, at the October 13, 2009, public hearing.

In general, we found the Ecology BART analyses to be informative and well-presented. We also recognize that the BART program is relatively new, which presents several challenges to all of us in its implementation. As a national office which conducts BART analyses for all Class I areas in the National Park System, we are able to call upon a growing information base and wish to take this opportunity to make that information available to Ecology. The State of Washington is fortunate to have an extraordinary number of magnificent national parks and wilderness areas within its borders and accessible to its citizens, as well as to numerous visitors. There are many reasons that the law mandates our highest levels of environmental protection for these special areas. National parks and wilderness areas are our natural and cultural heritage. Sociology studies confirm their importance, as do our individual experiences of recreation and renewal. We share your interest in insuring that these magnificent natural areas are protected for the benefit of all. As mentioned in our testimony at the October 13 public hearing, over 1.1 million people visited Mount Rainier National Park in 2008 and visitation as of the end of August of this year is already above the 1 million mark.

Regarding the economic benefits of the national parks, for example, in 2000, when our last visitor surveys were conducted, we learned that visitors to Mount Rainier and Olympic National Parks spent over $120 million in the area. The total economic impact of visitor spending was $95 million in direct sales, $38 million in personal income, $58 million in direct value-added and 2,530 jobs. With multiplier effects, created by the re-circulation of the money spent by tourists, visitor spending generated about $135 million in local sales, and an associated $52 million in personal income, $82 million in value-added and 3,102 jobs. These figures do not include park admission fees or the impacts of the NPS payroll and operations in the area, nor do they include the economic benefits resulting from visitation to North Cascades National Park or to the nine Class I wilderness areas and the Columbia River Gorge National Scenic Area that are also suffering from visibility impairment as a result of emissions from the Washington BART sources.

Our detailed comments on Ecology's BART proposals are enclosed. Based on our review, we believe the following pollution control technologies are technically feasible, cost-effective, and will substantially improve visibility in one of more of the 12 protected areas (including Mount Rainier and Olympic National Parks) included in Ecology's analyses:

- Selective Catalytic Reduction (SCR) to reduce nitrogen oxides emissions from the Centralia Power Plant
- Sodium-based scrubbing to reduce sulfur dioxide emissions from the potlines at the Intalco primary aluminum smelter
- Additional particulate control on the No. 10 Power Boiler and a limit of 0.5% sulfur on fuel oil burned at the Port Townsend Paper Company
- Low-NO_x and Ultra-Low-NO_x Burners proposed by Tesoro (and accepted by Ecology) to reduce nitrogen oxides emissions at its Anacortes refinery. (We recognize the timing issues and suggest that we work together to develop a Reasonable Progress strategy that will achieve the emission reduction goals proposed by Tesoro in a cost-effective, yet expeditious manner.)

Therefore, we ask that you revisit your BART proposals. It appears that that the key issue in these reviews is whether or not to consider the cumulative benefits of reducing emissions for multiple Class I areas. We address that issue below and in our enclosed comments.

Cost-Effectiveness Metrics

BART is not necessarily the most cost-effective solution. Instead, it represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. We believe that it is appropriate to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected. It simply does not make sense to use the same metric to evaluate the effects of reducing emissions from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas. And, it does not make sense to evaluate impacts at one Class I area, while ignoring

others that are similarly significantly impaired. If we look at only the most-impacted Class I area, we ignore that the other Class I areas are all suffering from impairment to visibility "caused" by the BART source. It follows that, if emissions from the BART source are reduced, the benefits will be spread well beyond only the most-impacted Class I area, and that must be taken into account. .[1]

The BART Guidelines represent an attempt to create a workable approach to estimating visibility impairment. As such, they require several assumptions, simplifications, and shortcuts about when visibility is impaired in a Class I area, and how much impairment is occurring. The Guidelines do not attempt to address the geographic extent of the impairment, but assume that all Class I areas are created equal, and that there is no difference between widespread impacts in a large Class I area and isolated impacts in a small Class I area. To address the problem of geographic extent, we have been looking at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there are certainly more sophisticated approaches to this problem, we believe that this is the most practical, especially when considering the modeling techniques and information available.

One of the options suggested by the BART Guidelines to evaluate cost-effectiveness is cost/deciview. Compared to the typical control cost analysis in which estimates fall into the range of $2,000 - $10,000 per ton of pollutant removed, spending millions of dollars per deciview (dv) to improve visibility may appear extraordinarily expensive. However, our compilation[2] of BART analyses across the U.S. reveals that the **average cost per dv proposed by either a state or a BART source is $12 - $19 million**,[3] with a maximum of almost $50 million per dv proposed by Colorado at the Martin Drake power plant in Colorado Springs. For example, considering the 12 Class I areas impacted by Centralia, our calculations show that the cost per dv of installing SCR at Centralia would be $5 million, which is relatively cost-effective.

Please note that EPA is proposing to consider the cumulative benefits at multiple Class I areas approach in its own BART determinations. For example, in an August 21, 2009, Advance Notice of Proposed Rulemaking regarding BART for the Navajo and Four Corners power plants, EPA Region 9 discusses an approach to assess visibility improvement that considers multiple Class I areas. And, Oregon considered the cumulative benefits of adding SCR at the Boardman power plant in its determination that SCR would be installed there under the reasonable progress provisions of the Regional Haze Rule. Finally, the Wyoming Department of Environmental Quality explicitly cited[4]

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[1] For example, our analysis, which is described in detail in our enclosed comments, indicates that the cumulative benefits of reducing NO_x emissions from the Centralia power plant are seven times greater than the benefit at Mt. Rainier, the most-impacted Class I area, alone.

[2] Sent to Ecology on 11/13/09 and located at http://www.wrapair.org/forums/ssjf/bart.html

[3] For example, PacifiCorp has stated in its BART analysis for its Bridger Unit #2 that "The incremental cost effectiveness for Scenario 1 compared with the baseline for the Bridger WA, for example, is reasonable at $580,000 per day and $18.5 million per deciview."

[4] As stated by the Wyoming Department of Environmental Quality, "Tuning the existing LNB with OFA and installing SCR is determined to be BART for Unit 3 for NOx based, in part, on the following conclusions: 4. The cumulative 3-year averaged 98th percentile visibility improvement from the baseline

the cumulative benefits to the Bridger and Fitzpatrick Wilderness Areas in its conclusion that adding combustion controls plus SCR to the Naughton Unit #3 is BART.[5]

Over the past several months, we have worked with Ecology staff to evaluate the BART sources under EPA's BART Guidelines, and we are very appreciative of your expertise and assistance. We look forward to continuing this cooperative working relationship as this process advances. We believe that good communication and sharing of information will help expedite this process, and suggest that you contact Don Shepherd at (303) 969-2075 or email him at don_shepherd@nps.gov if you have any questions or comments.

Sincerely,

Christine L. Shaver
Chief, Air Resources Division

Enclosures

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summed across both Class I areas achieved by tuning the existing LNB with OFA, SCR, wet FGD, and installing a new full-scale fabric filter, Post-Control Scenario B, was 1.849 Δdv."

[5] In addition, the Wyoming Department of Environmental Quality (WY DEQ) explicitly considered "visibility improvement from new [control options] summed across the [multiple] Class I areas" in its BART determinations for the Bridger, Johnston, and WYODAK power plants. WY DEQ also determined that SCR would be installed on Bridger units #3 & #4 under the Reasonable Progress provisions of the Regional Haze Rule.

National Park Service (NPS) Comments[1] on
TransAlta Centralia Generation LLC's Proposed
Best Available Retrofit Technology (BART) Determination for
TransAlta Centralia Generation
November 20, 2009

Present Unit Operation

TransAlta Centralia Generation LLC Power Plant (TransAlta) operates a two-unit, pulverized-coal-fired power plant near Centralia Washington, and approximately 70 km from Mount Rainier National Park (NP). The plant is located within 300 km of 12 Class I areas,[2] which also include North Cascades and Olympic National Parks (which are also Class I areas administered by the National Park Service).

Source Description and Background

Units 1 and 2 were commissioned in 1971 and 1972, are both tangentially-fired on sub-bituminous coals from the Powder River Basin (PRB), and are each rated at 702.5 MW net output.

Sulfur dioxide (SO_2) control on the two coal-fired boilers is provided by a limestone-slurry-forced-oxidation wet scrubber system. This system removes over 95% of SO_2 in the flue gas from the boilers. The SO_2 controls were installed in the 1999 – 2002 time period.

Particulate control is provided by two Electrostatic Precipitators (ESPs) in series followed by the wet scrubber system. The first ESPs were part of the original construction of the plant. The second ESPs date from the late 1970′s.

Current nitrogen oxides (NO_X) control is provided by combustion modifications incorporating Low-NO_X Burners with close-coupled and separated over-fire air. These combustion modifications are collectively known as "LNC3." The controls were installed in the 2000 – 2002 time period. The combustion controls were designed and optimized to suit Centralia mine coal.

For a variety of reasons, TransAlta stopped active mining at the Centralia coal mine and now purchases all coal from PRB coal fields. To accommodate the change, the company has modified the rail car unloading system to handle up to ten coal unit trains per week. Additional modifications are focused on the boilers. The boilers have been and will be modified to reduce temperatures in the flue gas to accommodate the higher Btu coal now being combusted. Additional changes include the reinstallation of specific soot blowers and installation of new soot blowing equipment (steam lances) necessary to accommodate the different ash characteristics of the PRB coals. Improved fire suppression equipment is being installed to accommodate the increased potential of PRB coals to catch fire spontaneously.

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[1] Electronic files are included separately.
[2] Please see the attached map titled "Current Impacts of Centralia PP on Class I Areas."

TransAlta anticipates operating the plant until at least 2030. They acknowledge that operation beyond 2025 will require significant plant upgrades to assure safe and reliable operation into the future.

According to EPA's Clean Air Markets (CAM) database, Centralia was the 92nd-largest stationary source of NO_x (out of 1,228 plants) in the U.S. in 2008 at 10,839 tons.

TransAlta's analyses[3] indicate that Centralia's Baseline emissions **cause**[4] visibility impairment in all 12 Class I areas (and in the Columbia River Gorge National Scenic Area—CRGNSA) within 300 km. TransAlta causes the third-greatest cumulative impact upon Class I area visibility of any single source we have evaluated to date.[5]

PREDICTED CHANGE TO THE 2003-2005 98TH PERCENTILE DAILY HAZE INDEX (dv)[6]

		Flex- Fuel	
Area of Interest	**Baseline**	**Imapct**	**Improvement**
Alpine Lakes Wilderness	4.103	**2.737**	1.367
Glacier Peak Wilderness	2.742	**1.700**	1.042
Goat Rocks Wilderness	4.336	**2.912**	1.424
Mt. Adams Wilderness	3.554	**2.356**	1.198
Mt. Hood Wilderness	2.797	**1.730**	1.067
Mt. Jefferson Wilderness	1.609	0.987	0.621
Mt. Rainier National Park	5.454	**3.899**	1.555
Mt. Washington Wilderness	1.446	0.844	0.603
N. Cascades National Park	2.060	**1.326**	0.734
Olympic National Park	4.037	**2.646**	1.391
Pasayten Wilderness	1.416	0.854	0.563
Three Sisters Wilderness	1.590	0.880	0.710
CRGNSA	2.228	**1.426**	0.801
Cumulative	37.373	24.298	13.076
Cumulative-CRGNSA	35.146	22.871	12.274

TransAlta's analysis indicates that, even after implementation of the Flex-Fuels project, Centralia will **cause** impairment in eight Class I areas (and CRGNSA) and contribute[7] to impairment in four. TransAlta would continue to cause the third-greatest cumulative impact upon Class I area visibility of any single source we have evaluated to date.[8]

[3] From Geomatrix Table 4-3: "YEARLY PREDICTED CHANGE TO THE 98TH PERCENTILE DAILY HAZE INDEX"
[4] A source "causes" visibility impairment if it degrades visibility by one deciview (dv).
[5] The two BART sources with higher cumulative impacts are the Four Corners Power Plant (47 dv) and the Navajo Generating Station (39 dv), both located on the Navajo nation.
[6] Deciview (dv) is a measure of visibility impairment.
[7] A source "contributes to" visibility impairment if it degrades visibility by 0.5 deciview (dv).
[8] However, if the Four Corners Power Plant and the Navajo Generating Station adopt the BART controls we have recommended, their cumulative impacts would drop to 19 dv and 16 dv, respectively, leaving Centralia as the source causing the greatest cumulative visibility impairment.

