BART DETERMINATION
SUPPORT DOCUMENT FOR
TRANSALTA CENTRALIA GENERATION, LLC POWER PLANT
CENTRALIA, WASHINGTON

by
WASHINGTON STATE DEPARTMENT OF ECOLOGY
AIR QUALITY PROGRAM
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Table of Contents

Executive Summary

Section 1.0 Introduction
1.1 The Best Available Retrofit Technology Analysis Process
1.2 Basic Description of the TransAlta Centralia Generation LLC Power Plant
1.3 Best Available Retrofit Technology Eligible Units and Pollutant at TransAlta Centralia Generation LLC Power Plant
1.4 Visibility Impact of Best Available Retrofit Technology Eligible Units at TransAlta Centralia Generation LLC Power Plant
1.5 Relationship to 1997 Reasonably Available Control Technology determination

Section 2.0 Summary of TransAlta Centralia Generation LLC Power Plant's Best Available Retrofit Technology Analysis
2.1 Nitrogen Oxides Controls evaluated
2.2 TransAlta Centralia Generation LLC Power Plant's Proposed Best Available Retrofit Technology

Section 3.0 Visibility Impacts and Degree of Improvement

Section 4.0 Ecology's Best Available Retrofit Technology Determination
4.1 Nitrogen Oxides Control
4.2 Ecology's Determination of the Nitrogen Oxides Emission Controls That Constitute Best Available Retrofit Technology

Appendix A Coal Characteristics
Appendix B Nitrogen Oxides Controls Evaluated in the 1997 Reasonably Available Control Technology Process
Appendix C References
Appendix D Modeling Result Information from June 2008 and January 2008 Best Available Retrofit Technology Modeling reports
Appendix E Table of Coal Fired Electric Generating Unit Best Available Retrofit Technology Determinations in Western US
Appendix F TransAlta Centralia Power Plant Site Plans and Profiles
Appendix G Centralia BART Control Technology Analysis, Response to Questions
Appendix H Additional Centralia Power Plant BART Modeling Simulations - Comparison of Flex Fuel and Flex Fuel plus SNCR

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.

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[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.

[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 Non-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: Where: f = the decimal fraction of ammonia present in unionized form; pKa = ; 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	8400.0 0
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 demonstrations 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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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

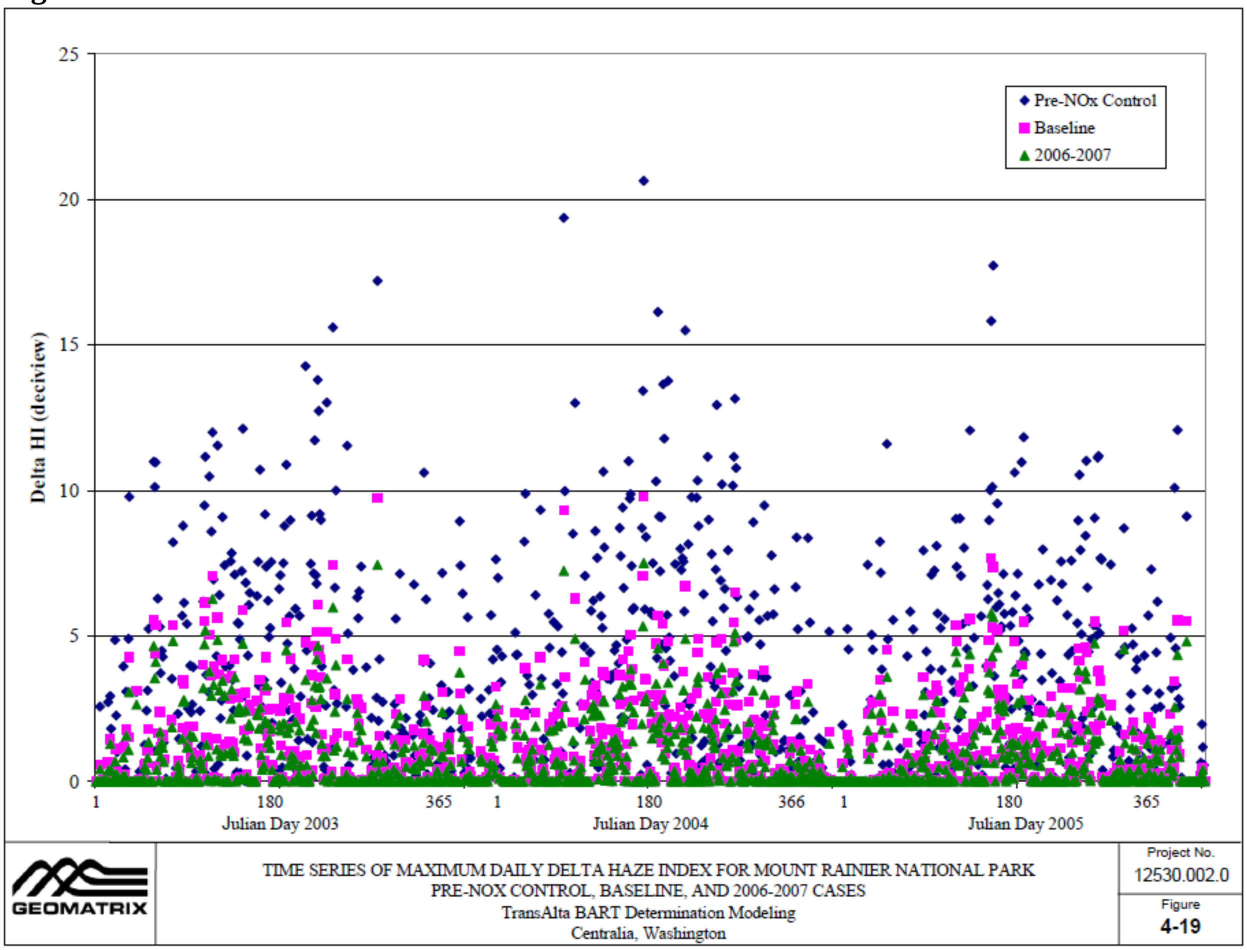
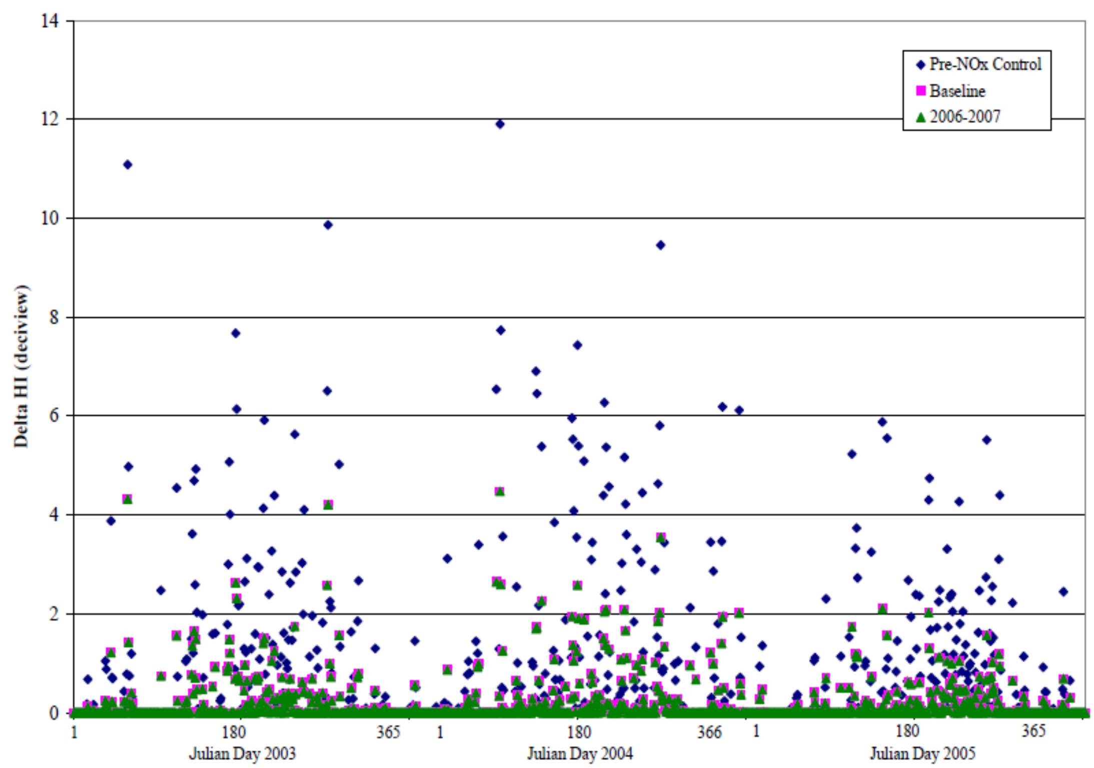


