STATE OF OREGON

Public Utility Commission

In the Matter of PacifiCorp's Filing of Revised Tariff Schedules for Electric Service in Oregon	Docket No. UE 246

Direct Testimony of Jeremy Fisher, Ph.D.

On Behalf of Sierra Club

PUBLIC VERSION

June 20, 2012

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Acronyms

BART	Best Available Retrofit Technology
CAI	Comprehensive Air Initiative
CCR	Coal Combustion Residuals
CO	carbon monoxide
CPCN	Certificate of Public Convenience and Necessity
DOJ	Department of Justice
EPA	Environmental Protection Agency
FGC	flue gas conditioning
FGD	flue gas desulfurization
HAPs	Hazardous Air Pollutants
LAER	Lowest Achievable Emissions Reductions
LNB	low-NOx burners
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
NAAQS	National Ambient Air Quality Standards
NO_x	nitrogen oxides
NSR	New Source Review
PM	particulate matter
PVRR(d)	present value revenue requirement differential
RACT	Reasonably Available Control Technology
RCRA	Resource Conservation and Recovery ACT
SAP	Strategic Asset Plan
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SO_2	sulfur dioxide
WYDEQ	Wyoming Department of Environmental Quality

1. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, business address and position.

A My name is Jeremy Fisher, and I am a scientist with Synapse Energy Economics (Synapse). My business address is 485 Massachusetts Avenue, Suite 2, Cambridge Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q Please summarize your work experience and educational background.

A I have ten years of applied experience as a geological scientist, and five years of working within the energy planning sector, including work on integrated resource plans, long-term planning for states and municipalities, electrical system dispatch, emissions modeling, the economics of regulatory compliance, and evaluating social and environmental externalities. I have provided consulting services for various clients, including the U.S. EPA, the National Association of Regulatory Utility Commissioners (NARUC), the California Energy Commission (CEC), the California Division of Ratepayer Advocates, the State of Utah Energy Office, the National Association of State Utility Consumer Advocates (NASUCA), the National Rural Electric Cooperative Association (NRECA), the State of Alaska, the Western Grid Group, the Union of Concerned Scientists (UCS), Sierra Club, National Resources Defense Council (NRDC), Environmental Defense Fund (EDF), the Stockholm Environment Institute (SEI), and Civil Society Institute.

Prior to joining Synapse, I held a post doctorate research position at the University of New Hampshire and Tulane University examining the impacts of Hurricane Katrina.

I hold a B.S. in Geology and a B.S. in Geography from the University of Maryland, and an Sc.M. and Ph.D. in Geological Sciences from Brown University.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of the Sierra Club.

Q Have you testified previously before the Oregon Public Utility Commission?

A I gave comments in the 2011 IRP process on behalf of Sierra Club, but I have not testified in front of this Commission previously.

Q What is the purpose of your testimony?

A My testimony reviews the regulatory requirements and economic justifications of specific environmental retrofits made by PacifiCorp, d.b.a Pacific Power (the "Company"), for which capital recovery is requested in this case. I find that there was no regulatory requirement for these retrofits in the timeframe stipulated by the Company, and that the economic justification for these retrofits was flawed and incorrect, resulting in significant liabilities rather than customer benefit.

Q Please identify the PacifiCorp documents and filings on which you base your opinion regarding the Company's expectations for and treatment of environmental compliance costs affecting its fleet of coal plants.

A In addition to Company witness testimony in this case, I have reviewed, amongst other documents and work papers:

- Strategic Asset Plans (SAPs) issued internally for Naughton, Hunter, and other PacifiCorp units in 2008, 2009, and 2011;
- "Present value of revenue requirement differential" (PVRR(d)) analyses for Naughton, Hunter, and other PacifiCorp units issued in 2008 and 2009;
- APRs for the projects discussed in this testimony;
- Regional haze State Implementation Plans and supporting documentation in Wyoming and Utah;

- The 2008 and 2011 Integrated Resource Plans (IRP), and updates; and
- The coal retrofit Screening Analysis distributed to Oregon IRP stakeholders in 2011.