The BART analysis five steps are:

Step 1 – Identify all available retrofit control technologies.
On coal-fired power plants, the most common type of Selective Catalytic Reduction (SCR) installation is known as the hot-side high-dust configuration, where the catalyst reactor is located downstream from the boiler economizer and upstream of the air heater and particulate control equipment. In this location, the SCR is exposed to the full concentration of fly ash in the flue gas that is leaving the boiler. An alternate location for an SCR system is downstream of the air heater or the particulate control device. In many cases, this location is compatible with use of a low temperature SCR catalyst or is within the low end of the temperature range of a conventional catalyst. Because the temperature of the flue gas leaving the air heaters and the ESPs is too cool for the low temperature versions of SCR catalyst to operate, the high-dust configuration was assumed by Ecology and TransAlta for Centralia.

A new installation type SCR was used as the basis for analysis at the Centralia Plant because of the lack of room to install an SCR catalyst in the existing flue duct and the higher removal rate provided by a new, full size catalyst bed. The short distance between the boiler economizer and the entrance to the first ESP does not provide the room required for a catalyst bed with reasonable velocities to be inserted in the existing flue gas duct. The ducts from each boiler to the ESP have a relatively high velocity, such that the amount of catalyst that could fit into the unmodified duct would have minimal effectiveness due to the short residence time through the catalyst bed.

While Ecology reviewed SCR in a high-dust location, it did not evaluate other feasible locations downstream of the ESPs. For example, Basin Electric Power Cooperative evaluated installation of SCR with reheat[9] downstream of the wet scrubbers proposed as BART for its Leland Olds Unit #2.[10] Because of the difficulties and costs associated with a conventional high-dust SCR location, TransAlta and Ecology should have evaluated both a low-dust location downstream of the ESPs and a tail-end location following the scrubbers.

Step 2 – Eliminate technically infeasible control technologies.
TransAlta believes that while the Rotating Over-fire Air (ROFA) and Rotamix technology are "available" control technologies as described in the BART guideline, the use of either ROFA as a replacement or addition to the current overfire air injection system or installation of the Rotamix process are not technically feasible technologies due to unknown difficulties with installation on their boilers. Due to perceived risks of scale-up to their unit size, TransAlta believes that these technologies are not applicable to their facility.

Step 3 – Evaluate the control effectiveness of remaining control technologies.
TransAlta has underestimated the effectiveness of SCR. While we agree with Ecology that SCR can reduce NO_x emissions by up to 95%, we disagree with TransAlta's and Ecology's estimate that the application of SCR could only achieve 0.07 lb/mmBtu on an

[9] Basin Electric estimated that, after recovering waste heat, natural gas would be required to increase the gas temperature by about 50 degrees Fahrenheit to achieve the proper SCR operating temperature.
[10] Basin Electric proposed the tail-end location to reduce the possibility of fouling of the SCR catalyst by constituents of the lignite burned at the plant.

annual basis. In estimating the annual cost-effectiveness of adding SCR, TransAlta and Ecology effectively assumed that SCR could only further reduce NO_x by 71% from the 0.24 lb/mmBtu level to be achieved through combustion controls, down to 0.07 lb/mmBtu. We believe that SCR can achieve lower emissions on an annual basis.

EPA's Clean Air Markets (CAM) data (Appendix A), state/source BART analyses,[11] and vendor guarantees[12] show that SCR retrofit to coal-fired EGUs can typically meet 0.05 lb/mmBtu (or lower) on an annual average basis. We found 34 examples (Please see Table A.1. in Appendix A.) of boilers that have been retrofitted with SCR and are achieving ozone-season emission rates below 0.06 lb/mmBtu. We were able to find 2006 hourly emissions in EPA's CAM database for 11 of those EGUs, and charts showing those emissions, as well as for 11 additional retrofit SCRs, are included in Appendix A. We believe that inspection of these data leads to the conclusions that

- SCRs retrofit to eastern EGUs burning bituminous coal can typically reduce NO_x emissions by 90%, and
- These units can achieve 0.05 lb/mmBtu (or lower) on a 30-day rolling average basis during the eastern ozone season.

Discussions of this data are also provided in Appendix A.

TransAlta and Ecology have not provided any documentation or justification to support the higher annual emission rates used in their analyses. Our review of operating data (Appendix A) also suggests that a NO_X limit of 0.06 lb/mmBtu is appropriate for LNB/OFA+SCR for a 30-day rolling average, and 0.07 lb/mmBtu for a 24-hour limit and for modeling purposes, but a lower rate (e.g., 0.05 lb/mmBtu or lower) should be used for annual average and annual cost estimates.

Step 4 – Evaluate impacts and document the results.

Following are excerpts from reports provided by TransAlta and by Ecology.

> As a result of electing to use a full scale, new installation type design, an adjustment was used for SCR cost estimates due to the Centralia Plant's extremely tight boiler outlet ductwork configuration and limited available space for new equipment. Installation of a full-scale SCR system requires reconfiguration of the flue ducts from the boilers, structural modifications of the ESP to accommodate the weight of the SCR catalyst and duct work, and realignment of the duct work from the SCR units to the ESP inlets. The restricted site layout, support structure needs, intricate duct routing, limited construction space, and complexity of erection increases the capital cost.
>
> Each boiler at the Centralia Plant has two exhaust gas ducts to aid in splitting the flow to the ESPs. As a result each boiler would require two smaller, separate catalyst vessels instead of a single large catalyst vessel. The capital cost of installing dual catalyst vessels for each unit is slightly greater than a single catalyst vessel for units of similar size.
>
> Costs for SCR were estimated using CH2M HILL's database. The capital costs are based on cost information gathered by CH2M HILL over the past 3 years for BART analyses developed for a number of utilities in the western U.S. The costs were adjusted upwards to account for the difficult retrofit requirements for the CPP units. EPA has published a

[11] Basin Electric Power—Leland Olds #2 @ 90%; PacifiCorp Naughton #1 @ 88% & #2 @ 87%; Great River Energy—Coal Creek @ 0.043 lb/mmBtu

[12] Minnesota Power has stated in its Taconite Harbor BART analysis that "The use of an SCR is expected to achieve a NO_X emission rate of 0.05 lb/mmBtu based on recent emission guarantees offered by SCR system suppliers."

similar cost analysis model called CUECost that was developed by Raytheon Engineers & Constructors and the Eastern Research Group in 1998. The cost estimates generated by CUECost are based on 10-year-old design and cost data that do not consider the large price increases that have occurred in the industry during this time period or the CPP's difficult retrofit requirements.

The emissions reduction for installation of SCR (at a 95% removal rate) on one unit would be 7,450 tons/year. The capital cost for including SCR on only one unit was estimated to be $290.1 million with a cost effectiveness of $8,205/ton NOx reduced.

The emissions reduction for installation of SCR (at a 95% removal rate) on both units would be 14,910 tons/year. The capital cost for including SCR on both units would be double that for one unit with a cost effectiveness of $9,091/ton NOx reduced.

For new coal fired power plants, SCR is becoming the BACT control technology of choice to reduce NOx emissions. In some cases, the use of SCR is being considered to be the technology to be implemented for BART. There are a number of technical difficulties to implementing SCR at the Centralia plant presented by TransAlta in its reports. The primary difficulties are a lack of space for the catalyst beds and ducts, leading to very high construction costs that far surpass ranges of acceptable cost effectiveness. Ecology concurs with TransAlta that the construction costs to overcome the technical difficulties of retrofitting an SCR system on its boilers given its current configuration render this technology economically infeasible for implementation at this time.

Following are summaries of TransAlta's and NPS' cost estimates for SCR.

Costs estimated by	**TransAlta/Ecology**	**NPS**
Emissions Reduction (tpy)	7,450	5,456
Capital Cost	$ 290,100,000	$ 227,046,261
Capital Cost ($/kW)	$ 413	$ 323
O&M Cost	$ 3,849,789	$ 6,538,253
Total Annual Cost	$ 35,706,198	$ 31,466,712
Cost-Effectiveness ($/ton)	$ 8,205	$ 5,768

However, we have a major concern with the way in which TransAlta estimated the costs of adding SCR at Centralia, and believe those costs are overestimated. While TransAlta did present "line item" costs for SCR, it is not possible to determine from the information provided how those "line item" costs were derived. Instead of CUECost and internal and proprietary databases, the BART Guidelines recommend use of the EPA Control Cost Manual:

> The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual, Fifth Edition, February 1996, 453/B-96-001). In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a BART analysis. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option.

EPA's belief that the Control Cost Manual should be the primary source for developing cost analyses that are transparent and consistent across the nation and provide a common means for assessing costs is further supported by this November 7, 2007, statement from EPA Region 8 to the North Dakota Department of Health:

> The SO_2 and PM cost analyses were completed using the CUECost model. According to the BART Guidelines, in order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual. Therefore, these analyses should be revised to adhere to the Cost Manual methodology.

TransAlta did not provide adequate justification or documentation for its cost estimates, and does not provide for a transparent method (as does the EPA Control Cost Manual) to determine how the costs were calculated.[13] We were not provided with any vendor estimates or bids for SCR. As a result, TransAlta's $413/kW estimate for Total Capital Cost is substantially higher than the $50 - $320/kW found in available cost surveys. (Please see "Cost Survey Results" and "SCR Cost Survey Report" in Appendix B.) While we understand that installation costs may be greater than average for Centralia due to space constraints, TransAlta should show the extra expenses and how they were estimated.[14] For these reasons, we believe that capital and annual costs are overestimated.

We conducted our own analysis using the EPA-recommended EPA Control Cost Manual,[15] but with some very important modifications. Although the Control Cost Manual approach incorporates a built-in retrofit factor[16] that adds $4 million to the Direct Capital Cost (DCC) of each unit at Centralia, we decided to assume that Centralia the would equal the most-expensive SCR retrofit (on a $/kW basis) in the cost survey literature by adding retrofit factors to escalate the DCC and the Indirect Capital Cost such that the Total Capital Cost would be about $320/kW, which is the cost of the most expensive SCR based upon the survey information in Appendix B. Nevertheless, even after we escalated those costs by applying "extra" retrofit factors of 3.0 – 3.5, we still derived the much lower costs shown in the table above.[17]

Step 5 – Evaluate visibility impacts.

As discussed previously, we have a fundamental concern with Ecology's decision not to consider the cumulative visibility improvements that would occur at all of the Class I areas within 300 km of the BART source.

TransAlta ran CALPUFF for SCR at 0.07 lb/mmBtu[18] and predicted that the greatest improvement would be at Mount. Rainier NP at 2.1 dv. The cumulative Class I area improvement would be 12.5 dv. (Please see the enclosed map titled "Benefits of SCRs at Centralia Power Plant on Class I areas.")

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[13] TransAlta submitted revised SCR retrofit costs in July 2008 to address increases in the price for steel, concrete, other building materials, and overall construction costs. Given the downturn in the economy and the resulting decreased demand for raw materials, these cost estimate increases seem unnecessary and inappropriate. The Chemical Engineering Plant Cost Index ("CEPCI") for 2008 is 575.4. The June 2009 index is 508.9, a 12% decline in 6 months.

[14] For example, TransAlta could use an approach similar to that discussed by William M. Vatavuk on pages 59 – 62 of his book Estimating Costs of Air Pollution Control.

[15] We attempted to adjust the cost derived by a direct application of the EPA Cost Manual by applying "extra" retrofit factors of 3.0 – 3.5 to the direct and indirect costs. Our "target" was to keep the capital cost of SCR around $320/kW, which is the cost of the most expensive SCR based upon the survey information in Appendix B.

[16] that applies to equation 2.39

[17] The Excel workbook we produced, which is based upon the approach provided in EPA's Control Cost manual, can be found in Appendix B.

[18] This is appropriate for a 24-hour average for SCR.