Figure D-2



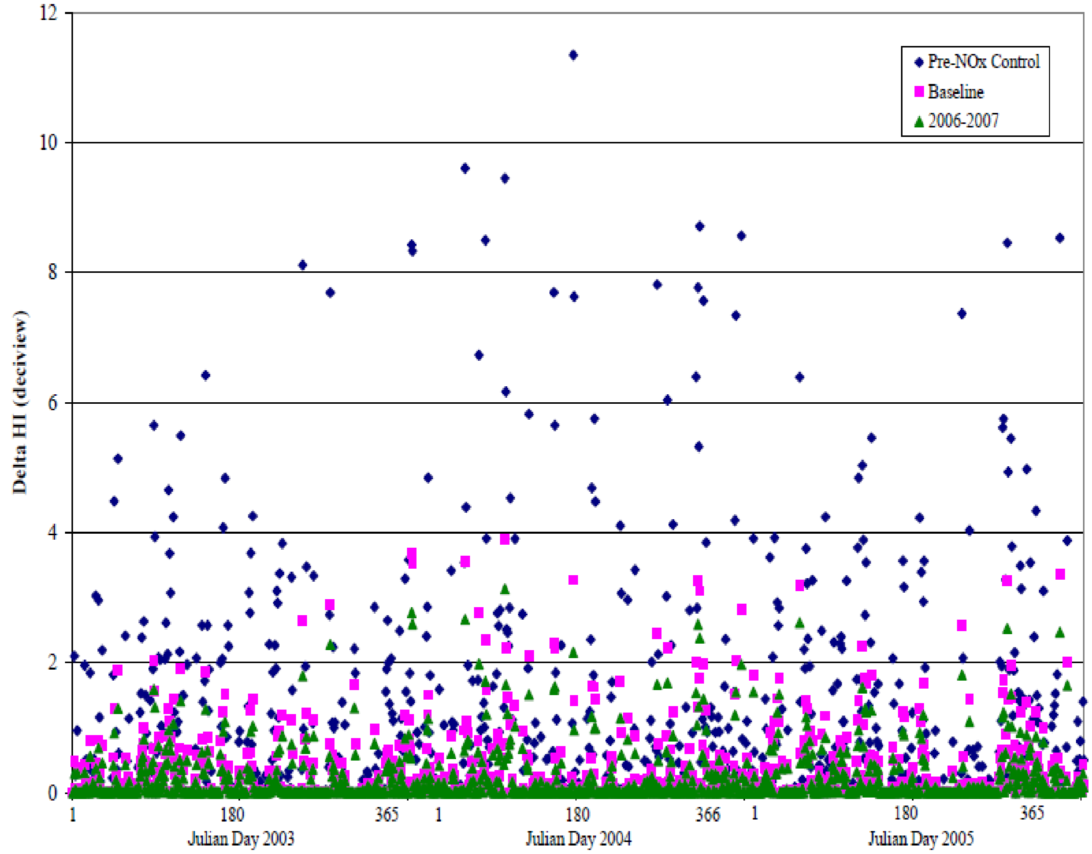
GEOMATRIX

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



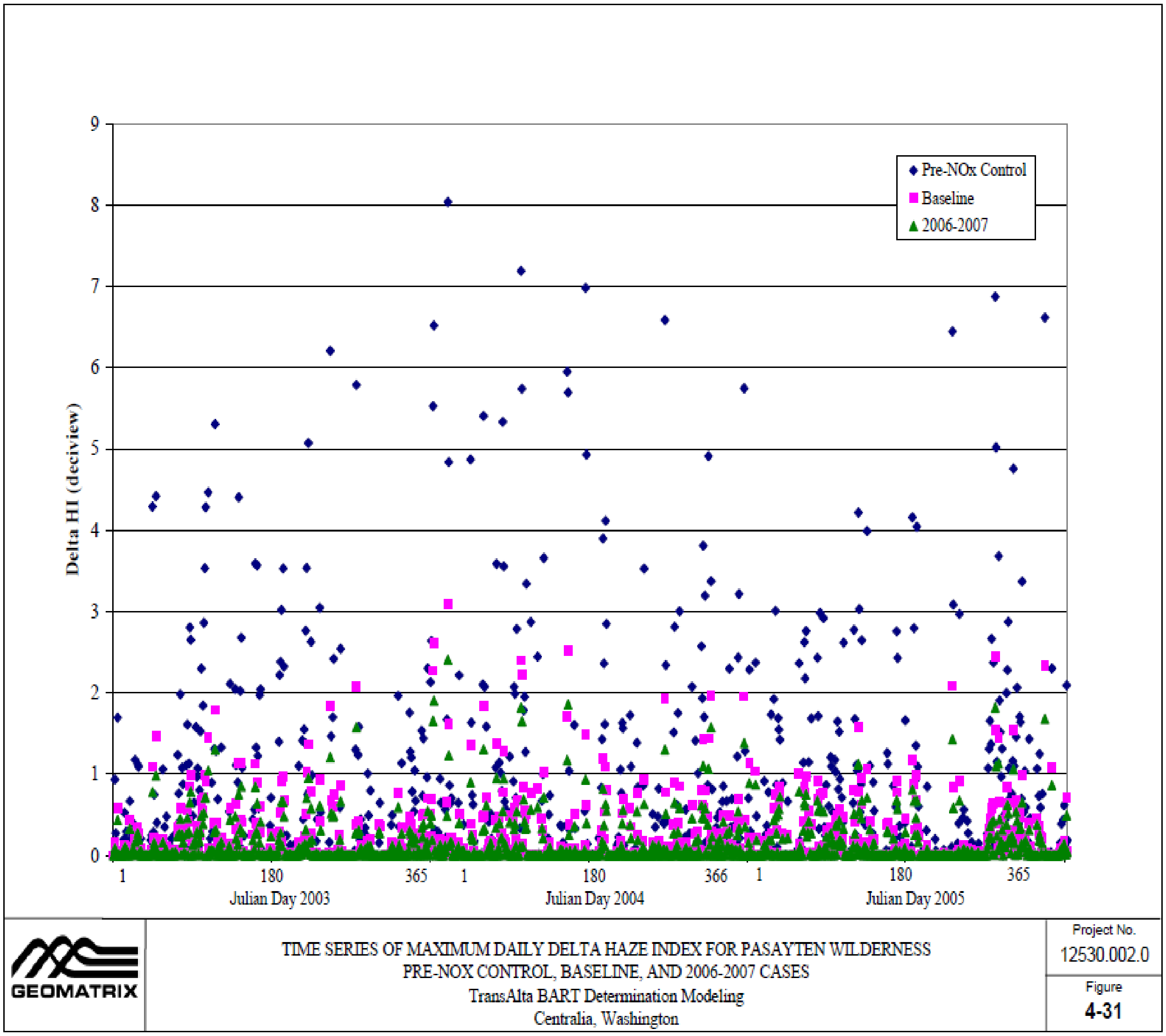
GEOMATRIX

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


Delta HI (deciview)
Pre-NOx Control
Baseline
2006-2007
Julian Day 2003
Julian Day 2004
Julian Day 2005
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	

Appendix F TransAlta Centralia Power Plant Site Plan and Profile

These 4 drawings are large, and intended to be reproduces at 11 X 17 or larger scale for readability. The drawings are available from Ecology and are located on the Ecology website.

Drawing 1 is an overall site plan of the power plant including the plant office, wet scrubbers storm water lagoons, maintenance buildings, etc. It does not include the coal pile area.

Drawing 2 is a site plan of the boiler building, ESPs, and wet scrubber area of the plant.