Q Are you filing any exhibits with this testimony?

A I have attached the following exhibits to this testimony:

- Exhibit Sierra Club 101: Curriculum vitae
- Exhibit Sierra Club 102: 2008 Strategic Asset Plan (SAP) for Naughton
- Exhibit Sierra Club 103: 2009 Strategic Asset Plan (SAP) for Naughton
- Exhibit Sierra Club 104: SO2 Milestones
- Exhibit Sierra Club 105: WYDEQ Permit MD-5156
- Exhibit Sierra Club 106: BART Analysis for Naughton 1
- Exhibit Sierra Club 107: BART Analysis for Naughton 2
- Exhibit Sierra Club 108: Addendum to Naughton Unit 1 BART Report
- Exhibit Sierra Club 109: APR 10003745
- Exhibit Sierra Club 110: APR 10003746
- Exhibit Sierra Club 111: BART Application Analysis, AP-6042
- Exhibit Sierra Club 112: PacifiCorp's Emissions Reduction Plan, November 2010
- Exhibit Sierra Club 113: US EPA letter to WY DEQ, Aug 2010
- Exhibit Sierra Club 114: CAI Control Report: Comprehensive Air Initiative Analysis, Feb 2003
- Exhibit Sierra Club 115: Air Quality Reference Case Investments, April 2005
- Exhibit Sierra Club 116: Accumulated Net Present Value (NPV) analysis from Naughton 1 & 2 PVRR(d) spreadsheet
- Exhibit Sierra Club 117: 2009 Strategic Asset Plan (SAP) for Hunter
- Exhibit Sierra Club 118: Response to Sierra 1.36
- Exhibit Sierra Club 119: 2009 Strategic Asset Plan (SAP) for Carbon

2. FINDINGS AND OVERVIEW OF TESTIMONY

Q In your opinion, do the facts and evidence presented in this case support the Company's revenue requirement increase?

A No. In particular, at least **$297 million** of steam plant additions associated with retrofits at Naughton units 1 & 2 are either inadequately supported or not economically justified by the Company. It is also my opinion that the Company has not justified the costs of upgrades at the Hunter 1 & 2 units, leaving at least an additional **$79 million** in doubt.

At the Naughton units, the Company failed to justify the costs of the following five steam plant additions (as listed in Company witness Dalley Exhibit PAC/1102 p8.6.5):

- "Naughton U2 Flue Gas Desulfurization Sys" at $154,748,900
- "Naughton U1 Flue Gas Desulfurization Sys" at $120,749,119
- "Naughton U1 NOx LNB" at $8,930,952
- "Naughton U2 NOx LNB" at $8,549,495
- "Naughton U0 FGD Reagent Loadout Facility" at $3,708,790

Generally, I will refer to the combination of the flue gas desulfurization (FGD) and low-NOx burner (LNB) projects as "the Naughton Environmental Retrofits."

At the Hunter units, I believe that the following four steam plant additions lack evidentiary support:

- Hunter U1 SO2 Upgrades at $51,918,028
- 302 – Hunter U2 SO2 Project at $25,068,777
- Hunter 302 Clean Air – PM at $1,503,979
- Hunter U1 Turbine Upgrade – Interconnection at $1,176,775

Generally, I will refer to these series of projects as "the Hunter Environmental Retrofits." I have included the turbine upgrade here because the project was implemented in the same time period and is not a standard operations and maintenance expense.

Q What is the basis of your objection to the Naughton Environmental Retrofits?

A My objection is two-fold.

First, these projects were initiated without a firm regulatory requirement because all of the regulators requirements either post-dated the initiation of these projects or were of the Company's own making. The Company was not required to install the Naughton Environmental Retrofits at the time they were initiated and constructed. Instead, these projects appear to represent a very expensive and premature gamble on controls that could ultimately be deemed inadequate by regulators.