Geomatrix Table 4-3: YEARLY PREDICTED CHANGE TO THE 98TH PERCENTILE DAILY HAZE INDEX 98th Percentile Delta HI (dv)

		Flex- Fuel		SCR	
Area of Interest	**Baseline**	**Imapct**	**Improve**	**Imapct**	**Improve**
Alpine Lakes Wilderness	4.103	2.737	1.367	**1.224**	1.513
Glacier Peak Wilderness	2.742	1.700	1.042	0.774	0.927
Goat Rocks Wilderness	4.336	2.912	1.424	**1.302**	1.610
Mt. Adams Wilderness	3.554	2.356	1.198	**1.061**	1.296
Mt. Hood Wilderness	2.797	1.730	1.067	0.796	0.934
Mt. Jefferson Wilderness	1.609	0.987	0.621	0.423	0.564
Mt. Rainier National Park	**5.454**	**3.899**	**1.555**	**1.775**	**2.125**
Mt. Washington Wilderness	1.446	0.844	0.603	0.391	0.452
N. Cascades National Park	2.060	1.326	0.734	0.576	0.750
Olympic National Park	4.037	2.646	1.391	**1.240**	1.406
Pasayten Wilderness	1.416	0.854	0.563	0.381	0.473
Three Sisters Wilderness	1.590	0.880	0.710	0.416	0.464
CRGNSA	2.228	1.426	0.801	0.598	0.828
Cumulative	**37.373**	**24.298**	**13.076**	**10.956**	**13.341**
Cumulative-CRGNSA	**35.146**	**22.871**	**12.274**	**10.358**	**12.513**

Even with SCR, Centralia would continue to cuse visibility impairment in five Class I areas and contribute to impairment in three more (and the CRGNSA).

Determine BART

According to Ecology

> The Department of Ecology (Ecology) determined that BART for NO_X emissions is the current combustion controls combined with the completion of the Flex Fuels project and the use of a sub-bituminous coal from the Powder River Basin or other coal that will achieve similar emission rates. This change results in a 20% reduction of NO_X emissions from the baseline period emission rate. The use of low sulfur PRB coal also reduces SO_2 emission by about 60% from the same period. The NO_X reduction from the BART controls selected by Ecology will result in a visibility improvement from the baseline impacts at Mt. Rainier National Park of approximately 0.6 dv, with improvements of 0.2 to 0.6 dv at other affected Class I areas. The controls are to be installed and start continuously meeting the emission limitation by October 1, 2009.
>
> There will be federal requirements to reduce mercury emissions. The Flex Fuels project does not interfere with any potential mercury control technologies required by a future federal mercury control program.
>
> In order to meet the requirement of the Governor's Executive Order on Climate Change, TransAlta will be making significant financial and plant viability analyses of how best to comply with the Executive Order directive and the resulting Agreed Order between the company and Ecology.
>
> Meeting the requirements of the Executive Order will significantly affect the NO_X emissions from the plant. This would occur whether compliance was achieved through shutdown of the plant, adding biofuels, or performing carbon removal and sequestration.

Based upon our reviews of BART analyses across the U.S., we believe that cost-per-deciview ($/dv) of visibility improvement is the most-common and most-useful parameter for assessing the cost-effectiveness of strategies to improve visibility in Class I

areas. Our compilation[19] of BART analyses across the U.S. reveals that the **average cost/dv proposed by either a state or a BART source is $12 - $19 million**,[20] with a maximum of almost $50 million/dv proposed by Colorado at the Martin Drake power plant in Colorado Springs. Using the information provided by TransAlta, we calculated the cost-effectiveness of its proposed combustion control option in $/ton and $/dv.

Cost-effectivenesss estimated by	**TransAlta/Ecology**	**NPS**
Cost-Effectiveness ($/ton)	$ 8,205	$ 5,768
Visibility Improvement (dv at Max Class I)	1.062	1.062
Cost-Effectiveness ($/98th % dv at Max Class I)	$ 33,611,106	$ 29,620,375
Visibility Improvement (dv at Summed Class I)	**6.257**	**6.257**
Cost-Effectiveness ($/98th % dv at Summed Class I)	**$ 5,707,056**	**$ 5,029,443**
Visibility Improvement (dv at Summed Class I+CRG)	6.671	6.671
Cost-Effectiveness ($/98th % dv at Summed Class I+CRG)	$ 5,352,718	$ 4,717,177

We believe that TransAlta has overestimated the costs and underestimated the benefits of SCR. However, we recognize that there are considerable uncertainties and differences between the TransAlta cost estimates and those we produced based upon the EPA Control Cost Manual approach. Nevertheless, either set of cost estimates, when placed into the context of cost per degree of cumulative visibility improvement (e.g., $/dv) and compared to the cost-effectiveness values accepted by other sources and states across the U.S.,[21] result in the conclusion that SCR at Centralia is relatively cost-effective.

Mercury Reduction

Addition of SCR may enhance mercury removal by oxidizing some of the elemental mercury to a form that is more-readily captured by the existing PM and SO_2 controls. Ecology may also consider a more-comprehensive approach in which an existing ESP is removed and replaced by SCR, powdered activated carbon injection, and a fabric filter. Such a multi-pollutant approach is underway at Minnesota Power's Clay Boswell station. PacifiCorp has also proposed to replace the existing ESPs with fabric filters at its Johnston and Naughton generating stations in Wyoming.

<u>NO_x BART Conclusions</u>

We believe that a valid "top-down" approach to reducing NO_x demonstrates that addition of SCR is BART for Centralia. We have conducted our own analysis using the procedures described in EPA's BART Guidelines and in EPA's Control Cost Manual.

- TransAlta and Ecology did not consider other, potentially less-expensive, locations for SCR

[19] See http://www.wrapair.org/forums/ssjf/bart.html; a more-current compilation was sent to Ecology on 11/13/09.

[20] For example, PacifiCorp has stated in its BART analysis for its Bridger Unit #2 that "The incremental cost effectiveness for Scenario 1 compared with the baseline for the Bridger WA, for example, is reasonable at $580,000 per day and $18.5 million per deciview."

[21] We recently sent our latest compilations of BART proposals to Ecology. That transmittal contained summaries of BART proposals by sources and/or states to reduce SO_2 and NOx. The average cost/dv for the NO_x proposals was $12 million/dv; and $19 million/dv for SO_2. The combined average was $15 million/dv.

- TransAlta and Ecology have underestimated the ability of modern NO_x control systems. SCR is capable of reducing emissions below TransAlta's target, and the amount of the reductions will increase.
- TransAlta's SCR costs are overestimated and unsubstantiated. EPA guidance advises that its Control Cost Manual should be used; TransAlta should follow this guidance.
- Ecology should consider the cumulative effects of improving visibility across all of the 12 Class I areas affected. Our results estimate a cost-effectiveness value for addition of SCR of $4.7 million/dv, which is much less than the average cost-effectiveness accepted by the states and sources we have surveyed. Even when we use TransAlta's estimates of control-effectiveness and costs, addition of SCR is cost-effective at $5.4 million/dv.

United States Department of Agriculture
Forest Service
Pacific Northwest Region
333 SW First Avenue (97204)
PO Box 3623
Portland, OR 97208-3623
503-808-2468

File Code: 2580
Date: November 3, 2009

Sarah Rees
Air Quality Program
Washington State Department of Ecology
PO Box 47600
Lacey, WA 98504-7600

Dear Ms. Rees:

On September 16, 2009, the USDA Forest Service received notification of the proposed Settlement Agreement between the State of Washington Department of Ecology and TransAlta Centralia Generation LLC on air quality matters. The proposed agreement includes both the determination of Best Available Retrofit Technology (BART) for the NOx emission limits and voluntary mercury reductions at this facility. Based upon our review of the BART documents, we are providing the following comments.

In brief we conclude:

- The TransAlta facility contributes to visibility impairment at 12 Class I areas (9 are FS managed) plus the Columbia River Gorge National Scenic Area.
- This visibility impairment is modeled to occur up to 144 days per year at the most impacted FS-managed Class I area (Alpine Lakes wilderness). Mt. Rainier National Park is impacted even more frequently at 168 days per year.
- New NOx controls as described in the BART documentation and the Settlement Agreement will do little to improve visibility; reducing the number of days impaired by only 6% at Alpine Lakes to 135 days per year and only 3 % at Mt. Rainier to 163 days per year.
- Post-combustion control technologies are available that can do a better job of reducing NOx and improving visibility than the Flex Fuels project alone. We encourage you to reconsider the value of visibility in the Class I areas and require additional NOx reductions through either Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR).
- We advocate a reduction in permitted SO_2 emission limits from the current limit of 10,000 tons per year (tpy) to approximately 2900 tpy. This emission level has been demonstrated to be achievable by the facility in the past two years and allows for upward adjustment for maximum heat input in the past 10 years.
- The provisions associated with the BART determination should be independent from provisions associated with voluntary mercury reductions, effectively removing the non-enforceability provisions intended for the voluntary mercury reductions.
- Ecology should not limit itself from opportunities to reduce haze-causing emissions at the TransAlta Centralia plant for the next 20 years.

The details of our concerns are presented below. Please direct questions to Rick Graw at 503 808-2918

Mary Wagner
Regional Forester

Enclosure

Forest Service Technical Comments on the Settlement Agreement between State of Washington Department of Ecology and TransAlta Centralia Generation LLC of Air Quality Matters

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Overall Comment

The Forest Service recognizes the substantial progress made by TransAlta in reducing its emissions of air pollutants from the Centralia electric generating facility in the past 10 years. Sulfur dioxide (SO_2) emissions have decreased by 98%. PM emissions are controlled by 99%. Recent testing has shown that mercury can be reduced by greater than 80%. However, NOx emissions have only been reduced by 40-50%. Due to its contribution to haze, we remain concerned about the proposed BART determination for NOx, as it does little to decrease the frequency and magnitude of visibility impairment in the 12 affected Federal Class I areas and the Columbia River Gorge National Scenic Area (CRGNSA). We would like to see NOx controlled to similar levels of control as the other pollutants.

Flex Fuels plus SNCR

In its support document for the BART determination, Ecology states that Flex Fuels plus selective non-catalytic control technology (SNCR) is both technically feasible and cost effective. While the rationale for not requiring installation of Flex Fuels plus SNCR technology are presented, these factors do not out-weigh the benefits of implementing this technology.

The benefits of implementing this control technology include:

- Increasing the level of visibility improvement at the 3 most heavily impacted Federal Class I areas due to NOx reductions by an additional 0.45 to 0.6 dv on the 98th percentile day, or about double that of flex fuels or SNCR alone.
- Reducing the NOx emissions to 0.18 lbs/mmBtu, much closer to the EPA presumptive limit (0.15 lbs/mmBtu) than achieved solely through the Flex Fuels program (0.24 lbs/mmBtu)
- Reducing annual NOx emissions by 8,022 tpy
- Achieve these at a cost of $2,162/ton.

The factors weighing against this control technology are manageable, conflict with EPA's view, and would simply delay measurable improvements in visibility. Ecology also recognizes that the energy and non-air quality environmental impacts of compliance will be manageable. Contrary to Ecology's argument that the LNC3 combination of combustion controls previously installed should be considered BART, EPA has stated that "while the NOx emission limitation may have represented BART when the emission limit in the RACT Order were negotiated, recent technology advances have been made. EPA cannot now say that the emission limitations in the RACT Order for NOx represent BART." The Forest Service advocates a similar position.

Finally, while green house gas emissions will be reduced by December 31, 2025 in order for the facility to meet the Governor of Washington's Executive Order, this does not guarantee

reductions in NOx. Even if NOx emissions were further reduced by this deadline that still leaves at least a 15 year window in which impairment to visibility could be substantially reduced, a window in which 12 Class I areas and one National Scenic Area will still be impacted. Thus the benefits of implementing Flex Fuels plus SNCR to achieve an emission limit of 0.18 lbs NOx/mmBtu out-weigh the costs.

SCR Cost Effectiveness

Use of post-combustion technology such as Selective Catalytic Reduction (SCR) could reduce NOx by an additional 76% over the base line condition. As demonstrated by the modeling analysis, this would achieve far greater improvement in visibility as compared with the currently proposed 20% reduction.

Ecology has determined SCR technology as technically feasible, but did not select SCR technology as BART due to costs. Upon reviewing the basis for this decision, we note that Ecology relied solely upon the $/ton metric for determining that the technology is not cost effective. That metric has an acknowledged level of uncertainty of -20%/+50%[1]. This is considerably more than the ± 30 percent uncertainty typically used by EPA[2].

Additionally, the annualized costs of the SCR system are based upon a 15 year plant economic life. This should be revised to a 20 year life to be consistent with both the default assumption used in the EPA Cost Control Manual for SCR and TransAlta's response to comments to Ecology[3]. Correction of this error will reduce the estimated total annualized cost.

Performing a cost-effectiveness analysis based solely upon $/ton offers no consideration of visibility improvement, let alone cumulative impacts at multiple Class I areas. As this is a visibility rule, more transparency is needed in Ecology's determination of BART and how specifically it considered the visibility impacts from this facility.