Drawing 3 is an elevation drawing looking from the south at the overall steam turbine/boiler building, ESPs and old stacks.

Drawing 4 is an elevation drawing showing subset elevation indicated in Drawing 3 showing the plant boiler outlet area, and the ESPS.

Appendix G Centralia BART Control Technology Analysis, Response to Questions

RICHARD L. GRIFFITH, LLC
ATTORNEY

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March 12, 2010

VIA EMAIL AND FEDERAL EXPRESS

Alan R. Newman, PE
Washington Department of Ecology
PO Box 47600
Olympia, WA 98504-7600

Re: Partial Response to Department of Ecology's Request for Additional Information Related to Centralia Power Plant Emissions

Dear Mr. Newman:

On behalf of TransAlta Centralia Generation LLC ("TransAlta"), I have enclosed responses to Questions 1 and 3 of your letter to Mr. Richard DeBolt, dated January 5, 2010, related to the proposed BART determination. The responses were prepared by CH2M Hill, which prepared the Centralia Plant's BART Analysis (July 2008). As clarified in our recent phone conversation, the response to Question 1 consists of larger copies of the SCR drawings from the July 2008 BART Analysis showing dimensions and distances.

We will forward responses to the other questions as soon as they are completed. Please contact me if you have questions regarding this information.

Sincerely,

Richard L. Griffith

Richard L. Griffith

cc: Richard DeBolt, TransAlta

CH2MHILL

CH2M HILL
9193 South Jamaica Street
Englewood, CO 80112-5946
Tel 303.771.0900
Fax 720.286.9250

March 11, 2010

Mr. Richard L. Griffith, LLC
1580 Lincoln Street, Suite 700
Denver, CO 80203

Subject: Centralia BART Control Technology Analysis
Partial Response to Department of Ecology Questions

Dear Mr. Griffith:

Regarding the questions presented by the Washington Department of Ecology for the Centralia BART analysis, this letter provides responses to Questions 1 and 3. Also attached are five sets of the dimensioned general arrangement sketches requested in Question 1.

CH2M HILL continues to work on responses to remaining Ecology questions, and will forward responses when they are completed. Please contact us if you have any questions.

Sincerely,

CH2M HILL

Robert Pearson, Ph.D.
Vice President

Attachments:

CENTRALIA BART
RESPONSES TO ECOLOGY QUESTIONS

Question 1:

To help answer questions about the 'lack of space' to install SCR, please provide scale drawings of the plant site and specific process areas, including plan and profile drawings of the boilers, the ductwork to and between the Koppers and Lodge-Cottrell ESPs, the duct work to the set scrubbers and the wet scrubbers and the new stack. The drawings need to indicate dimensions and distances, not the general arrangement of components. The drawings can cover multiple pages, must contain readable dimensions, and can be in a CAD interchange format file or equivalently detailed PDF format file instead of paper.

Response:

A. The following drawings are attached in response to the question from the Washington Department of Ecology:

   Plan and elevation general arrangement drawings from the Centralia BART report revised June 2008 depicting SCR equipment layouts, have been revised and presented to include dimensions. CH2M HILL developed sketches with proportional probable dimensions, and 11" by 17"sketches are included as an attachment.

B. As described within the BART report, the Centralia site conditions have the potential of significantly impacting the cost estimates for all emissions control options. In general, any site condition which restricts construction activities will likely increase overall project costs. These site conditions may include space restrictions inhibiting material and equipment installation, access limitations which limit the free movement and placement of construction equipment, interferences which may require pre-construction demolition or design change considerations, operational constraints which may impact construction approach and schedule, and construction staging issues such as laydown area and employee parking availability.

   Specifically for the Centralia plant, many of these site conditions are projected to significantly contribute to increased project costs for any construction activities. In large part due to previous environmental retrofit installations at Centralia, the available space for new equipment installation at the Centralia plant site is very limited. This limitation resulted in the consideration of locating a potential SCR installation over existing electrostatic precipitators, instead of being located closer to the boiler in order to minimize cost. Restricted site area may also impact costs for longer duct work runs and remotely located ancillary equipment.

Question 3:

Ecology has requested details of the SCR cost analysis produced by CH2M-Hill, specifically the analysis contained in the July, 2008 analysis. Specific issues with the cost analysis:

- *Explanation of all cost elements in the CH2M [sic] cost estimating spreadsheet, including discussion of differences on specific cost elements from the EPA Control Cost Manual defaults, especially the cost items not explicitly included in the EPA Control Cost Manual.*

  The summary table below compares the specific cost elements of the CH2M HILL SCR capital cost estimate with the default values from the EPA Air Pollution Control Cost Manual. Table A is intended as a response to the Ecology request.

  The cost estimating equations in Section 4.2, Chapter 2 "Selective Catalytic Reduction" of the EPA Air Pollution Control Cost Manual are based on equations developed by The Cadmus Group, Bechtel Power and SAIC in 1998 and follow the costing methodology of EPRI. CH2M HILL used alternative estimating methodologies which have extensively been utilized to develop budgetary cost estimates for utility power and air pollution control projects.

  The EPA Cost Manual methodology is generally applicable for new or existing sources, and allows inclusion of unique site-specific retrofit or lost generation costs. It should be noted that at a "study" level estimate of +/- 30% accuracy, the Manual states that "a retrofit factor of as much as 50 percent can be justified". Therefore, it is difficult to make a direct comparison of all of the cost elements, since the two methodologies breakdown costs differently.

  Because the EPA Cost Manual contains default values which are provided for a range of general applications, CH2M HILL considers the estimating methodology utilized for the Centralia BART analysis to be more accurate since specific site information and conditions were considered. In addition, current vendor cost information was utilized in developing the estimates.

TABLE A
Economic Analysis Summary for Both Units 1 and 2
CPP

Parameter	SCR		
NO_x Emission Control System	SCR		
SO_2 Emission Control System	Forced Oxidation Limestone Scrubber		
PM Emission Control System	Dual ESPs		
CAPITAL COST COMPONENT	**Cost**	**CH2M HILL Basis**	**EPA Control Cost Manual Basis**
Major Materials Design and Supply ($)	277,685,000	CH2M HILL factored estimate	EPA control cost manual
Eng, Startup, & Indirect ($)	57,500,000	CH2M HILL factored estimate	20% of total direct capital costs
Total Indirect Installation Costs (TIIC)	**335,185,000**		
Contingency ($)	50,277,750	15% of total indirect installation costs	15% of total indirect installation costs
Sales Tax ($)	26,814,800	8% of total indirect installation costs	Included in total direct capital costs
Plant Cost (PC)	**412,277,550**		
Margin ($)	41,227,755	10% of plant cost	No margin
Total Plant Cost (TPC)	**453,505,305**		**Includes 2% of total plant cost, AFUDC and cost to store 29 wt% aqueous ammonia for 14 days**
Owner's Costs ($)	45,350,531	10% of total plant cost	No owners costs
Allows for funds during construction (AFUDC) ($)	54,420,637	12% of total plant cost	No AFUCD
Lost Generation ($)	27,014,400	Calculated at $20MW-hr and 42 days	
TOTAL INSTALLED CAPITAL COST ($)	**580,290,872**		
FIRST YEAR O&M COST ($)			
Operating Labor ($)	351,250	CH2M HILL estimate	Assumed none required for SCR
Maintenance Material ($)	702,500	CH2M HILL estimate	Combined with maintenance labor, 1.5% of total capital cost
Maintenance Labor ($)	351,250	CH2M HILL estimate	
Administrative Labor ($)	0		
TOTAL FIXED O&M COST	**1,405,000**		
Reagent Cost	1,783,475	Anhydrous ammonia at $0.20/lb	Anhydrous ammonia at $0.058/lb
SCR Catalyst	2,107,500	Catalyst cost estimated at $3000/m^3	Catalyst cost at $85/ft^3
Electric Power Cost	2,403,603	Power cost estimated at $50/MW-hr	Power cost at $0.05/kW-hr, 1795 kW
TOTAL VARIABLE O&M COST	**6,294,577**		
TOTAL FIRST YEAR O&M COST	**7,699,577**		
FIRST YEAR DEBT SERVICE ($)	63,712,819	Calculated using 7% annual interest rate for 15 years	Calculated using 7% annual interest rate for 15 years
TOTAL FIRST YEAR COST ($)	**71,412,396**		
Power Consumption (MW)	**7.03**		
Annual Power Usage (kW-Hr/Yr)	**48.1**		
CONTROL COST ($/Ton Removed)			
NO_x Removal Rate (%)	**72.0%**		
NO_x Removed (Tons/Yr)	**7,855**		
First Year Average Control Cost ($/Ton NO_x Rem.)	**9,091**		

- *Basis of 16% multiplier in the calculations*

  We assume that Ecology is referring to the 15% Project Contingency in the SCR cost estimate. When developing a cost estimate, there is always an element of uncertainty since costs are based upon several assumptions and variables. Contingency provides an amount added to an estimate, which covers project uncertainties and added costs which experience dictates will likely occur. The magnitude of the contingency used in the CH2M HILL cost estimate is typical of contingency utilized in similar budgetary estimates, and matches the default 15% Project Contingency shown in Table 2.5 "Capital Cost Factors for an SCR Application" on page 2-44 of Section 4.2, Chapter 2 of the EPA Air Pollution Control Cost Manual, Sixth Edition.

