Washington State Regional Haze State Implementation Plan

Appendix L Supplement

Best Available Retrofit Technology Technical Support Documents and Compliance Orders

.

Contents

Overview of Appendix L Supplement

Appendix L Supplement has three major sections: (1) this overview, (2) copy of a new law, and (3) revised Best Available Retrofit Technology (BART) determination for TransAlta Centralia Generation, LLC. All materials related to the public comment period and hearing on the revised BART determination are included in Appendix K Supplement.

On April 29, 2011 Governor Christine Gregoire signed into law Senate Bill 5769 (SB 5769) (Chapter 180, Laws of 2011) affecting coal-fired energy production at the TransAlta power plant in Centralia. SB 5769 solidifies into law a collaborative agreement between the plant owner and employees, environmental groups, the Governor's Office, and the local community. The law requires that TransAlta's two coal-fired boilers meet specific greenhouse gas emission performance standards on a schedule specified in the law and TransAlta install Selective Non-Catalytic Reduction technology to reduce nitrogen dioxide emissions by 2013. The complete text of the new law is found in second section of this appendix supplement.

In the fall of 2011, Ecology held a public hearing and took public comments on draft revisions of the TransAlta BART compliance order, TransAlta BART Technical Support Document (TSD), and related parts of the Regional Haze State Implementation Plan. The revised TransAlta BART compliance order dated December 13, 2011 and the TransAlta BART TSD are found in the third section of this appendix.

Copy of Senate Bill 5769 (Chapter 180, Laws of 2011)

CERTIFICATION OF ENROLLMENT

ENGROSSED SECOND SUBSTITUTE SENATE BILL 5769

Chapter 180, Laws of 2011

62nd Legislature
2011 Regular Session

COAL-FIRED ELECTRIC GENERATION FACILITIES

EFFECTIVE DATE: 07/22/11

Passed by the Senate April 21, 2011
YEAS 33 NAYS 14

BRAD OWEN

President of the Senate

Passed by the House April 11, 2011
YEAS 87 NAYS 9

FRANK CHOPP

Speaker of the House of Representatives

Approved April 29, 2011, 10:59 a.m.

CHRISTINE GREGOIRE

Governor of the State of Washington

CERTIFICATE

I, Thomas Hoemann, Secretary of the Senate of the State of Washington, do hereby certify that the attached is **ENGROSSED SECOND SUBSTITUTE SENATE BILL 5769** as passed by the Senate and the House of Representatives on the dates hereon set forth.

THOMAS HOEMANN

Secretary

FILED

April 29, 2011

Secretary of State
State of Washington

ENGROSSED SECOND SUBSTITUTE SENATE BILL 5769

AS AMENDED BY THE HOUSE

Passed Legislature - 2011 Regular Session

State of Washington 62nd Legislature 2011 Regular Session

By Senate Ways & Means (originally sponsored by Senators Rockefeller, Pridemore, Kohl-Welles, White, Chase, Murray, Ranker, Regala, Fraser, Shin, and Kline)

READ FIRST TIME 02/25/11.

AN ACT Relating to coal-fired electric generation facilities; amending RCW 80.80.040, 80.80.070, 80.50.100, 43.160.076, and 19.280.030; reenacting and amending RCW 80.80.010 and 80.80.060; adding new sections to chapter 80.80 RCW; adding a new section to chapter 43.155 RCW; adding new sections to chapter 80.04 RCW; adding a new section to chapter 80.70 RCW; adding a new chapter to Title 80 RCW; creating a new section; providing an expiration date; and providing a contingent expiration date.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF WASHINGTON:

NEW SECTION. **Sec. 101.** (1) The legislature finds that generating electricity from the combustion of coal produces pollutants that are harmful to human health and safety and the environment. While the emission of many of these pollutants continues to be addressed through application of federal and state air quality laws, the emission of greenhouse gases resulting from the combustion of coal has not been addressed.

(2) The legislature finds that coal-fired electricity generation is one of the largest sources of greenhouse gas emissions in the state,

and is the largest source of such emissions from the generation of electricity in the state.

(3) The legislature finds coal-fired electric generation may provide baseload power that is necessary in the near-term for the stability and reliability of the electrical transmission grid and that contributes to the availability of affordable power in the state. The legislature further finds that efforts to transition power to other fuels requires a reasonable period of time to ensure grid stability and to maintain affordable electricity resources.

(4) The legislature finds that coal-fired baseload electric generation facilities are a significant contributor to family-wage jobs and economic health in parts of the state and that transition of these facilities must address the economic future and the preservation of jobs in affected communities.

(5) Therefore, it is the purpose of this act to provide for the reduction of greenhouse gas emissions from large coal-fired baseload electric power generation facilities, to effect an orderly transition to cleaner fuels in a manner that ensures reliability of the state's electrical grid, to ensure appropriate cleanup and site restoration upon decommissioning of any of these facilities in the state, and to provide assistance to host communities planning for new economic development and mitigating the economic impacts of the closure of these facilities.

Sec. 102. RCW 80.80.010 and 2009 c 565 s 54 and 2009 c 448 s 1 are each reenacted and amended to read as follows:

The definitions in this section apply throughout this chapter unless the context clearly requires otherwise.

(1) "Attorney general" means the Washington state office of the attorney general.

(2) "Auditor" means: (a) The Washington state auditor's office or its designee for consumer-owned utilities under its jurisdiction; or (b) an independent auditor selected by a consumer-owned utility that is not under the jurisdiction of the state auditor.

(3) "Average available greenhouse gas emissions output" means the level of greenhouse gas emissions as surveyed and determined by the energy policy division of the department of commerce under RCW 80.80.050.

(4) "Baseload electric generation" means electric generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least sixty percent.

(5) "Cogeneration facility" means a power plant in which the heat or steam is also used for industrial or commercial heating or cooling purposes and that meets federal energy regulatory commission standards for qualifying facilities under the public utility regulatory policies act of 1978 (16 U.S.C. Sec. 824a-3), as amended.

(6) "Combined-cycle natural gas thermal electric generation facility" means a power plant that employs a combination of one or more gas turbines and steam turbines in which electricity is produced in the steam turbine from otherwise lost waste heat exiting from one or more of the gas turbines.

(7) "Commission" means the Washington utilities and transportation commission.

(8) "Consumer-owned utility" means a municipal utility formed under Title 35 RCW, a public utility district formed under Title 54 RCW, an irrigation district formed under chapter 87.03 RCW, a cooperative formed under chapter 23.86 RCW, a mutual corporation or association formed under chapter 24.06 RCW, or port district within which an industrial district has been established as authorized by Title 53 RCW, that is engaged in the business of distributing electricity to more than one retail electric customer in the state.

(9) "Department" means the department of ecology.

(10) "Distributed generation" means electric generation connected to the distribution level of the transmission and distribution grid, which is usually located at or near the intended place of use.

(11) "Electric utility" means an electrical company or a consumer-owned utility.

(12) "Electrical company" means a company owned by investors that meets the definition of RCW 80.04.010.

(13) "Governing board" means the board of directors or legislative authority of a consumer-owned utility.

(14) "Greenhouse ((~~gases~~)) gas" includes carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

(15) "Long-term financial commitment" means:

(a) Either a new ownership interest in baseload electric generation or an upgrade to a baseload electric generation facility; or

(b) A new or renewed contract for baseload electric generation with a term of five or more years for the provision of retail power or wholesale power to end-use customers in this state.

(16) "Plant capacity factor" means the ratio of the electricity produced during a given time period, measured in kilowatt-hours, to the electricity the unit could have produced if it had been operated at its rated capacity during that period, expressed in kilowatt-hours.

(17) "Power plant" means a facility for the generation of electricity that is permitted as a single plant by a jurisdiction inside or outside the state.

(18) "Upgrade" means any modification made for the primary purpose of increasing the electric generation capacity of a baseload electric generation facility. "Upgrade" does not include routine or necessary maintenance, installation of emission control equipment, installation, replacement, or modification of equipment that improves the heat rate of the facility, or installation, replacement, or modification of equipment for the primary purpose of maintaining reliable generation output capability that does not increase the heat input or fuel usage as specified in existing generation air quality permits as of July 22, 2007, but may result in incidental increases in generation capacity.

(19) "Coal transition power" means the output of a coal-fired electric generation facility that is subject to an obligation to meet the standards contained in RCW 80.80.040(3)(c).

(20) "Memorandum of agreement" or "memorandum" means a binding and enforceable contract entered into pursuant to section 106 of this act between the governor on behalf of the state and an owner of a baseload electric generation facility in the state that produces coal transition power.

Sec. 103. RCW 80.80.040 and 2009 c 448 s 2 are each amended to read as follows:

(1) Beginning July 1, 2008, the greenhouse gas emissions performance standard for all baseload electric generation for which electric utilities enter into long-term financial commitments on or after such date is the lower of:

(a) One thousand one hundred pounds of greenhouse gases per megawatt-hour; or

(b) The average available greenhouse gas emissions output as determined under RCW 80.80.050.

(2) This chapter does not apply to long-term financial commitments with the Bonneville power administration.

(3)(a) Except as provided in (c) of this subsection, all baseload electric generation facilities in operation as of June 30, 2008, are deemed to be in compliance with the greenhouse gas emissions performance standard established under this section until the facilities are the subject of long-term financial commitments.

(b) All baseload electric generation that commences operation after June 30, 2008, and is located in Washington, must comply with the greenhouse gas emissions performance standard established in subsection (1) of this section.

(c)(i) A coal-fired baseload electric generation facility in Washington that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008 must comply with the lower of the following greenhouse gas emissions performance standard such that one generating boiler is in compliance by December 31, 2020, and any other generating boiler is in compliance by December 31, 2025:

(A) One thousand one hundred pounds of greenhouse gases per megawatt-hour; or

(B) The average available greenhouse gas emissions output as determined under RCW 80.80.050.

(ii) This subsection (3)(c) does not apply to a coal-fired baseload electric generating facility in the event the department determines as a requirement of state or federal law or regulation that selective catalytic reduction technology must be installed on any of its boilers.

(4) All electric generation facilities or power plants powered exclusively by renewable resources, as defined in RCW 19.280.020, are deemed to be in compliance with the greenhouse gas emissions performance standard established under this section.

(5) All cogeneration facilities in the state that are fueled by natural gas or waste gas or a combination of the two fuels, and that are in operation as of June 30, 2008, are deemed to be in compliance with the greenhouse gas emissions performance standard established

under this section until the facilities are the subject of a new ownership interest or are upgraded.

(6) In determining the rate of emissions of greenhouse gases for baseload electric generation, the total emissions associated with producing electricity shall be included.

(7) In no case shall a long-term financial commitment be determined to be in compliance with the greenhouse gas emissions performance standard if the commitment includes more than twelve percent of electricity from unspecified sources.

(8) For a long-term financial commitment with multiple power plants, each specified power plant must be treated individually for the purpose of determining the annualized plant capacity factor and net emissions, and each power plant must comply with subsection (1) of this section, except as provided in subsections (3) through (5) of this section.

(9) The department shall establish an output-based methodology to ensure that the calculation of emissions of greenhouse gases for a cogeneration facility recognizes the total usable energy output of the process, and includes all greenhouse gases emitted by the facility in the production of both electrical and thermal energy. In developing and implementing the greenhouse gas emissions performance standard, the department shall consider and act in a manner consistent with any rules adopted pursuant to the public utilities regulatory policy act of 1978 (16 U.S.C. Sec. 824a-3), as amended.

(10) The following greenhouse gas emissions produced by baseload electric generation owned or contracted through a long-term financial commitment shall not be counted as emissions of the power plant in determining compliance with the greenhouse gas emissions performance standard:

(a) Those emissions that are injected permanently in geological formations;

(b) Those emissions that are permanently sequestered by other means approved by the department; and

(c) Those emissions sequestered or mitigated as approved under subsection (16) of this section.

(11) In adopting and implementing the greenhouse gas emissions performance standard, the department of ((~~community, trade, and economic development~~)) <u>commerce</u> energy policy division, in consultation

with the commission, the department, the Bonneville power administration, the western electricity ((~~coordination [coordinating]~~)) coordinating council, the energy facility site evaluation council, electric utilities, public interest representatives, and consumer representatives, shall consider the effects of the greenhouse gas emissions performance standard on system reliability and overall costs to electricity customers.

(12) In developing and implementing the greenhouse gas emissions performance standard, the department shall, with assistance of the commission, the department of ((~~community, trade, and economic development~~)) commerce energy policy division, and electric utilities, and to the extent practicable, address long-term purchases of electricity from unspecified sources in a manner consistent with this chapter.

(13) The directors of the energy facility site evaluation council and the department shall each adopt rules under chapter 34.05 RCW in coordination with each other to implement and enforce the greenhouse gas emissions performance standard. The rules necessary to implement this section shall be adopted by June 30, 2008.

(14) In adopting the rules for implementing this section, the energy facility site evaluation council and the department shall include criteria to be applied in evaluating the carbon sequestration plan, for baseload electric generation that will rely on subsection (10) of this section to demonstrate compliance, but that will commence sequestration after the date that electricity is first produced. The rules shall include but not be limited to:

(a) Provisions for financial assurances, as a condition of plant operation, sufficient to ensure successful implementation of the carbon sequestration plan, including construction and operation of necessary equipment, and any other significant costs;

(b) Provisions for geological or other approved sequestration commencing within five years of plant operation, including full and sufficient technical documentation to support the planned sequestration;

(c) Provisions for monitoring the effectiveness of the implementation of the sequestration plan;

(d) Penalties for failure to achieve implementation of the plan on schedule;

(e) Provisions for an owner to purchase emissions reductions in the event of the failure of a sequestration plan under subsection (16) of this section; and

(f) Provisions for public notice and comment on the carbon sequestration plan.

(15)(a) Except as provided in (b) of this subsection, as part of its role enforcing the greenhouse gas emissions performance standard, the department shall determine whether sequestration or a plan for sequestration will provide safe, reliable, and permanent protection against the greenhouse gases entering the atmosphere from the power plant and all ancillary facilities.

(b) For facilities under its jurisdiction, the energy facility site evaluation council shall contract for review of sequestration or the carbon sequestration plan with the department consistent with the conditions under (a) of this subsection, consider the adequacy of sequestration or the plan in its adjudicative proceedings conducted under RCW 80.50.090(3), and incorporate specific findings regarding adequacy in its recommendation to the governor under RCW 80.50.100.

(16) A project under consideration by the energy facility site evaluation council by July 22, 2007, is required to include all of the requirements of subsection (14) of this section in its carbon sequestration plan submitted as part of the energy facility site evaluation council process. A project under consideration by the energy facility site evaluation council by July 22, 2007, that receives final site certification agreement approval under chapter 80.50 RCW shall make a good faith effort to implement the sequestration plan. If the project owner determines that implementation is not feasible, the project owner shall submit documentation of that determination to the energy facility site evaluation council. The documentation shall demonstrate the steps taken to implement the sequestration plan and evidence of the technological and economic barriers to successful implementation. The project owner shall then provide to the energy facility site evaluation council notification that they shall implement the plan that requires the project owner to meet the greenhouse gas emissions performance standard by purchasing verifiable greenhouse gas emissions reductions from an electric ((~~generating~~)) generation facility located within the western interconnection, where the reduction would not have occurred otherwise or absent this contractual

agreement, such that the sum of the emissions reductions purchased and the facility's emissions meets the standard for the life of the facility.

Sec. 104. RCW 80.80.060 and 2009 c 448 s 3 and 2009 c 147 s 1 are each reenacted and amended to read as follows:

(1) No electrical company may enter into a long-term financial commitment unless the baseload electric generation supplied under such a long-term financial commitment complies with the greenhouse ((~~gases [gas]~~)) gas emissions performance standard established under RCW 80.80.040.

(2) In order to enforce the requirements of this chapter, the commission shall review in a general rate case or as provided in subsection (5) of this section any long-term financial commitment entered into by an electrical company after June 30, 2008, to determine whether the baseload electric generation to be supplied under that long-term financial commitment complies with the greenhouse ((~~gases [gas]~~)) gas emissions performance standard established under RCW 80.80.040.

(3) In determining whether a long-term financial commitment is for baseload electric generation, the commission shall consider the design of the power plant and its intended use, based upon the electricity purchase contract, if any, permits necessary for the operation of the power plant, and any other matter the commission determines is relevant under the circumstances.

(4) Upon application by an electric utility, the commission may provide a case-by-case exemption from the greenhouse ((~~gases [gas]~~)) gas emissions performance standard to address: (a) Unanticipated electric system reliability needs; (b) extraordinary cost impacts on utility ratepayers; or (c) catastrophic events or threat of significant financial harm that may arise from unforeseen circumstances.

(5) Upon application by an electrical company, the commission shall determine whether the company's proposed decision to acquire electric generation or enter into a power purchase agreement for electricity complies with the greenhouse ((~~gases [gas]~~)) gas emissions performance standard established under RCW 80.80.040. The commission shall not decide in a proceeding under this subsection (5) issues involving the actual costs to construct and operate the selected resource, cost

recovery, or other issues reserved by the commission for decision in a general rate case or other proceeding for recovery of the resource or contract costs.

(6) An electrical company may account for and defer for later consideration by the commission costs incurred in connection with a long-term financial commitment, including operating and maintenance costs, depreciation, taxes, and cost of invested capital. The deferral begins with the date on which the power plant begins commercial operation or the effective date of the power purchase agreement and continues for a period not to exceed twenty-four months; provided that if during such period the company files a general rate case or other proceeding for the recovery of such costs, deferral ends on the effective date of the final decision by the commission in such proceeding. Creation of such a deferral account does not by itself determine the actual costs of the long-term financial commitment, whether recovery of any or all of these costs is appropriate, or other issues to be decided by the commission in a general rate case or other proceeding for recovery of these costs. For the purpose of this subsection (6) only, the term "long-term financial commitment" also includes an electric company's ownership or power purchase agreement with a term of five or more years associated with an eligible renewable resource as defined in RCW 19.285.030.

(7) The commission shall consult with the department to apply the procedures adopted by the department to verify the emissions of greenhouse gases from baseload electric generation under RCW 80.80.040. The department shall report to the commission whether baseload electric generation will comply with the greenhouse ((~~gases [gas]~~)) gas emissions performance standard for the duration of the period the baseload electric generation is supplied to the electrical company.

(8) The commission shall adopt rules for the enforcement of this section with respect to electrical companies and adopt procedural rules for approving costs incurred by an electrical company under subsection (4) of this section.

(9) This section does not apply to a long-term financial commitment for the purchase of coal transition power with termination dates consistent with the applicable dates in RCW 80.80.040(3)(c).

(10) The commission shall adopt rules necessary to implement this section by December 31, 2008.

Sec. 105. RCW 80.80.070 and 2007 c 307 s 9 are each amended to read as follows:

(1) No consumer-owned utility may enter into a long-term financial commitment unless the baseload electric generation supplied under such a long-term financial commitment complies with the greenhouse ((~~gases~~)) gas emissions performance standard established under RCW 80.80.040.

(2) The governing board shall review and make a determination on any long-term financial commitment by the utility, pursuant to this chapter and after consultation with the department, to determine whether the baseload electric generation to be supplied under that long-term financial commitment complies with the greenhouse ((~~gases~~)) gas emissions performance standard established under RCW 80.80.040. No consumer-owned utility may enter into a long-term financial commitment unless the baseload electric generation to be supplied under that long-term financial commitment complies with the greenhouse ((~~gases~~)) gas emissions performance standard established under RCW 80.80.040.

(3) In confirming that a long-term financial commitment is for baseload electric generation, the governing board shall consider the design of the power plant and the intended use of the power plant based upon the electricity purchase contract, if any, permits necessary for the operation of the power plant, and any other matter the governing board determines is relevant under the circumstances.

(4) The governing board may provide a case-by-case exemption from the greenhouse ((~~gases~~)) gas emissions performance standard to address: (a) Unanticipated electric system reliability needs; or (b) catastrophic events or threat of significant financial harm that may arise from unforeseen circumstances.

(5) The governing board shall apply the procedures adopted by the department to verify the emissions of greenhouse gases from baseload electric generation under RCW 80.80.040, and may request assistance from the department in doing so.

(6) For consumer-owned utilities, the auditor is responsible for auditing compliance with this chapter and rules adopted under this chapter that apply to those utilities and the attorney general is responsible for enforcing that compliance.

(7) This section does not apply to long-term financial commitments for the purchase of coal transition power with termination dates consistent with the applicable dates in RCW 80.80.040(3)(c).

NEW SECTION. **Sec. 106.** A new section is added to chapter 80.80 RCW to read as follows:

(1) By January 1, 2012, the governor on behalf of the state shall enter into a memorandum of agreement that takes effect on April 1, 2012, with the owners of a coal-fired baseload facility in Washington that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008. The memorandum of agreement entered into by the governor may only contain provisions authorized in this section, except as provided under section 108 of this act.

(2) The memorandum of agreement must:

(a) Incorporate by reference RCW 80.80.040, 80.80.060, and 80.80.070 as of the effective date of this section;

(b) Incorporate binding commitments to install selective noncatalytic reduction pollution control technology in any coal-fired generating boilers by January 1, 2013, after discussing the proper use of ammonia in this technology.

(3)(a) The memorandum of agreement must include provisions by which the facility owner will provide financial assistance:

(i) To the affected community for economic development and energy efficiency and weatherization; and

(ii) For energy technologies with the potential to create considerable energy, economic development, and air quality, haze, or other environmental benefits.

(b) Except as described in (c) of this subsection, the financial assistance in (a)(i) of this subsection must be in the amount of thirty million dollars and the financial assistance in (a)(ii) of this subsection must be in the amount of twenty-five million dollars, with investments beginning January 1, 2012, and consisting of equal annual investments through December 31, 2023, or until the full amount has been provided. Only funds for energy efficiency and weatherization may be spent prior to December 31, 2015.

(c) If the tax exemptions provided under RCW 82.08.811 or 82.12.811 are repealed, any remaining financial assistance required by this section is no longer required.

(4) The memorandum of agreement must:

(a) Specify that the investments in subsection (3) of this section be held in independent accounts at an appropriate financial institution; and

(b) Identify individuals to approve expenditures from the accounts. Individuals must have relevant expertise and must include members representing the Lewis county economic development council, local elected officials, employees at the facility, and the facility owner.