While the BART guideline does not offer specific guidance on how to consider the visibility metric in assessing cost effectiveness, the BART guideline does mention use of such a metric as dollars per deciview ($/dv). The FLMs have developed draft guidance which has been provided to Ecology[4]. Additionally, EPA Region 9 has developed a draft methodology which also considers visibility in evaluation of cost effectiveness. As this is a visibility rule, and this source contributes to visibility impairment at 12 Class I areas and a National Scenic Area, a cumulative $/dv metric is appropriate and should be used.

In the most recent compilation of proposed and final BART determinations for NOx prepared by the National Park Service (which includes 46 EGUs from across the country), cumulative cost effectiveness ranges from $0.6 million/dv to $15.3million/dv (August 12, 2009). Using costs

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[1] BART Analysis for Centralia Power Plant. Prepared for TransAlta by CH2MHill, January 2008, Revised July 2008.
[2] US Environmental Protection Agency. Cost Control Manual, Chapter 2: Cost Estimation: Concepts and Methodology. EPA/452/B-02-001. January 2002.
[3] Preliminary Responses to Department of Ecology and SWCAA on the January 2008 TransAlta Centralia Power Plant BART Analysis. May 23, 2008.
[4] Estimating Regional Haze Cost/Benefit. Draft, September 25, 2008.

provided in the BART documentation for this facility, implementing SCR at Centralia is estimated to cost approximately $8.5 million/dv (sum of 98th percentile across all affected Class I areas). Thus from this perspective, SCR is cost effective.

Given the high degree of uncertainty in the cost estimate, and the frequency, magnitude and number of Class I areas impacted by this facility, we advocate that Ecology reconsider the cost effectiveness of SCR control technology and the potential benefits to our nation's natural resources in making its BART determination.

SO_2 Emission Reductions

The actual SO_2 emissions from this facility are far less than the currently permitted emission rates. According to the EPA Clean Air Markets database, the SO_2 emissions from this facility during 2008 were only 2318 tpy compared with their currently permitted emission rate of 10,000 tpy. This was accomplished through the increase efficiency of the wet scrubbing system as obtained through experience with the system and the reduction in sulfur content of the PRB coals compared with the coal from the local mine. We recognize that during 2008, the plant only operated at 80% of its historical capacity. If the plant operated at full capacity, it would have emitted approximately 2918 tpy of SO_2. Given the adverse effects of acid deposition caused by sulfuric acid and its significant role in causing haze, SO_2 should be limited to 2918 tpy at this facility.

Additionally, it would be helpful if Ecology would quantify and present the improvement in visibility likely to occur from both SO_2 and NOx emission reductions resulting from the Flex Fuels project. Looking at the change in impacts from reductions in NOx emissions alone, as was provided in the modeling analyses, underestimates the actual reductions in haze anticipated from both SO_2 and NOx emission reductions.

BART Compliance Section of the Settlement Agreement

The BART compliance section of the settlement agreement is missing a key provision proposed by Ecology in its Support Document for BART Determination (August 2009). In section 4.2 of that document, Ecology proposed BART to be the Flex Fuels project plus "use of a sub-bituminous Power River Basin coal or other coal that will achieve similar emission rates…" Since PRB coal contains approximately 1/3 of the sulfur content of the local TransAlta coal and 90% of the nitrogen content, this provision is key to keeping SO_2 and NOx emissions at or below the level achieved in recent years. As such, we advocate retaining this provision in the BART compliance requirements.

Continuous Improvement/Regional Haze Goal for NOx

The Forest Service objects to excluding the TransAlta facility from future evaluation for opportunities to reduce haze-causing pollutants before submission of the comprehensive periodic revision of the RH SIP due to EPA by July 21, 2018. This would effectively prevent any evaluation of advancement in new control technology for another 20 years (until the 2028 SIP). This seems unreasonable given the periodic advancements in air pollution control technology and the substantial impact caused by this facility at multiple Class I areas.

General Terms and Conditions

The last phrase of paragraph 2 of the Settlement Agreement is troublesome. It states conditions under which TransAlta, in its sole discretion, may terminate the Settlement Agreement. Because the TransAlta Centralia electrical generating facility is subject to BART, TransAlta should not have the right to terminate portions of the Settlement Agreement pertaining to compliance with BART. The BART compliance section of the Settlement Agreement ought to be addressed separately from the voluntary mercury reductions.

Early Mercury Emission Reductions

Mercury has been found in fish from remote areas in Washington at levels exceeding those thought safe for consumption by wildlife and humans and is a concern for the Forest Service. The Forest Service commends TransAlta's desire to reduce mercury prior to state or federal regulation.

The Settlement Agreement identifies sorbent injection as the sole technology planned to reduce mercury emissions by 50%. However, recent tests at the facility demonstrate that mercury may be reduced by greater than 80% using sorbent injection technology. As such, we would like to see incentives in place to encourage TransAlta to remove as much mercury as possible. Once federal and/or state regulations are developed for mercury, we would like to see emission limits in place which promote the maximum level of control achievable for this bio-accumulating toxic compound.

Section 7: Compliance Phase, Paragraph b. If construction of the sorbent injection system triggers New Source Review (NSR), please explain why TransAlta should be exempt from NSR.

Paragraph 13 creates a "hollow agreement" in that if TransAlta does not comply with the early reduction provisions of the Settlement Agreement, Ecology can effectively do nothing. This paragraph should be removed from the Settlement Agreement.

From: Rees, Sarah (ECY) on behalf of ECY RE AQComments
Sent: Thursday, April 29, 2010 5:32 PM
To: Schneider, Doug
Subject: FW: Comments on Proposed Agreement for TransAlta's Centralia Coal-fired Plant

Form Letter #1

-----Original Message-----
From: steve12698@comcast.net [mailto:steve12698@comcast.net]
Sent: Friday, October 09, 2009 9:27 PM
To: ECY RE AQComments
Subject: Comments on Proposed Agreement for TransAlta's Centralia Coal-fired Plant

Mr. Alan Newman
Air Quality Program, Wash. Dept. of Ecology
P.O. Box 47600
Lacey, WA 98504-7600

Dear Mr. Newman,

Thank you for the opportunity to comment on air pollution at TransAlta's coal-fired power plant. As a national park tourist and advocate for our national parks, I treasure the beauty and pristine air quality of Mount Rainier and Olympic National Parks and recognize that the State of Washington has a unique opportunity to protect these and other treasured public spaces. In order to preserve these park resources for present and future generations, it is important that air quality laws and regulations are strictly followed.

Mount Rainier and Olympic National Parks, as well as multiple wilderness areas, are threatened by air pollution from the Centralia coal plant. To protect these public spaces Washington must require that TransAlta significantly reduce its air pollution.

The Clean Air Act requires power plants to reduce haze-causing pollutants, including nitrogen oxides, and toxic chemicals like

mercury. Washington should require the most effective pollution controls to reduce TransAlta's nitrogen oxide and mercury emissions. Without these controls, the Centralia coal plant will continue to unnecessarily obscure views and contaminate water and wildlife in our national parks and wilderness areas for decades to come.

Thank you for considering my comments.

Sincerely,
Steve Lovelace
PO Box 245
Wilkeson, WA 98396

From: Rees, Sarah (ECY) on behalf of ECY RE AQComments
Sent: Thursday, April 29, 2010 5:29 PM
To: Schneider, Doug
Subject: FW: Fight Coal Pollution in Washington!

Form Letter #2

-----Original Message-----
From: Sierra Club Membership Services
[mailto:membership.services@sierraclub.org] On Behalf Of Frank And Nola Allen
Sent: Monday, November 09, 2009 10:04 PM
To: ECY RE AQComments
Subject: Fight Coal Pollution in Washington!

Nov 10, 2009

Sarah Rees

Dear Rees,

I have the following concerns regarding the proposed Settlement Agreement between the Department of Ecology and the TransAlta corporation regarding its coal plant.

From health care professionals to park rangers to fishermen, the Washington public has grave concerns about that this plant generates in our communities. As the state's largest polluter for global warming, mercury and haze (from nitrogen oxide pollution), the cumulative impact of this plant affects Washingtonians from every walk of life. The State should not move forward with the Settlement Agreement as proposed until a more substantive review can take place.

There are four main problems with this Settlement Agreement as it now stands:

1. This agreement is insufficient in controlling nitrogen oxide, the main cause of haze in our national parks and wilderness areas.

2. The reductions required for toxic mercury emissions are insufficient and should be improved to 90 percent.

3. The pollutant-by-pollutant process has distorted the pollution impacts of this plant on public health.
4. The public process has been insufficient.
I hope the state will carefully consider our concerns. The TransAlta coal plant is the dirtiest form of energy in the state and is the leading source of top environmental problems. I know we can do better than the specifics in this Settlement Agreement and for the overall pollution problems caused by the state's only coal plant.

Sincerely,

Dr Frank And Nola Allen
2147 E Shelby St
Seattle, WA 98112-2027
(206) 323-3168

Jerry: We're gonna get started in just a few minutes. So if you want to find a seat that would be great. There's a hand-out on the outside table just outside these doors. If you didn't get a chance to pick one of these up and you'd like to have one just raise your hand, we'll have a staff person bring it to you. It's like a focus sheet so we'll have Kim bring some of these focus sheets in. Can you all hear me way there in the back? You guys can come on up front if you like.

Female: Okay.

Jerry: Can you hear me okay? All right. So good evening, my name is Jerry Feelin and I'll be the facilitator public hearings officer for tonight's public hearing. On behalf of the Department of Ecology I want to thank you for coming out here tonight to provide testimony for the proposed ecology TransAlta Mediation Agreement. Let the record show that it is 6:38 on Tuesday, September 13, 2009 and this public hearing is being held at the Department of Ecology Headquarters Building at 300 Desmond Drive in Lacy, Washington.

A couple of logistical things. If you have not already turned off or silenced your cell phone, PDA's, pagers, anybody even carry a pager anymore? If you would do that at this time that would be great. Restroom facilities back out through this set of double-doors. Don't take the big stairs up although there are some up there at the top of those stairs. Just go through to the little stairs for those of you who came down the elevator and on the right hand side where you get to the elevators there's signage once you get to that little foyer there.

You will find restroom facilities and you begin – okay, would you bring in a couple of the focus sheets please? There's some folks that would like to get a copy of that and we did. If you want to hold your hand back up. If you didn't get those we'll make sure that those get to you.

Female: Anybody else.

Jerry: And as you came in you were asked if you wanted to, if you would sign in on one of our attendance cards. We're required to do this for the security of the building. And there's also the opportunity for you to indicate whether you want – would like to testify or not. There's about eight or nine of you that have indicated such. If you didn't realize you had to check that box, don't worry. When I

exhaust the list of those who have identified that they want to testify I'll come back, see who else wants to, or maybe you maybe changed your mind and you now want to testify. So just because you didn't check it on the way in doesn't mean that you still won't get a chance to do some testimony.

Basically the agenda is going to go like this. We're going to have a short presentation by a couple of staff folks from the air quality program. That will be followed by a short question and answer period. We'll have some – we have some marvelous microphones and we'll bring those up to you. Just raise your hand and we'll bring those to you. We'll facilitate the short question and answer period and then we'll get right into the formal public comment public testimony. So far, so good?

We're gonna run over just a couple of ground rules. Nothing earth-shattering or ground-breaking here. Most of the things are things that we learned about being nice to one another back in kindergarten. So we're gonna ask that you hold your questions during the presentation so we can get through the presentation and then we'll get – facilitate the questions of staff at the end of that. No distracting or destructive behavior. We request that you have respectful voices.

We could be recognized during the Q&A part and I'll do that recognition and then we'll have one of the microphone runners go to you. For the public comment I'm gonna call you up in the order in which you signed in, and again, if you didn't sign in or you didn't indicate that you wanted to testify and if you didn't so indicate we'll give you a chance to do so at the end. We have to use this one a lot sometimes.

We're gonna ask that you respect the right of others to have an opinion even if you don't agree with that opinion. Okay. You respect the right that they have – they have the right to have their opinion. We're gonna limit the testimony to some reasonable length of time. There's only like, say, nine or 10 of you that have indicated – we're probably gonna start at about five minutes. Hopefully you can get through in five minutes.

There's only a few of you. I'm gonna let that go a little bit. I won't let it go 12 or 15 minutes because there are people who are patiently waiting at the end of that list to testify. You have the parents' statement. If you'd like to turn that into us tonight that has the same weight as any oral testimony that you might present as does any of the written comments that you might submit during

the public comment period. So I'll – we'll wait until we get all the cards in as a few other people are trickling in but we're probably gonna go somewhere in the five to seven minute range. That's definitely about an hour's worth or so in barely about an hour's worth of testimony. So that sound reasonable to you folks? Somewhere between five and seven minutes. I mean you can probably speak to your concerns during that time frame.