- *Sources of 'vender quotes' referenced in the CH2M HILL documents*

  The cost estimates were developed as "budgetary estimates", therefore CH2M HILL did not use vendor quotes for the SCR cost estimate. A factored approach was utilized for the determining the SCR capital cost which utilized in-house cost information, and consists of compilation of vendor and previous project information.

- *Whether any structural analyses were done in support of SCR cost analysis and the results of the analyses*

  Detailed structural analyses were not performed for the SCR cost analysis. However, a cursory review of structural requirements was completed to locate the SCR reactor and ductwork. CH2M HILL assumed a separate structure for the SCR reactor and ductwork because the existing ESP structure was not designed for these additional loads.

Appendix H Additional Centralia Power Plant BART Modeling Simulations - Comparison of Flex Fuel and Flex Fuel plus SNCR

CH2MHILL

CH2M HILL

9193 South Jamaica Street
Englewood, CO 80112-5946

Tel 303.771.0900
Fax 720.286.9250

March 31, 2010

Mr. Richard L. Griffith
1580 Lincoln Street, Suite 700
Denver, CO 80203

Subject: Centralia BART Control Technology Analysis
Second Response to Department of Ecology Questions

Dear Mr. Griffith:

This letter provides responses to Washington Department of Ecology's (Ecology) Questions 4 and 5, regarding the Centralia BART analysis. Also included is additional cost estimating background information for SCR and SNCR, in response to Ecology's request.

A response to Ecology Question 2, which was prepared by TransAlta, is also included in this response. Therefore, CH2M HILL does not have knowledge of, or accept responsibility for, the information presented within the Question 2 response.

In response to the last bullet of Question 2, we are submitting on behalf of TransAlta confidential, proprietary documents that are enclosed in a separate envelope marked "Confidential Business Information." Pursuant to RCW 43.21A.160, TransAlta certifies that the Alstom Power Instruction Manual, TransAlta Centralia Generation LLC, Centralia Plant Unit 2, cover page and p. 1-3 (Rev. 1, 06/21/01) relate to processes of production unique to TransAlta or may affect adversely the competitive position of TransAlta if released to the public or to a competitor. Accordingly, TransAlta requests that those records be made available only to the Director and appropriate personnel of the Department of Ecology.

We believe this transmittal completes CH2M Hill's responses to Ecology questions.

Please contact us if you have any questions.

Sincerely,

CH2M HILL

Robert L Pearson

Robert Pearson, Ph.D
Vice President

Cc: Mr. Alan Newman, State of Washington Department of Ecology
Mr. Richard DeBolt, TransAlta USA
Mr. Gary MacPherson, TransAlta USA

Attachments:

CENTRALIA BART
RESPONSES TO ECOLOGY QUESTIONS

Question 2 (Response prepared by TransAlta):

A copy of all reports on combustion analyses performed on the installed LNC3 combustion control system. Include a copy of the original LNC3 burner system specifications and vendor/contractual guarantee for the system currently installed. The information supplied needs to assist Ecology in answering specific comments on the proposed BART determination related to the NO_x reduction effectiveness of the installed combustion control system.

Response: TransAlta is not aware of any reports on combustion analyses performed on the LNC3 system.

Specific questions needing to be evaluated include:

- All analyses and test programs to improve the effectiveness of the installed system to reduce thermal NO_x emissions since the equipment installed in the boilers. Reports could have been produced by TransAlta or by PacifiCorp prior to the ownership change.

  Response: TransAlta is not aware of such analyses or reports.

- Any specific analysis that addresses the ability or inability of the system to meet the EPA presumptive BART emission limitation must be included (whether performed by or for TransAlta or PacifiCorp).

  Response: TransAlta is not aware of any such analysis.

- Design intent of the original LNC3 installation and whether the installation of LNC3 met its design intent.

Response: For original design specifications, see attached Alstom Power Instruction Manual, TransAlta Centralia Generation LLC, Centralia Plant Unit 2, cover page and p. 1-3 (Rev. 1, 06/21/01) (These pages are enclosed in a separate envelope marked "Confidential Business Information." Pursuant to RCW 43.21A.160, TransAlta is requesting that these documents not be released to the public.) The same design specifications apply to Unit 1. The Instruction Manual, p. 1-3, estimates emissions from the "low NO_x concentric firing system level III" installed at the Centralia Plant to range from: (a) 0.33 lb/mmBTU NO_x for eastern bituminous coal with a nitrogen content of about 1.48 lb/mmBTU and an oxygen to nitrogen content ratio of 5, and (b) about 0.35 lb/mmBTU for western subbituminous coal with a nitrogen content of about 0.82 lb/mmBTU and an oxygen to nitrogen content ratio of 20.

- What are the physical differences and similarities between these specific boilers and other similar boilers that have been able to achieve the presumptive BART limit of 0.15 Ib/MMBtu through the use of LNC3 control?

Response: A major engineering study by an engineering firm would be required to answer this. Ecology agreed not to require such a study.

- What can be done to the configuration of overfire air ports or by replacing the low NO_x burners to reduce thermal NO_x formation?

Response: TransAlta considered these types of controls and boiler reconstruction but did not identify any that would achieve the presumptive BART levels or that would be more cost-effective than Flex Fuel or SNCR.

Follow-up Information to Question 3:

While an initial response to Question #3 was previously prepared and submitted, Ecology requested additional detail regarding vendor information. As previously noted, CH2M HILL utilized a factored approach in the development of SCR costs for the Centralia BART analysis. In addition, previous CH2M HILL and other BART analysis SCR costs were considered when completing the cost estimates. In response to Ecology's request, a compilation of SCR BART analysis information was prepared and presented in Attachment 1. Previous project information was considered in applying a factored approach to developing SCR costs.

In addition, an updated SCR Economic Analysis Summary was prepared which clarifies responses regarding the EPA Cost Manual Basis for Total Fixed O&M Costs. The revised summary is presented as Attachment 2.

The following information provides additional explanation regarding the CH2M HILL cost estimating approach for the Centralia BART analysis:

Centralia Capital Cost Estimating Approach

For the Centralia BART analysis, CH2M HILL cost estimates were developed for the SCR and SNCR NO_x control technology alternatives. As explained within the BART analysis, the level of accuracy of the cost estimate can be broadly classified as "Order of Magnitude", which can be categorized as a -20/+50 percent estimate.

The approach utilized for Centralia is consistent with previous BART analyses completed by CH2M HILL; where the level of accuracy of cost estimating matches the preliminary nature of the level of BART engineering and design. In depth design information for each emissions control technology was not completed for Centralia, due to time and resource limitations. In addition, the accuracy of BART study estimates is only intended to allow economic comparison of alternatives. In order to increase the level of accuracy of the estimate, a preliminary engineering design would have been needed that would require significantly greater site information, more engineering effort, firm vendor quotations, a thorough constructability review, and a definitive estimating approach.