(5) The memorandum of agreement must include a provision that allows for the termination of the memorandum of agreement in the event the department determines as a requirement of state or federal law or regulation that selective catalytic reduction technology must be installed on any of its boilers.

(6) The memorandum of agreement must include enforcement provisions to ensure implementation of the agreement by the parties.

(7) If the memorandum of agreement is not signed by January 1, 2012, the governor must impose requirements consistent with the provisions in subsection (2)(b) of this section.

NEW SECTION. **Sec. 107.** A new section is added to chapter 80.80 RCW to read as follows:

No state agency or political subdivision of the state may adopt or impose a greenhouse gas emission performance standard, or other operating or financial requirement or limitation relating to greenhouse gas emissions, on a coal-fired electric generation facility located in Washington in operation on or before the effective date of this section or upon an electric utility's long-term purchase of coal transition power, that is inconsistent with or in addition to the provisions of RCW 80.80.040 or the memorandum of agreement entered into under section 106 of this act.

NEW SECTION. **Sec. 108.** A new section is added to chapter 80.80 RCW to read as follows:

(1) A memorandum of agreement entered into pursuant to section 106 of this act may include provisions to assist in the financing of emissions reductions that exceed those required by RCW 80.80.040(3)(c) by providing for the recognition of such reductions in applicable state policies and programs relating to greenhouse gas emissions, and by encouraging and advocating for the recognition of the reductions in all established and emerging emission reduction frameworks at the regional, national, or international level.

(2) The governor may recommend actions to the legislature to strengthen implementation of an agreement or a proposed agreement relating to recognition of investments in emissions reductions described in subsection (1) of this section.

Sec. 109. RCW 80.50.100 and 1989 c 175 s 174 are each amended to read as follows:

(1)(a) The council shall report to the governor its recommendations as to the approval or rejection of an application for certification within twelve months of receipt by the council of such an application, or such later time as is mutually agreed by the council and the applicant.

(b) In the case of an application filed prior to December 31, 2025, for certification of an energy facility proposed for construction, modification, or expansion for the purpose of providing generating facilities that meet the requirements of RCW 80.80.040 and are located in a county with a coal-fired electric generating facility subject to RCW 80.80.040(3)(c), the council shall expedite the processing of the application pursuant to RCW 80.50.075 and shall report its recommendations to the governor within one hundred eighty days of receipt by the council of such an application, or a later time as is mutually agreed by the council and the applicant.

(2) If the council recommends approval of an application for certification, it shall also submit a draft certification agreement with the report. The council shall include conditions in the draft certification agreement to implement the provisions of this chapter, including, but not limited to, conditions to protect state or local governmental or community interests affected by the construction or operation of the energy facility, and conditions designed to recognize the purpose of laws or ordinances, or rules or regulations promulgated thereunder, that are preempted or superseded pursuant to RCW 80.50.110 as now or hereafter amended.

((~~(2)~~)) (3)(a) Within sixty days of receipt of the council's report the governor shall take one of the following actions:

((~~(a)~~)) (i) Approve the application and execute the draft certification agreement; or

((~~(b)~~)) (ii) Reject the application; or

((~~(c)~~)) (iii) Direct the council to reconsider certain aspects of the draft certification agreement.

(b) The council shall reconsider such aspects of the draft certification agreement by reviewing the existing record of the application or, as necessary, by reopening the adjudicative proceeding for the purposes of receiving additional evidence. Such reconsideration shall be conducted expeditiously. The council shall resubmit the draft certification to the governor incorporating any amendments deemed necessary upon reconsideration. Within sixty days of receipt of such draft certification agreement, the governor shall either approve the application and execute the certification agreement or reject the application. The certification agreement shall be binding upon execution by the governor and the applicant.

((~~(3)~~)) (4) The rejection of an application for certification by the governor shall be final as to that application but shall not preclude submission of a subsequent application for the same site on the basis of changed conditions or new information.

NEW SECTION. **Sec. 201.** (1) A facility subject to closure under either RCW 80.80.040(3)(c) or a memorandum of agreement under section 106 of this act, or both, must provide the department of ecology with a plan for the closure and postclosure of the facility at least twenty-four months prior to facility closure or twenty-four months prior to start of decommissioning work, whichever is earlier. This plan must be consistent with the rules established by the energy facility site evaluation council for site restoration and preservation applicable to facilities subject to a site certification agreement under chapter 80.50 RCW and include but not be limited to:

(a) A detailed estimate of the cost to implement the plan based on the cost of hiring a third party to conduct all activities;

(b) Demonstrating financial assurance to fund the closure and postclosure of the facility and providing methods by which this assurance may be demonstrated;

(c) Methods for estimating closure costs, including full site reclamation under all applicable federal and state clean-up standards; and

(d) A decommissioning and site restoration plan that addresses restoring physical topography, cleanup of all hazardous substances on the site, potential future uses of the site following restoration, and coordination with local and community plans for economic development in the vicinity of the site.

(2) All cost estimates in the plan must be in current dollars and may not include a net present value adjustment or offsets for salvage value of wastes or other property.

(3) Adoption of the plan and significant revisions to the plan must be approved by the department of ecology.

NEW SECTION. **Sec. 202.** (1) A facility subject to closure under either RCW 80.80.040(3)(c) or a memorandum of agreement under section 106 of this act, or both, must guarantee funds are available to perform all activities specified in the decommissioning plan developed under section 201 of this act. The amount must equal the cost estimates specified in the decommissioning plan and must be updated annually for inflation. All guarantees under this section must be assumed by any successor owner, parent company, or holding company.

(2) The guarantee required under subsection (1) of this section may be accomplished by letter of credit, surety bond, or other means acceptable to the department of ecology.

(3) The issuing institution of the letter of credit must be an entity that has the authority to issue letters of credit and whose letter of credit operations are regulated by a federal or state agency. The surety company issuing a surety bond must, at a minimum, be an entity listed as an acceptable surety on federal bonds in circular 570, published by the United States department of the treasury.

(4) A qualifying facility that uses a letter of credit or a surety bond to satisfy the requirements of this act must also establish a standby trust fund as a means to hold any funds issued from the letter of credit or a surety bond. Under the terms of the letter of credit or a surety bond, all amounts paid pursuant to a draft from the department of ecology must be deposited by the issuing institution directly into the standby trust fund in accordance with instructions from the department of ecology. This standby trust fund must be approved by the department of ecology.

(5) The letter of credit or a surety bond must be irrevocable and issued for a period of at least one year. The letter of credit or a surety bond must provide that the expiration date will be automatically

extended for a period of at least one year unless, at least one hundred twenty days before the current expiration date, the issuing institution notifies both the qualifying facility and the department of ecology of a decision not to extend the expiration date. Under the terms of the letter of credit, the one hundred twenty days will begin on the date when both the qualifying plant and the department of ecology have received the notice, as evidenced by certified mail return receipts or by overnight courier delivery receipts.

(6) If the qualifying facility does not establish an alternative method of guaranteeing decommissioning funds are available within ninety days after receipt by both the qualifying facility plant and the department of ecology of a notice from the issuing institution that it has decided not to extend the letter of credit beyond the current expiration date, the department of ecology must draw on the letter of credit or a surety bond. The department of ecology must approve any replacement or substitute guarantee method before the expiration of the ninety-day period.

(7) If a qualifying facility elects to use a letter of credit as the sole method for guaranteeing decommissioning funds are available, the face value of the letter of credit must meet or exceed the current inflation-adjusted cost estimate. If a qualifying facility elects to use a surety bond as the sole method for guaranteeing decommissioning funds are available, the penal sum of the surety bond must meet or exceed the current inflation-adjusted cost estimate.

(8) A qualifying facility must adjust the decommissioning costs and financial guarantees annually for inflation and may use an amendment to increase the face value of a letter of credit or a surety bond each year to account for this inflation. A qualifying facility is not required to obtain a new letter of credit or a surety bond to cover annual inflation adjustments.

NEW SECTION. **Sec. 203.** Sections 201 and 202 of this act constitute a new chapter in Title 80 RCW.

Sec. 301. RCW 43.160.076 and 2008 c 327 s 8 are each amended to read as follows:

(1) Except as authorized to the contrary under subsection (2) of this section, from all funds available to the board for financial

assistance in a biennium under this chapter, the board shall approve at least seventy-five percent of the first twenty million dollars of funds available and at least fifty percent of any additional funds for financial assistance for projects in rural counties.

(2) If at any time during the last six months of a biennium the board finds that the actual and anticipated applications for qualified projects in rural counties are clearly insufficient to use up the allocations under subsection (1) of this section, then the board shall estimate the amount of the insufficiency and during the remainder of the biennium may use that amount of the allocation for financial assistance to projects not located in rural counties.

(3) The board shall solicit qualifying projects to plan, design, and construct public facilities needed to attract new industrial and commercial activities in areas impacted by the closure or potential closure of large coal-fired electric generation facilities, which for the purposes of this section means a facility that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008. The projects should be consistent with any applicable plans for major industrial activity on lands formerly used or designated for surface coal mining and supporting uses under RCW 36.70A.368. When the board receives timely and eligible project applications from a political subdivision of the state for financial assistance for such projects, the board from available funds shall give priority consideration to such projects.

NEW SECTION. **Sec. 302.** A new section is added to chapter 43.155 RCW to read as follows:

The board shall solicit qualifying projects to plan, design, and construct public works projects needed to attract new industrial and commercial activities in areas impacted by the closure or potential closure of large coal-fired electric generation facilities, which for the purposes of this section means a facility that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008. The projects should be consistent with any applicable plans for major industrial activity on lands formerly used or designated for surface coal mining and supporting uses under RCW 36.70A.368. When the board receives timely and eligible project applications from a political subdivision of the state for financial assistance for such projects, the board from available funds shall give priority consideration to such projects.

<u>NEW SECTION.</u> **Sec. 303.** A new section is added to chapter 80.04 RCW to read as follows:

The legislature finds that an electrical company's acquisition of coal transition power helps to achieve the state's greenhouse gas emission reduction goals by effecting an orderly transition to cleaner fuels and supports the state's public policy.

<u>NEW SECTION.</u> **Sec. 304.** A new section is added to chapter 80.04 RCW to read as follows:

(1) On the petition of an electrical company, the commission shall approve or disapprove a power purchase agreement for acquisition of coal transition power, as defined in RCW 80.80.010, and the recovery of related acquisition costs. No agreement for an electrical company's acquisition of coal transition power takes effect until it is approved by the commission.

(2) Any power purchase agreement for the acquisition of coal transition power pursuant to this section must provide for modification of the power purchase agreement to the satisfaction of the parties thereto in the event that a new or revised emission or performance standard or other new or revised operational or financial requirement or limitation directly or indirectly addressing greenhouse gas emissions is imposed by state or federal law, rules, or regulatory requirements. Such a modification to a power purchase agreement agreed to by the parties must be reviewed and considered for approval by the commission, considering the circumstances existing at the time of such a review, under procedures and standards set forth in this section. In the event the parties cannot agree to modification of the power purchase agreement, either party to the agreement has the right to terminate the agreement if it is adversely affected by this new standard, requirement, or limitation.

(3) When a petition is filed, the commission shall provide notice to the public and potentially affected parties and set the petition for hearing as an adjudicative proceeding under chapter 34.05 RCW. Any party may request that the commission expedite the hearing of that

petition. The hearing of such a petition is not considered a general rate case. The electrical company must file supporting testimony and exhibits together with the power purchase agreement for coal transition power. Information provided by the facility owner to the purchasing electrical company for evaluating the costs and benefits associated with acquisition of coal transition power must be made available to other parties to the petition under a protective order entered by the commission. An administrative law judge of the commission may enter an initial order including findings of fact and conclusions of law, as provided in RCW 80.01.060(3). The commission shall issue a final order that approves or disapproves the power purchase agreement for acquisition of coal transition power within one hundred eighty days after an electrical company files the petition.

(4) The commission must approve a power purchase agreement for acquisition of coal transition power pursuant to this section only if the commission determines that, considering the circumstances existing at the time of such a review: The terms of such an agreement provide adequate protection to ratepayers and the electrical company during the term of such an agreement or in the event of early termination; the resource is needed by the electrical company to serve its ratepayers and the resource meets the need in a cost-effective manner as determined under the lowest reasonable cost resource standards under chapter 19.280 RCW, including the cost of the power purchase agreement plus the equity component as determined in this section. As part of these determinations, the commission shall consider, among other factors, the long-term economic risks and benefits to the electrical company and its ratepayers of such a long-term purchase.

(5) If the commission has not issued a final order within one hundred eighty days from the date the petition is filed, or if the commission disapproves the petition, the power purchase agreement for acquisition of coal transition power is null and void. In the event the commission approves the agreement upon conditions other than those set forth in the petition, the electrical company has the right to reject the agreement.

(6)(a) Upon commission approval of an electrical company's power purchase agreement for acquisition of coal transition power in accordance with this section, the electrical company is allowed to earn the equity component of its authorized rate of return in the same manner as if it had purchased or built an equivalent plant and to recover the cost of the coal transition power under the power purchase agreement. Any power purchase agreement for acquisition of coal transition power that earns a return on equity may not be included in an imputed debt calculation for setting customer rates.

(b) For purposes of determining the equity value, the cost of an equivalent plant is the least cost purchased or self-built electric generation plant with equivalent capacity. In determining the least cost plant, the commission may rely on the electrical company's most recent filed integrated resource plan. The cost of an equivalent plant, in dollars per kilowatt, must be determined in the original process of commission approval for each power purchase agreement for coal transition power.

(c) The equivalent plant cost determined in the approval process must be amortized over the life of the power purchase agreement for acquisition of coal transition power to determine the recovery of the equity value.

(d) The recovery of the equity component must be determined and approved in the review process set forth in this section. The approved equity value must be in addition to the approved cost of the power purchase agreement.

(7) Authorizing recovery of costs under a power purchase agreement for acquisition of coal transition power does not prohibit the commission from authorizing recovery of an electrical company's acquisition of capacity resources for the purpose of integrating intermittent power or following load.

(8) Neither this act nor the commission's approval of a power purchase agreement for acquisition of coal transition power that includes the ability to earn the equity component of an electrical company's authorized rate of return establishes any precedent for an electrical company to receive an equity return on any other power purchase agreement or other power contract.

(9) For purposes of this section, "power purchase agreement" means a long-term financial commitment as defined in RCW 80.80.010(15)(b).

(10) This section expires December 31, 2025.

Sec. 305. RCW 19.280.030 and 2006 c 195 s 3 are each amended to read as follows:

Each electric utility must develop a plan consistent with this section.

(1) Utilities with more than twenty-five thousand customers that are not full requirements customers shall develop or update an integrated resource plan by September 1, 2008. At a minimum, progress reports reflecting changing conditions and the progress of the integrated resource plan must be produced every two years thereafter. An updated integrated resource plan must be developed at least every four years subsequent to the 2008 integrated resource plan. The integrated resource plan, at a minimum, must include:

(a) A range of forecasts, for at least the next ten years, of projected customer demand which takes into account econometric data and customer usage;

(b) An assessment of commercially available conservation and efficiency resources. Such assessment may include, as appropriate, high efficiency cogeneration, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources;

(c) An assessment of commercially available, utility scale renewable and nonrenewable generating technologies including a comparison of the benefits and risks of purchasing power or building new resources;

(d) A comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using "lowest reasonable cost" as a criterion;

(e) The integration of the demand forecasts and resource evaluations into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs at the lowest reasonable cost and risk to the utility and its ratepayers; and

(f) A short-term plan identifying the specific actions to be taken by the utility consistent with the long-range integrated resource plan.

(2) All other utilities may elect to develop a full integrated resource plan as set forth in subsection (1) of this section or, at a minimum, shall develop a resource plan that:

(a) Estimates loads for the next five and ten years;

(b) Enumerates the resources that will be maintained and/or acquired to serve those loads; and

(c) Explains why the resources in (b) of this subsection were chosen and, if the resources chosen are not renewable resources or conservation and efficiency resources, why such a decision was made.

(3) An electric utility that is required to develop a resource plan under this section must complete its initial plan by September 1, 2008.

(4) Resource plans developed under this section must be updated on a regular basis, at a minimum on intervals of two years.

(5) Plans shall not be a basis to bring legal action against electric utilities.

(6) Each electric utility shall publish its final plan either as part of an annual report or as a separate document available to the public. The report may be in an electronic form.

NEW SECTION. **Sec. 306.** A new section is added to chapter 80.70 RCW to read as follows:

(1) An applicant for a natural gas-fired generation plant to be constructed in a county with a coal-fired electric generation facility subject to RCW 80.80.040(3)(c) is exempt from this chapter if the application is filed before December 31, 2025.

(2) For the purposes of this section, an applicant means the owner of a coal-fired electric generation facility subject to RCW 80.80.040(3)(c).

(3) This section expires December 31, 2025, or when the station-generating capability of all natural gas-fired generation plants approved under this section equals the station-generating capability from a coal-fired electric generation facility subject to RCW 80.80.040(3)(c).

NEW SECTION. **Sec. 307.** If any provision of this act or its application to any person or circumstance is held invalid, the remainder of the act or the application of the provision to other persons or circumstances is not affected.

Passed by the Senate April 21, 2011.
Passed by the House April 11, 2011.
Approved by the Governor April 29, 2011.
Filed in Office of Secretary of State April 29, 2011.

Revised Technical Support Document and Revised Compliance Order for TransAlta Centralia Generation, LLC dated December 13, 2011

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

December 14, 2011

Mr. Bob Nelson
TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, WA 98531

Dear Mr. Nelson:

Revised Regional Haze Best Available Retrofit Technology (BART) Determination Order No. 6426

Best Available Retrofit Technology (BART) is required to reduce the regional haze impacts of emissions of your facility. The enclosed revised order #6426 contains our BART determination for your facility including a schedule for compliance.

If you have any questions or requests relating to this order, please contact Alan Newman at (360) 407-6810 or by mail at the address above.

Sincerely,

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

jj/te

Enclosures

cc: Brian Brazil, TransAlta
Richard DeBolt, TransAlta
Clint Lamoreaux, SWCAA
Alan Newman, Ecology
Julie Oliver, Ecology

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN ADMINISTRATIVE ORDER AGAINST: TransAlta Centralia Generation LLC	]]]]]	 FIRST REVISION: ORDER NO. 6426

TO: Mr. Bob Nelson,
TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, WA 98531

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

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

FINDINGS

A. The TransAlta Centralia Generation LLC ("TransAlta") Centralia Power Plant is a coal fired power plant larger than 750 MW output subject to BART. The power plant is comprised of 2 identical coal fired units referred to as BW21 and BW22.

B. BART emission limitations for sulfur dioxide and particulate matter were determined by the Environmental Protection Agency in 2003. The Centralia Power Plant's Operating Permit incorporates the BART emission limitations determined by EPA.

C. BART for nitrogen oxides at the Centralia Power Plant is based on:

a. Use of selective noncatalytic reduction (SNCR) for nitrogen oxides control.
b. Use of low NO_x burners with separated and close coupled over fire air systems (aka LNC3).
c. Use of a sub-bituminous Powder River Basin coal or other coal that will achieve similar emission rates.

d. Use and installation of additional boiler heat recovery equipment and boiler tube cleaning equipment to maximize the extraction of fuel energy into boiler steam.

D. RCW 80.80.040 was amended in 2011 (Chapter 180, Laws of 2011) adding greenhouse gas emission requirements applicable to this facility that reduce the remaining useful life of each coal fired unit at the plant to approximately 8 and 13 years, starting from June 2011. The greenhouse gas emission requirements are:

a. Amendments to Chapter 80.80, Revised Code of Washington passed in 2011 require both coal fired units at the Centralia Power Plant to comply with the greenhouse gas emission performance standard requirements of Revised Code of Washington 80.80.040. One unit is required to comply by December 31, 2020. The other unit is required to comply by December 31, 2025. The plant owner, the Governor's office, and environmental organizations anticipate that compliance with this requirement will be accomplished by decommissioning the units.
b. The requirement to meet the greenhouse gas emission performance standard does not apply if the Department of Ecology determines that a state or federal requirement requires the installation of selective catalytic reduction for Nitrogen oxides control on the coal units.

Additional information and analysis is available in the BART Determination Support Document for the Centralia Power Plant, by the Washington State Department of Ecology, November 2008 (revised April 2010 and May 2011); and the BART Analysis for the Centralia Power Plant, June 2008 and the BART Analysis Supplement, December 2008, and supplemental information dated March 2010; and Chapter 180, Laws of 2011.

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

BART Emission Limitations

1. Nitrogen Oxides Emissions

1.1. Starting no later than the dates in Condition 1.1.1 and 1.1.2, emissions of nitrogen oxides from the two coal-fired utility steam generating units (known as BW21 and BW22) at the Centralia Power Plant are limited to a maximum of:

1.1.1. From the date of issuance of this Order, until 30 operating days after December 31, 2012, the nitrogen oxides emission limitation is 0.24 lb/MMBtu, 30 operating day rolling average, both units averaged together, including all emissions during unit start-up and shut-down.

1.1.2. Beginning on the 31st operating day after December 31, 2012, the nitrogen oxides emission limitation is 0.21 lb/MMBtu, 30 operating day rolling average, both units averaged together, including all emissions during unit start-up and shut-down.

1.1.3. The 30 day rolling average will be determined per Condition 7.

1.2. Beginning January 1, 2013, injection of ammonia or urea to control nitrogen oxides from a specific boiler must:

1.2.1. Commence when the flue gas at the point(s) of injection in the boiler has reached the minimum SNCR operating temperature as identified by the system vendor in the system specific operation manual.

1.2.2. End no sooner than the time coal is no longer introduced to the furnace of the boiler or the flue gas temperature at the injection point(s) is below the minimum SNCR operating temperature.

1.3. Compliance with the nitrogen oxides emission limitation will be determined by use of a continuous emission monitoring system meeting the requirements of 40 CFR Part 75.

1.4. Coal used is required to be a sub-bituminous coal from the Powder River Basin or other coal that will achieve similar emission rates.

1.5. Nitrogen oxides emission reduction through the use of SNCR will be optimized as required in Condition 5. At the conclusion of the SNCR optimization study, the nitrogen oxides emission limitation contained in Condition 1.1.2 may be revised based on the results of the SNCR optimization study.