Okay. With that we're gonna turn it over to the ecology staff for their presentation. We have Sarah Rees and Al Newman and you can follow along with their slideshow here and, again, we'll ask you to hold your questions and we'll facilitate that question and answer at the end. Sarah?

Sarah: Great, hi. So can folks hear me? I was just getting close enough to the mic. So again, my name is Sarah Rees and I'm a manger with the Air Quality program and I'm gonna go over the basics of the mediation agreements and the mercury agreement that we have here and then I'm gonna turn it over to my Senior Engineer, Al Newman, who is gonna go over some of the details of our draft board determination.

So before I get into that I just wanted to give a little bit of a background on the TransAlta Centralia facility. It is the only coal fire power plant that we have in the State of Washington which is a bit unusual. In most states you'll have several of these but we only have the one. It started operating in 1971 so it's an existing facility. It's been around for quite a while. It's rated at 1400 megawatts of capacity which is a significant coal-fired power plant.

That generating capacity is important not only for the power that it produces but the location of that power. It's the only facility that's sized this side of the Cascades so it's really important for good stabilization.

Why we're taking action right now on this? As with all coal-fired power plants TransAlta generates mercury and it generates significant amounts of mercury. So in ecology mercury is a priority chemical for us and so it was important for us to work towards getting reductions of mercury emissions from the facility. It is the top source, single source of mercury in the states.

We also have some requirements that are triggered under the Federal regional haze rule and so because of the time the TransAlta was built and the type of facility it is there were some requirements

we had to go through and we knew we needed to do something about that and work with the facility on that and we decided that the best way to go about doing that given these two issues was to go into mediation. There were significant environmental issues that we wanted to resolve, we started this mediation process in the Fall of 2007.

Jerry: Sarah, move that just a little bit closer. This is – it's up as far as it'll go.

Sarah: Okay.

Jerry: It's just hard to hear you in the back.

Sarah: Can you guys hear me? Is this better?

Jerry: Speak up.

Sarah: Sorry about that. So we started this mediation process in the Fall of 2007. It was subject to the Uniform Mediation Act so it was a confidential mediation and we did that for a couple of reasons. One, we wanted to have open discussions with the facility so that TransAlta would be able to share some information that might be confidential business information.

Because we're a public agency unless we do that under a confidentiality agreement we can't protect that information and so we wanted to be able to have that environment to have those discussions with the plants. There was also the threat of litigation here. Certainly under the Federal regional haze rules ecology had the position that that facility was subject to a review to see if there were additional controls required.

Doing this on the mediation allows us to proceed and to work through with the facility and get to some resolution without having to go through a lengthy litigation process. And we did agree going through the mediation that there would be a public process coming out of this. Before signing any agreement with TransAlta there would be an opportunity for public review and comment.

We had a public meeting in the end of March of 2009 and now today we're having this public hearing, we also have a public comment period that's open and that will be open through November 9.

So what did we agree to in this mediation? It's focused on significant air issues. For mercury TransAlta is gonna be making voluntary reductions in their mercury emissions. They're gonna be installing controls to do so. On regional haze, ecology has come up with a determination of what constitutes best available retrofit technology, also known as BARTS for nitrogen oxides.

It's important to note that this mediation agreement does not include any agreement on greenhouse gas emissions from TransAlta. I know there's a lot of interest about that because TransAlta is clearly a significant emitter of greenhouse gas emissions in this state but that's covered under executive order 0509 by Governor Gregoire. That executive order requires ecology to work with TransAlta to come up with ways to reduce greenhouse gas emissions from the facility by about 50 percent by 2025. So that will be an entirely separate process from this mediation agreement.

Now on mercury, and I mentioned that TransAlta is voluntarily reducing their mercury emissions. There's currently a regulatory gap for mercury. The Federal government had started a rule making for mercury from coal-fired power plants in 2005. That rule would have given Washington a budget for mercury. It would have then allowed plants that were subject to that budget to trade mercury nationally.

That rule by the Federal government was struck down by the D.C. Court of Appeals in February of 2008. So when that rule got struck down there was a gap left behind. The Federal government is currently proceeding with developing a max standard for mercury for coal-fired power plants. That standard would constitute basically the top 12 percent of technologies for mercury control from those facilities. That process is gonna take several years.

EPA is undergoing it right now. They're in the way of doing some information collecting but there likely won't be a standard in place until the 2016 or 2017 time frame. Meanwhile what we have with our agreement, TransAlta is currently testing controls. They've installed emission monitors so they'll be able to start self-reporting what their mercury emissions are to ecology this year and, because they're going through the testing and starting to look at this they're starting to get some reductions in mercury.

By 2012 they'll be reducing their mercury emissions by 50 percent. So going through this process really gives us the fastest

path to get some mercury reductions today instead of waiting for a Federal process to work itself out. So the type of controls that they're installing, it's an activated carbon injection. You may also hear the term sorbent injection. Basically that is kind of like it sounds. You would inject activated carbon into the flu gasses of the facility. You pick an injection point where you want to maximize the contact of this activated carbon to the flu gasses and the carbon acts a little bit like a sponge and it takes up the mercury and separates it out from the flu gas.

These are state of the art controls for any existing coal-fired power plant. If you wanted to reduce mercury you would install this kind of system. As I mentioned before TransAlta is already testing this. They went out and hired a consultant and they've been running some tests through the summer and they've seen some pretty promising results coming out of this work, again, oriented towards a 50 percent reduction goal.

One thing I do want to mention is that there are some potential impacts to other processes as a result of activated carbon injection. When you move mercury from air it goes somewhere else and so one of the consequences of this process is that there will be – there may be some mercury contamination in fly ash from TransAlta. The plan is to have the controls fully-integrated into the system and operating by 2012 and the total cost to implement this would be about $20 to $30 million range.

So, as I mentioned, TransAlta is currently running tests to optimize mercury controls. These controls are not the kinds of things that you buy off the rack and you just slap onto the end of the tail pipe. They do require that there is a number of tests to go on to try to get the right point of injection, to try to get the right sorbents included, try to get the right injection rate.

And so there's a lot of work that has to go on to optimize this and make this work out right. From the current tests it does look like TransAlta will be able to get at least 50 percent reduction. The current emissions we believe are in the ballpark of 400 to 500 pounds per year.

So these are very significant reductions in mercury that we're looking at and, again, the preliminary test results look like it would be possible to go even higher than that. It's just preliminary results so we can't bank on those numbers but again the technology looks very promising.

So now I'm gonna turn this over to Al Newman and he'll give you some more detail on the regional haze rule and BARTS.

Al: All right. The – there's a Federal regional haze rule that was issued a number of years ago and, among other things, it requires ecology to submit a – what's known as a state implementation plan which is the outline of how we intend to get from the current visibility conditions in wildernesses and national parks to what's considered or defined as natural conditions by 2064.

The plan is in steps. It's in a number of 10-year steps and the first plan is considered a foundation plan upon which the others are based. As part of the initial set plan we have to make sure that all facilities that are BART eligible and subject to BART are evaluated for their emission controls and if a further emission reductions that meet the criteria of the best available retrofit technology definition exist and can be implemented on the plant to require those controls.

So the best available retrofit control technology applies to a family of 26 specific source categories. In Washington that includes the TransAlta plant and six other facilities. All of these facilities have equipment that was built in between August '62 and August 1977 which is a period of time defined by the Federal Clean Air Act. They all have the potential of their BART eligible equipment to emit at least 250 tons per year of one of the visibility impairing pollutants and that the actual emissions from these facilities either cause a visibility impairment through modeling of one deciview or greater, which is a metric of visibility impairment, or contribute to visibility impairment by having an impact of half of a deciview or greater.

In the BART analysis process as defined by EPA and their guidance where the process starts with identifying all of the available retrofit controls that can be applied to a facility and elimination of all of the control technologies that are infeasible to operate on the facility, evaluating the control effectiveness of all of the remaining opportunities, evaluating the various impacts of the – those controls and documenting the results of that analysis and evaluating the visibility impacts and potential improvements from the emission controls that are proposed for BART.

So in the case of TransAlta's power plant emissions the BART determination process is limited to the Nitrogen Oxides emissions only. There was a regulatory process operated by the Southwest Clean Air Agency starting in 1997 that resulted in the construction

of emission controls for sulfur dioxide, nitrogen dioxides and particulate matter. Graphs on the side of the room here show the reductions that have occurred over that time due to those requirements for sulfur oxides and nitrogen oxides. As part of a 1999 visibility submittal, EPA approved in 2003, EPA accepted that the sulfur dioxide and particulate emission limitations that came out of that 1997 regulatory action represented BART for those pollutants and specifically said that nitrogen oxides did not currently represent BART or could not be defined whether it did or did not represent BART.

As a result this analysis that we've done is with the information developed in part by the company is limited to the nitrogen oxides portion of their emissions. So they evaluated a number of controls. The actual list started with the 37 different control technologies that were evaluated in 1997, looked at the most promising of the nitrogen oxide controlled technologies out of that list and added additional ones that had been found or developed in the meantime.

The primary new control technology that had showed up in the meantime has been over fire air – alternative over fire air systems and improved boiler optimization process, both of which were evaluated as part of this process. The more run of the mill and commonly applied technologies of selective catalytic reduction and selective non-catalytic reduction were evaluated in greater detail.

Both of these processes involve the injection of ammonia or urea into the flu gas from the boilers where it react – the urea or ammonia reacts with the nitrogen oxides to produce nitrogen gas and water. The big difference is the non-catalytic does not use a catalyst. The catalytic version uses a catalyst to achieve the controls at a lower temperature.

So one of the projects that I did not list on that was called the flexible fuels project or flex fuel project. It was a project that was ongoing with the plant at the time of the BART analysis and, as a result of the use of this project, nitrogen oxides were going to reduce approximately 20 percent. The primary reason for this was being able to operate on non-centralia coal. The target coal of the design has been a powder river basin type low sulfur sub-bituminous coal.

Along with this process and as part of the mediation agreement, the company has agreed to go – continue to work on how to further reduce the nitrogen oxides emissions over time and as a side benefit since the coals that are targeted from the flex fuel project

contained lower sulfur than the Centralia coals that they are currently replacing there will be a significant reduction in sulfur dioxide emissions.

So there are a number of other considerations in the BART process that are looked at. Some of them which are not listed on the slide include the costs of compliance, the energy and non-air quality impacts of the potential to control technology, the existing controls already in place at the plant and the remaining useful life of the plant in addition to the degree of visibility improvement that might be achieved.

In the analysis in the end the flex fuels project and selective non-catalytic reduction result in approximately the same improvement in visibility and approximately the same emissions reduction. Along with that we have some legislation laws that exist that reflect the carbon dioxide emissions and also in that process limit the opportunities of the plant to make modifications that increase its emissions.

There's an economic impact of the fly ash recycling and sort of as an also-ran the Governor's Climate Change Executive Order has the potential of limiting the useful life of the facility.

So what follows this meeting? We will – and the public comment period on the BART analysis is that we will evaluate all of the comments that we receive and we will write up a response to those comments and as necessary make changes as appropriate to our BART determination.

Later after this, after we've reviewed the comments, the mediation agreement would be signed or otherwise and later in early 2010 this BART determination along with the other six BART determination and our regional haze SIP as a whole will be open for public comment again and that's it.

Jerry: All right. Thank you very much. Thank you for your patience in holding your questions. Appreciate that. I will now open it up for the next 15 or so minutes so – to take your questions. This will be the opportunity for them to respond directly to your questions. We'll set apart a little bit the process where we get to the public hearing. You can certainly ask a question of staff on the record but the staff will not be engaging in responding to that comment that you might make during that public hearing.

So if it's a question that you want an answer from tonight ask it during the Q&A. It goes onto the official hearing transcript. We're not gonna allow them to engage in dialog at that time. So we have Miriam and we have Tammy who will bring a microphone to you so that everyone can hear and I see a hand right here. We'll start right there. If you would stand and give us your name that would be great.

Brimmer: Hi, I love miseries. I'm Jennifer Brimmer with Earth Justice and I'm here on behalf of Sierra Club National Parks Conservation Association and the Northwest Environmental Defense Center and I actually have a question about questions. I have a lot of questions and it would probably show up more than the 15 minutes so I would like to make a proposal that I forego asking those questions here in the interest of speeding things along, and that I submit them to you in writing and you respond in writing but that we post those so that everyone that's here for the public hearing would get the benefit of the public exchange. Would that be an acceptable process?