CH2M HILL visited the Centralia site to examine boiler outlet ductwork configuration, space availability for new equipment, and construction requirements and potential limitations. A restricted site impacted the SCR cost estimate primarily due to the limited space to install an SCR catalyst reactor vessel. Since each unit has separate flue gas exhaust trains, the resultant design has one SCR system for each outlet exhaust duct from the economizer that would be located on top of the existing electrostatic precipitators. The congested site with limited access would also significantly influence construction costs and schedule. Therefore, as an overall assessment, the Centralia site was considered to be a difficult retrofit for an SCR installation with a resulting higher cost compared to other power plant units of similar size.

Background estimating information was assembled through re-evaluation of historical information, updated with current project equipment, material, and construction costs. Construction costs were estimated for the Centralia area, and were developed from preliminary engineering sketches.

In addition to consideration of the site specific information, a factored approach was utilized in developing the Centralia SCR and SNCR cost estimates. With this approach, common historical cost basis from previous projects are used to develop an estimate for the project under consideration. For example, a common cost comparison factor for an SCR installation between different project sites may be based on size of unit ($/Kilowatt) or flue gas flow rate ($/Actual Cubic Feet Minute). This factor from a baseline unit is then utilized to calculate the approximate cost for another unit.

For the Centralia BART analysis, a $/KW factor was primarily utilized in calculating the total project cost estimate. In estimating the SCR equipment and installation costs, a factor of approximately $200/KW was used. This factor was based on other project cost information, with allowance for specific Centralia site information retrofit considerations. Centralia was considered to be a very difficult SCR retrofit installation, and this was reflected in the ultimate cost estimate.

Estimates from previous CH2M HILL and other BART analysis were also considered when reviewing and verifying reasonableness of the total cost estimate. A compilation of previous SCR and SNCR BART information was prepared and presented in Attachment 1 – "SCR BART Cost Estimate Information", and Attachment 3---"SNCR BART Cost Estimate Information". While this previous project cost information was considered in applying a factored approach in developing the SCR cost estimate, no specific project information was utilized. Information from Attachments 1 and 3 were primarily used as a comparative check for reasonableness of estimate. Two other BART analyses, Boardman Station and Nebraska City 1, were completed by B&V and HDR respectively with SCR $/KW costs comparable to Centralia. While the Centralia SCR cost estimate of 413 $/KW is the largest value on the list, CH2M HILL considers this reasonable given the retrofit difficulty. BART analysis cost estimates from Attachment 3 demonstrate that the Centralia SNCR estimate is consistent with other units.

CH2M HILL's approach to preparing the SCR and SNCR order of magnitude cost estimate for the Centralia BART analysis may be summarized as follows:

1) Determine preliminary background information regarding each technology
2) Establish site specific information, including any limitations or restrictions
3) Review comparable project information, both internal and external, to establish factors used for estimating
4) Complete an estimating reasonableness review utilizing similar SCR and SNCR estimates

While several sources of information were used as background information in developing the SCR and SNCR cost estimates, no single piece of information was exclusively utilized as the basis for the cost estimates.

Question 4:

Ecology has requested details of the SNCR cost analysis produced by CH2M HILL, specifically the analysis contained in the July, 2008 analysis. Specific issues with the cost analysis:

- *Explanation of all cost elements in the CH2M [sic] cost estimating spreadsheet, including discussion of differences on specific cost elements from the EPA Control Cost Manual defaults, especially the cost items not explicitly included in the EPA Control Cost Manual.*

  The summary table below (Table B, Attachment 4) compares the specific cost elements of the CH2M HILL SNCR capital cost estimate with the default values from the EPA Air Pollution Control Cost Manual. Table B is intended as a response to the Ecology request.

  The cost estimating equations in Section 4.2, Chapter 2 "Selective Catalytic Reduction" of the EPA Air Pollution Control Cost Manual are based on equations developed by The Cadmus Group, Bechtel Power and SAIC in 1998 and follow the costing methodology of EPRI. CH2M HILL used alternative estimating methodologies which have extensively been utilized to develop budgetary cost estimates for utility power and air pollution control projects.

  The EPA Cost Manual methodology is generally applicable for new or existing sources, and allows inclusion of unique site-specific retrofit or lost generation costs. It should be noted that at a "study" level estimate of +/- 30% accuracy, the Manual states that "a retrofit factor of as much as 50 percent can be justified". Therefore, it is difficult to make a direct comparison of all of the cost elements, since the two methodologies break down costs differently.

  Because the EPA Cost Manual contains default values which are provided for a range of general applications, CH2M HILL considers the estimating methodology utilized for the Centralia BART analysis to be more accurate since specific site information and conditions were considered. In addition, current vendor cost information was utilized in developing the estimates.

- *Basis of 16% multiplier in the calculations*

  We assume that Ecology is referring to the 15% Project Contingency in the SNCR cost estimate. When developing a cost estimate, there is always an element of uncertainty since costs are based upon several assumptions and variables. Contingency provides an amount added to an estimate, which covers project uncertainties and added costs which experience dictates will likely occur. The magnitude of the contingency used in the CH2M HILL cost estimate is typical of contingency utilized in similar budgetary estimates, and matches the default 15% Project Contingency shown in Table 1.4 "Capital Cost Factors for an SNCR Application" on page 1-32 of Section 4.2, Chapter 1 of the EPA Air Pollution Control Cost Manual, Sixth Edition.

- *Sources of 'vender quotes' referenced in the CH2M HILL documents*

  SNCR cost estimates were developed as "budgetary estimates", and preliminary vendor equipment cost and estimated NO_x reduction efficiencies were provided by Fuel Tech. CH2M HILL completed the economic analysis through a combination of utilizing a factored approach from in-house cost information, previous project information, and vendor information. A summary of previous CH2M HILL and other BART analysis SNCR costs is provided as Attachment 3. Previous project information was considered in using factored estimates in developing SNCR costs.

  For additional explanation regarding the SNCR cost estimate, please see the response to Question 3 above.

- *Whether any structural analyses were done in support of SNCR cost analysis and the results of the analyses*

  Detailed structural analyses were not performed in completing the SNCR cost analysis.

<u>Question 5:</u>

A number of questions specific to the SCR system have been posed which the information TransAlta has already submitted does not answer. These are:

- *Specific information about the design of the SCR system evaluated by CH2M [sic]which may include a discussion or drawings for adding SCR to the plant, including flow paths, placement of catalyst (vertical or horizontal placement), catalyst cleaning method, ducting to the Boilers and ESPs.*

Response:

The preliminary design of the SCR presented with the Centralia BART analysis assumed that the full flue gas flow would be extracted from the boiler temperature region conducive to good SCR performance (580 degrees F to 750 degrees F). This temperature region on a coal fired boiler is typically located after the boiler economizer and before the air heater. The SCR design proposed for the Centralia units was a full scale system, where the flue gas is routed to a separate SCR reactor vessel which has cross-sectional area greater than the ductwork. An expanded reactor vessel allows lower flue gas velocity through the catalyst, as opposed to an in-duct SCR where the catalyst is placed in the existing ductwork with resulting higher velocity.

The flue gas would be extracted the boiler ductwork at the appropriate temperature region, pass through the SCR system, and then would be returned to the boiler discharge ductwork at a point just downstream of the extraction point. If space allows, an in-duct configuration may also include an expanded ductwork reaction chamber in order to reduce flue gas velocity and increase residence time.

For the Centralia BART analysis it was assumed that the full scale SCR catalyst would be installed in a horizontal configuration, with the flue entering the catalyst from the top of the catalyst and exiting from the bottom. Ammonia would be introduced ahead of the catalyst. For purposes of the conceptual layout and budgetary estimate for BART analysis, no detailed design was completed regarding catalyst cleaning methodology.

- *A discussion of alternate locations to install an SCR system such as in the duct from the ESPs to the wet scrubber. This location would include and need an evaluation of gas stream reheat requirements and costs. Include an evaluation of how much catalyst could be placed inside the duct at its current dimensions and the NO_x reduction which could be accomplished without expanding the existing ducts.*

Response:

The flue gas from the Centralia ESPs to the wet scrubber is approximately 300 degrees F, which is well below the desired temperature range of 580 to 750 degrees F. Operating an SCR system outside of the optimum temperature window will significantly decrease NO_x reduction efficiency. After the ESPs, the particulate loading in the flue gas has been reduced which would lessen the potential for SCR catalyst erosion. Consistent with typical utility design, the current ESP to scrubber full load ductwork flue gas velocity is assumed to be approximately 60 ft/sec. As requested, this analysis was based on utilizing the current ductwork dimensions, which maintains existing ductwork flue gas velocity.