2. Ammonia emissions

2.1. Starting no later than the date in Condition 2.2, emissions of ammonia from the two coal-fired utility steam generating units at the Centralia Power Plant are limited to a maximum of:

2.1.1. Starting on January 1, 2013, the ammonia emission limitation is 10 parts per million, dry volume (ppmdv) 30 operating day rolling average, both units averaged together.
EXCEPTION: During the portion of the optimization study directed by Condition 5.2.3.1, the ammonia emission limitation is 20 ppmdv daily average, both units averaged together.

2.1.2. In the event that during a given day, only one unit operated, the average of both units will be the calendar day average of the operating boiler. The emission rate of zero for the unit that did not operate must not be included in calculating the average emissions.

2.2. Determination of compliance with the 30 operating day rolling average for ammonia will commence at midnight on the end of the 30th operating day after January 1, 2013.

2.3. Ammonia emission resulting from the use of SNCR will be optimized as required in Condition 5. The ammonia emission limitation contained in Condition 2.1.1 may be revised based on the results of the SNCR optimization study.

Schedule for Compliance

3. Compliance with the 30 operating day rolling average nitrogen oxides limitations begin on the dates given in Condition 1.1.1 and 1.1.2. Compliance with the 30 operating day rolling average ammonia emission limitations begins on the date given in Condition 2.1.

4. Coal units BW21 and BW22 will permanently cease burning coal and be decommissioned as follows:

4.1. One coal fired unit must permanently cease burning coal no later than December 31, 2020.

4.2. The second coal fired unit must permanently cease burning coal no later than December 31, 2025.

4.3. Conditions 4.1 and 4.2 do not apply in the event the Department of Ecology determines as a requirement of state or federal law or regulation that the selective catalytic reduction technology must be installed on either coal fired unit.

Nitrogen Oxides and Ammonia Reduction Optimization

5. The operation of the selective noncatalytic reduction (SNCR) system for control of nitrogen oxides will be optimized to produce both the lowest nitrogen oxides emission rate and the lowest ammonia emission concentration possible at the same time.

5.1. The nitrogen oxides control system will be optimized to achieve both the lowest 30 operating day average pound nitrogen oxides/MMBtu emission rate and the lowest 30 day average concentration of ammonia in the flue gas that is reasonably achievable without significant adverse effect on mercury capture, boiler cleaning processes (aka soot blowing) or byproduct salability .

5.2. To achieve the goal of Condition 5.1, The owner of the Centralia Power Plant will:

5.2.1. Develop an SNCR optimization plan and submit it by April 30, 2013 to Ecology and the SWCAA for their joint review and acceptance.

5.2.1.1. A draft optimization plan will be submitted to Ecology and SWCAA by January 30, 2013 for their review and comment. Ecology and/or SWACAA will respond with written comments within 45 days of receipt of the draft optimization plan. If a request for a copy of this draft optimization plan is received, the agency receiving the request will provide the requester a copy of the draft optimization plan.

5.2.1.2. TransAlta will submit a final optimization plan reflecting all comments provided by Ecology and SWCAA. The plan must be submitted no later than April 30, 2013. The plan will be deemed to be accepted and the owner will immediately implement the plan if Ecology and/or SWCAA do not respond by May 30, 2013. If TransAlta, Ecology, or SWCAA receive a request for a copy of the final optimization plan, the entity receiving the request will provide a copy of the optimization plan to the requestor.

5.2.2. The optimization plan will:

5.2.2.1. Provide for all optimization testing to be complete and a report on the findings submitted to Ecology and SWCAA not later than December 31, 2014.

5.2.2.2. Identify the start and end dates of the optimization study.

5.2.2.3. Describe the optimization process to be followed, including:

5.2.2.3.1. The overall schedule.

5.2.2.3.2. The specific dates for each stage of the optimization program, especially the start and end dates of the testing to determine how low of a nitrogen oxides emission rate can be achieved per condition 5.2.3.1.

5.2.2.3.3. Whether testing will be done on only one boiler at a time or both together.

5.2.2.4. Identify acceptable maximum ammonia content of fly ash used for cement and gypsum used to produce wallboard, including the basis for those maximums.

5.2.2.5. Identify all additional flue gas monitoring that will be used to determine optimum urea or ammonia injection rates for maximum nitrogen oxides reduction.

5.2.2.6. Evaluate the effect of ammonia injection on mercury capture effectiveness, fly ash ammonia content, and gypsum product ammonia content. This includes a description of the sampling and analysis processes.

5.2.3. The focus of the optimization plan, is to determine :

5.2.3.1. The maximum nitrogen oxides reduction possible with an ammonia emission rate of up to 20 ppmdv, daily average, each unit individually;

5.2.3.2. The maximum nitrogen oxides reduction with which compliance can be reasonably achieved within an ammonia emission rate of 5 ppm; and

5.2.3.3. Determine the lowest nitrogen oxides emission rate reasonably achievable that coincides with the minimum ammonia emission rate.

5.2.3.4. The ability to achieve a nitrogen oxides emission rate of less than 0.19 lb/MMbtu, 30 operating day rolling average, each unit individually.

5.3. Ecology and SWCAA will review the optimization study report for 60 days. At the end of the 60 days the two agencies will either request TransAlta make changes to the report or accept the report in writing.

5.4. Within 90 days of receiving written acceptance of the optimization study report by Ecology and SWCAA, the plant operations and maintenance manual(s) will be amended to include the operating parameters reflecting the optimized ammonia or urea injection rates developed.

5.5. Revisions to this BART Order

5.5.1. Within 30 days of acceptance of the optimization study report by Ecology and SWCAA, TransAlta will submit a request to Ecology to revise the emission limits in Conditions 1.1.2 and 2.1.1 to reflect the results of the optimization.

5.5.2. Upon receipt of the request to revise the emission limits, or within 60 days of acceptance of the optimization report by Ecology and SWCAA, Ecology will proceed to revise the emission limitations in Conditions 1.1.2 and 2.1.1 to reflect the results of the optimization study. Other approval conditions, including this condition, may be revised based on the final emission limitations.

5.5.3. The nitrogen oxides limitation will not be raised above the level in Condition 1.1.2 as it existed on the date of issuance of this Revised Order.

5.5.4. The ammonia limitation will not be raised above the level in Condition 2.1.1 as it existed on the date of issuance of this Revised Order.

Monitoring and Recordkeeping Requirements

6. Ammonia:

6.1. Ammonia emissions for compliance will be monitored by means of periodic emissions testing utilizing Bay Area Air Quality Management District (BAAQMD) Method ST1B or Environmental Protection Agency Conditional Test Method 027 (CTM-027). The sampling point will be in the stack following the wet scrubber. Stack testing shall occur on the following frequency:

6.1.1. Testing shall occur once each calendar quarter, with no consecutive tests less than 80 or more than 110 calendar days apart.

6.1.2. If 3 consecutive tests are each less than the ammonia limitation, then the testing frequency reduces to once every 6 calendar months, provided the nitrogen oxides emission limit is complied with during the test.

6.1.3. If, after there are 3 consecutive tests less than the ammonia limitation, the next 2 consecutive tests are less than 50% of the ammonia emission limitation, then the testing frequency reduces to once annually, provided the nitrogen oxides emission limit is complied with during the tests.

6.1.4. If at any time there is a test showing emissions above the emission limitation, then the testing frequency reverts to quarterly until the requirements in Conditions 6.1.2 and 6.1.3 are met.

6.1.5. The ammonia concentration measured during the periodic emissions testing is the 30 operating day rolling average value used for compliance starting on the date of the completion of the test until the completion of the next required periodic emission test.

6.1.6. During the ammonia testing using BAAQMD Method ST1B (or CTM-027), the 30 rolling ammonia emission limit is to be treated as an hourly average for the purpose of Conditions 6.1. and 6.2.

6.2. For use as a routine indicator of compliance between the tests required in Condition 6.1, ammonia emissions will be estimated. The estimate will be based on a calculation which uses as inputs the reagent concentration and flow rate, a calculation or measurement of the uncontrolled nitrogen oxides rate, the continuous nitrogen oxides monitoring results measured in the stack, and other parameters as necessary.

6.3. At TransAlta's option, an ammonia continuous monitoring system may be used instead of periodic emissions tests. A continuous ammonia monitoring system used for compliance must meet the monitor location requirements contained in 40 CFR Part 60 Appendix B, Performance Specification 1 or 2, and the quality assurance and quality control requirements of 40 CFR Part 60 Appendix F as applicable.

7. Nitrogen oxides monitoring and averaging

7.1. For any hour in which coal is combusted in a unit, the owner/operator of each unit shall calculate the hourly nitrogen oxides concentration in lb/MMBtu at the CEMS installed in accordance with the requirements of 40 CFR Part 75. The 30-day average lb/MMBtu rate is calculated by summing the hourly emissions in pounds (unit lb/MMBtu times unit heat input) from all operating units and dividing that by the sum of the hourly heat inputs in million Btu for all operating units. At the end of each boiler operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from all valid hourly data for that boiler operating day and the previous 29 successive boiler operating days.

7.2.). An hourly average nitrogen oxides emission rate is valid only if the minimum number of data points, as specified in 40 CFR Part 75, is acquired as necessary to calculate nitrogen oxides emissions and heat rate.

7.3. Data reported to meet the requirements of this section shall not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75.

7.4. A boiler operating day is a 24-hour period between 12 midnight and the following midnight during which coal is combusted at any time in the boiler. It is not necessary for coal to be combusted for the entire 24-hour period.

8. Ammonia emission limitation compliance based on periodic stack sampling and parameter monitoring.

8.1. Compliance with the ammonia emission limitation is demonstrated by meeting the limitation during the stack testing period. The average of the 3 discrete sampling runs will be used to determine compliance with the ammonia emission limitation until the next periodic stack testing occurs.

8.2. During each periodic stack test on each boiler, the ammonia or urea reagent injection rate and the ammonia to nitrogen oxides ratio for each sampling run shall be determined, recorded and reported as part of the testing report.

8.3. During plant operation between periodic stack testing, compliance with the ammonia emission limitation will be indicated by:

8.3.1. Injecting ammonia or urea reagent at the injection rate for ammonia or urea reagent used during the most recent stack sampling at the appropriate operating rate; and

8.3.2. Meeting the nitrogen oxides emission limit.

9. Coal Quality Monitoring

9.1. Coal nitrogen and sulfur content will be determined by taking a sample of the coal from the transfer belts between the coal pile and coal silos. An alternate location that provides a sample representative of the coal fired by the boilers may be proposed to Ecology by TransAlta for approval for use.

9.2. A sample of coal for nitrogen and sulfur content analysis will be taken at least once per week when at least one coal fired boiler is in operation. The sample must be taken following ASTM Method D2234/D2234M-07.

9.3. Coal nitrogen and sulfur content will be determined using ASTM Method D3176-89 (as reapproved in 2002). Note, other ASTM methods related to sample collection and preparation may need to be followed in order to perform this test.

9.4. As an alternate to coal nitrogen and sulfur content testing at the plant, certified results of testing by the coal mine operator of coal actually sent to the Centralia Power Plant may be used. Testing frequency should be no less frequent than required above.

Reporting Requirements

10. A letter reporting of achievement of each compliance date in the schedule in Conditions 3 and 4 must be submitted to the Washington State Governor, Ecology, and SWCAA within 30 days of achieving the milestone.

11. Emissions above the emission limitations in this order due to malfunctions must, at a minimum, be documented in writing and submitted to SWCAA and Ecology with the emissions monitoring data per Condition 12. Additional recordkeeping and notifications related to excess emissions may also be required by SWCAA or Ecology regulation. Excess emissions that TransAlta believes are unavoidable must be documented as required in WAC 173-400-107 (or section 109 after that section is approved into the Washington SIP) and SWCAA's unavoidable excess emissions requirements.

12. Emission monitoring data will be reported to Ecology and to the SWCAA.

12.1. Continuous emission monitoring reports will be submitted within 30 days after the end of each calendar quarter. The reports must contain the following information:

12.1.1. The 30 operating day rolling average pound nitrogen oxides/MMBtu for each operating day in the reporting period. The 30 day rolling average nitrogen oxides emission rate shall be reported in units of lb/MMBtu, utilizing at least 2 significant figures;

12.1.2. The cumulative short tons of nitrogen oxides per unit and combined that has been emitted during the current calendar year. The cumulative tons shall be rounded to the nearest ton;

12.1.3. Periodic stack testing for ammonia emissions shall be submitted within 45 days of completion of the test.

If TransAlta elects to use continuous emission monitoring of ammonia instead of periodic stack testing, the quarterly report shall contain the 30 operating day rolling average ammonia concentration for both units averaged together for each operating day in the reporting period. Average ammonia concentrations shall be reported in units of ppmdv to 2 significant figures.

12.1.4 For each hour of boiler operation, the ammonia or urea injection rate in units of pounds of ammonia or urea/hour, , the boiler temperature at the point of injection, injection level in use, and the estimated ammonia emission concentration.

12.2. The emission monitoring report will be sent to SWCAA and Ecology electronically in a format acceptable to the SWCAA. Reporting to Ecology under this condition will end January 1, 2018.

13. Coal nitrogen and sulfur content information must be submitted to SWCAA and Ecology within 30 days of the end of each calendar quarter.

13.1. Coal nitrogen and sulfur reporting must include the date each coal sample is taken, the nitrogen and sulfur content of each coal sample analyzed, the average sulfur and nitrogen concentrations for the calendar quarter, and the maximum and minimum concentrations found during the calendar quarter.

13.2. After June 30, 2011, the report will include the rolling annual averages for nitrogen and sulfur content plus the maximum and minimum concentrations in the prior year.

13.2.1. The weekly coal sample test results will be retained for at least 5 years and available for review by Ecology or SWCAA upon request.

13.2.2. Coal quality reporting to Ecology will end the earlier of:

13.2.2.1. January 1, 2018, or
13.2.2.2. The decommissioning of either unit BW21 or BW22, or
13.2.2.3. The date monitoring of the quality of coal fired in units BW21 and BW22 is required by a regulation issued by EPA under the authority of Section 112 of the federal Clean Air Act.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order. Ecology shall enforce the terms of this Order only until such time as SWCAA incorporates the terms of the Order into the Centralia Power Plant's Air Operating Permit or except as provided by RCW 70.94.785.

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

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.
- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal you must:

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

To file your appeal with the Pollution Control Hearing Board:

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

To serve your appeal on the Department of Ecology:

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

And send a copy of your appeal packet to:

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

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

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

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

DATED this 13 day of Dec, 2011 at Olympia, Washington.

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

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

Prepared by

Washington State Department of Ecology
Air Quality Program

August 2009
Revised April 2010
Revised November 2011

Table of Contents

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 when using coal from the Centralia coal field. Current output capacity reported by TransAlta is 670 MW/unit as a result of using coals from the Powder River Basin (PRB). Operation of a coal-fired power plant results in the emissions of Particulate Matter (PM), Sulfur Dioxide (SO_2) and Nitrogen Oxides (NOx). 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, NOx, 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 NOx 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 NOx 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]

Future operation of the TransAlta facility is specifically addressed in Chapter 180, Laws of 2011 (also known as E2SSB 5769). Under this law, the Governor is to enter a Memorandum of Agreement whereby the plant owners will bring the two coal-fired units into compliance with the greenhouse gas

[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.

(GHG) emission performance standard in RCW 80.80.040.[5] The law also requires the plant owner to install and operate selective noncatalytic reduction (SNCR) for NOx by January 1, 2013. The schedule in the law for bringing the coal units into compliance with the GHG emission performance standard directs that one unit is to comply by December 31, 2020, and the other is to comply by December 31, 2025. Based on testimony at the legislature and in the press, it is expected that the units will comply with the GHG emission standard by being decommissioned. The law also states that the requirement to meet the GHG emission performance standard does not apply in the event the Washington State Department of Ecology (Ecology) determines as a requirement of state or federal law or regulation that the selective catalytic reduction (SCR) technology must be installed on either coal-fired unit.

In accordance with this law and its effects on potential NOx emission controls, Ecology has revised its determination of BART. We now find that BART for NOx emissions is the current combustion controls, the Flex Fuels Project, the use of a sub-bituminous coal from the PRB or other coal that will achieve similar emission rates and the installation and use of SNCR. In addition to the 20 percent reduction in NOx emissions by use of the Flex Fuels Project, SNCR will further reduce NOx emissions.

The exact amount of NOx reduction attributable to SNCR at this plant is unknown. However, all analyses of the effects of the use of SNCR are based on an assumption of an additional 25 percent reduction. The SNCR system is required to be installed and operating by January 1, 2013. Ecology has established an interim emission limitation of 0.21 lb/MMBtu that will be in effect after start-up of the SNCR system until the BART Order is revised in 2015. During calendar years 2013 and 2014, TransAlta will be required to optimize the SNCR system to maximize the NOx reduction while maintaining an acceptable ammonia emission rate.

The use of low sulfur PRB coal also reduces SO_2 emission by about 60 percent from the same period. The NOx reduction anticipated from the revised BART controls selected by Ecology will result in a visibility improvement from the baseline impacts at Mt. Rainier National Park of approximately 1.99 dv, with improvements of 0.67 to 1.65 dv at other affected Class I areas. We estimate that the visibility improvement from meeting the interim emission limitation will be approximately 1 dv at Mt. Rainier National Park.
Looking to the future, the 2020 decommissioning of one coal unit will further decrease the visibility impacts and the final 2025 decommissioning of the other unit will eliminate all visibility impacts from the combustion of coal at this facility. Ecology considers the future decommissioning of the coal units to be reasonable progress elements of the Regional Haze State Implementation Plan.

[5] RCW 80.80.040(3)(c)(i) A coal-fired baseload electric generation facility in Washington that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008 must comply with the lower of the following greenhouse gas emissions performance standard such that one generating boiler is in compliance by December 31, 2020, and any other generating boiler is in compliance by December 31, 2025:
(A) One thousand one hundred pounds of greenhouse gases per megawatt-hour; or
(B) The average available greenhouse gas emissions output as determined under RCW 80.80.050.
(ii) This subsection (3)(c) does not apply to a coal-fired baseload electric generating facility in the event the department determines as a requirement of state or federal law or regulation that selective catalytic reduction technology must be installed on any of its boilers.

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 two 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 haze visibility impairment at Mt. Rainier National Park. The NPS 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 NOx 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, NPS, U.S. Forest Service, Ecology, and EPA Region 10.

On June 11, 2003, EPA Region 10 approved Ecology's Visibility State Implementation Plan (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, EPA specifically did not include the NOx emission limit in the RACT Order as BART stating "while the NOx 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 NOx represent BART."

[6] 68 *Federal Register* 34821, June 11, 2003.
[7] At the time, SWCAA was known as the Southwest Air Pollution Control Agency (SWAPCA).

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 NOx emissions.[8]

1.1 The BART 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 five steps are:

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

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

In accordance with the EPA BART guidance, Ecology weighs all five factors in its BART determinations. To be selected as BART, a control has to be available, technically feasible, cost effective, provide a visibility benefit, and have 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 two-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 when using coal from the Centralia coal field. The units are physically identical, tangentially fired, wet bottom units designed by Combustion Engineering.

TransAlta also operates two other generating resources that are part of the Centralia Power Plant complex. Operating under the name of Centralia Gas is a group of four 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

[8] Mahbubul Islam, EPA Region 10, "Best Available Retrofit Technology Applicability for the TransAlta Centralia Power Plant," letter, addressed to Robert Elliott, SWCAA, and Phyllis Baas, Ecology, September 18, 2007.

units. There is also a one 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 percent 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 two coal-fired boilers is provided by a wet limestone, forced oxidation wet scrubber system. This system removes over 95 percent of SO_2 in the flue gas from the boilers. The SO_2 controls were installed in the 1999–2002 time period.

Particulate control is provided by two electrostatic precipitators 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 1970s.

Current NOx control is provided by combustion modifications incorporating Alstom concentric firing, low NOx burners with close coupled and separated over-fire air.[9] These combustion modifications are collectively known as Low NOx 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.

The use of PRB coals has resulted in the derating of the output capacity of the facility. TransAlta reports on their corporate internet pages that the Centralia facility is rated at 1340 MW or 670 MW per unit.

Prior to 2010, TransAlta anticipated 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 State issued Executive Order 09-05, Washington's Leadership on Climate Change. This Executive Order contained provisions that affected the

[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.

remaining useful lifetime of the coal units at the plant. This Executive Order has now been superseded by amendments to Chapter 80.80 RCW contained in Chapter 180, Laws of 2011. These amendments require the coal units at the plant to come into compliance with the GHG emission performance standard established in RCW 80.80.040. One unit is required to be in compliance by December 31, 2020, while the other is required to comply by December 31, 2025. The amendments also provide that if Ecology determines that state or federal law or regulations require the installation of SCR on the coal units, that the requirement to comply with the GHG emission standard will not apply.

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-R3, issued September 2009 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. The original BART determination was issued June 2010.

The Revised BART Order is based on the above materials supplemented by additional BART decision information and material submitted by letter from Bob Nelson, Plant Manager, to Alan Newman of Ecology on August 8, 2011. This letter responded to a preliminary draft of the Revised BART Order and a Revised BART Determination Support Document that was developed for review and comment by the company, environmental group representatives, and EPA Region 10.

1.3 BART 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 two 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, NOx 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 NOx 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 BART 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 three years of metrological information to evaluate visibility impacts. As directed in the protocol, TransAlta used the highest 24-hour emission rates for NOx, 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 to 1997 RACT 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 NOx emissions 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, SNCR, SCR, and several options which could control NOx 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 NOx 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 NOx 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.

[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.

2.0 SUMMARY OF TRANSALTA CENTRALIA POWER PLANT'S BART ANALYSIS

The TransAlta's BART technology analysis was based on the 5-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 NOx Controls Evaluated

The plant already has installed combustion controls to reduce NOx emissions from thermal NOx. 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 over-fire air (LNC3)	--	Yes, already installed under RACT
Flex Fuels 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 and both units are operating in compliance with the original BART Order signed June 18, 2010
SCR	Up to 95% reduction	Yes
SNCR	20%-40% reduction	Yes
ROFA/RotaMix	Unknown	No
Neural net controls	Up to 15%	Yes

Low NOx Combustion, Level 3

As noted above, the **combustion controls** known as Low Nitrogen Oxides Combustion, Level 3, (LNC3) are currently installed on each of the coal-fired boilers at the plant. These controls have demonstrated an ability to meet the current NOx emission limit of 0.30 lb NOx/MMBtu using Centralia Mine coal and PRB coals.