Sarah: Let me get close to the mic here. Yeah, I think that would be an acceptable process and we'd be happy to do that.

Brimmer: I will submit those questions hopefully tomorrow, no later than next week.

Sarah: Thank you.

Brimmer: Thank you.

Jerry: All right. Who's next? Yes sir, right over here.

Quinn: Hello, my name is Mark Quinn. You mentioned that part of the agreement with TransAlta obligates them to begin addressing carbon dioxide emissions at some point up to 2025 to meet an early requirement for global warming emission, greenhouse gas emissions. I was just wondering how is that going to happen?

Sarah: Well again this agreement doesn't address carbon dioxide emissions. There's a separate process for doing that under Governor Gregoire's Executive Order 0509, and so that's ongoing right now and what that does is requires ecology to engage at TransAlta to work with them to get to a 50 percent reduction by 2025, and so getting that amount of reduction of greenhouse gas emissions from a traditional coal-fired power plant, it's gonna take a lot of looking at different technologies that are out there,

potentially different fuels that would be used. That process is very much in the starting point so that we haven't thought through all of that but we're just embarking on that process to figure it out.

Jerry: Thank you. Anyone else? You must have questions. Did I see a hand?

Male: Yes.

Jerry: All right. Right back here in the – hand me your – we can get there to you.

Male: I was wondering do you know the potential impacts of these mercury emissions and also BARTSA's reduce emissions as much as possible. Do you have an estimate of what that would work out to as it's defined in the percentage compared to the current emission rate?

Sarah: Okay. On the mercury emissions the mercury that's emitted from TransAlta is likely in a form that is gonna deposit much further away from Washington State. It's – mercury in general, there's an atmospheric mercury pool. Most of what we get is from Asia for the most parts and it circles the world several times before falling out and some coal-fired power plants that don't have any controls on them like the ones you find out in the Ohio River Valley for example, their mercury is in a form that falls out pretty close to the plants.

But TransAlta is a facility that has installed sulfur dioxide scrubbers and other emission controls that put their mercury in a form that's gonna go up, join this global mercury budget and kind of circle around for a while. So it's hard really to trace an impact here in Washington on that. We do know overall that mercury is a very important and toxic biocumulative toxin and so it's something that's important for Washington that we take steps to reduce and given that this is our single largest source of mercury in the state it's important that we look at that.

And then for the BART question I think I'll let Al answer that.

Al: Yeah, could you repeat it so I understand? I want to make sure I answer the question you're asking. Okay. If you need to ask me questions afterwards about what it means don't be afraid to come up.

Jerry: Yeah, staff will stay around following the end of the close here of the public hearing to address any one on one questions or comments that you might want to have. Yes?

ACI: I have part of a two-part question. The activated carbon injection, I'm curious if this process has ever been proven before to work and how effective it is, where – how deep down is the mercury going? Could it ever get out? If you could explain a little bit more about what that's about, that would be great.

And my other question is is are you counting the 50 percent reduction in mercury within that or is the reduction coming from something else as well?

Al: Yeah, Activated Carbon Injection for mercury control is actually a very well-proven technology. It's used on municipal waste and hazardous waste incinerators routinely for a number of purposes. It's been used in Europe for two decades at least for mercury reductions.

The mercury enters the pour space on the activated carbon and if it's an oxidized form of mercury it then binds in the carbon. If it's an elemental form of mercury it doesn't bind as well and that's why halogenated versions of activated carbon are often better at removing mercury from flu gasses when there are low quantities of – or I should say when the mercury is primarily in an elemental form.

There's a lot of research around whether the mercury stays in the carbon over time and the bulk of it that I have read which, granted, is not the bulk of the research that's available, indicates that once the mercury is in the carbon it will stay there as long as you don't burn the carbon. Okay. And the other part of your question was –

ACI: Is that part of the 50 percent reduction?

Al: 50 percent reduction is entire – that is being evaluated here is entirely due to the carbon injection. There is some – in the case of the Centralia facility with the wet limestone scrubber system there is some additional small removal that can be achieved through the web scrubbing system but that's not part of the 50 percent as it's been evaluated to date in their testing.

Adam: My name is Adam and this is a question direct towards Sarah but I guess all of you. You had mentioned earlier that the mercury that would be emitted into our atmosphere and by "our" I mean the

world would not directly – you know – would not really be affecting us in Washington, wouldn't be very near us. It would be spread out throughout the world and that most of our mercury in the atmosphere that we get is actually from Asia and that first strikes me as a little bit immoral to put our mercury on someone else, but first I want to just real quick read the Department of Ecology's mission and then I have the question.

The mission of the Department of Ecology is to protect, to preserve, and enhance Washington's environment and promote the wise management of our air, land and water for the benefit of current and future generations. In order to fulfill our mission and move Washington forward in a global economy the Department of Ecology has three goals: prevent pollution, clean up pollution and support sustainable communities and natural resources.

And a key word that you had mentioned that stuck out to me was "bioaccumulation," and I'm sure a lot of us have all heard about this and the fact that there is mercury build-up, especially in the fish that we eat, especially like the salmon which are so much an important element of our Washington culture.

And so my question is how is just putting our mercury on someone else wise management, let alone moral?

Sarah: And I – we do take mercury very seriously. It's one of the top priority chemicals of concern at ecology and that's one of the reasons why we worked with TransAlta to get a reduction in emissions and to get a very significant reduction in emissions faster than what the Federal government would require.

My statements as to the mercury traveling around the world and kind of joining this global mercury budget, I mean that's just really what happens with this type of mercury and it's a phenomenon that's pretty well-documented that most of what we do get in the U.S. is from coal-fired power plants in China.

That said, we take it very seriously that there is an emission source coming from Washington. It's gonna fall out somewhere. It doesn't necessarily not aware, and so that's why we're taking steps to reduce it to the extent we can.

You know we feel that going through this process with TransAlta, they're installing the best possible controls for mercury that are available and they are taking steps to do it as soon as they can. They're not waiting for any kind of later deadline, so we feel that

this is making a very substantial step in reducing mercury emissions within this state.

Jerry: Any more questions? We have time for a couple more. Yes, way in the back?

Wilcox: Yeah, I'm Jim Wilcox of Trout Unlimited here. I just want to agree with Adam. It's real wise for a young man like him to say, "Are we not good neighbors in Washington? Should we be able to do like others and put our garbage in the air?"

And I'm curious about with mercury, I'm not sure about this, but how does that look like acid rain? What happens to the mercury when it – when we get rains? And then fish and wildlife as a member of Trout Unlimited is certainly important. In talking with a Fish and Wildlife biologist recently he said there's concerns about the salmon and other fish that the Orca whales are eating and causing problems. So there's some issues there and if we could get any of those touched on it would be great. Thanks.

Sarah: Okay. So again we do acknowledge that mercury is a significant issue within the state and most of what we get from deposition isn't coming from within Washington but, that said, we are taking steps to try to manage and reduce our sources internally.

As for the – what it looks like compared to acid rain, mercury that's emitted from coal-fired power plants that's in a form that would deposit locally, meaning from those facilities that don't have additional controls that TransAlta has, those would fall out closer to home kind of in the way that acid rain would work.

But the stuff that's mostly kind of going up and circling around in the global budget, we don't get as much of that. So it doesn't really line up for this particular case as much as well with the acid rain analogy.

Jerry: Time for one more, right up here.

Brimmer: Have you – Jennifer again. Have you sent a draft of this to EPA and solicited their input?

Sarah: A draft of the overall agreement?

Brimmer: The Mercury Environment Agreement.

Sarah: EPA has seen our draft BART analysis. We've not worked with them on the mercury.

Brimmer: What's been the reaction?

Sarah: BART's, they've had some comments and we've had some dialog about it. We – it's part of our normal course of working with EPA on any of our BART submissions.

Brimmer: What were EPA's comments?

Sarah: EPA has asked us some questions about our analysis, to ask us more about how we've justified using different technologies over the other and asked us for more supporting information.

Brimmer: Was EPA then critical?

Sarah: EPA has asked us for additional supporting information where they felt the analysis needed it.

Jerry: Okay. Any other questions? No? Oh, we have one. Okay. One more. This will be the final one and we'll move into the public hearing. Right back here.

Female: Now I'm just trying to figure out how much of this agreement was coming from TransAlta and how much of it was coming from you guys. How much pressure did you actually put on them to reduce their emissions and get the best possible agreement?

Sarah: It was a joint agreement. We worked with the facility because we had an interest in reducing mercury and we also needed to work through a process on reducing nitrogen oxide emissions for BART and so I think it was really a joint agreement that we reached.

Jerry: Take one more?

Female: Why not reduce emissions altogether? That would be a great goal to shoot for and eliminate, not produce any mercury at all.

Sarah: Elimination to not produce mercury at all would likely require this facility to be shut down and that's not where we were going with this agreement.

Jerry: We're gonna go ahead and wrap up the Q&A part at this time and move right into the public hearing. I don't like this microphone.

Male: Here, try that one.

Jerry: All right. Maybe this one isn't quite as sensitive. Okay. I'm gonna call you up in the order in which you signed in. I'll apologize in advance for any mispronounced names.

I'm gonna ask you to step into this microphone here, state your name and any affiliation that you might have, and again, we'll put a loose timer on you, somewhere between five and seven minutes as, again, we only have seven or eight folks that have currently identified that they want to testify.

If we go way beyond that I will apologize again in advance for interrupting you and asking you to submit to wrap up your comments or otherwise submit those in writing. Okay. First up, we have Donna Albert. She will come up and she will be followed by Mark Quinn. I'll have you speak right into that microphone.

Female: Donna Albert?

D. Albert: Right here, back here.

Jerry: Is that her back there?

Sarah: Is that mic on at all?

D. Albert: I'm not representing my employer but here as an individual representing my grandchildren: Austin, Donovan, Terrance.

Jerry: Okay. Tell me – then those are some – it's an emotional issue for a lot of people. Mark Quinn?

Quinn: My name is Mark Quinn. I'm here on behalf of the Washington Wildlife Federation. We are the state affiliate for the National Wildlife Federation and, like them, one of our top priorities is advocating for the establishment of a clean energy economy. We appreciate ecology's efforts to try to make emissions from the TransAlta coal – trying to reduce emissions from the TransAlta coal-fired power plant and make them cleaner and safer according to existing state and Federal rules which unfortunately don't do a very good job of making the air safe.

Even more unfortunately, the burning of coal to generate electricity is a process that even the most advanced technologies cannot make clean. Coal is the dirtiest source of energy on the planet and while we can argue that new technology makes it cleaner it's still the

dirtiest way to generate electricity when burned coal produces almost twice as much carbon dioxide as natural gas, four times as much carbon monoxide, four and a half times as much nitrogen oxide, almost 2,600 times as much sulfur oxide particulates, mercury, one of the most toxic substances known, as well as radioactive uranium and thorium.

If that wasn't enough to make you want to stop burning coal you can look further to the destroyed landscapes that result from the mining of coal and the huge stockpile of 130 million tons a year of hazardous coal ash, the leftovers after the coal is burned.

Ads about clean coal and the notion that its development is just around the corner with carbon capture and sequestration are very disingenuous. There are huge technological obstacles to overcome. When you consider where to store approximately six billion tons of carbon dioxide annually from the nation's coal plants you begin to understand the complexity and insanity of such a proposal.

We should leave coal in the ground where it and the carbon locked in its molecules can be used to continue filtering our ground water. We want to see every effort taken to control toxic emission like nitrogen oxides and mercury, and eventually carbon dioxide at TransAlta but a better approach in Washington, a state that according to Governor Gregoire when she talked to the Washington Conservation Breakfast just a few days ago, she said she wants to make Washington a global leader in reducing greenhouse gas emissions.

So a better plan for Washington would be to slowly but surely phase out the burning of coal as a fuel source for electricity in the first place. It won't be easy but it will be much better for our long-term health and welfare, something that is clearly the responsibility of government to ensure. Please figure out a way to get this state out of the coal business once and for all and transition to a clean energy economy that can sustain our health and welfare and our economy.

That's the vision that we'll – that's the vision that we'll get Governor Gregoire and the State of Washington where she wants it, leading the nation and the rest of the world in the fight against climate change. Thanks.

Jerry: Thank you, very much. Next we have Randy King and he'll be followed by Jonathan Smith.