In order to allow the in-duct SCR system to within the optimum temperature window, increasing the flue gas temperature ahead of the SCR would be required. This could be achieved through the installation of a flue gas heating system such as a regenerative heat exchanger or duct burner arrangement. While implementing a flue gas reheat system is a technically feasible alternative, utilizing this approach in the duct work from the ESPs to the scrubber creates significant operating concerns for an SCR system in this location.

If the flue gas is reheated to approximately 700 degrees F, the calculated velocity in the existing ductwork would be increased from 60 ft/sec to approximately 90 ft/sec.

Typical catalyst flue gas velocity design values are generally in the range of 15 to 20 ft/sec, which is approximately one-fifth of the reheated flue gas velocity. From discussions with an SCR catalyst supplier, a 90 ft/sec velocity level would render the SCR essentially ineffective. The primary ramifications from higher SCR velocities are greater potential for catalyst erosion, less time available for chemical reactions to occur, and increased pressure drop across the SCR system. From a catalyst vendor response, this configuration was considered infeasible.

- *For the SCR option, evaluate the quantity of catalyst that can be installed in the ducts from the boiler to the ESP, and how much NO_x reduction could be accomplished with that quantity of catalyst. Also, a cost estimate for this installation location. This analysis was requested previously.*

Response:

While meeting many design criteria is necessary for good SCR operation, the following issues may be especially essential to an in-duct configuration:

- Flue gas residence time through the catalyst
- Good mixing of ammonia prior to entering SCR catalyst
- Ammonia slip, or un-reacted ammonia passing through the catalyst
- Catalyst erosion
- Maintain reasonable pressure drop

The SCR system evaluated within the BART report was located in an area between the boiler outlet and ESP inlet, in the optimal flue gas temperature region between the economizer outlet and the air heater. This system was assumed to consist of ductwork to and from an expanded SCR reactor vessel, where the flue gas velocity through the catalysts would operate at approximately 20 ft/sec.

The above question requests an evaluation for the "ducts from the boiler to the ESP", which consists of flue gas entering the air heater at approximately 700 degrees F and flue gas temperature exiting the air heater is approximately 300 degrees F. For this analysis it was assumed that the current ductwork dimensions would be maintained, and no expansion of the ductwork size was considered. Since a review of an SCR system located in the 300 degree F temperature region has been addressed in the responses to the previous question, only an in-duct SCR system utilizing the existing ductwork dimensions between the economizer outlet and the air heater inlet will be considered. The flue gas in this area would be within the optimum SCR temperature region, therefore no flue gas reheat would be required for this configuration.

The design criteria for an in-duct SCR unit were developed from information provided by TransAlta. The boiler flue gas from the economizer sections on each unit passes through two separate sections of ductwork, one for each of the two air heaters for each unit. The ductwork to the air heater appears to be tapered and expands toward the air heater, and mid-duct dimensions were estimated from general arrangement drawings to be 43 feet by 14 feet. There appears to be approximately 17 feet of ductwork length available to install catalyst.

Utilizing the tested flow rate from each unit and the estimated cross-sectional area of the ductwork, the flue gas velocity in this ductwork from the economizer to the air heater inlet was calculated to be approximately 50 to 60 ft/sec. This is approximately three times the desired SCR design target velocity. While in-duct SCR catalysts have been installed, most have been designed to operate in a "polishing" mode with upstream NO_x reduction occurring through an SNCR system. The use of this configuration allows the SCR catalyst to utilize any ammonia slip from the SNCR system. In order to achieve an overall high level of NO_x reduction, dual systems are required due to the lower anticipated NO_x reduction efficiency from a stand-alone SNCR or in-duct SCR installation.

Preliminary SCR design information, and a budgetary cost estimate, was requested and received from a catalyst vendor for the in-duct configuration described above. The catalyst vendor response confirmed that the in-duct configuration resulted in duct velocities about three times higher than recommended, which would cause significant erosion concerns. However, with this alternative one layer of catalyst was estimated to reduce NO_x emissions by approximately 5% with an additional 5 inches water gage pressure drop. Two catalyst layers were estimated to achieve about 12% NO_x reduction at an additional 10 inches water gage pressure drop. Therefore, with the anticipated low NO_x reduction potential, significant additional pressure drop, and potential for erosion, this in-duct SCR configuration is not considered a practical alternative for Centralia.

Attachments

ATTACHMENT 1
SCR BART Cost Estimate Information

Unit Name	Unit size (kW)	Total Installed Capital Cost/unit	$/kW	Source
Dave Johnston Unit 3	250000	67,000,000	268	CH2M HILL
Colstrip	307000	25,300,000	82	TRC
Wyodak	365000	99,000,000	271	CH2M HILL
Dave Johnston Unit 4	360000	99,900,000	278	CH2M HILL
Jim Bridger Unit 3	530000	120,900,000	228	CH2M HILL
Laramie River 1	550000	99,000,000	180	B&V
Boardman	584000	223,000,000	382	B&V
Nebraska City 1	650000	244,400,000	376	HDR
Navajo 1	750000	210,000,000	280	ENSR
CPP Unit 1 & 2	1405000	580,300,000	413	CH2M HILL

ATTACHMENT 2
Table A – SCR Economic Analysis Summary

CPP

Parameter	SCR		
NO_x Emission Control System	SCR		
SO2 Emission Control System	Forced Oxidation Limestone Scrubber		
PM Emission Control System	Dual ESPs		
CAPITAL COST COMPONENT	**Cost**	**CH2M Hill Basis**	**EPA Control Cost Manual Basis**
Major Materials Design and Supply ($)	277,685,000	CH2M HILL factored estimate	EPA control cost manual
Eng, Startup, & Indirect ($)	57,500,000	CH2M HILL factored estimate	20% of total direct capital costs
Total Indirect Installation Costs (TIIC)	**335,185,000**		
Contingency ($)	50,277,750	15% of total indirect installation costs	15% of total indirect installation costs
Sales Tax ($)	26,814,800	8% of total indirect installation costs	Included in total direct capital costs
Plant Cost (PC)	**412,277,550**		
Margin ($)	41,227,755	10% of plant cost	No margin
Total Plant Cost (TPC)	**453,505,305**		Includes 2% of total plant cost, AFUDC and cost to store 29 wt% aqueous ammonia for 14 days
Owner's Costs ($)	45,350,531	10% of total plant cost	No owners costs
Allows for funds during construction (AFUDC) ($)	54,420,637	12% of total plant cost	No AFUCD
Lost Generation ($)	27,014,400	Calculated at $20/MW-hr and 42 days	
TOTAL INSTALLED CAPITAL COST ($)	**580,290,872**		
FIRST YEAR O&M COST ($)			
Operating Labor ($)	351,250	CH2M HILL estimate	Assumed none required for SCR
Maintenance Material ($)	702,500	CH2M HILL estimate	Combined with maintenance labor, 1.5 % of total capital cost
Maintenance Labor ($)	351,250	CH2M HILL estimate	
Administrative Labor ($)	0		
TOTAL FIXED O&M COST	**1,405,000**		
Reagent Cost	1,783,475	Anhydrous ammonia at $0.20/lb	Anhydrous ammonia at $0.058/lb[2]
SCR Catalyst	2,107,500	Catalyst cost estimated at $3000/$m^3$	Catalyst cost at $85/$ft^3$[1]
Electric Power Cost	2,403,603	Power cost estimated at $0.05/kW-hr, 7025 kW	Power cost at $0.05/kW-hr, 1795 kW
TOTAL VARIABLE O&M COST	**6,294,577**		
TOTAL FIRST YEAR O&M COST	**7,699,577**		
FIRST YEAR DEBT SERVICE ($)	63,712,819	Calculated using 7% annual interest rate for 15 years	
TOTAL FIRST YEAR COST ($)	**71,412,396**		
Power Consumption (MW)	**7.03**		
Annual Power Usage (kW-Hr/Yr)	**48.1**		
CONTROL COST ($/Ton Removed)			
NO_x Removal Rate (%)	**72.0%**		
NO_x Removed (Tons/Yr)	**7,855**		
First Year Average Control Cost ($/Ton NO_x Rem.)	**9,091**		

Notes:

1 - Catalyst cost used for EPA Cost Manual calculations based on current cost estimate of $3000/$m^3$. Cost manual recommends using the current cost estimate for catalyst cost.