The Centralia Power 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 NOx/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 Power 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 CH2M HILL to Mr. Richard Griffith (Appendix G).

The LNC3 system installed met its original design intent of a one-third reduction in NOx 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 Fuels Project

TransAlta has proposed its Flex Fuels Project as an addition to the currently installed LNC3 combustion controls for consideration as BART emission control. The Flex Fuels 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 NOx.

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 Fuels 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 September 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 Fuels 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 NOx by approximately 20 percent from the rates during 2003–2005 period. The emission rates during that baseline period averaged 0.304 lb NOx/MMBtu and at the completion of the Flex Fuels Project are expected to be below 0.24 lb/MMBtu.

Annual average NOx 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 Fuels Project is $11,184,197. Based on the estimated NOx reductions of 3,139 tons/year, the cost effectiveness of the Flex Fuels Project is $3,563/ton of NOx reduced. Since the Flex Fuels Project also reduces SO_2 emissions by an estimated 1,287 tons/year, TransAlta has calculated that the overall cost effectiveness of the Flex Fuels Project as $2,526/ton of NOx 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 vendors 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 NOx reduction at some facilities. Both CombustionOpt and SootOpt are control-system-based products. CombustionOpt provides for optimized control of fuel and air to reduce NOx 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 NOx reduction technologies.

NeuCo predicts that generally CombustionOpt can reduce NOx by 15 percent, and SootOpt can provide an additional 5 to 10 percent. Expected NOx reductions are very unit-specific, and actual results may vary greatly. Previously received budgetary prices for CombustionOpt and SootOpt were

[12] Because the Flex Fuels 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 NOx 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 NOx technology for this BART analysis. Because of the potential NOx reductions and cost effectiveness, TransAlta is continuing to investigate use of this technique at this plant.

Selective Noncatalytic Reduction

SNCR is generally used to achieve modest NOx 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 NOx to nitrogen and water. NOx 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 NOx, 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 NOx. 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 or 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 NOx SNCR has the potential to reduce NOx 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 NOx 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 its evaluation.

TransAlta's cost analysis uses a urea-based SNCR system providing a nominal 25 percent reduction in NOx 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 use 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 percent 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 NOx 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 CH2M HILL to Mr. Richard Griffith (Appendix G). The additional detail indicates the cost estimating approach utilized by CH2M HILL 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 NOx removal efficiency from Fuel Tech.

Selective Catalytic Reduction

[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 the heat input rate at 8500 MMBtu/hr/boiler.

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 NOx 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 NOx and ammonia emissions. Typically, an SCR system can provide between 70 and 95 percent reduction in NOx 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 Power Plant because of the limited space to install an SCR catalyst in the existing flue duct and the ability to design for a 90-plus percent 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-plus percent NOx reduction, an adjustment was used for SCR cost estimates due to the Centralia Power 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 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

[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.

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 Power 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, a 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 twp 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 NOx/MMBtu, both units averaged together. The other option included SCR on both units.

The emissions reduction for installation of SCR (at a 95 percent 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 NOx reduced.

The emissions reduction for installation of SCR (at a 95 percent 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 NOx 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 CH2M HILL to Mr. Richard Griffith (Appendix G). The additional detail indicates the cost estimating approach utilized by CH2M HILL on this BART analysis. The approach described involved a company reevaluation 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 a SCR system of $200/kW was used as the basis for the cost estimate. This basic cost was then scaled by CH2M HILL's engineering judgment of the costs and complexity to install a SCR system on these boilers. As part of this additional analysis, the predicted TransAlta costs were compared to costs for

[17] Associated with providing a gas velocity through the catalyst beds below 20 ft/sec.

other coal-fired power plants in the western U.S. (in Attachment 1 of the March 31, 2010 report). The cost analyses compared were performed by CH2M HILL and four 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 CH2M HILL's +50%/-20% estimate range of each other's cost analyses.

The March 31, 2010, report also contains an improved description of how CH2M HILL 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 CH2M HILL evaluate two 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, CH2M HILL 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. CH2M HILL presents information that in this location, one layer of catalyst would provide a five percent decrease in NOx with a five inch water gauge pressure drop. A 2-layer system would increase removal to 12 percent 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 CH2M HILL's contract.

Rotating Over-fire Air and Rotamix

Mobotec markets Rotating Over-fire Air (ROFA) as an improved second-generation over-fire 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 NOx 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 over-fire 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 BART

The existing LNC3 combustion controls (low NOx burners, close coupled and separated over-fire air) currently installed at the plant and the Flex Fuels Project meeting an emission limitation of 0.24 lb NOx/MMBtu, 30-day average, were proposed as BART for their facility.

Subsequent to TransAlta's BART analysis submittals, which proposed the Flex Fuels Project as BART, TransAlta, the Governor's office, environmental organizations, and state legislators negotiated a different set of emission control requirements.

The end result of the negotiation and agreement was enactment of amendments to Chapter 80.80, Revised Code of Washington, which requires the coal units at the plant to implement SNCR control by January 1, 2013, and to meet the state GHG emission performance standard in 2020 and 2025. All parties of the negotiation anticipate compliance will be through decommissioning of the existing coal fired units at the Centralia Power Plant.

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

[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.

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 three 98th percentile days of each year modeled, and the 98th percentile day of all three years modeled. Also shown is the modeled visibility impairment resulting from the control scenarios modeled by TransAlta. The modeled dv impacts for the baseline condition and the three control scenarios for the 98th percentile day (22nd day over the 3-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 three 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 Power Plant in all Class I areas modeled and in the Columbia River Gorge NSA. For example, Table 3-1[20] shows that at the three 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 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 NOx 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 NOx 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/year from the baseline emission rates. Subsequent to the public

[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.

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 four 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 National Park and Goat Rocks and Mt. Adams Wildernesses) most impacts occurred in the summer due to SO_2 emissions. The expected high impacts due to NOx do not occur because the weather patterns transport the plant's plume to other areas in the winter seasons. The impacts on Olympic National Park, (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 four 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 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 two scenarios using the same modeling protocol as used in the initial modeling. The two scenarios were the Flex Fuels and the Flex Fuels plus SNCR control options. The emission rates are consistent between the scenarios, with only the NOx rate changing to reflect the anticipated 25 percent reduction in NOx 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).

[21] From Geomatrix BART Modeling Reports, June 2008 and January 2008.

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 2003–2005 time period. The maximum 24-hour NOx emission rate used in the Flex Fuels only control scenario is as modeled previously. The NOx rate for Flex Fuels plus SNCR is a 25 percent 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 Three-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 ECOLOGY'S BART DETERMINATION

Ecology has reviewed the information submitted by TransAlta. The following discussions present our rationale for our determination.

4.1 NOx 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 NOx controls for use at the Centralia Power 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 NOx at the Centralia Power Plant.

Rotating Over-fire Air/RotaMix

TransAlta did evaluate the installation of the Mobotec ROFA technology. Both Ecology and TransAlta found 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.

Neural Nets

[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. Jay Crilley (Nalco), telephone conversation, 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.

This technique is an available control technology. However, Ecology agrees with TransAlta that the use of this technique at the Centralia Power 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 NOx emissions. Natural gas reburning is a technique where natural gas is injected into the boiler above the last over-fire air ports and additional over-fire 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 to 50 percent.

Ecology has looked briefly at the use of natural gas reburning to reduce NOx 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 leads us to question whether this control technique is truly available. A review of NOx control literature from the late 1990s 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 NOx burner/combustion controls were the dominant technology being implemented at that time.

A 2005 review of NOx 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 NOx 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 costs in Washington State have increased significantly since 1997, while natural gas pipeline capacity serving the part of Washington west of the Cascade Mountains 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.

[25] See Reference 5 for details.

4.1.2 Evaluation of controls determined to be feasible

Low NOx 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 higher energy content. These two factors work together to reduce the NOx 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 Fuels Project is $11,184,197. Based on the estimated NOx reduction of 3,139 tons/year, the cost effectiveness of the Flex Fuels Project is $3,563/ton of NOx reduced. Since the Flex Fuels Project also reduces SO_2 emissions by an estimated 1,287 tons/year, the cost effectiveness of the Flex Fuels Project is $2,526/ton of NOx plus SO_2 reduced.

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. TransAlta has presented a number of technical difficulties to implementing SCR at the Centralia Power Plant. The primary difficulty identified is a lack of space for easy installation of the catalyst beds and ducts, leading to very high estimated 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 a 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 currently has to turn 90 degrees and spread it out across the full width of the ESP inlet.

TransAlta also supplied an explanation of the anticipated flow routing for the proposed SCR installation. As described in CH2M HILL's March 31, 2010, report to TransAlta (Appendix G), they envision a "hot, dirty" SCR installation. In other words, the flu gas would be intercepted on leaving the boiler economizer (located before/above the preheater), routed through the SCR unit, and returned to the air preheater inlet.

A "hot, dirty" installation provides flue gas within the normal operating range of a SCR catalyst, but a high concentration of particulate matter. Installing a SCR catalyst after the air preheater or after the ESPs would require reheating the flue gas to SCR operating temperatures.

The March 2010 report identified additional engineering analyses that would be required to improve the construction cost estimate. These additional analyses include 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 CH2M HILL's March 2010 report.

At Ecology's request, TransAlta had CH2M HILL evaluate two alternate SCR locations: in the diverging duct between the air preheater and the ESP and between the ESP and the wet FGD system.

CH2M HILL acquired vendor information about the removal efficiency and head loss of a one and two layers of catalyst that could be installed within the duct between the air preheater and the ESP. Due to velocity and the limited depth of catalyst bed possible in this location, SCR removal seems to be limited to five percent for a single layer system and 12 percent for a 2-layer system. As a result of the low removal rates that would be provided by a catalyst system in this location, CH2M HILL 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 was 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. CH2M HILL 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.

Subsequent to the finalization of the original BART order, EPA Region 9 received BART submittals for the Navajo Generating Station and the Four Corners Power Plant. Region 9 has proposed BART for the Four Corners plant and is continuing to evaluate additional submittals for the Navajo station. Separately, EPA Region 6 rejected New Mexico's BART determination and is issuing its final BART determination for the San Juan Generating station.

NPS provided Ecology a copy of a presentation made by the Navajo Generating Station plant owners to EPA and the FLMs. This presentation gives the result of a detailed construction evaluation and a design level construction cost estimate to install SCR at the Navajo Power plant. The units at the Navajo plant are approximately the same capacity as Centralia and the construction difficulties due to layout and previously installed emission controls present a similarly difficult construction project with three existing boilers with their existing particulate controls, SO_2 scrubbers and stacks placed adjacent to each other with little space between them. The tight construction configuration results in SCR catalyst beds being installed above and to the sides of existing ESPs and FGD control systems, with the exact configuration depending on which unit is being looked at. Due to the more detailed design and construction evaluation developed by the owners of the Navajo plant, their estimated costs of construction are significantly lower than the Navajo plant owners originally proposed and lower than the estimates produced for Centralia.
As part of the Four Corners Power Plant BART evaluation, EPA developed construction cost estimates for the installation of SCR. The EPA construction cost estimate for the Four Corners Power Plant units 4 and 5 is similar to the Navajo Generating Station estimate.

For the initial BART evaluation, Ecology concurred 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, rendered this technology economically infeasible for implementation. As demonstrated in the next paragraphs, Ecology still agrees that installation of the technology is not cost effective as a NOx control at the Centralia Power Plant.

We have reevaluated the cost effectiveness of SCR at the Centralia Power Plant to include the limited remaining lifetime of the units. For purposes of this evaluation, we assume the design/build process would start about November 2012 and take four years to complete[26] (resulting in starting operation in 2016). Using this 2016 starting date, one unit (Unit A) would operate with SCR for only four years (calendar years 2017 through calendar year 2020) and the other (Unit B) would operate for nine years.[27] Using the revised cost estimate provided by TransAlta in the March 2010 submittal, the cost effectiveness for SCR on Unit A would be $14,800/ton NOx reduced and Unit B would be $8,400/ton NOx reduced.

Ecology also has used the cost estimate prepared by Sargent and Lundy for the Navajo Generating Station to estimate alternative cost effectiveness for the Centralia Power Plant. Based on the site description for the Navajo plant compared to the Centralia site, Ecology scaled the construction cost based on the gross MW output for a coal unit at each plant. For Unit A, Ecology used the cost estimate for Unit 2 at the Navajo station and for Unit B; Ecology used the Unit 3 cost estimate for the Navajo station. The estimate Ecology derived based on the Navajo estimate results in a cost effectiveness of $12,000/ton NOx reduced over the 4-year operating lifetime of the SCR installation on the Unit A and $6,400/ton NOx reduced over the 9-year operating lifetime of the SCR installation on the Unit B.

These costs are both above cost effectiveness levels for NOx that Ecology has determined to represent Best Available Control Technology to any source type in recent years. For comparison, EPA Region 9 has proposed SCR as BART for NOx on Units 4 and 5 at the Four Corners Power Plant. Since EPA rejected the owner's cost calculation, EPA developed a revised cost effectiveness estimate for Unit 4 of $2,622 and for Unit 5 of $2,908/ton NOx reduced.[28] Similarly, EPA disagreed with the BART determination of the state of New Mexico for the San Juan Generating Station and proposed SCR as BART with the cost effectiveness for the four units at that plant ranging from $1,579 to $1,920/ton NOx reduced. EPA has not yet proposed BART for the Navajo station.

[26] For illustration, a constructability analysis and proposed construction schedule for the Navajo Generating station indicates a construction time of 55 months (4.5 years) to install SCR and baghouses on two of the three units at the plant. This time period includes initial engineering design and equipment procurement for all three units ahead of the start of on-site construction. Construction at the Navajo site is difficult and the proposal includes significant demolition prior to installation of a construction crane between two of the three existing units to assist in construction. Centralia would not require this same degree of demolition or so sophisticated of a crane system.
EPA's final BART determination for the San Juan Generating Station is allowing five years for the design and construction of the required SCR system.

[27] "Unit A" and "Unit B" are used here to designate the two coal units for this cost discussion. TransAlta has not yet identified to Ecology which unit (BW21 or BW22) would be the first to be decommissioned.

[28] Ibid., Table 15.

Based on this additional information, analyses performed, and especially considering the limited remaining operating lives of the units, Ecology finds that SCR is not economically feasible to implement.

Selective Noncatalytic 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 NOx reductions required to comply with the Clean Air Interstate Rule (CAIR) program, and for seasonal NOx 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 NOx burner technology similar to that already installed at the Centralia Power Plant with SNCR or SCR added later as further progress emission reductions. We evaluated a 25 percent 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 NOx/MMBtu, the resulting emission limit becomes 0.23 lb NOx/MMBtu. This is marginally better than the limit of 0.24 lb NOx/MMBtu limit proposed for the Flex Fuels Project.

As can be seen in June 2008 Modeling Report, visibility improvement resulting from the NOx 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.[29] The March 2010 modeling, which includes the effects of the reduced SO_2 emissions from use of the Flex Fuels Project, indicates that Flex Fuels provides significantly better visibility improvement than SNCR alone.

As can be seen by looking at Table 3-1, the visibility improvement modeled from the NOx reduction aspects of the Flex Fuels Project (Control Scenario 2) ranges from 1.13 to 1.45 dv at the three 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 alone (Control Scenario 1). At the most impacted Class I area, the improvement in visibility from adding SNCR to Flex Fuels provides an additional 0.7 dv of improvement, while at the least impacted Class I areas the visibility improvement is about 0.2 dv.

Ammonia slip from the use of an SNCR system is inevitable. TransAlta assumed a 5 ppm slip in its BART analyses for calculating ammonia costs. An SNCR system of the type contemplated for installation on these boilers normally results in an ammonia slip of 5–10 ppm[30], though a review of the EPA RACT/BACT/LAER Clearinghouse data indicates SNCR systems on coal-fired units with ammonia slip emission limits as high as 41 ppm. As noted in Section 2's discussion of SNCR, there are a number of potential adverse impacts that can result from ammonia slip. The higher the ammonia slip, the higher chance that one of the potential adverse impacts could occur.

[29] The effects of the SO_2 reduction was modeled and included in the January 2008 BART report. However, the NOx 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.
[30] For comparison, actual monthly average SO_2 emissions from this plant are currently under 20 ppm.

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 in the plume and ultimately in the concentration of $PM_{2.5}$ at downwind locations. This secondary $PM_{2.5}$ is comprised of ammonium aerosols. These ammonium aerosols have been included in the dispersion modeling of the effects on Class I areas. The modeling assumes an unlimited supply of ammonia in the atmosphere available to react with NO_2 and SO_2 to produce ammonium compounds.

Flex Fuels Plus Selective Noncatalytic Reduction

Ecology has also evaluated the impacts of utilizing the Flex Fuels Project and adding SNCR to further reduce NOx emissions. Assuming a 25 percent reduction in NOx to occur from adding SNCR to Flex Fuels, the resulting emission limit would be 0.18 lb NOx/MMBtu. The capital costs to add SNCR to Flex Fuels would increase by about one-third 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 NOx for a net reduction of 8,022 tons NOx per year. The annual cost increase is mostly to cover the cost of ammonia or urea, and to remove ammonium sulfate and bisulfite from boiler tubes and duct work downstream from the ammonia injection point.

The Centralia Power Plant has already installed the LNC3 technology and the Flex Fuels Project, the cost of adding SNCR now is 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 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[31] NOx over Flex Fuels alone.

The combination of Flex Fuels and SNCR would increase the level of visibility improvement at the three most heavily impacted Class I areas due to NOx reductions by 1.99 dv on the 98th percentile day, with improvement of 0.67 to 1.45 dv at other Class I areas modeled.

Under the interim NOx emission limitation, visibility would also improve. We estimate that the improvement would be approximately midway between the projected improvements for Control Scenarios 2 and 3 in Table 3-1. At Mt. Rainier NP, this would be an improvement of approximately 0.35 dv from the Flex Fuels impacts, and at the Three Sisters Wilderness approximately 0.1 dv additional improvement from the Flex Fuels impacts.

Subsequent to the passage of the amendments to Chapter 80.80 RCW, TransAlta issued a Request for Proposal and received responses from vendors for installation of a SNCR system. The TransAlta requested proposals from six SNCR system suppliers and received responses from two of them. None of the responses indicated an anticipated NOx reduction rate expected. TransAlta working with one SNCR system vendor to determine what emission reduction may actually be possible form the use of SNCR at this plant. The vendor is unwilling to set any guaranteed minimum level of removal until it has performed a through computational fluid dynamics (CFD) analysis of the boilers. The CFD modeling is unable to start until there are more detailed temperature and flow measurements

[31] Based on 78% capacity factor, which is below the company target rate of over 84 percent.

within the boilers to calibrate the models. As of the first week of August 2011, these measurements have not occurred. As a result of an oversupply of hydro and wind power within the BPA system, the two coal units had not been fired since the middle part of March 2011. Plant restart occurred in late August and the necessary measurements for the CFD modeling occurred shortly after the units resumed normal operation. As of early August 2011, TransAlta anticipated CFD modeling will be completed during October 2011. At that time, the vendor's anticipated minimum NOx removal will be known.

However, TransAlta and the vendor have identified several issues that may limit the amount of reduction possible while holding ammonia slip to a reasonable level. The items that cause concern are the location of the beginning of the SNCR reaction temperature zone, the presence of falling slag removed by the soot blowers from the superheater tubing, the anticipated short residence time at the SNCR reaction temperatures, and some concerns about inconsistent mixing provided by the separated over-fire air system (SOFA). The actual residence time at proper SNCR reaction temperatures is the only issue that is unique to the TransAlta boilers. All other issues have been addressed at other facilities.

As presented by the company, based on temperature measurements inside the boiler, of the temperatures at bottom of the superheater pendants is higher than occurred when burning Centralia coal. This results in the beginning of the SNCR reaction zone being within the superheater zone. As a result, there is concern that inadequate reaction time is available.

As explained by the company, the Centralia mine coal produced a slag on the boiler waterwall tubes that was a gray/dark color that aided heat absorption by the water in the waterwall tubes. This kept the temperature at the super heater lower than is now occurring. The burning characteristics of the Centralia mine coal also resulted in a boiler firebox configuration that is different than many eastern US boilers that have been designed for or converted to PRB coal combustion. The different furnace geometry affects the temperature at the superheater also.

The PRB coal now used by the plant produces a white slag on the waterwall tubes that impedes the heat transfer to the water in the waterwall tubes, resulting in higher temperatures at the superheater. The Flex Fuels Project did install additional boiler tubes to capture this excess heat, but the new tubes do not affect the combustion gas temperature at the superheater.

The SNCR system vendor anticipates 3 levels of reagent injection to be installed in the boilers. These injection lances would be located within the elevation range of the superheater pendants. This location exposes the injection lances to slag falling off the superheater pendants and other boiler tubing located above the firebox leading to a recurring maintenance issue. This boiler tubing in this area has relatively constant soot blowing to remove the soot (slag) from the boiler tubes. Chunks of slag fall off the pendants and currently damage soot blowing lances (these lances are retractable to enable slag removal all along their length).

There is also a concern about competing combustion reactions as a result of the expected inconsistent mixing of secondary combustion air from the SOFA system in the firebox. The effect of poor mixing and competing reactions should be minimized by the location of the reagent injection lances based on the CFD modeling.

Based on the information from their vendors, a review of other BART decisions in the western U.S. where SNCR was selected as BART, TransAlta has proposed a modest additional reduction from Flex Fuels attributable to SNCR. TransAlta has proposed a starting NOx limit of 0.22 lb/MMBtu as a reasonable expectation.

Remaining useful life of the plant

There was an issue of the remaining useful life of the Centralia Power Plant. TransAlta's investor information about its facilities has indicated that continued operation of the Plant beyond 2030 will require a substantial capital investment[32] with decisions to be made by 2025. This projected lifetime is longer than the BART guidance would consider as a limiting factor for making a BART technology decision on economic grounds.