R. King: Good evening, I'm Randy King, the acting superintendent of Mount Rainier National Park and I appreciate this opportunity to present comments of the National Park Service on the proposed consent to create addressing best available retrofit technology BART emissions reductions at the Centralia facility.

Centralia facility is located in proximity to majestic national parks and wilderness areas whose resources are significantly affected by its nitrogen oxide emissions.

Mount Rainier National Park was established by the citizens of Washington in 1899 as the nation's fifth national park. It's about 50 miles away. Emissions from Centralia facility almost impact Olympic and North Cascades National Parks and I'm also speaking this evening on behalf of Superintendent Karen Gustin of Olympic National Park, and Superintendent Chip Jenkins of North Cascades National Park.

By law our nation strives to conserve on par national parks and wilderness areas in their natural state, protected from the adverse impacts of air pollution.

In 1995 we testified regarding the need for strong limits on emissions of sulfur dioxide at the Centralia facility to address the visibility impairment and other environmental concerns of the park and in the region caused by those emissions.

We note with appreciation that since those strong emission limits were put in place and the facility came into compliance there has been a dramatic reduction in measured sulfate at Mount Rainier and a corresponding statistically significant improvement in visibility on the 20 percent worst visibility measured at the park.

Today we note that the proposed consent to create does not require the best technology to reduce emissions of nitrogen oxide, also a key component and visibility impairment at the parks. Our review of the technical support documents provided by the state concludes that applying the best technology to reduce nitrogen oxide, an example of this led to cataylitic reduction technology, is both technically feasible and the most cost effective option when considering the visibility improvements that would occur at Mount Rainier, Olympic and North Cascades National Parks, and nine other class one wilderness areas administered by the U.S. Forest Service.

We are also concerned that the consent decree which addresses the BART component of the Environmental Protection Agency's 1999 regional haze SIP rules was negotiated without participation by the Federal land managers.

Since BART is a critical element of the State implementation plan for visibility protection it is uncertain if the state's consent decree process met the requirements and the spirit of the Federal land manager consultation provisions of the Clean Air Act.

On June 24, 2009 the Department of Interior was petitioned by the National Parks Conservation Association, Washington Wildlife Federation, Sierra Club and the Northwest Environmental Defense Center to certify that emissions and nitrogen oxides from the Centralia facility are reasonably anticipated to cause or contribute to visibility impairment at Mount Rainier and Olympic National Parks.

Such a certification would also require the State to specify BART for Centralia to address any reasonable attributable impairment under existing provisions of the state implementation plan. The Department of the Interior's initial response to the petitioners expressed the hope that the State's actions on BART for regional haze would address any concerns for reasonably attributable impacts. The consent decree as proposed does not adequately address these impacts.

The Department of the Interior will make a final decision regarding the petition pending the outcome of the Department of Ecology's actions for regional haze BART.

To remedy our concerns with the BART limits established in the consent decree we request that the Department of Ecology take a strong leadership role similar to its sulfur dioxide actions in 1995 and incorporate a BART requirement for selective catalytic reduction technology in the regional haze State implementation plan requirements for Centralia.

This would limit Centralia's emissions and nitrogen oxides to approximately 3,000 tons per year or approximately 12,000 tons per year less than that proposed in the consent decree.

Like the reduction in sulfur oxide clearly indicated such a reduction of nitrogen oxide would lead to a direct improvement in visibility of Mount Rainier National Park as well as contribute to

improve visibility and increased health effects from fine particular matter region-wide.

While the focus of our concern is the nitrogen oxide emissions we are also concerned with mercury deposition at Mount Rainier and throughout the region. We note that addition of selected catalytic reduction technology, if appropriately designed, would be compatible with emissions reductions of mercury and would not interfere with future mercury emissions removal should pending new regulations from EPA require more reduction than the co-benefit resulting from sulfur dioxide, scrubbing and selected catalytic reduction.

In closing I would like you to think about the importance of Mount Rainier National Park to this region and the world for today's public and for future generations. There are many reasons that the law mandates our highest levels of environmental protection for these special areas. National Parks and wilderness areas are our natural and cultural heritage.

Sociology studies confirm their importance as do our individual experiences of recreation and renewal. Over 1.1 million people visited Mount Rainier National Park in 2008 to recreate and visitation as of the end of August of this year is already above the one million mark.

Regarding the economic benefits of the park, for example, in 2001 when our last visitor survey was conducted we learned that recreation visitors to Mount Rainier National Park spent $29.8 million within a 30-mile radius of the park. The total economic impact of visitor spending was $24 million in direct sales, $9 million in personal income, $13 million in direct value added in 649 jobs.

With multiplier effects created by the recirculation of money spent by tourists, visitor spending generated about $35 million in local sales and an associated $13 million in personal income, $20 million in value added and 812 jobs. These figures do not include park emission fees or the impacts of the MPSP role in operations in the area.

National Parks and wilderness areas not only guard the natural and cultural assets of our nation but they are also among our most sensitive gauges of environmental stewardship. Harm to these resources that our nation strives hardest to protect must signal an alarm for other resources and for us.

The National Park Service's desired outcome in this process is a solution and a decision that protects air and other important resources by using proven cost effective technologies to significantly reduce nitrogen emissions from the Centralia facility, to be clear an outcome that the National Park Service does not seek as a closure of the Centralia Power Plant.

Experience from other states and the success of the 1995 collaborative effort in reducing sulfur dioxide emissions from the plant tells us that these two outcomes achieving a significant reduction in nitrogen emissions and keeping an important facility operating are wholly compatible. We stand ready to work with all interested parties towards these outcomes.

This concludes my testimony. The National Park Service will be submitting detailed technical comments on a consent decree before the close of the public comment period. I thank you for the opportunity to testify on that. Thank you.

Jerry: Jonathan Smith, and he'll be followed by – is Maya Face?

Maia: Maia.

Jerry: Maia. Mr. Smith?

J. Smith: Hi, and I've worked for the past couple of years as a political campaigner and what I would call to light something that I think we're all pretty aware of. Right now coal is not very popular. It just isn't. People are waking up and becoming aware of coal as the dirtiest form of energy and we've seen a lot of campaign dollars come in to various campaigns and to TV ads and radio ads in our state making an awareness of coal.

Your comment was really enlightening when you responded to – I forget whose question but when you talked about keeping the facility open, this process of dividing C02 emissions, doing the closed door arbitration to talk about mercury reduction seems like a tailor-fit project to try to keep this facility open but this facility is not popular in Washington state.

I want to make you aware and I want to raise the issue up to the Governors through this comment period that this is not gonna work out as a positive – as a positive spin but it's going to play back politically, it plays back with the citizens of Washington state.

It may well prove at some point soon that siding with the bad guys against the will of the people may be a dicy prospect in a democracy. Thank you.

Jerry: All right. Thank you. Maia? And she'll be followed by Adam – is it Fleishman?

A. Fleisher: Fleisher.

Maia: Hi, my name is Maia. I'm another organizer and campaigner and I've seen a lot of different companies try to brainwash themselves and say that they're doing something good and in pretty much every single case the situation is that they're not actually doing nearly what they say that they're doing and that they're not doing even a small fraction of what they actually could be doing.

So basically I think you just gave yourself away saying that it was a collaborative process, basically saying that you guys don't have that much of a backbone to stand up against them and push for some more tough regulations and it's – it basically shows that you're not doing everything that you possibly can to reduce the mercury, to reduce the carbon dioxide and to reduce the nitrogen oxide.

I also, I wanted to bring up that there's – I don't know if people are aware that there is an online sludge pond from the mining that happened originally there that still hasn't been cleaned up and this plan doesn't address that at all and it'd be really great if that could get cleaned up some time. In my opinion it's also a big – it's a liability issue and there's also people who live near there so it's – the mercury there and the mercury that's being emitted from this plant is a huge danger to our health and to the – I was really happy to see this person from the National Park Service come because I think that this is having – I've studied mercury. It has a significant, significant impact on human health and on wild areas, and I think any level is unacceptable but 50 percent isn't nearly what is possible.

In states like Maryland and Illinois they have reduced their mercury emissions from 80 to 90 percent and this is all carbon – activated carbon where is the – how about out of the stack? You know, how about some reduction in mercury emissions from another source or how about – and still then addressing like you said the elemental mercury.

So I'm very concerned about that. I think that our first priority when we're talking about these issues should be reducing our consumption overall and then we can talk about increasing efficiency and then we can talk about alternative energy, and then – and after that we shouldn't need any coal-fired power plants.

So I just want to say that this is just the beginning. There's gonna be – we're gonna meet every step of the way. We have direct action groups who are ready to throw down for this. We have a whole slough of non-governmental organizations, non-profits behind this and we are very unhappy with this proposal and you made a grandmother cry.

Jerry: All right, thank you very much. Adam, you're next?

A. Fleisher: Hello, my name is Adam. I am a student here in Washington. I'm also a Washington state voter and a personal member of the Sierra Club but, for the record, I would just like to point out that the proposed agreement between the Department of Ecology and TransAlta contains, as we've been saying no controls for mercury but instead of voluntary mercury controls by TransAlta to reduce mercury – I think that 50 percent by 2012 was the number – while using well-established carbon injection technology which puts this mercury into the ground for my grandkids, for your grandkids, for everyone's grandkids in here, for the other people of this Earth's future including the plants and animals as well as using technologies which puts our mercury somewhere else for other peoples in the world.

And the fact that we get most of our mercury in Washington state from China doesn't mean that we should give the rest of the world our mercury that we expose. In addition this proposed agreement goes against the EPA suggestions that in fact the nitrogen oxide controls on the plant did not impact BART, that the EPA asked for more justification in these conclusions and, in fact, also not only EPA but now that the official statement of the National Park Service that this is not BART which is being agreed upon and that, in fact, would then be not legal.

And finally, like I said before, but just again for the public record it says in the Department of Ecology's mission that it is among other things the department's mission to promote the wise management of our air, land and water for the benefit of current and future generations and this agreement just to me does not seem to be doing that and, thus, it's breaking the department's own mission. Thank you.

Jerry: Thank you. We have a Shane – is it McCarter?

S. Macover: Macover.

Jerry: You said "maybe," on your testimony. Do you want to testify?

S. Macover: Yeah.

Jerry: Come on up.

S. Macover: All right. Mainly – hello? Yeah.

Jerry: You need to state your name and any affiliation for the record.

S. Macover: I'm Shane Macover. I'm not affiliated with any political group so I did once try to get a job with the environment in Washington but that fell through.

[Audience laughing]

S. Macover: Anyway.

Jerry: You can meet with him in the lobby afterwards, exchange business cards.

S. Macover: Anyway, the only thing I want to comment on really is that this says it's – the plant's volunteering mercury reduction which we have seen voluntary plans to do environmental benefits for a long time that happened with the EPA that we – would have made the Clean Air and Clean Water Act voluntary and typically it's a real surprise, they usually don't follow these voluntary compliances.

I think that, really, what we need is something with much more teeth than this and that the voluntary response is really just a way to throw some legislation and it and pretend it goes away. Thank you.

Jerry: Thank you and good luck on that job hunting. Next we have Jeanette – is it Brimmer?

Brimmer: Yes.

Jerry: And then Donna, you'll be back up if you're ready to go.

D. Albert: Yes. Do you want to go before me? You can.

Brimmer: Okay.

Jerry: Yeah, go ahead.

Brimmer: Hi, I'm Jeanette Brimmer. I'm with Earth Justice. As I stated previously I'm here on behalf of the Sierra Club Special Parks Preservation Association in the Northwest Environmental Defense Center.

I want to begin by noting that we will provide detailed written comments within the comment period which will include an – a report. We've engaged the services of Dr. Sabo to help us with that. I will note, as stated in an e-mail earlier today that constrained access to the documents, the fact that we're having trouble getting documents because of claimed mediation privileges and confidentiality has hampered that review and I hope that we can work toward getting access to those in a timely fashion so that we can, in fact, complete our review.

I'd like to echo Superintendent King that testified earlier that Washington is home to some pretty astounding resources. In fact I think our natural resources in many ways define this state. It's a hugely critical part of the region's economy from subsistence fishing to commercial fishing, tourism, agriculture and forestry, and I'm sure that the Department of Ecology doesn't need to be told that.

Mercury and nitrogen oxides emissions among others, global warming has been raised here tonight, CO2 emissions, are harming those industries, harming our resources, harming the industries that rely on them as well as public health, and TransAlta is the number one source of all of those harmful pollutants, and yet I have the feeling that we're not treating it like the number one source and not doing what we need to.