2 – Calculated based on pure anhydrous ammonia, and not a 29% solution as listed in the EPA Cost Manual.

ATTACHMENT 3
SNCR BART Cost Estimate Information

Unit Name	Unit size (kW)	Total Installed Capital Cost/unit	$/kW	Source
Navajo 1	750,000	10,000,000	13	ENSR
Coal Strip	307,000	6,076,000	20	TRC
CPP - One Unit	702,000	16,600,000	24	CH2M HILL
RG1, 2, 3	100,000	2,497,500	25	CH2M HILL
Jim Bridger Unit 3	530,000	13,273,632	25	CH2M HILL
Jim Bridger 1, 2, 4	530,000	13,427,239	25	CH2M HILL
Dave Johnston Unit 4	360,000	10,105,779	28	CH2M HILL
Boardman	584,000	17,400,000	30	B&V
Wyodak	335,000	10,195,654	30	CH2M HILL
Laramie River 1	550,000	17,777,778	32	B&V
Tracy 3	113,000	3,661,875	32	CH2M HILL
Dave Johnston Unit 3	250,000	8,135,543	33	CH2M HILL
FC 1, 2, 3	113,000	3,760,313	33	CH2M HILL
Cholla 4	425,000	14,706,000	35	CH2M HILL
Cholla 2, 3	300,000	11,610,000	39	CH2M HILL
Apache 2, 3	195,000	7,781,130	40	CH2M HILL
Tracy 2	83,000	3,661,875	44	CH2M HILL
Naughton Unit 3	356,000	15,788,530	44	CH2M HILL
Apache 1	85,000	4,250,000	50	CH2M HILL
Naughton Unit 2	226,000	12,378,764	55	CH2M HILL
Naughton Unit 1	173,000	10,226,855	59	CH2M HILL
Tracy 1	55,000	3,661,875	67	CH2M HILL

ATTACHMENT 4
Table B – SNCR Economic Analysis Summary

CPP

Parameter	SNCR		
NO_x Emission Control System	SNCR		
SO2 Emission Control System	Forced Oxidation Limestone Scrubber		
PM Emission Control System	Dual ESPs		
CAPITAL COST COMPONENT		**CH2M Hill Basis**	**EPA Control Cost Manual Basis**
Major Materials Design and Supply ($)	14,711,977	Based on quote from Fuel Tech	EPA control cost manual
Eng, Startup, & Indirect ($)	5,400,000	Based on quote from Fuel Tech	20% of total direct capital costs
Total Indirect Installation Costs (TIIC)	**20,111,977**		
Contingency ($)	3,016,797	15% of total indirect installation costs	15% of total indirect installation costs
Sales Tax ($)	1,608,958	8% of total indirect installation costs	Included in total direct capital costs
Plant Cost (PC)	**24,737,732**		
Margin ($)	2,473,773	10% of plant cost	No margin
Total Plant Cost (TPC)	**27,211,505**		Includes 2% of total plant cost, AFUDC and cost to store urea for 14 days
Owner's Costs ($)	2,721,150	10% of total plant cost	No owners costs
Allows for funds during construction (AFUDC) ($)	3,265,381	12% of total plant cost	No AFUCD
Lost Generation ($)			
TOTAL INSTALLED CAPITAL COST ($)	**33,198,036**		
FIRST YEAR O&M COST ($)			
Operating Labor ($)	281,000	CH2M HILL estimate	Assumed none required for SNCR
Maintenance Material ($)	562,000	CH2M HILL estimate	Combined with maintenance labor, 1.5 % of total capital cost
Maintenance Labor ($)	281,000	CH2M HILL estimate	
Administrative Labor ($)			
TOTAL FIXED O&M COST	**1,124,000**		
Reagent Cost	909,012	Urea at $0.185/lb	Urea at $0.85/gal
SCR Catalyst			
Electric Power Cost	480,721	Power cost estimated at $0.05/kW-hr, 1405 kW	Power cost at $0.05/kW-hr, 158 kW
TOTAL VARIABLE O&M COST	**1,389,733**		
TOTAL FIRST YEAR O&M COST	**2,513,733**		
FIRST YEAR DEBT SERVICE ($)	3,644,966	Calculated using 7% annual interest rate for 15 years	
TOTAL FIRST YEAR COST ($)	**6,158,699**		
Power Consumption (MW)	**1.41**		
Annual Power Usage (kW-Hr/Yr)	**9.6**		
CONTROL COST ($/Ton Removed)			
NO_x Removal Rate (%)	**25.0%**		
NO_x Removed (Tons/Yr)	**2,727**		
First Year Average Control Cost ($/Ton NO_x Rem.)	**2,258**		

From: Ken Richmond [krichmond@Environcorp.com]
Sent: Friday, March 26, 2010 2:00 PM
To: Newman, Alan (ECY); Bowman, Clint (ECY)
Cc: RickLGrif@aol.com; Gary_MacPherson@TransAlta.com; Lori_Schmitt@transalta.com; richard_debolt@transalta.com
Subject: Additional Centralia Power Plant BART simulations
Attachments: flex-vs-flexwsncr.pdf

Al & Clint

I've attached the results from the additional BART simulations that you requested for the Centralia Power Plant. The results supplement the earlier BART simulations with 2 new cases.

Revised Flex Fuels: (PM10 242 lb/hr, NOx 3936 lb/hr & SO2 1854 lb/hr) The Flex Fuels SO2 emissions are based on the ratio of sulfur content of Jacobs Ranch (PRB) coal to Centralia Mine coal (41%) times the 2003-2005 maximum 24-hr baseline rate of 4522 lb/hr.

Flex Fuels with SNCR: (PM10 242 lb/hr, NOx 2952 lb/hr & SO2 1854 lb/hr) NOx emissions are reduced by 25% to 0.18 lb/MMBtu from the Flex Fuel factor of 0.24 lb/MMBtu.

In all respects the simulations were performed in the same manner as the original BART analysis. The results are summarized in the attached Tables that augment the tables from the original BART modeling analysis. How many copies of the modeling files do you want? As before the modeling files will contain spreadsheets with the extinction budgets for the top 8 days each year and top 22 days in three years for each Class I area of interest.

Regards,

Ken Richmond
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VISIBILITY MODELING FOR CENTRALIA POWER PLANT

COMPARISON OF FLEX FUEL AND FLEX FUEL WITH SNCR

March 2010

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TABLE 1

BASELINE (2003-2005) 24-HOUR MAXIMUM EMISSION RATES

Year	NOx (lb/hr)		SO_2 (lb/hr)		PM_{10} (lb/hr)	
	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2
2003	2,474	2,293	1,898	1,783	91	57
2004	2,440	2,510	2,062	2,460	91	90
2005	2,415	2,496	740	1,135	98	144
Max Rate Used	2,474	2,510	2,062	2,460	98	144
Date of Max	02/28/03	06/17/04	10/13/04	10/13/04	12/16/05	7/12/05
MMBtu/hr on Max day	8,201	8,198	7,516	7,295	8,175	8,461
lb/MMBtu on Max Day	0.302	0.306	0.274	0.337	0.012	0.017

TABLE 2

BART NOX EMISSION RATES

Case	Emission Factor (lb/MMBtu)	Heat Demand (MMBtu/hr)	Unit 1 NOx (lb/hr)	Unit 2 NOx (lb/hr)
Flex Fuels	0.240	8,200	1,968	1,968
Flex Fuels w SNCR [1]	0.180	8,200	1,476	1,476

1. NOx emission rate for "Flex Fuels w SNCR" case is based on 75% of Flex Fuels case.

TABLE 3

BART EMISSION RATES BY CASE, TOTAL FOR BOTH UNITS

Case	NOx (lb/hr)	SO_2 (lb/hr)	PM_{10} (lb/hr)
Baseline [1]	4,984	4,522	242
Flex Fuels [2]	3,936	1,854	242
Flex Fuels w SNCR [2]	2,952	1,854	242

1. Maximum actual 24-hour emissions during 2003-2005.
2. Flex Fuel SO_2 emissions based on the ratio of sulfur in Jacobs Ranch coal to Centralia Mine coal (41%) times the 2003-2005 maximum 24-hour rate of 4,522 lb/hr. NOx emissions reduced by 25% for SNCR.