However, since TransAlta made that statement in 2007, other circumstances that affect the remaining lifetime of this plant in its current configuration have occurred. On May 21, 2009, the Governor of Washington issued Executive Order 09-05, Washington's Leadership on Climate Change. This Order would have ultimately resulted in the shutdown of the coal units at the plant by 2025.

Governor's Executive Order 09-05 has now been superseded by amendments to Chapter 80.80, Revised Code of Washington.[33] Under the amendments to this law, the Governor is directed to sign a Memorandum of Agreement by January 1, 2012, whereby the plant owners will:

- Install selective noncatalytic reduction for nitrogen oxides by January 1, 2013.

- Bring the two coal-fired units into compliance with the GHG emission performance standard in RCW 80.80.040,[34] one unit by December 31, 2020, and the other unit by December 31, 2025.

- Incorporate other specific requirements in the law into the Memorandum of Agreement.

As noted in public testimony to the legislature and the press during development and passage of these amendments, the plant owners, the legislators sponsoring the bill, the Washington environmental community, and the Governor's Office have all publically stated that compliance with the GHG emission performance standard will be through decommissioning of the coal-fired units at the plant.

The law also states that in the event Ecology determines as a requirement of state or federal law or regulation that the selective catalytic reduction technology must be installed on either coal-fired unit, the requirement to meet the GHG emission performance standard does not apply. This would then imply that the coal units would continue to operate indefinitely.

The current GHG emission rate for the Plant is about 2,300 lb total GHGs/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 GHGs/MWh of electricity produced. Meeting that performance standard

[32] TransAlta Investor Day 2007, presentations published as PDF file on Nov. 17, 2007, Slide 38 of 101.
[33] Enacted in Chapter 180, Laws of 2011.

would require a GHG reduction in excess of 50 percent, on the order of 6–7 million tons of CO_2 per year. The law (Chapter 80.80, RCW) also requires an evaluation of the GHG emission capabilities of natural gas fired combined cycle power plants every five years and a revision to this limitation based on that evaluation 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 U.S. 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.

The effect of the 'decommissioning process' is to limit the economic lifetime of the units. Using a starting point of June 2011, the maximum remaining useful life of the units is reduced to 8 and 13 years.

4.2 Ecology's Determination of BART

Ecology has determined BART for the Centralia Power Plant to be the Flex Fuels Project plus SNCR and the use of a sub-bituminous PRB coal or other coal that will achieve similar emission rates. This determination is based on the information synopsized above, information submitted by TransAlta, and additional materials collected by Ecology.

Considerations in our decision include:

- The Flex Fuels Project provides a 20 percent reduction from the 2003–2005 average emissions rate. The use of SNCR, as required by state law, will further reduce emissions by at least an additional 10 - 25 percent.
- The Flex Fuels emission reductions are not exclusively NOx, but include SO_2 reductions from ability to use PRB type coals.
- The NOx emissions reduction from the use of Flex Fuels and SNCR will result in reduced visibility impairment at all Class I areas within 300 km of the plant.
- Additional NOx reductions from adding SNCR will start by January 1, 2013, less than 1½ years from June 2011. January 2013 is also approximately 13 months from the time the revised BART order is anticipated to be issued and submitted to EPA.
- In order to meet the requirement of state law, TransAlta will be making significant financial and plant viability analyses of how best to comply with the GHG emission performance standard requirements of the law to be included in the Memorandum of Agreement.
- The law provides that if Ecology determines that state or federal law or regulation requires the use of SCR to control NOx emissions from the plant, then the requirement to comply with the GHG emission performance standard (shut down the coal units) does not apply and the plant can operate beyond 2025.

The emission limitation and coal quality limitation reflecting Ecology's determination of BART for NOx from the Centralia Power 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. Additional discussion on the basis for selecting the initial NOx emission limitation is contained in Appendix I.

Table 4-1 Ecology's Determination of the Emission Controls That Constitute BART

BART Control Technology	Emission Limitation
Flex Fuels Project plus SNCR	0.21 lb NOx/MMBtu, 30 operating 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
SNCR optimization	Optimize SNCR operation for lowest NOx reduction while minimizing ammonia slip. Revise the NOx emission limitation to reflect that optimization.

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 Over-fire Air (CCOFA)				Increased UBC potential	Yes	Meets	
6	Separated Over-fire 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 Reburn (1st	Not demonstrated			Reduced ash sales	No	Meets	High variable cost of operation

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
	Generation)	on Centralia sized unit						
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 Cleanup Process	Pilot level or limited use				No	Exceeds	
31	Lehigh University Low-Temperature	Pilot level or limited use				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
	SCR Process							
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 NOx Emission Rate (lb/MMBtu)
Boiler Tuning	0.40 to 0.44
Fuel and Air Tip Replacement	0.40 to 0.44
LNB & Close Coupled Over-fire Air (CCOFA)	0.38 to 0.42
LNB & Separated Over-fire 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

1. CH2M HILL, **BART ANALYSIS FOR CENTRALIA POWER PLANT at Centralia Washington,** January, 2008, Revised July 2008, Supplemented December 2008 and March 2010

2. ***TransAlta Centralia Boiler Emissions Modeling Study*** by Black & Veatch, dated September. 2007, Attachment to September 10, 2007 Air Permit Applicability Analysis for TransAlta Centralia Generation, LLC., Fuel Conversion Project.

3. Raytheon Engineers and Constructors, Inc. and Easter Research Group, Inc., **COAL UTILITY ENVIRONMENTAL COST (CUECost) WORKBOOK USERS MANUAL** and Excel Spreadsheet, Version 1.0, 1998, Provided by EPA.

4. Air and Waste Management Association, Editors, Anthony Buonicore and Wayne Davis, **AIR POLLUTION ENGINEERING MANUAL**, Von Nostrand Reinhold, 1992

5. Srivastava, Ravi K., Hall, Robert E., et al, **Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers**, Journal of the Air & Waste Management Association, Sept. 2005

6. Comparato, J. R., NOx **Control Technologies: Focus SNCR**, Presented at Western Coal Council, Burning PRB Coal Seminar, Presentation TPP-550

7. Cardone, Carol, Kim, Ann, & Schroeder, Karl, **Release of Ammonia from SCR/SNCR Fly Ashes**, 2005, http://www.flyash.info/2005/68car.pdf.

8. EPRI project summary, **Evaluation of an SNCR Trim System on a 720 MW Tangential Design Coal-Fired Utility Boiler**, May 2003, EPRI report 1008029

9. Southwest Air Pollution Control Agency, **1997 Technical support Document for RACT Order No. 97-2057**

10. Harmon, A., et al, **Evaluation of SNCR Performance on Large-Scale Coal-fired Boilers**., Institute of Clean Air Companies Forum on Cutting NOx emissions, March 1998

11. US EPA, **Air Pollution Control Cost manual, 6th Edition**, January, 2002, EPA/452/B-02-001

12. New Mexico Dept. of Environment, **Discussion of Nalco-Mobotec ROFA and Rotamix,** evaluation for application at San Juan Generating Station, March 29, 2008, http://www.nmenv.state.nm.us/aqb/reghaz/documents/03292008DiscussionofNalco-MobotecROFAandRotamixRev080329.pdf

13. SNCR Committee, **White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions**., Institute of Clean Air Companies, February 2008
14. TransAlta Investor Meeting presentations, September, 2007, 2007 Investor Day Presentations (produced Nov. 2007)

15. Letter to Lewis Dendy, North Dakota Department of Health, from Debra Nelson, Great River Energy, February 9, 2010, including attachments, concerning Fly Ash usage and properties related to ammonia

BART Analyses from other states, such as:

16. Black and Veatch, **Public Service Company of New Mexico, San Juan Generating Station Best Available Retrofit Technology Analysis**, June, 2007

17. CH2M HILL, **BART Analysis for Jim Bridger Unit 1** {also Units 2 – 4}, January 2007

18. Black & Veatch, **Portland General Electric Boardman Plant Best Available Retrofit Technology (BART) Analysis**, November, 2007

19. Northern States Power Co. d/b/a Xcel Energy – **Sherburne County Generating Plant Units 1 and 2 Best Available Retrofit Technology Analysis**, October, 2006

20. Pinnacle West, **Arizona Public Services, Four Corners Power Plant**, BART Analysis Conclusions, January, 2008

21. BART analyses by Region 9 for the 4 Corners Power Plants as included in federal rule docket EPA-R009-OAR-2010-0683 supporting Federal Implementation Plan proposal published in the Federal Register February 25, 2011

22. Salt River Project and Sargent & Lundy, Presentation to EPA Region 10 and Federal Land Managers for the Navajo Generating Station, July 20, 2010.

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 percent contribution to visibility impairment on the days listed, the specific day, and the modeled visibility on those days. The days shown are the 98th percentile for each year and the three 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. This information is from the referenced report. The modeling addendum received in March 2010 did not extract this information from the model results.

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

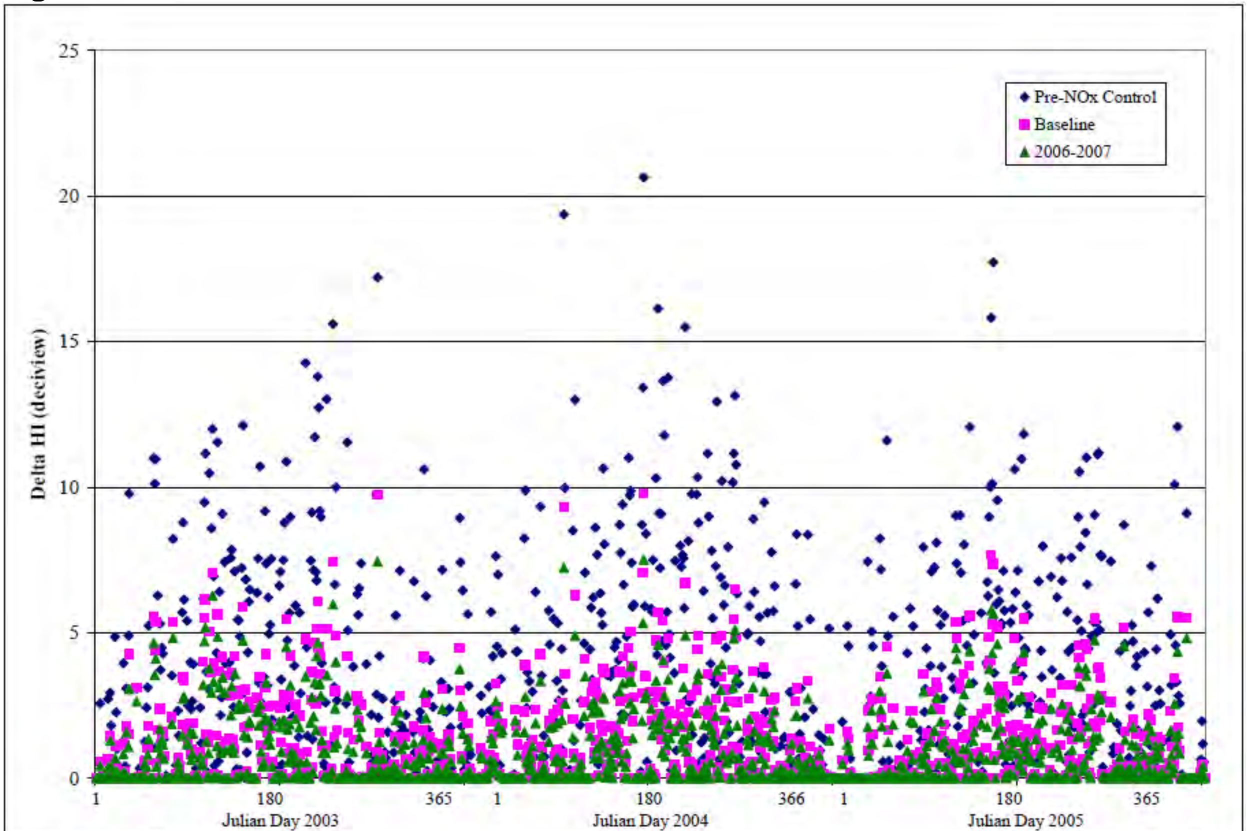
Table D-3 January 2008 Report

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. Five 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



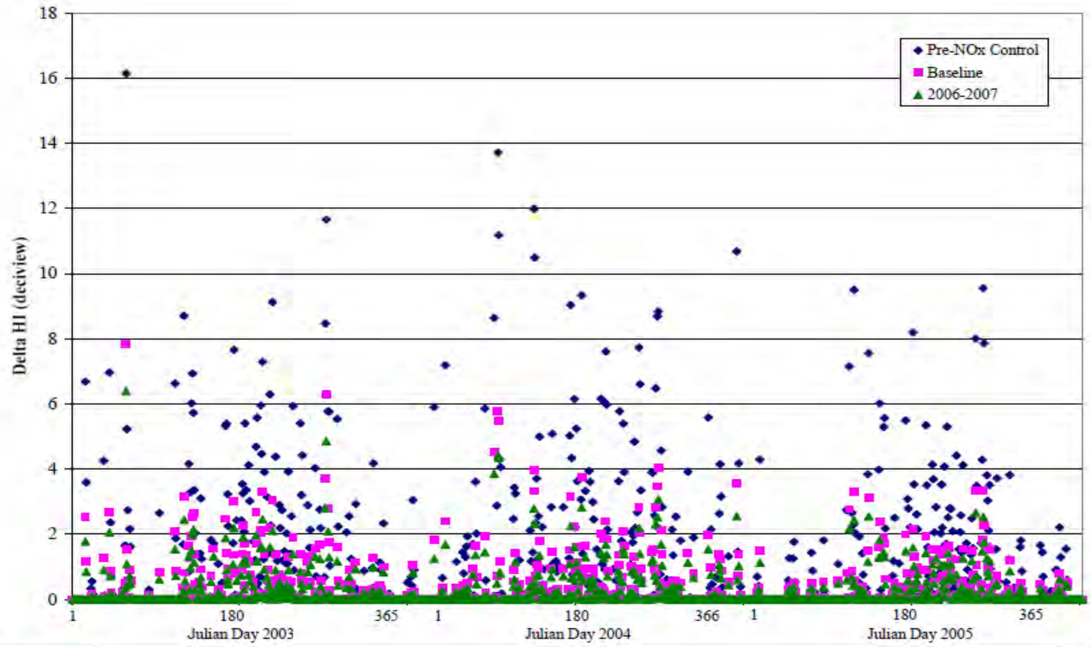
GEOMATRIX

TIME SERIES OF MAXIMUM DAILY DELTA HAZE INDEX FOR MOUNT RAINIER NATIONAL PARK
PRE-NOX CONTROL, BASELINE, AND 2006-2007 CASES
TransAlta BART Determination Modeling
Centralia, Washington

Project No. 12530.002.0

Figure 4-19

Figure D-2



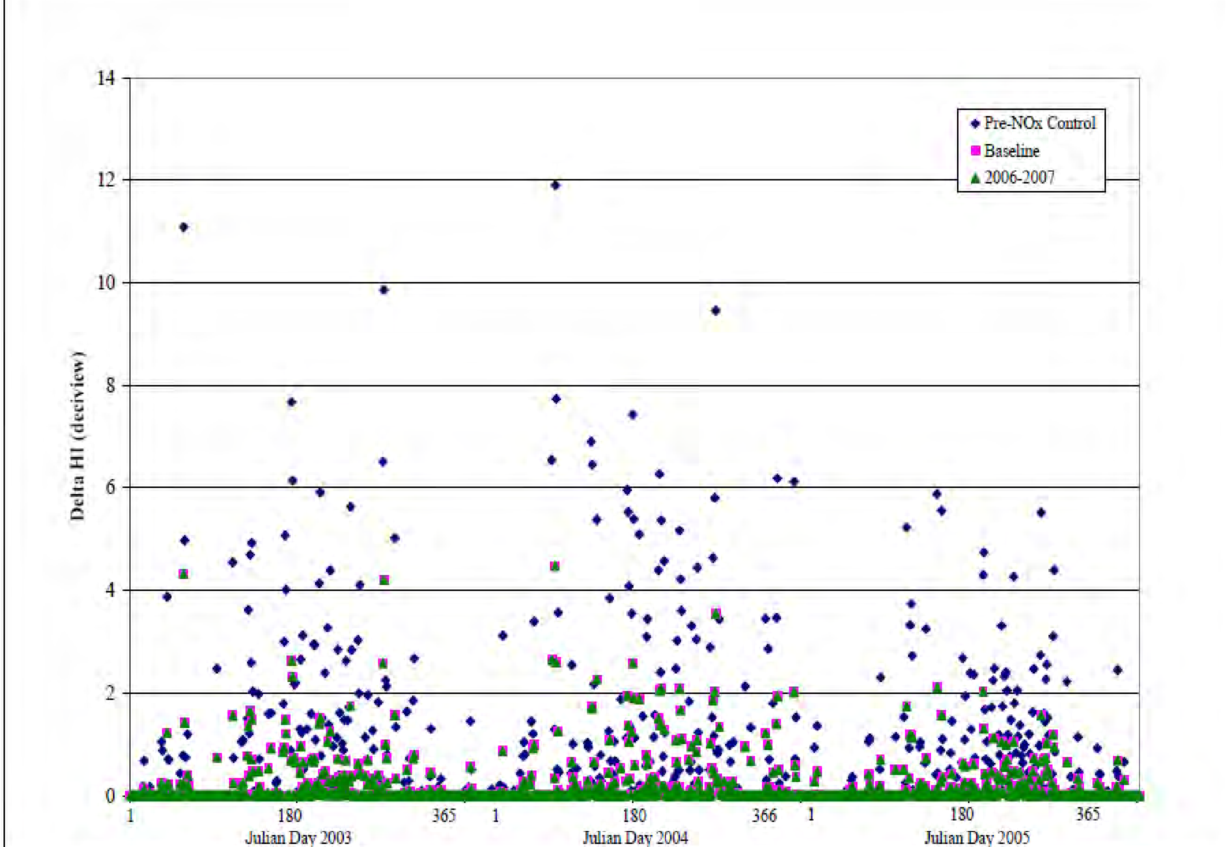
GEOMATRIX

TIME SERIES OF MAXIMUM DAILY DELTA HAZE INDEX FOR MOUNT HOOD WILDERNESS
PRE-NOX CONTROL, BASELINE, AND 2006-2007 CASES
TransAlta BART Determination Modeling
Centralia, Washington

Project No. 12530.002.0

Figure 4-13

Figure D-3



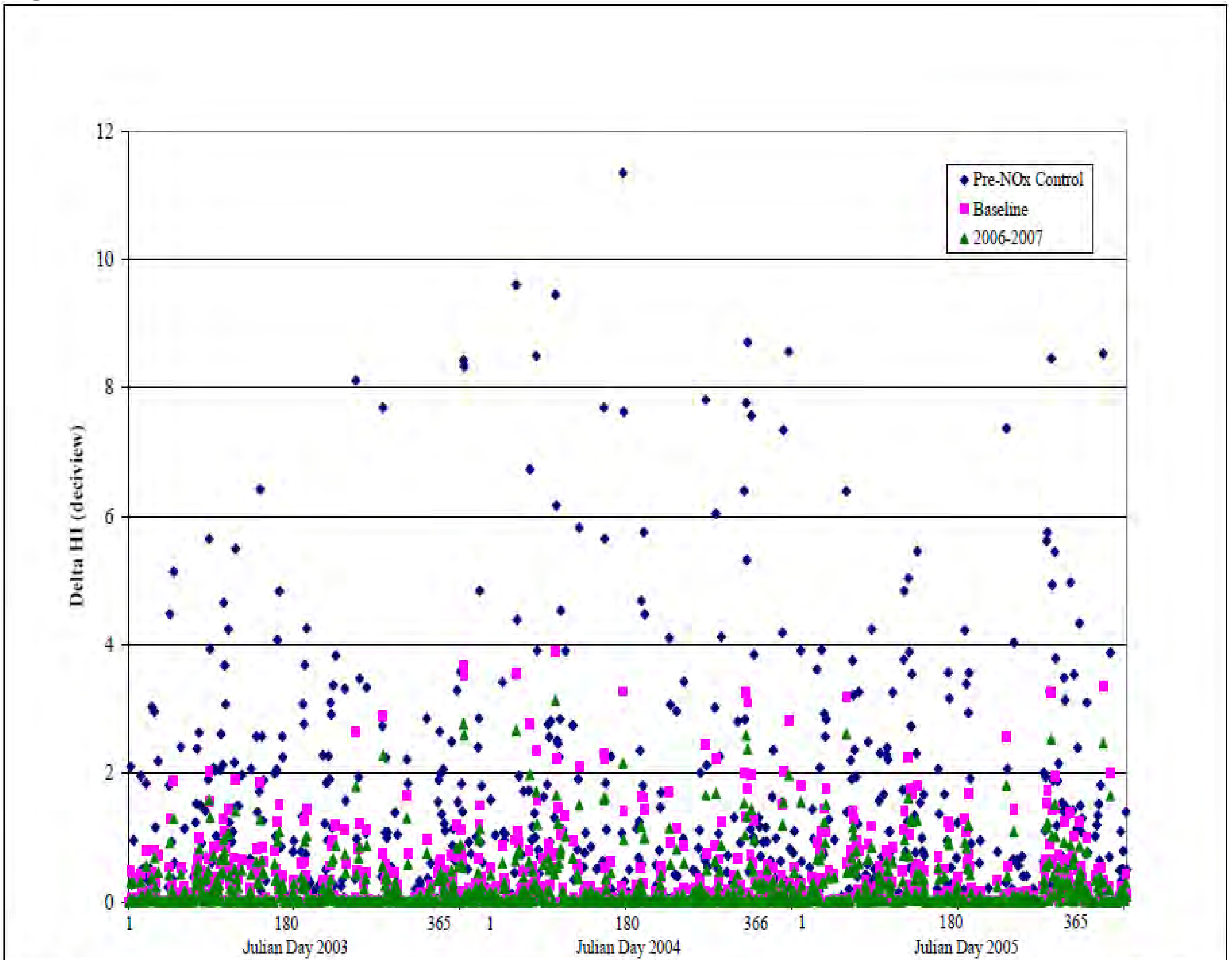
GEOMATRIX

TIME SERIES OF MAXIMUM DAILY DELTA HAZE INDEX FOR MOUNT JEFFERSON WILDERNESS
PRE-NOX CONTROL, BASELINE, AND 2006-2007 CASES
TransAlta BART Determination Modeling
Centralia, Washington