We are encouraging Washington to lead on these important issues, encouraging the governor to do so but we feel – we feel that this agreement and consent decree fail to demonstrate that leadership. They will simply perpetuate current haze conditions in particular and may do the same relative to mercury.

We also see that the State, the Department of Ecology appears to be tying its own hands in this agreement. We have a lot of concerns about some of the enforceability clause and some of the clauses with respect to promises about working with TransAlta in

the future that's going to prevent ecology from stepping forward, protecting these resources and the health of its – of Washington's citizens and the economy.

So let me turn directly to some of the pollutants at issue. So we've got that BART and nitrogen oxides or NOx issue. As I said, TransAlta as a coal plant is the single largest source of these emissions in the state of Washington but here's a really important thing to keep in mind.

According to the National Park Service TransAlta is the single largest cumulative impact to class one areas – class one areas of course being National Parks and wilderness areas in the nation. Now Four Corners has the dubious distinction of being the largest impact to a single class one area, and that being the Grand Canyon National Park, but this, I would say that we should not be proud that TransAlta is in our back yard having this level of an effect.

As the Department of Ecology is very aware haze is a significant problem even at current emissions levels and current levels is what we believe – and I think that this will be born out in the experts report and our written comments – current levels are going to be maintained.

I also want to just make note that while haze is a significant problem a lot of people might say, "Oh geez, big deal, visibility," what would we do if we couldn't see Mt. Rainier? I think people would find that to be a big deal.

But nitrogen deposition is an emerging environmental problem. I'm increasingly seeing studies. I know the National Park Service has these concerns as does the Forest Service, that a lot of our most precious areas are actually having their ecosystems changed as a result of nitrogen deposition and that's a direct result of nitrogen oxide emissions and that's something that we cannot afford.

Particularly with the changes that are going to be wrought from global warming we need those resources. We need them for the adaptability of the species and others that are going to rely on those.

I also want to point out with respect to the BART issue, EPA has made abundantly clear years ago with respect to the whole '97-99 agreement, that the low announced burners in the current technology of the plant is not BART.

I also want to emphasize what Superintendent King pointed out that there was a failure to consult the Federal land managers with respect to that process, so that too would contribute to the legal response that that is note BART, and I want to point out that the emissions control systems at the facility right now do not meet EPA's presumptive BART limit.

I know that the State entered into this process because they felt they were perhaps vulnerable or they want to avoid litigation with TransAlta. If that's the best arguments TransAlta can come up with those are weak. I think you have the legal arguments to withstand that and I would like to see that leadership for the State.

The SCR technology is available and feasible. I think we've already heard that tonight. The only arguments that I have seen from TransAlta are monetary. They just don't want to spend the money and, in fact, I think that the analysis by our expert and apparently the analysis by the National Park Service and the Federal land managers will demonstrate that, perhaps, it is in fact cost effective and that perhaps TransAlta's numbers have been inflated with respect to the costs of the SCR technology.

Other states are imposing SCR and we'll include information on that. We're researching that in our written comments and certainly, I would think, our resources here in Washington deserve the level of protection that other states are affording there.

I would like to move then to mercury. I strongly, strongly disagree that this department cannot regulate mercury simply because the Federal government has not taken a stand. The States, in all instances, have independent authority and obligations to regulate air pollutants including mercury.

The states can always regulate to a stricter standard than the Federal government can and I would invite the State to take that seriously. You do not have to wait for the Federal government. Other states are not waiting for the Federal government.

States in the Midwest and the Northeast have moved forward. They are imposing, and in some instances, achieving 90 percent mercury reduction or better and they are doing it with this technology, activated carbon technology. It's simply a matter of how much of that technology you use, how much carbon you use, how you work the process. You can remove larger amounts of mercury than this agreement provides.

In fact, interestingly enough, TransAlta on their own website has indicated that they are achieving 70 percent mercury reduction and they applaud themselves for doing so, and yet they don't seem willing to do that here.

I would submit that perhaps, again, it is that they don't want to spend the money on the level of activated carbon injection necessary and that they do not want to forego the profits they make from selling their ash to the cement kilns in Seattle, a whole 'nother environmental problem, one that is fraught with environmental justice issues as well.

I think one of the most egregious – that's probably a little hyperbole. One of the most concerning components with respect to mercury is the voluntary nature and, it's not just that it's voluntary. We also put a money cap on it. They can only have to spend so much money and that, voluntarily.

And then it appears that ecology said, "You know, if you don't even abide by this agreement we won't enforce it, we won't enforce the consent decree, there's nothing we will do to you if you choose not to abide by this," meaning that you're not even going to assert contractual obligations that would normally arise from a settlement agreement. That actually makes me wonder why we're bothering with a consent decree in the first place.

I, again, really believe that a greater mercury reduction is doable. I think Washington's resources are worth it. I think the health of Washington's citizens are worth it, and I would urge the State to lead on that and take a much stronger stance with respect to mercury regulation here, and with that, I'll conclude my remarks and you can put that in writing. Thank you.

Jerry: Great. Thank you, very much. Donna, would you like to come back up?

D. Albert: My name is Donna Albert. I'm a Licensed Civil Engineer with a Master's Degree in Civil Engineering working for the State of Washington as an Energy Engineer. I am not representing my employer but here as an individual representing my grandchildren: Austin, Donovan, Terrance and Tristin, who will be in their 40's and 50's in 2050, very possibly with grandchildren of their own.

To dramatically reduce the greenhouse gas emissions due to our use of electricity in the Northwest we must stop burning coal. According to the Northwest Power Planning Counsel's sixth power

plan, coal comprises only 13 percent of electric power capacity in the Northwest but is responsible for 85 to 90 percent of the carbon dioxide from the Northwest electricity sector.

In contrast coal is the major source of electric power in the United States as a whole. Why are we still burning coal in the Northwest? We have hydroelectricity waves, a mild climate west of the Cascades, plenty of great sunshine east of the Cascades. We have not accomplished all of the cost-effective energy conservation measures.

We are in the position to show that coal-free energy is possible now and essentially greenhouse gas emissions free electricity is possible in our future. We must do this. The UNEN Climate Science Compendium 2009 which is sort of an update from the IPCC report 2007, says that the actual warming since the IPCC's 2007 census report has exceeded all scenarios used in the 2007 report, including the business as usual scenario and appears to be accelerating.

The recent economic downturn slowed this but the trend is expected to continue upon recovery. Climate scientists are now warning that we need to act quickly to avoid catastrophic events and are now recommending more aggressive emissions reductions.

Sometimes they express this goal in terms of atmospheric concentrations of greenhouse gasses, 350 parts per million carbon dioxide. I believe that the State of Washington's goal of reducing emissions to 1990 levels by 2020 is no longer remotely in line with what we know about climate change today.

When my grandchildren are looking into the eyes of their own grandchildren in 2050 they will be living the consequences of our actions today. Arctic sea ice will be gone due to warming that is already in the pipeline due to the carbon dioxide accelerating the atmosphere.

The Maldives will be underwater, probably most of Bangladesh. The glaciers that feed rivers which people depend on for water in places like Pakistan and Chile will be gone. Hundreds of millions of people will be displaced or dead. We don't know how much agricultural land will be lost to flooding and drought.

Nations will be destabilized by conflict over shortages and refugees. We don't know what condition the oceans will be in by then but the possibilities frighten those who understand them now.

We don't know if methane stores in the permafrost and deep in the ocean will still be intact and we don't know how we would act if that happened.

The price of continuing to burn coal is too high. It is disingenuous to identify other pollutants from the TransAlta plant as dangerous and require mitigation while the most deadly pollutant of all continues to be ignored. We have no right to destroy the future of or grandchildren for convenience or narrowly-defined economics for pennies per kilowatt hour.

Other regions will find it much more challenging to close their coal plants than we will. The Pacific Northwest must lead the way. No more excuses. We must retire our coal plants now.

Jerry: Thank you. Next up we have Doug Howe.

D. Howe: Thank you. My name is Doug Howe. I'm with the Sierra Club and I have two general areas that I'd like to comment on, and the tremendous – the first is the tremendous disappointment we have about the public process.

When it came out in the press last March about the settlement agreement it was very clear that people were very concerned and there hadn't been adequate review. Then we had the climate legislation where there was a provision put in, a climate bill at the end of the season that never went through a public hearing, and I think it was in part because of that that that legislation failed for a lack of public process.

Then we have the – now the Governor has committed to a transparent process in her executive order in dealing with TransAlta and we are very hopeful that she delivers on that.

Then we had our Title 5 hearing of the Local Air Agency and we requested a public hearing on the Title 5 which is supposed to be the catch-all for all air pollutant issues but many issues were excluded in that permit and there was no public hearing in that Title 5 permit process.

Then we saw the settlement agreement and there was no opportunity to review that settlement agreement and, of course, there is gonna be a large public outcry when there was no opportunity to review and the provisions that we see on the agreement on the face of it appear week, but as Jeanette Brimmer mentioned, there has still been an issue about getting access to

necessary documents to allow the public to do a full assessment. Again, that's a tarnish on the respect for public process.

And then when we had this process we had asked that we could have hearings in Seattle, Vancouver, even Olympia, to allow greater public process but again we were denied and even simple things like getting a phone in the room tonight so others could join in.

And when you look at the cataloging of where the public process has been snubbed, it is an extremely poor record and what we ask for is a large public process that's at the front end so that no settlement agreement or no negotiation gets too far down the track without meaningful public engagement. That's the first point to be made, a failure of public process.

The second major point to be made is that I believe it is extremely problematic to be dealing with the issues, the pollution issues associated with the TransAlta plant in isolation. Yes, you have Federal requirements to proceed with BART determinations. We understand that but that does not preclude ecology doing a more meaningful and all-inclusive process for the many liabilities that the plant has.

We know there are NOx liabilities and we know it's not just the haze but there could be an issue of nitrogen deposition that needs to be thoroughly reviewed. We need to know the impacts from mercury. We can't just have one hearing but we need to know what damage is being done from these mercury emissions.

Even if this agreement were to achieve the hoped-for 50 percent there is still huge amount of damage coming out for that remaining 50 percent. What is the public health risk for that remaining 50 percent if, in fact, that's what gets achieved?

And then we simply cannot separate it from the CO2 issues. The liability associated with CO2 is tremendous. Just under the Waxman-Markey alone if the estimate is $20.00 a ton and the plant puts out 10 million tons a year that's $200 million a year of carbon liability, and that carbon pricing as we talk about it under Waxman-Markey, that is going for reducing emissions. That does not reduce the fact of carbon damages which is in addition to carbon pricing as we know it which is only about for reducing emissions.

The rough estimates and the science on this, the economic science on monetizing climate damages is extremely difficult but some preliminary estimates from very esteemed economists like Sir Nicholas Stern, Chief Financial Officer or Advisor to Tony Blair, has tried to put a price tag on it and puts it at $80.00 a ton.

$80.00 a ton times 10 million tons a year from the TransAlta Coal Plant, $800 million a year in 2009 dollars. So then you want to add on potential violations that EPA is asking about about new source review, and then we want to look at the waste handling from SO2 scrubbers, and what about other hazardous air pollutants that were mentioned tonight, potential existing and ongoing liabilities to the mine waste, and what about the management of coal combustion waste.

And then we still don't get at the upstream damages happening in the Powder River basin from the coal being taken out of the ground in Montana and Wyoming. What we request is that you do public forums and bring all these environmental liabilities to the forefront, and when you do that, you will see a very large public outcry calling for the transition of that plant off of coal to cleaner sources of energy. We urge you to take that path. Thank you.

Jerry: Thank you. Thank you, very much. That exhausts the initial list of those of you who identified that you wanted to testify and I'll now ask if anyone has either changed their mind or perhaps didn't realize that you could have, should have marked that little 'X' in the box which would have allowed me to call you up here. Is there anyone now that would like to come up?

And this testimony, that would be great. While you're contemplating that prospect I'll remind you that the comment period runs through November 9 of this year, 2009, and if you picked up this focus sheet in the back, and if you haven't thrown it away or turned it into a paper airplane it shows the various ways in which you can provide that comment to us.

There's – there is a snail mail address as well as an AQComments@Ecology.wa.gov address that you can do this, make your comments on-line. So you can, regular mail or over the Internet. No one else? Seeing that there's no one else that wants to testify, let the record show that it is now 7:57 p.m. and this hearing is now closed. Thank you, very much.

[End of Audio]