TABLE 4
STACK PARAMETERS

Case	Stack Location xlcc (km) [1]	Stack Location ylcc (km) [1]	Base Elevation (m) [2]	Stack Height (m)	Diameter (m)	Velocity (m/s)	Temperature (K)
All	-136.702	-239.551	108.6	143.3	12.82 [3]	15.0 [4]	332.3 [4]

1 Lambert Conic Conformal (LCC) coordinates with reference Latitude 49 North and reference Longitude 121 West.

2 Source elevation based on bilinear interpolation of the 4-km mesh size terrain used by CALMET

3 The units were simulated as a release from a single stack. The two stacks are next to one another and the flows were combined using an equivalent diameter calculated from the combined area of the two stacks

4 Velocity and temperature are based on the average measured data from 2003-2005

TABLE 5
PM10 SPECIATION

Case	$(NH_4)_2SO_4$	NH_4NO_3	OC	PMC	PMF	EC
Baseline [1]	22.68%	0.00%	5.67%	39.81%	30.67%	1.18%
Flex Fuels [1]	22.68%	0.00%	5.67%	39.81%	30.67%	1.18%
Flex Fuels w SNCR [1]	22.68%	0.00%	5.67%	39.81%	30.67%	1.18%

1. NPS PM_{10} profile for Dry Bottom Boiler burning pulverized coal with FGD and ESP assuming a sulfur content of 0.92%, an ash content of 14.9%, and a heat content of 7,961 Btu/lb

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TABLE 6

CALPUFF EMISSION RATES, TOTAL FOR BOTH UNITS

	Maximum 24-hour Emission Rates (lb/hr)								
Case	**SO_2**	**SO_4**	**NOx**	**HNO_3**	**NO_3**	**OC [1]**	**PMC**	**PMF**	**EC**
Baseline	4,522.0	40.0	4,984.0	0.0	0.0	13.7	96.4	74.3	2.9
Flex Fuels	1,854.0	40.0	3,936.0	0.0	0.0	13.7	96.4	74.3	2.9
Flex Fuels w SNCR	1,854.0	40.0	2,952.0	0.0	0.0	13.7	96.4	74.3	2.9

1. OC emissions were actually labeled secondary organic aerosols (SOA) in the CALPUFF input files to facilitate post-processing with CALPOST. This assumes all OC emitted forms SOA with the same molecular weight.

TABLE 7

NUMBER OF DAYS WITH PREDICTED CHANGE TO THE HAZE INDEX GREATER THAN 0.5 DECIVIEWS

		Number of Days in 2003-2005 with Delta HI > 0.5 dv		
Area of Interest	**Period**	**Baseline**	**Flex Fuels**	**Flex Fuels w SNCR**
Alpine Lakes Wilderness	2003-2005	432	361	323
Glacier Peak Wilderness	2003-2005	275	202	168
Goat Rocks Wilderness	2003-2005	414	354	318
Mt. Adams Wilderness	2003-2005	329	271	241
Mt. Hood Wilderness	2003-2005	224	176	147
Mt. Jefferson Wilderness	2003-2005	130	89	77
Mt. Rainier National Park	2003-2005	505	462	428
Mt. Washington Wilderness	2003-2005	101	63	45
N. Cascades National Park	2003-2005	206	137	103
Olympic National Park	2003-2005	254	216	199
Pasayten Wilderness	2003-2005	141	82	55
Three Sisters Wilderness	2003-2005	105	68	51
CRGNSA	2003-2005	245	173	140
Overall	Min	101	63	45
	Mean	259	204	177
	Max	505	462	428

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TABLE 8

PREDICTED CHANGE TO THE 98TH PERCENTILE DAILY HAZE INDEX FOR 2003-2005

		98th Percentile Daily Delta HI (dv) [1]		
Area of Interest	**Period**	**Baseline**	**Flex Fuels**	**Flex Fuels w SNCR**
Alpine Lakes Wilderness	2003-2005	4.346	2.994	2.598
Glacier Peak Wilderness	2003-2005	2.622	1.905	1.532
Goat Rocks Wilderness	2003-2005	4.286	3.180	2.637
Mt. Adams Wilderness	2003-2005	3.628	2.591	2.147
Mt. Hood Wilderness	2003-2005	2.830	1.997	1.665
Mt. Jefferson Wilderness	2003-2005	1.888	1.267	1.053
Mt. Rainier National Park	2003-2005	5.489	4.225	3.501
Mt. Washington Wilderness	2003-2005	1.414	0.872	0.737
N. Cascades National Park	2003-2005	2.212	1.486	1.228
Olympic National Park	2003-2005	4.024	2.991	2.486
Pasayten Wilderness	2003-2005	1.482	0.999	0.822
Three Sisters Wilderness	2003-2005	1.538	0.993	0.819
CRGNSA	2003-2005	2.353	1.657	1.378
Overall	Min	1.414	0.872	0.737
	Mean	2.932	2.089	1.739
	Max	5.489	4.225	3.501

1. Based on the 22nd highest on a Class I area basis

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TABLE 9

YEARLY PREDICTED CHANGE TO THE 98TH PERCENTILE DAILY HAZE INDEX

		98th Percentile Delta HI (dv) [1]		
Area of Interest	**Year**	**Baseline**	**Flex Fuels**	**Flex Fuels w SNCR**
Alpine Lakes Wilderness	2003	3.599	2.490	2.092
	2004	4.871	3.564	2.949
	2005	3.856	2.841	2.306
Glacier Peak Wilderness	2003	2.070	1.399	1.153
	2004	3.615	2.403	2.049
	2005	2.554	1.857	1.525
Goat Rocks Wilderness	2003	4.207	3.002	2.440
	2004	4.993	3.676	3.069
	2005	3.826	2.815	2.308
Mt. Adams Wilderness	2003	3.667	2.646	2.194
	2004	3.628	2.591	2.128
	2005	3.379	2.543	2.096
Mt. Hood Wilderness	2003	2.773	1.939	1.586
	2004	3.471	2.346	1.978
	2005	2.159	1.470	1.225
Mt. Jefferson Wilderness	2003	1.570	1.059	0.867
	2004	2.079	1.399	1.150
	2005	1.182	0.813	0.656
Mt. Rainier National Park	2003	5.552	4.318	3.606
	2004	5.447	4.252	3.573
	2005	5.373	4.092	3.401

1. Based on the 8th highest on a Class I area basis

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TABLE 9 (Continued)

YEARLY PREDICTED CHANGE TO THE 98TH PERCENTILE DAILY HAZE INDEX

		98th Percentile Delta HI (dv) [1]		
Area of Interest	**Year**	**Baseline**	**Flex Fuels**	**Flex Fuels w SNCR**
Mt. Washington Wilderness	2003	1.374	0.925	0.755
	2004	2.027	1.323	1.106
	2005	0.945	0.594	0.485
N. Cascades National Park	2003	1.557	1.172	0.935
	2004	2.821	1.852	1.570
	2005	1.811	1.373	1.084
Olympic National Park	2003	3.848	2.824	2.432
	2004	4.645	3.192	2.695
	2005	3.629	2.734	2.214
Pasayten Wilderness	2003	1.131	0.767	0.618
	2004	1.954	1.287	1.075
	2005	1.172	0.771	0.622
Three Sisters Wilderness	2003	1.538	0.993	0.807
	2004	2.172	1.333	1.139
	2005	1.071	0.651	0.553
CRGNSA	2003	2.431	1.699	1.411
	2004	2.545	1.748	1.446
	2005	1.714	1.259	1.013
Overall	Min	0.945	0.594	0.485
	Mean	2.878	2.052	1.700
	Max	5.552	4.318	3.606

1. Based on the 8th highest on a Class I area basis