Project No. 12530.002.0

Figure 4-16

Figure D-4



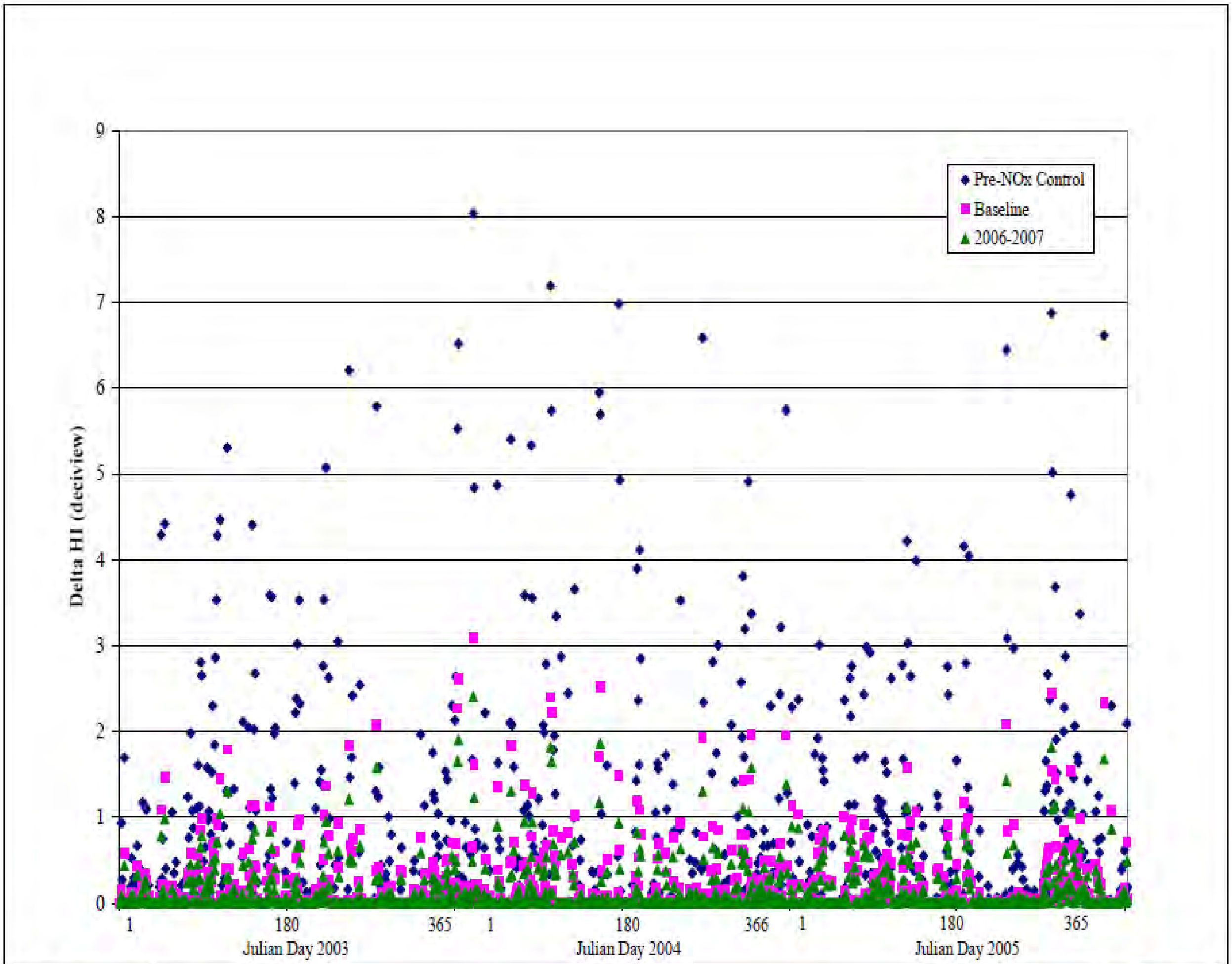
GEOMATRIX

TIME SERIES OF MAXIMUM DAILY DELTA HAZE INDEX FOR NORTH CASCADES NATIONAL PARK
PRE-NOX CONTROL, BASELINE, AND 2006-2007 CASES
TransAlta BART Determination Modeling
Centralia, Washington

Project No. 12530.002.0

Figure 4-25

Figure D-5



GEOMATRIX

TIME SERIES OF MAXIMUM DAILY DELTA HAZE INDEX FOR PASAYTEN WILDERNESS
PRE-NOX CONTROL, BASELINE, AND 2006-2007 CASES
TransAlta BART Determination Modeling
Centralia, Washington

Project No. 12530.002.0

Figure 4-31

Appendix E—Coal-Fired Electric Generating Unit BART Determinations in Western U.S.

Table of Coal-Fired Electric Generating Unit BART Determinations in Western U.S.

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 August 2011.

Table E-1

State	Unit	NOx Technology	lb/MMBtu, 30 day avg.	Comments
EPA Region 6, New Mexico	San Juan Generating Station	SCR	0.05, 30 day rolling average, each unit	
EPA Region 8, Montana	Colstrip			No final Decisions publicly available
EPA Region 9, Navajo Reservation	Navajo	SCR		No final Decision publicly available
	Four Corners	SCR	0.11 plant wide rolling 30 day average Unit specific limits ranging from 0.11 to 0.21	Proposed Decision, see Federal Register, Vol. 76, No. 38, Friday, February 25, 2011
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 over-fire 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

State	Unit	NOx Technology	lb/MMBtu, 30 day avg.	Comments
	Public Service of Colorado, Cherokee Unit 4	Modify existing Low NOx burner and over fire air or install new burners	0.28	
	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	

State	Unit	NOx Technology	lb/MMBtu, 30 day avg.	Comments
	Northshore Mining, Silver Bay, Boiler 2	LNB + OFA	0.4	
Iowa	Used CAIR for BART			
Louisiana	Used CAIR for BART			
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 over-fire air	0.19	
(All Lignite units)	Olds Unit 2	SNCR plus over-fire air	0.35	
	Coal Creek Units 1and 2	Additional over-fire 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 over-fire air plus SNCR for a 58% reduction	0.36	
	Milton Young Station Unit 2	Advanced over-fire air plus SNCR for a 58% reduction	0.35	
Oregon	Boardman	LNC3	0.23 between July1, 2011 and Dec. 31, 2020.	Note Plant Closure by Dec. 31, 2020.
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 over-fire air under minor NSR program.

State	Unit	NOx Technology	lb/MMBtu, 30 day avg.	Comments
	Huntington Power Plants, Units 1 and 2	LNC3	0.26	Replacing LNC1 burners and add 2 levels of over-fire air under minor NSR program.
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 Plans and Profiles

These four drawings are large, and intended to be reproduced 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

1580 LINCOLN STREET, SUITE 700
DENVER, COLORADO 80203-1501
TEL (303) 534-4615
FAX (303) 825-3202
CELL (303) 725-0446
RickLGriff@aol.com

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

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 L. Pearson

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 $20/MW-hr and 42 days	
TOTAL INSTALLED CAPITAL COST ($)	**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
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

RECEIVED
APR 5 2010
DEPARTMENT OF ECOLOGY
AIR QUALITY PROGRAM

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

<u>Question 2 (Response prepared by TransAlta):</u>

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.

<u>Response</u>: 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.

  <u>Response</u>: 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).

  <u>Response:</u> 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.

<u>Response</u>: 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

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
Sr. Air Quality Scientist
ENVIRON International Corp.
19020 33rd Avenue W, Suite 310
Lynnwood, WA 98036
Phone: 425.412.1800
Direct: 425.412.1809
Fax: 425.672.1840

ENVIRON

VISIBILITY MODELING FOR CENTRALIA POWER PLANT

COMPARISON OF FLEX FUEL AND FLEX FUEL WITH SNCR

March 2010

TABLE 1

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

	NOx (lb/hr)		SO_2 (lb/hr)		PM_{10} (lb/hr)	
Year	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

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

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

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

TABLE 9 (Continued)
YEARLY PREDICTED CHANGE TO THE 98TH PERCENTILE DAILY HAZE INDEX

Area of Interest	Year	98th Percentile Delta HI (dv)[1] 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

Appendix I—Establishing SNCR NOx Emission Limitation for Revised Order

The 2011 amendments to RCW 80.80 require the Centralia Power Plant to install and operate SNCR by January 1, 2013. This SNCR technology is in addition to the emission reduction resulting from implementation of the Flex Fuels Project.

A number of considerations are discussed below related to determining the most appropriate averaging period and initial NOx emission limitation for SNCR. Included is a discussion of the results expected from the SNCR optimization study.

<u>What is the removal rate that can be expected by SNCR?</u>

The literature contains a reasonable amount of information compiled for existing coal-fired utility boilers. The various sources all indicate that minimum expected removal rates of 20 percent with maximum removal for boilers above 500 MW of 35 percent. For boilers above 500 MW, the most commonly reported removal rates are 25 to 35 percent. The following paragraphs are synopsis of three representative reviews.

A 2003 EPRI report synopsis[35] reported on an evaluation of a single level SNCR Trim system on a 720 MW tangential boiler. The single level system was operated over a load range from 40 to 100 percent of the boiler maximum continuous rating. NOx reductions as measured at the economizer exit showed the highest levels of NOx reduction occurred in the furnace nearest the injectors. The system provided NOx reductions of 20 to 25 percent while the boiler operated at rates of 300–710 MW with an ammonia slip of 6–9 ppm.

A 2008 report on SNCR by the Institute of Clean Air Companies supports SNCR on Centralia sized units producing 20 to 30 percent NOx reductions with ammonia slip as low as 5 ppm. The report notes that this level of NOx removal is anticipated for any installation, with the main criteria being able to adequately distribute the reagent within the reaction zone. The report indicates for various sizes of coal-fired utility boiler applications, the range of reduction is 20 to 90 percent and the most commonly reported reduction is 25 percent.

A 2005 report in the Journal of the Air and Waste Management Association[36] evaluated NOx controls systems in operation in the U.S. Table 3 of this report indicates that for larger coal-fired units, SNCR reduction of NOx can be anticipated in the range of 25 to 35 percent for units over 200 MW. The data indicates smaller units can achieve higher removal rates. The units reviewed for this report had higher pre control emissions than Centralia, so the reported reductions may be more illustrative of the capability of SNCR in general rather than specifically applicable to TransAlta's Centralia units. The article does not include information on ammonia slip.

Based on SNCR vendor reluctance[37] to provide a proposal to TransAlta, there is a reasonable doubt about the ability to achieve the 20 to 25 percent NOx reduction that is normally anticipated

[35] Evaluation of an SNCR Trim System on a 720 MW Tangential Design Coal-fired Utility Boiler, May 2003, Document #E214967, by R. Himes on EPRI Report #1008029, April 2003.
[36] Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers, Ravi K. Srivastava, Robert E. Hall et al, Journal of the Air & Waste Management Association, Volume 55, September 2005.
[37] TransAlta has noted that they sent out six requests for proposal and received two responses, each with two variations in return. Anecdotally, the system supplier with the greatest familiarity with the plant (Black and Veatch) did not submit a proposal.

through the use of SNCR. Two SNCR system vendors supplied four proposals for SNCR systems. The vendors did not propose an ability to meet a specific NOx emission rate or removal percentage. The system vendors indicated that some small NOx removal would occur, but until they had completed modeling of the boilers, they would not be able to provide any guarantee of performance. Using the information supplied by the two vendors, TransAlta has proposed an initial NOx emission limit based on the use of SNCR of 0.22 lb/MMBtu (about a nine percent additional reduction). The rationale for this proposal is contained in the August 8, 2011, letter from Bob Nelson of TransAlta to Alan Newman of Ecology. In short, the company identifies operational and mixing issues resulting from the location of ammonia/urea injection lances within the superheater pendants, the end of the active combustion zone in the firebox at the bottom of the superheater pendants,[38] and damage to injection lances from falling slag removed from the superheater tubes. Other normal operational problems are identified such as the formation of ammonium bisulfate and ammonium sulfate deposits in the air preheaters and economizer.

As part of the design for the SNCR system, TransAlta's system vendor will be performing computational fluid dynamics modeling of the boilers. This modeling will determine a number of aspects of the SNCR system design, such as optimum locations for the injection system, the reaction time in the SNCR reaction temperature zone, and the anticipated nitrogen oxides emission rate and ammonia slip. Due to the lack of operation of the TransAlta coal boilers between mid February and mid August of 2011, the vendor was unable to acquire the temperature and flow rate information necessary to complete the modeling exercise. The earliest this information is expected to be available is the end of October 2011.

The rationale presented to Ecology by TransAlta is very boiler specific. It is compelling information, but based on the literature on operation of SNCR in existing boilers, does not present many unexpected issues. The most unexpected issue is the higher temperatures at the super heater pendants when burning the PRB coal producing a smaller than anticipated size for the SNCR reaction zone.

Based on literature reviewed, a reasonable minimum reduction rate to expect from the application of SNCR at this facility would be 25 percent as proposed by TransAlta in their BART analysis reports and as modeled by TransAlta to estimate the degree of visibility improvement that could be achieved. However, based on the recent information provided by TransAlta[39] and the prospective SNCR system vendors, a lower minimum expected reduction rate on the order of 10 percent may be more reasonable as the basis for setting the initial NOx reduction rate.

Potential basis for emission limit

The proposed limitation is based on a 30-day rolling average, both units averaged together. This scenario tends to smooth out the hourly/daily variability in the NOx emissions from the boilers, especially when start-up emissions are included in the emission limitation. Thirty-day rolling

[38] The combustion zone ended well below the superheater pendants when using Centralia coal. The Centralia coal have a different volatility than the PRB coals, leading to the larger combustion zone.
[39] Letter and attachments from Bob Nelson, Plant Manager, to Alan Newman, August 8, 2011.

averages are used by other states for other coal-fired power plants and by EPA in its coal-fired boiler rules.

Two approaches were used to evaluate the appropriate basis for setting the emission rate to apply the percent reduction from use of SNCR. One approach was to look at the available emissions data; the other was to utilize the basis used to set the current BART emission limitation.

Actual emissions rate based limitation

Rolling 30-day average emissions from the TransAlta plant were evaluated. These averages were based on the daily average values of NOx lb/MMBtu values for 2010 reported for the Acid Rain Program. The Acid Rain Program uses a different missing data substitution process for periods of start-up and extended monitor outages that result in higher values being inserted for missing data than the data substitution process in the BART Order. The data substitution process in the BART Order better reflects operating realities of the system than the process used in the Acid Rain Program.[40] As a result, the use of this Acid Rain Program information is for illustrative purposes only and does not indicate compliance or noncompliance. This review is in an Ecology-generated spreadsheet titled CentraliaAnnualSummary2003-2010.xlsx.

As a result of the Acid Rain Program missing data substitution, there were several 30-day periods where 30-day averages were above the current and proposed BART emission limitation. Upon inspection, these periods are almost entirely based on 30-day periods when only one boiler was in operation, when daily values were dominated by start-up of a boiler, or when Acid Rain Program substituted data was reported. There were no exceedances of the emission limitation contained in the current BART Order when the process contained in the BART Order was used for missing data substitution.

Prior to using the missing data process in the BART Order, all 30-day periods with emission averages above 0.24 lb/MMBtu (the NOx limit in the current BART Order) were dominated by the Acid Rain Program's substitute data, especially when one unit was in start-up mode.

The current limitation is based on a 30-day rolling average, both units averaged together. This scenario tends to smooth out the hourly/daily variability in the NOx emissions from the boilers. A 30-day rolling average is used by other states for other coal-fired power plants and by EPA in its coal-fired boiler rules.

During the last three months of 2010, operation of the plant was consistent and continuous. During that 3-month period, the NOx emissions averaged 0.227 lb/MMBtu. A proposed NO_2 emission limitation based on this 3-month period and a 25 percent reduction from SNCR would be 0.170 lb/MMBtu. A 10 percent reduction would result in limits of 0.204 lb/MMBtu.

Emission limit reduction basis

[40] The data substitution process in the Acid Rain Program is designed to estimate the maximum theoretical emissions during periods of time such as unit start-up and shutdown (when certified CEMs are not available for use), extended monitoring equipment outages, rather emissions that are more akin the unit actually operates.

The current Flex Fuels emission limitation is based on a 20 percent reduction from the RACT emission limitation of 0.30 lb/MMBtu. The RACT limit value was conservatively set at 0.30 lb/MMBtu to include a reasonable compliance margin. The current BART Order limit for Flex Fuels uses the RACT emission limit then applies the 20 percent reduction attributable to Flex Fuels (resulting in the current BART limit of 0.24 lb/MMBtu) continues to incorporate a reasonable compliance margin. Applying a further reduction resulting from the use of SNCR would result in a NOx limitation of 0.180 lb/MMBtu (25 percent reduction) or 0.21 lb/MMBtu (12 percent reduction).

Operating day versus calendar day

We are proposing to use the concept of operating day rather than calendar day. The use of an operating day means that any day where neither coal unit is in operation (zero emissions) is not used to evaluate compliance with an emission limitation.

Operating day is used in many EPA regulations for combustion units.[41] An operating day has been defined as any day in which fuel is fired for any amount of time in either coal unit or a day where fuel is fired for more than a specified minimum amount of time (such as 4 or 8 hours). Recent revisions to EPA's New Source Performance Standards for boilers have defined an operating day as any calendar day when fuel is fired at least one hour during the day. One rationale given by EPA to use the 'any number of hours' definition of operating day was specifically to include start-up and shutdown emissions in the 30 operating day rolling average emission limitation.

The same operating day concept is also used in some BART determinations that have been reviewed for this revision of the BART Order. Of most importance to this discussion is EPA Region 6's use of a rolling 30 operating day average in its BART determination for the San Juan Generating station and proposed by Region 8 for coal-fired power plants in North Dakota. Alternately, EPA Region 9 has proposed to use a 30 calendar day average for the Four Corners Power Plant.

The Centralia Power Plant has a history of not operating for 2–6 weeks each year due to the availability of lower cost hydropower in the market. Operating records for the past several years indicate several time periods during each year where only one unit may be operating continuously while the other unit operates for a few days at a time then be shut down or operate at minimum firing rate.

Another reason for considering the operating day concept is that Ecology and EPA are now requiring emissions during start-up and shutdown to be addressed specifically in permits and orders such as this. In the recent revisions to 40 CFR Part 60, Subpart DA, EPA retained the minimum hours of operation definition for operating day specifically for use in the preexisting NSPS requirements while using a definition of operating day that includes any hours where fuel is fired for use in the revised NSPS standard.

[41] In the EPA rules, both types of operating day have been used, though the most recent EPA rules have defined an operating day as any day when fuel is fired, regardless of the duration of fuel firing.

Rather than going through the process of establishing emission limitations covering start-up and shutdown, Ecology is choosing to follow EPA's lead on more recent emission standards of addressing start-up and shutdown emissions by establishing longer averaging period emission standards. The use of a 30 operating day averaging period that includes all days with fuel combustion in either coal unit addresses start-up and shutdown.

Alternate form of the emission limitation

Ecology could change from the current emission standard expressed in terms of lb/MMBtu fired to an output based limitation such as lb of NOx per gross or net MWh produced. This approach would make the BART result more difficult to compare to other facilities. However, this form of emission limitation may be very appropriate for a new power plant or an existing plant undergoing significant renovation to assure maximum net efficiency in generating electricity. The approach of using lb/MWh has not been analyzed in detail, though based on information from some combined and simple cycle combustion turbines, it may not be adequate to address periods of low load and unit start-up and shutdown.

An annual NOx emission limit in terms of tons per calendar year, like the current SO_2 limit for the plant, could be established for the plant. One difficulty in this approach is the number of variables involved in setting the number. The current boilers have been modified and changed fuel from Centralia coal to PRB coal, all of which affect the plant heat input rate, NOx emissions from the boilers, and gross output rates. A result of these changes are that a number of values must be estimated or assumed such as the current design firing rate, controlled emission rate, plant capacity factor, and annual operating hours.

Rationale for establishing the initial NOx emission limitation

Based on the above information, plus additional considerations explained below, Ecology proposes to establish an initial NOx emission limitation that will be achievable by the facility, low enough that use of the SNCR system on both units will be required to comply with the limitation, but not be so low as to result in an extensive SIP limit relaxation analysis by Ecology and EPA if the actual emissions from the power plant are unable to achieve the limitation.

The emission limitation selected is in the form of pounds of pollutant per million Btu heat input, 30 operating day average. This is selected primarily for comparative purposes to other coal-fired power plants across the country, which commonly have emission limits in this form. This is also the unit of measure used in the federal New Source Performance Standard for utility boilers, and is the unit the plant is required to report its NOx emissions to EPA under the Acid Rain Program requirements. The use of a 30-day rolling average will also meet EPA guidance on setting emission limits that are enforceable in practice.

For the numerical value of the NOx limit, several pieces of information were considered. One is that during periods of sustained operation, where neither unit is shut down or started up, emissions data indicate it is possible for the plant to demonstrate compliance with the Company's proposed 0.22 lb/MMBtu limitation without operating the SNCR system.

As noted above there is a state law that affects the operation of this facility, Chapter 180, laws of 2011 amending RCW 80.80.040. The specific requirement in RCW 80.80.040(3) says:

> (c)(i) A coal-fired baseload electric generation facility in Washington that emitted more than one million tons of greenhouse gases in any calendar year prior to 2008 must comply with the lower of the following greenhouse gas emissions performance standard such that one generating boiler is in compliance by December 31, 2020, and any other generating boiler is in compliance by December 31, 2025:
>
> (A) One thousand one hundred pounds of greenhouse gases per megawatt-hour; or
>
> (B) The average available greenhouse gas emissions output as determined under RCW 80.80.050.
>
> (ii) This subsection (3)(c) does not apply to a coal-fired baseload electric generating facility in the event the department determines as a requirement of state or federal law or regulation that selective catalytic reduction technology must be installed on any of its boilers.

Ecology interprets subsection (3)(c)(ii) to mean that if the plant is required to install SCR to comply, that the requirement to meet the GHG emission performance standard goes away for both units. Such a requirement to install SCR can derive from a revised New Source Performance Standard , a requirement to comply with an emission limitation unachievable by SNCR in the BART order (as a requirement under state regulations), or after the BART order is included in the SIP (becoming a requirement of federal regulation too). It is in the interests of the state to see the coal units at the plant decommissioned. If the BART limitation is set at a level that SNCR cannot achieve, and would require the installation of SCR, then it is Ecology's opinion that the decommissioning requirement in state law goes away.

In comments to Ecology on a preliminary draft of the Revised BART Order, TransAlta suggested an initial emission limitation of 0.22 lb/MMBtu (a <9% reduction from the current emission limitation of 0.24 lb/MMBtu). As noted previously, our review of the Acid Rain Program data indicates that the units at the plant could achieve this proposed emission limitation without the operation of the required SNCR system during extended periods of consistent operation.

In recent years, the Acid Rain Program report for the facility indicates plant operation has changed to lower capacity factors accompanied by more unit start-up and shutdown occurrences. During unit shutdown and start-up, emissions are higher on a pound/MMBtu basis than during consistent operation. For example, during 2011, the plant stopped producing electricity in February, and did not resume operations until August due primarily to two factors: an excess of hydropower from the Bonneville Power Administration system, and the large increase in electric generation from wind turbines, which receives preferential treatment by power purchasers. During 2010, the data also shows numerous unit shutdowns, periods of one unit operation and periods of no operation. Historically, the plant has not operated in the late spring/early summer for periods of 2–4 weeks due to the availability of lower cost hydropower.[42]

As a result of the increased number of unit start-ups with their relatively higher emissions, the potential for extended operation to comply with the company's proposed initial NOx emission limitation without operating the SNCR system, and Ecology's desire that the plant be required to utilize the system to comply while not triggering a requirement to install SCR, we propose to establish an initial NOx emission limitation a slightly lower emission limitation than proposal by the company.

Projected Visibility Improvement as a result of implementing SNCR and ceasing to burn coal at the TransAlta Centralia plant

The following table depicts the projected visibility impacts at 3 future years resulting from the emissions reductions and coal unit decommissioning. SNCR is to be installed and operational in 2013. It will then have a period of optimization to achieve the maximum NOx reduction; this will be achieved in 2015. By law, one unit must be decommissioned by the end of 2020 and the other coal unit by the end of 2025. These shutdowns are portrayed as starting in 2021 and 2026 respectively.

The visibility improvement analysis assumes that the result of the SNCR optimization study will result in at least a 25% reduction in NOx emissions from the rates required for the Flex Fuels project (as reflected in the original BART Order). This reduction is projected to occur in 2015

Based on this analysis, by 2015 when the results of the SNCR optimization study are required to be implemented, we anticipate the visibility improvement from SNCR will be at least 0.7 dv at all Class I areas within 300 km of the plant. By 2021 when the first unit will be decommissioned the visibility improvement is expected to be even more dramatic, leading to no impact by 2026 when the second unit has been decommissioned. The following table indicates the visibility impacts and emission rates expected in the future.

		Visibility Impacts from TransAlta Centralia Power Plant			
Class I Area	**Visibility Criterion**	**Baseline (2002) Emissions**	**2015 Flex Fuels and SNCR**	**2021, one unit decommissioned**	**2026, both units decommissioned**
Alpine Lakes Wilderness	Max 98% value (8th high) in any year	4.871	2.949	1.475	0
	3-yrs Combined 98% value (22nd high)	4.346	2.598	1.299	0
Glacier Peak Wilderness	Max 98% value (8th high) in any year	3.615	2.049	1.025	0
	3-yrs Combined 98% value (22nd high)	2.622	1.532	0.766	0
Goat Rocks Wilderness	Max 98% value (8th high) in any year	4.993	3.069	1.535	0

[42] As a result of this known period of time when hydropower is available, the plant has routinely scheduled major maintenance for the late spring time period.

Class I Area	Visibility Criterion	Visibility Impacts from TransAlta Centralia Power Plant			
		Baseline (2002) Emissions	**2015 Flex Fuels and SNCR**	**2021, one unit decommissioned**	**2026, both units decommissioned**
	3-yrs Combined 98% value (22nd high)	4.286	2.637	1.319	0
Mt. Adams Wilderness	Max 98% value (8th high) in any year	3.628	2.194	1.097	0
	3-yrs Combined 98% value (22nd high)	3.628	2.147	1.074	0
Mt. Hood Wilderness	Max 98% value (8th high) in any year	3.471	1.978	0.989	0
	3-yrs Combined 98% value (22nd high)	2.83	1.665	0.833	0
Mt. Jefferson Wilderness	Max 98% value (8th high) in any year	2.079	1.15	0.575	0
	3-yrs Combined 98% value (22nd high)	1.888	1.053	0.527	0
Mt. Rainier National Park	Max 98% value (8th high) in any year	5.447	3.606	1.803	0
	3-yrs Combined 98% value (22nd high)	5.489	3.501	1.751	0
Mt. Washington Wilderness	Max 98% value (8th high) in any year	2.027	1.106	0.553	0
	3-yrs Combined 98% value (22nd high)	1.414	0.737	0.369	0
North Cascades National Park	Max 98% value (8th high) in any year	2.821	1.57	0.785	0
	3-yrs Combined 98% value (22nd high)	2.212	1.228	0.614	0
Olympic National Park	Max 98% value (8th high) in any year	4.645	2.695	1.348	0
	3-yrs Combined 98% value (22nd high)	4.024	2.486	1.243	0
Pasayten Wilderness	Max 98% value (8th high) in any year	1.954	1.075	0.538	0
	3-yrs Combined 98% value (22nd high)	1.482	0.822	0.411	0
Three Sisters Wilderness	Max 98% value (8th high) in any year	2.172	1.139	0.570	0
	3-yrs Combined 98% value (22nd high)	1.538	0.819	0.410	0
Columbia River Gorge National Scenic Area	Max 98% value (8th high) in any year	2.545	1.446	0.723	0
	3-yrs Combined 98% value (22nd high)	2.353	1.378	0.689	0
Modeled Emission Rates (lb/hr)	**Both units added together**				
	NOx -->	4,984	2,952	1476	0
	SO_2 -->	4,522	1,854	927	0

It is anticipated that there will at least 700 MW of replacement power generation located at the TransAlta site. This replacement power is anticipated to be provided by a new natural gas fired combined cycle combustion turbine facility that will have to receive a Prevention of Significant Deterioration permit.

Proposed BART emission limitation

Based on the above analysis, Ecology proposes to establish an emission limitation of 0.21 lb/MMBtu, 30 operating day rolling average as the initial NOx emission limitation. The emission limitation will be revised in the future to reflect optimization of the installed SNCR system.[43] An operating day is any calendar day when a boiler was fired. A more precise estimate of the nitrogen oxides emission reduction achievable with the SNCR system could be made based on the upcoming computational fluid dynamics analysis of the boilers. However, the state law requires the installation of SNCR and the revision of the BART Order for this plant be completed prior before December 31, 2011, prior to the completion of that analysis.

EPA has adopted the definition of operating day and 30 operating day averaging period for a number of its regulations and at least one BART determination established by Regions 6 and 9. The NSPS rules and BART determination intend covering unit start-up and shutdown emissions within the 30 operating day averaging period. Ecology agrees with EPA that a 30 operating day period is suitably long to moderate the effects of unit start-ups and low load operation.

Based on the above review, Ecology proposes that the NOx emission limits for the Revised BART Order to be:

- Starting on date of order issuance, 0.24 lb/MMBtu, 30 operating day rolling average, both units averaged together.

- Starting on the 31st operating day after January 1, 2013, 0.21 lb/MMBtu/hr 30 operating day rolling average, both units averaged together, 30-day rolling average.

- A NOx reduction optimization program will be required. The initial NOx limitation based on the use of SNCR will be revised to reflect the NOx reduction rate derived from the required NOx reduction optimization program.

The monitoring and emission calculation process in the Revised BART Order is based on the BART Federal Implementation Plans issued by EPA for coal fired power plants in North Dakota and New Mexico. Similar to EPA and other states in BART determinations, we do not propose to include tons of NOx per year, operating rate, or operating time limit in the BART Order.

<u>NOx Reduction Optimization Program</u>

The goal of the SNCR optimization program is to determine the lowest NOx emissions that may be achievable and the lowest NOx emission rate that is paired with the lowest ammonia emission rate. The revised emission rate to be inserted in the Revised BART Order will be based on lowest NOx rate achievable with a minimum ammonia slip rate. The target of the optimization is not to determine how little ammonia injection is required to achieve the initial NOx emission limitation, but to determine the lowest NOx and ammonia rates achievable and that do not result in contamination of fly ash or gypsum[44] produced by the FGD system that would render these byproducts unsalable.

[43] This revision will be submitted to EPA as a revision to the SIP emission limitations for this plant.
[44] The use of fly ash to make concrete reduces the quantity of greenhouse gases and other air pollutants produced to make concrete by reducing the quantity of cement required. The use of gypsum to make wallboard for the local area reduces the pressure to mine natural gypsum in Mexico (the alternate gypsum source for the purchaser of the

The goal of the optimization process is to identify three operating points of the SNCR system:

- The lowest NOx emission rate that will meet an ammonia slip of less than 5[45] ppmdv.
- The lowest NOx emission rate that will meet an ammonia slip of up to 20 ppmdv.
- The lowest NOx emission rate that coincides with the lowest ammonia slip.
- The ability to achieve a NOx emission rate no higher than 0.180 ppmdv, 30 operating day rolling average, each unit individually.

To facilitate a true optimization of the SNCR system, the revised Order will allow a higher ammonia slip during part of the optimization period. This higher slip is necessary to allow excess ammonia to be injected to determine how much NOx emissions can be reduced.

The Revised BART Order will then be revised again to incorporate the results of the optimization study. Based on the results of the study, the NOx limit will be revised to a lower limit. The ammonia slip limit may also be revised to a higher or lower limit, depending on the findings of the optimization study. Ecology intends to then submit the revision as an amendment to the Regional Haze portion of the Washington State Implementation Plan.

TransAlta gypsum) or import wallboard from other countries. If these byproducts cannot be beneficially used the environmental and direct costs are more than simply the cost to TransAlta to landfill the materials.

[45] Change per request of Company during public comment. The 5 ppm value here and the 10 ppm limit in the Order are both 30 day averages.

TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, Washington
USA 98531

(360) 736-9901
www.transalta.com

August 8, 2011

Mr. Alan Newman
Washington Department of Ecology
Air Quality Program
P.O. Box 47600
300 Desmond Drive
Lacey, WA 98504-7600

Re: TransAlta Centralia Generation LLC's Comments on Proposed Revisions to BART Order to Address SNCR

Dear Mr. Newman:

TransAlta Centralia Generation LLC ("TransAlta") has reviewed the Department of Ecology's proposed revisions to the Implementation Order that was issued in June of 2010 ("BART Order") and we would like to provide the following comments. The issues of concern are described in this letter and suggested changes to address these concerns are made in attached red-line version of the draft BART Order.

<u>Nitrogen Oxides Limit (Condition 1.1.1)</u>
The draft Order proposes a nitrogen oxides ("NOx") emission limit of 0.18 lb/MMBtu based on a presumed reduction factor of 25% of the Flex Fuels Project emission rate. However, for the following reasons, the 25% factor does not necessarily apply and is unlikely to be achieved in practice.

As background, the CH2M Hill "BART Analysis for Centralia Power Plant," p.3-6 (rev. July 2008) cites a study by Harmon (1998) concluding that tangentially fired boilers are able to achieve a 20 to 25 percent reduction with the application of SNCR. Based on the study and other information, CH2M Hill's 2008 BART Analysis applied the high end of the range, 25 percent, to the baseline emission rate of 0.30 lb/MMBtu to derive an estimated emission rate of 0.228 or 0.23 lb/MMBtu for the purpose of modeling visibility benefits from SNCR. (See Case 3 SNCR estimated emissions of 0.228 in 2008 BART Analysis).

www.transalta.com

Ecology's BART Determination Support Document (rev. April 2010) concurred that the 25 percent reduction factor was a reasonable assumption. TransAlta's May 2008 response to Ecology's comments on the January 2008 BART Analysis report reiterated the Harmon findings and implicitly acknowledged that the high end of the range from adding SNCR to existing LNC3 and Flex Fuels is 25%:

> "The control effectiveness of SNCR is a function of many variables including the uncontrolled emissions concentrations, physical conditions, and operational conditions. The greatest control effectiveness is generally achieved with high uncontrolled NOx concentrations, on new units that have been specifically designed for SNCR, and at a specific load … In addition, a study by Harmon indicates that a large coal fired tangentially fired unit equipped with a low NOx SNCR has the potential to reduce NOx emissions by only 20-25 percent with an ammonia slip of less than 10 ppm…."

The conclusion that 25 percent reduction is highest likely reduction is supported by PGE's "Alternative BART Analysis for the Boardman Power Plant," p. 3-4 (Aug. 27, 2010) concludes that SNCR achieves "emissions reduction levels of 15 to 25 percent for retrofit applications." At Ecology's request, in March 2010 TransAlta modeled the visibility benefits from adding SNCR to Flex Fuels. Based on the previous 25 percent reduction factor from the 2008 BART Analysis report, the 2010 visibility modeling assumed an emission rate of 0.18 lb/MMBtu based on the Flex Fuel Project rate of 0.24 lb/MMBtu. It is important to note that the 25 percent assumption was not based on an engineering study or a vendor estimate. The emission reduction was not intended to be relied upon as a potential enforceable limit but only as an approximation of the visibility benefits.

TransAlta did not begin to develop SNCR emission rates for use as an enforceable BART limit until the passage of SB 5769 earlier this year. In recent months TransAlta selected and is currently working with a SNCR system vendor to determine what NOx reduction efficiency and emission rates will be achievable with the proposed SNCR systems when they are installed on the TransAlta units. A computational fluid dynamics (CFD) model of each of the two Centralia furnaces must be generated as the first step in designing the optimal emissions reduction systems. This modeling and design must be completed before a construction contract for the systems can be issued and a warranty for the projected NOx reduction efficiency is obtained from the vendor.

The creation and verification of CFD models allow the vendor's technical experts to predict temperature distribution, gas flow paths and concentration and distribution of constituents including O2, CO, NOx, and unburned carbon within the boilers. The model is used to select the size, location and design of the SNCR system components and capabilities. The first step in the CFD modeling process is to generate a model based on the Plant's engineering drawings for each boiler. The next step is to develop a baseline simulation at low & high boiler loads on each Centralia unit. This requires gathering operational data on temperature distribution, gas flow paths and concentration and distribution of constituents including O2, CO, NOx, and unburned carbon during operation of the units at different production levels. Since both units were off-line from early March through late July, the testing to gather the required data is currently scheduled for August 2011.

The data gathered in August will be used to calibrate the CFD models developed for each unit and estimate potential NOx reductions achievable over the anticipated operating range of the units. The information obtained from the CFD modeling will allow the selected vendor to finalize the design of the SNCR system equipment and warranty the design NOx removal efficiency of the SNCR systems in October 2011.

Prior to completion of the CFD modeling and based on current information, the limit that can be achieved with reasonable assurance would be 0.22 lb/MMBtu, which is already a reduction of more than 25% from the pre-BART baseline emission levels. The study by Srivastava et al, Table 3, cited in the draft Determination Support Document lists 20 plants with SNCR that had emission rates ranging from 0.274 to 0.755, significantly higher than the 0.22 lb/MMBtu rate that TransAlta is proposing for Centralia. Although the removal rates may be higher, TransAlta understands that SNCR has diminishing efficiency at lower levels of baseline emissions, such as the Flex Fuel Project rates of the Centralia Plant.

An emission rate of 0.22 lb/MMBtu is substantially lower than the median emission rate of 0.27 for all the SNCR systems proposed as BART in the Western United States (see attached table). The attached table and the Department's own draft BART Determination Support Document show that no coal-fired plant in the Western United States has been determined to be capable of achieving a BART emission rate less than 0.19 lb/MMBtu with SNCR technology and LNC3 combustion controls combined.

Based on the foregoing information and TransAlta's operating experience with LNC3 technology, an emission rate of 0.22 lb/MMBtu should be achievable with the addition of SNCR technology to the current LNC3 technology and an ammonia slip of less than 5 ppm. This would result in a greater than 25 percent reduction from the pre-BART emissions. Operating experience will determine whether an additional emission reduction to a level of 0.20 lb/MMBtu (a 33% reduction from 0.30 and 17% reduction from 0.24) is achievable with optimization of an SNCR system. However, as explained in the CH2M Hill BART Analysis, the reduction achievable depends upon many factors, including higher ammonia slip than the proposed limit. Achieving the Department's proposed emission rate of 0.18 is considered very unlikely (see attached discussion). A discussion of the unique factors that influence NOx the installation of SNCR for NOx reduction in the TransAlta units is attached in the letter from the Centralia Plant engineer.

In conclusion, it is necessary to complete the study required by Section 5 of the order to determine the lowest level that SNCR can reasonably achieve before a limit lower than 0.22 lb/MMBtu is set. TransAlta proposes that, at the conclusion of the study required by Section 5, a lower emission limit (as low as 0.20 lb/MMBtu) will be requested if it is shown to be achievable by the result of the study. If the plant is able to optimize the systems to reach 0.20 lb/MMBtu, this level would be among the lowest achieved by any plant in the Western U.S. utilizing SNCR with LNC3 technology.

Ammonia Emissions Limit
Compliance with the ammonia emissions limit must be determined on the same 30-day rolling average time frame as the NOx limit. Without the flexibility to adjust ammonia addition rates as needed to operate the SNCR system optimally, we cannot assure that we can achieve compliance with the 0.22 lb/MMBtu NOx limit.

Ammonia Emissions Monitoring
We have not been able to find any CEMS for ammonia that will provide the required accuracy and repeatability on our plants when controlled by SNCR. A recent review of the technology confirms this (http://www.ladco.org/about/general/Emissions_Meeting/Greaves_032510.pdf). NDIR/FTIR ammonia analyzers have proven to be unreliable and inaccurate for measuring ammonia slip in the 5 ppm range. UV ammonia analyzers have also proven to be inaccurate for measuring ammonia slip in the desired range. TDLAS in-situ analyzers cannot be used on the saturated stack following the SO_2 scrubber.

The Differential NOx/NH3 Converter Method described on slide 8 of the presentation is the only technology that might be effective; however this type of system only works accurately when NOx emissions are at very low levels. For our process with SNCR the full scale of the analyzers must be set at levels approximately 200 ppm. The allowable 2.5% daily drift on an analyzer with a full scale of 200 ppm is 5 ppm. Since two analyzers are used to determine the ammonia concentration, the allowable drift of the two analyzers could compound the potential error to 10 ppm which is double the proposed limit for ammonia and would be unable to pass the proposed certification requirements. Based upon this review, it has been determined that monitors for ammonia that can be certified as CEMS are not available for our units.

While we intend to install some type of process monitoring equipment on the SNCR system to provide necessary ammonia data for optimizing the SNCR operation, as we described above, the current technology cannot meet requirement for use as a CEMS. We therefore propose removing the ammonia monitoring requirements from the Order and replacing them with an annual compliance test. Once we determine the best system to monitor ammonia levels for the ammonia optimization study and where it can be installed to provide the most useful information (with assistance from the SNCR system supplier), we will include that information in the study plan required by condition 5.2.

Greenhouse Gas Emissions
Including SB 5769's greenhouse gas (GHG) emission limitations is inappropriate. The GHG requirements are unrelated to the BART Order and the requirements of the Regional Haze SIP. SB 5769 provides that these requirements will be incorporated in an enforceable agreement between TransAlta and the State. There is no implication in the statute that the GHG limits should be incorporated in a BART determination. To the extent necessary to support the timelines used for the cost benefit calculations in the BART determination Support Document, State law establishes the enforceability of those timelines for EPA.

TransAlta believes that completely removing this section is appropriate; however, we have proposed alternative language if the Department cannot rely on State law to establish the enforceability of the timelines. The proposed language utilizes the language "cease burning coal" similar to the EPA approved Oregon BART language.

Operating Days and Startup/Shutdown (Section 8.3)
Removal of the 360 MW minimum operating rate references in the BART Order has essentially eliminated the startup/shutdown allowance from the existing Order. There must be an allowance for partial operating days or startups and shutdowns in the Order because the limits are based upon operation of the SNCR systems. These systems cannot operate under startup and shutdown conditions. EPA concurs that BART determinations may take into account higher emissions during startup and shutdown. (Letter from EPA Region 8 to South Dakota Department of Environment and Natural Resources, Sept. 13, 2010, p. 2, attached). If Ecology does not concur with the 360 MW minimum operating rate approach, then one alternative would be that an operating day with less than 8 hours of operation would have to be eliminated from the 30-day average since it will represent either startup or shutdown conditions. We propose that section 8.3 reflect that only days with 8 or more hours of firing coal would be averaged into the 30-day average. This is similar to the 8-hour startup allowance in our Title V permit condition M9 and we believe would exclude a portion of emissions that occur only during the beginning of a startup or ending of a shutdown from the 30-day average.

BART Determination Support Document (Section 4.2 and Appendix I)
We request that Ecology leave the BART determination as LNC3 and Flex Fuels. The installation of SNCR could be based on the technology needed to meet the State's Visibility Reasonable Progress goals. This approach would avoid the need to issue a new BART Order but would still accomplish the goal of setting a lower enforceable limit to improve visibility.

Please contact Brian Brazil or Rick Griffith if you have any questions regarding these comments.

Sincerely,

Bob Nelson
Director, Centralia Operations
TransAlta Centralia Generation LLC

cc: Clint Lamoreaux, Southwest Clean Air Agency
Rick Griffith

SNCR BART/RFP Determinations for Western Coal Plant Sources					
Emission Unit	**Assumed NOx Control Type**	**NOx Emission Limit**	**Assumed SO_2 Control Type**	**SO_2 Emission Limit**	**Reasonable Progress NOx Controls**
Alaska (http://www.dec.state.ak.us/air/anpms/rh/rhdoc/Section III.K.6.pdf)					
GVEA Healy Unit 1	existing LNB with OFA, SNCR required to be added	**0.20 lb/MMBtu**	existing dry sorbent injection system	0.30 lb/MMBtu	Will be evaluated if not shut down by 2024
Colorado (http://www.cdphe.state.co.us/ap/regionalhaze.html)					
CENC Unit 5	new LNB with SOFA, and SNCR	**0.19 lb/MMBtu Or** 0.26 lb/MMBtu Average for Units 4 & 5 (30-day rolling)	None	1.0 lb/MMBtu (30-day rolling)	no
TSG&T Craig Unit 1	new SNCR System	0.28 lb/MMBtu (30-day rolling)	Wet Limestone scrubber	0.11 lb/MMBtu (30-day rolling)	**BART is 0.27**, 0.28 allowed with SCR on Unit 2
TSG&T Craig Unit 2	(SNCR is BART) new SCR System for RP	0.08 lb/MMBtu (30-day rolling)	Wet Limestone scrubber	0.11 lb/MMBtu (30-day rolling)	**BART is 0.27,** 0.08 required for reasonable progress goal
Nevada (http://deq.state.wy.us/aqd/308 SIP/309(g) SIP 1-7-11 Clean Final.pdf)					
NVE Reid Gardner Units 1 & 2	ROFA with Rotamix	**0.20 lb/MMBtu** (12-month rolling)	existing wet soda ash FGD	0.15 lb/MMBtu (24-hr)	no
NVE Reid Gardner Unit 3	ROFA with Rotamix	**0.28 lb/MMBtu** (12-month rolling)	existing wet soda ash FGD	0.15 lb/MMBtu (24-hr)	no
North Dakota (http://www.ndhealth.gov/AQ/RegionalHaze/Regional Haze Link Documents/Main SIP Sections 1-12.pdf)					
BEPC Leland Olds Unit 1	new LNB with SOFA and SNCR	**0.19 lb/MMBtu** (30-day rolling)	new Wet Limestone scrubber	0.15 lb/MMBtu (30-day rolling)	no
BEPC Leland Olds Unit 2	new LNB with ASOFA and SNCR	**0.35 lb/MMBtu** (30-day rolling)	new Wet Limestone scrubber	0.15 lb/MMBtu (30-day rolling)	no
GRE Stanton Unit 1	new LNB with OFA and SNCR	0.29 or **0.23 lb/MMBtu** (30-day rolling)	new Wet Limestone scrubbers	0.24 or 0.16 lb/MMBtu (30-day rolling)	Note: limits on lignite and subbituminous
MPC Milton R.Young Unit 1	new LNB with ASOFA and SNCR	**0.36 lb/MMBtu** (30-day rolling)	new Wet Limestone scrubber	0.15 lb/MMBtu (30-day rolling)	no
MPC Milton R.Young Unit 2	new LNB with ASOFA and SNCR	**0.35 lb/MMBtu** (30-day rolling)	existing Wet Limestone scrubber	0.15 lb/MMBtu (30-day rolling)	no

Average SNCR BART Limit	0.26 lb/MMBtu
Median SNCR BART Limit	0.27 lb/MMBtu
Lowest SNCR BART Limit	0.19 lb/MMBtu

TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, Washington
USA 98531

(360) 736-9901
www.transalta.com

July 28, 2011

Mr. Brian Brazil

Re: Selective Non Catalytic Reduction (SNCR) Technology implementation at Centralia Plant

Brian:

Station #1 & #2 boilers were retrofitted with Low NOx Burners (LNB) in 2002 and 2001, respectively. This modification, which included installation of Separate Over Fire Air (SOFA) and Close Coupled Over Fire Air (CCOFA) injection ports, allowed the NOx emissions to be lowered to 0.30 lbs/mm BTU. In 2008 as part of conversion to PRB fuels which are inherently lower in nitrogen content, and additional fine tuning of the boilers, the achievable NOx level was further reduced to 0.24 lbs/mm BTU.

Earlier this year, we embarked on installation of SNCR technology on both boilers for additional reduction of NOx. In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. The reagent generates ammonia and the process reaction converts NOx to nitrogen and water vapor. The performance of an SNCR system depends on a variety of factors such as the furnace baseline oxygen and carbon monoxide concentrations, injected reagent quantity and distribution, residence time, and flue gas temperature.

The influence of these parameters can have a significant impact on the performance of an SNCR system. The theoretical reduction for SNCR reaction is one mole of NOx to one mole of ammonia. However, experience has shown that a portion of ammonia can exit the boiler and cause numerous environmental and operational concerns such as formation of detached plumes, corrosion and boiler component pluggages. The unreacted ammonia reacts with other compounds in the flue gas to form ammonia compound such as NH4 HSO4 or NH4 Cl. These compounds are corrosive and can create blockages of the air preheater baskets that will lead to forced unit outages. Free ammonia also has the potential to contaminate the captured fly ash and the station SO2 control system's by-products creating additional problem.

Since the PRB fuels conversion at the plant we have had numerous issues unique to our boilers. These fireboxes, which were originally designed for combusting the native fuel from the mine next door, are too short to allow sufficient heat adsorption from PRB fuels which generate higher radiant heat. This has resulted in excessive furnace exit gas temperature leading to non stratified isothermal planes. The excessive heat also generates fluid slag (due to high sodium PRB ash) on the walls that plug up observation ports and instrumentation taps on the boiler walls. The SOFA injection can also create pocket of high CO gas and unpredictable mixing zones for the reaction between the SNCR reagent and the NOx in the flue gas stream. These issues would significantly affect the performance of SNCR systems relying on injection above the furnace.

The SNCR systems using multi nozzle lances injecting at the superheater pendant positions, rely on rotary insertion systems identical to our long lance IK soot blowers. These lances are unreliable, experience routine failures from clinker falls, and remain out of service on a regular basis. The long term viability of any SNCR system relying on multi nozzle lances is questionable.

We have had multiple conversations with potential suppliers of SNCR technology and there appears to be a significant reluctance to offer an ironclad guarantee regarding the removal efficiency and the free ammonia slip stream at the boiler outlet. One of the contributors to this issue is the fact that we are already operating with extremely low NOx levels (0.24 lbs/mm BTU) that the actual realized system performance may be hard to predict.

We are currently working with a SNCR system vendor to determine what NOx reduction efficiency and emission rates will be achievable with their proposed design of SNCR systems. We have also retained the services of an independent consulting firm specializing in modeling of SNCR components and their interaction with various parameters within a boiler. The outcome of these models will provide additional insight as to the performance of the SNCR system.

The above mentioned concerns and due to the fact that the actual long term performance of any SNCR system can only be verified by post commissioning optimization, we do not anticipate to be able to achieve more than 19-20% NOX removal efficiency. However, it is our intention to push our system to its highest sustainable capability.

Please feel free to contact me if you have any questions regarding these comments.

Sincerely,

Jim Khorsand, P.E.
Plant Lead Engineer

cc: Trevor Ebl

Implementation of NH3 measurement on Post Combustion NOx Reduction Systems.

LADCO WORKSHOP

March 24-25th, 2010

Ammonia Slip Measurement

Post Combustion NO_x Reduction:

- Selective non-catalytic reduction (SNCR)
- Selective catalytic reduction (SCR)
- Common requirement: introduction of NH_3

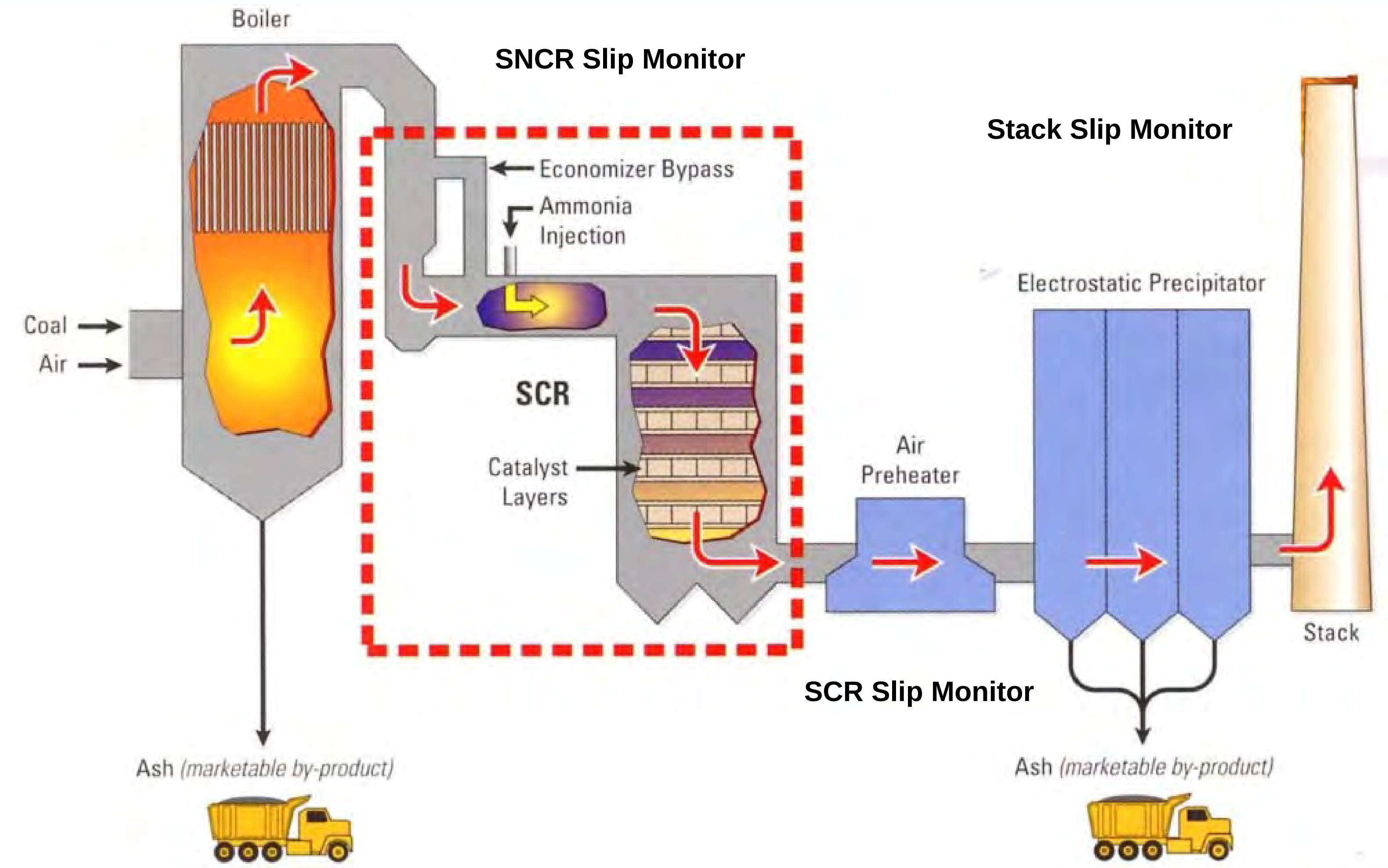
$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

Ammonia Slip Measurement

Consequences of Ammonia Slip:

- If over-titrated NH_3 escapes – pollutes and wastes
- Violates permit limit if applicable
- If due to incomplete mixing – NO_x escapes
- With high sulfur fuels ammonia sulfate and bisulphate formed – can foul air pre-heater
- Ammonia contaminates fly ash making it hazardous

Ammonia Slip Measurement



Ammonia Slip Measurement

Monitoring Methods:

- FULLY EXTRACTIVE (DRY BASIS)
- FULLY EXTRACTIVE (HOT-WET BASIS)
- DILUTION EXTRACTIVE (WET BASIS)
- IN-SITU (CROSS STACK or PROBE)

Measurement Types:

- Chemiluminescence ,UV Absorption, FTIR, DOAS,
- (TDLAS)

Ammonia Slip Measurement

- **Analyzer Glossary**
- **Chemiluminescence:** (Chemical Light) a measurement technique for NO/NOx that measures the light given off as a result of the reaction between NO and Ozone. The light output is proportional to the concentration of NO. NO_2 is converted to NO using a high temperature catalytic converter. NO_2 does not react with Ozone so it must be converted to NO.
- **UV Absorption:** a measurement technique that uses a UV spectrometer to measure a particular wavelength where the gas of interest absorbs (measurement) and a wavelength where the gas of interest does not absorb (reference). Most often used for SO_2 measurement in high concentrations.
- **Tunable Diode Laser Absorption Spectroscopy (TDLAS):**By scanning across a very narrow bandwidth in the IR region where no cross interferences occur, the absorption of the IR source by the targeted gas is proportional to the target gas concentration.
- **Fourier Transform-Infrared Spectroscopy (FTIR):** This technique measures the absorption of infrared radiation by the sample gas versus wavelength. The infrared absorption bands identify molecular components.
- **Differential Optical Absorption Spectroscopy (DOAS):** is a method to determine concentrations of trace gases by measuring their specific narrow band absorption structures in the UV and visible spectral region

Ammonia Slip Measurement

Inlet/Outlet Differential NOx Method

- First method is based on the calculation of ammonia slip using the inlet/outlet differential NOx method along with ammonia flow rate and stack flow calculation. This method has been employed successfully in many EPA permitted CEMS, the SCAQMD and many other AQMD's for control and compliance monitoring. This method is reliable and low in cost for sources where SCR inlet monitoring is a requirement.

- The inlet/outlet method is used where SCR control is also a requirement since both the SCR inlet NOx and SCR outlet NOx are measured on a continuous basis. The outlet measurement is usually the CEMS compliant system. The inlet system requires a second probe mounted on the duct before the SCR and a second NOx analyzer.

- The NOx and NH3 react on a 1:1 basis. Therefore, the amount of NH3 reacted is equal to the amount of NOx reduced in the SCR. The simplified formula is:

$$NH_3 \text{ slip} = NH_3 \text{ fed} - (NO_x \text{ in} - NO_x \text{ out})$$

Ammonia Slip Measurement

Differential NOx/NH3 Converter Method:

- An alternate ammonia method using direct measurement of differential NOx on the stack. This method utilizes two (2) NOx analyzers on the outlet (stack) CEMS. An ammonia converter is included at the stack probe which converts NH3 slip to NOx. The sample line includes an additional sample tube to transport the NH3 converted sample stream to an additional NOx analyzer.
- One analyzer is used to measure NOx emissions and the second is installed to measure the converted stream which includes the NOx and ammonia converted to NOx for the ammonia slip calculations. The NOx analyzers are identical – range, manufacturer, model number.
- A special probe Is used to catalytically convert NH3 into NOx. The increase in NOx that results is NH3 slip. The probe contains an electrically heated oxidation catalyst where NH3 is oxidized with oxygen on the catalyst surface into nitric oxide (NO) and water, as follows:

$$4\,NH_3 + 5\,O_2 = 4\,NO + 6\,H_2O$$

- The NH3 conversion process has an efficiency of 90-98% depending on the sample flowrates, age of converter, and NH3 concentrations. Conversion efficiencies of 95%+ can be expected on typical combustion turbine applications.

NH3 slip (ppm) = NOx (ppm) (total converted) – NOx (ppm) (unconverted)

Ammonia Slip Measurement

Direct measurement of NH3:

- This can be done using several methods, both across the stack or duct measurement or Insitu probe type systems.
- Typical across duct measurements use the Tunable Diode Laser method, or DOAS monitor.

Ammonia Slip Measurement

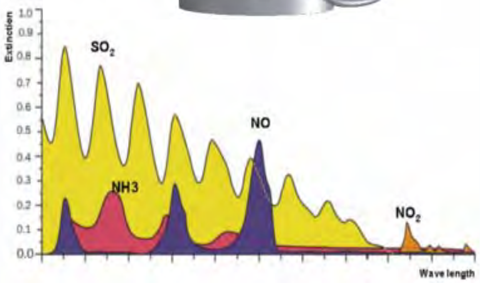
In-Situ…Advantages:

No gas transport

- Fast response time
- No loss of components in a sample system
- No filters, sample lines, pumps to clean

Lower planning expenses

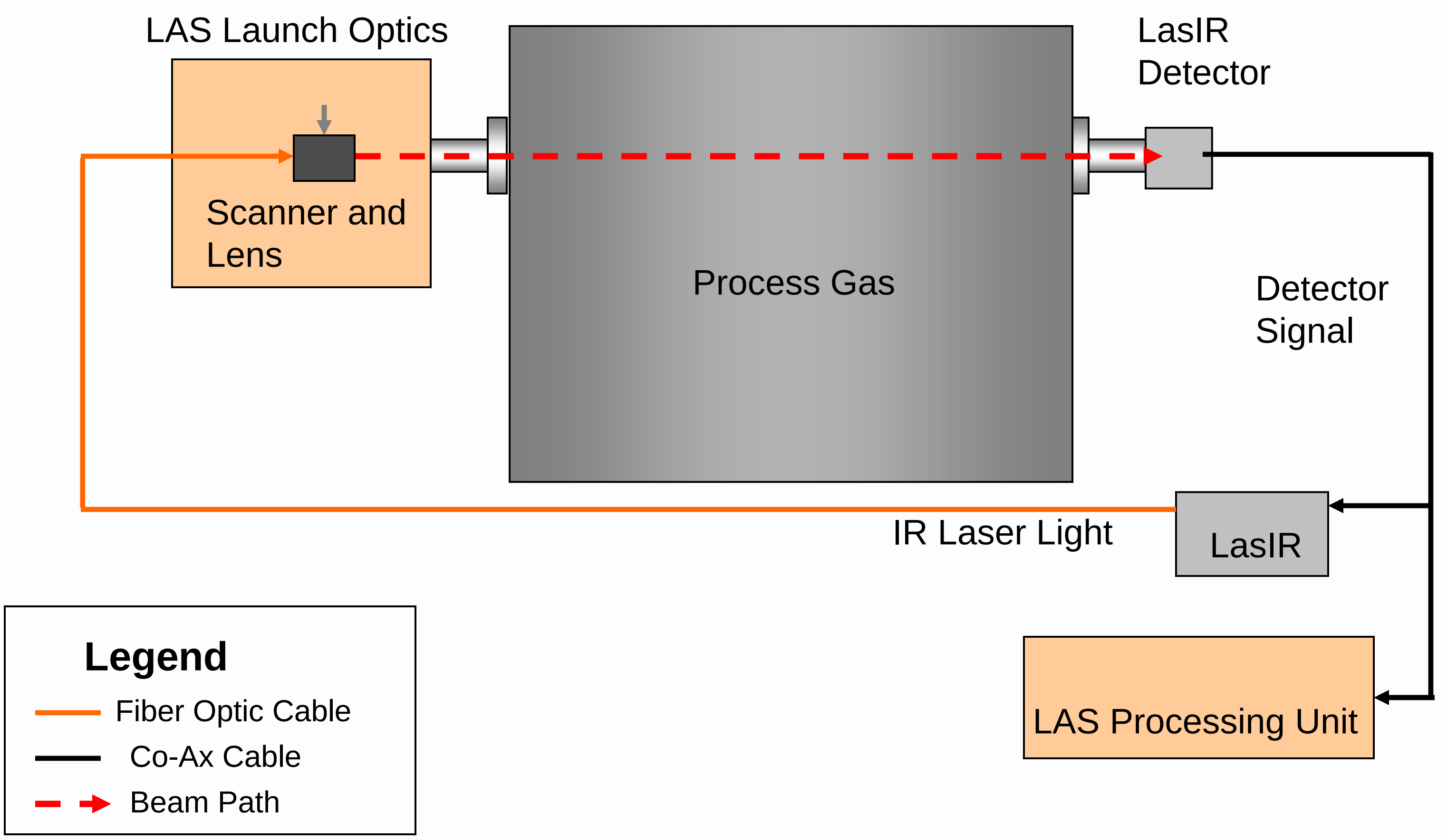
- Support for heated sample gas lines
- Analysis container
- Disposal of sample gas and condensate



Lower installation and operation cost

- No Heated sample gas lines (\$50/ft)
- Larger component Inventory and Replacement requirements
- Cost for shelter or space in existing analyzer rooms.

Ammonia Slip Measurement



Tunable Diode Laser Analyzer

Ammonia Slip Measurement

TDLAS Ammonia slip Monitoring:

- In-situ measurement avoids loss of sample integrity, to Minimize NH3 Slip
- Single Indicator of direct measurement of Slip for compliance or performance of DeNOx system
- Fast response better then 60 seconds allows better feedback for control, less violations.

Ammonia Slip Measurement

EXTRACTIVE :

- Sample delivered to analyzer mounted in typical cabinet , possibly integrated with CEMS.
- Useful for Dirty Applications such as certain Coal Fired Plants.
- Measurement type: Chemiluminescence, UV Absorption, FTIR
- Minimal performance at low concentrations
- Easy to calibrate, since standard calibration gas procedures are incorporated.
- Not the most cost effective when equipment, install and maintenance costs are accounted for.

Ammonia Slip Measurement

UV photometer

DEFOR

For measurement of

1 to 3 UV components

Includiing O_2

Ammonia Slip Measurement

Certification of NH3 Slip Measurements

- There are no performance standards against which NH3 monitors can be certified, and there are no adopted methodologies for the certification of continuous NH3 monitoring.
- CTM-027 defines how best to obtain representative stack test samples for verification of stack conditions, against which any analyzer system would be referenced,.
- In addition, there are no NIST traceable Protocol calibration gases for NH3 at lower levels. The most accurate calibration gas for NH3 is a working class gas with an accuracy of +/- 5%. Also, the lowest level that can be commercially obtained is 7 ppm.
- Spiking is an accepted method by which relative accuracy data can be obtained but once again no standards are set on how to achieve this.
- Most Insitu analyzers have built in calibration standards either by filters or calibration gas cells. All have the ability to do self check zero and span, and most can be checked against a standard gas at a higher value working class

Ammonia Slip Measurement

SUMMARY:

- Until a clear acceptable method for accurate measurement of NH3 at the lowest concentrations now seen (less than 2ppm) is commercially available, and one that can be applied to all applications, then Industry must rely on the vendors to assist in meeting their needs whether it be permit verification or process optimization.
- Insitu while giving the best accuracy will be considered the front runner for most applications, but without the ability to do all applications at the low level measurements will struggle for acceptability.
- Extractive surrogate measurements will continue to dominate the Utility market for now because of the ease of acceptability as part of a CEMS.
- Tunable Diode Laser technology is proving to be the most accurate method, but will have to wait until a suitable calibration method has been defined and accepted.