Second, the Company performed only a cursory and flawed internal economic justification prior to pursuing the Naughton Environmental Retrofits. Had the Company tested the sensitivities of its own analysis, it would have determined that these were very high risk expenditures. The Company also would have quickly determined that the projects were not economically justified if it had reexamined its own modeling assumptions prior to executing contracts for, or initiating construction of, the Naughton Environmental Retrofits. Fixing any one of a number of flaws in the Company's analysis clearly demonstrates that the Naughton units are liabilities, and retrofitting these plants was not in the best interest of ratepayers.

My testimony shows that the Company acted prematurely and without due consideration to a reasonable economic outlook for the Naughton units. In order to make this showing, my testimony:

- Reviews the environmental regulations the PacifiCorp coal plants are subject to along with the incumbent costs of those regulations;
- Reviews the timeline in which these regulations have emerged and in which compliance must be complete;

- Compares the Company's actions against regulatory requirements; and,
- Reviews the Company's analysis in support of the Naughton Environmental Retrofits and shows that a reasonable utility acting in the interests of its customers would have chosen <u>not</u> to proceed with the Naughton retrofits.

Q What is the basis of your objection to Hunter Environmental Retrofits?

A My objection to the Hunter Environmental Retrofits is fundamentally the same as in the case of the Naughton facility. Again, the Company proceeded to retrofit the Hunter units without a regulatory requirement and did not consider the merits of deferring this decision. The Company's analysis supporting the cost efficacy of the retrofits was flawed. When corrected, the analysis shows that the Hunter Environmental Retrofits are risky and provide only marginal benefits to customers under the best circumstances, and a significant liability under reasonably expected conditions. Finally, the Company's analysis of the cost of the Hunter Environmental Retrofits should have included a component of the avoided cost of new transmission from central Utah to the Salt Lake City area.

Q Please summarize the findings of your analyses of the Naughton Environmental Retrofits and the Hunter Environmental Retrofits.

The Company failed to justify its decision to move forward with the Naughton Environmental Retrofits and Hunter Environmental Retrofits in light of the environmental regulations that were known and likely at the time of the decisions. Rather than waiting for final environmental rulings and deferring judgment on the cost efficacy of retrofitting their aging fleet, the Company simply began to install air pollution controls without a formal requirement. The permitting and installation process began during the time that the regulations were still under consideration, and proceeded well before the regulations were finalized.

Even if the Company had been required to act when it did, which was not the case, based on my review and analysis of the data available to the Company at the time the decisions were made, it is my opinion that the Company should have concluded that the Naughton Environmental Retrofits and Hunter Environmental Retrofits would not be cost effective. The Company performed economic analyses, which Mr. Teply refers to as the "present value of revenue requirement differential" or "PVRR(d)" analyses (PAC/500, Teply/21 at 14-18), several months prior to signing a contract to proceed with the work at the Naughton units. These simple analyses indicated that the retrofits were just barely economic, with benefits of [redacted] and [redacted] million for Naughton units 1 & 2, respectively. However, the Company's assumptions in these analyses were inconsistent with risks and costs known at the time. For example, the analyses assumed that the Company must have either retrofitted the Naughton units or retire them in 2009, even though there was no particular regulatory impetus for doing so. When these flawed assumptions are corrected, the analysis indicates that the Naughton Environmental Retrofits would have resulted in a liability of <u>at least</u> [redacted] and [redacted] million, respectively. Finally, had these analyses been performed around the time that the contract was signed, the Company would have found that the retrofits were significant liabilities at around [redacted] and [redacted] million, respectively.

At Hunter units 1 & 2, the story is very similar. Correcting similar flaws as in the Naughton analyses reveals that the economic justification for the retrofits at Hunter 1 & 2 drops quickly from [redacted] and [redacted], respectively, to [redacted] and [redacted]. The Company also failed to consider that the Hunter units would have become a significant liability of at least [redacted] and [redacted], respectively if the Company had considered mid-level or high-level CO_2 prices. Finally, in addition to these corrections that shift the analysis of the Hunter Environmental Retrofits from a net benefit to a net liability, the Company's analysis did not factor in any opportunities to avoid the cost of new transmission from central Utah to the Salt Lake City area. If the Company had ultimately decided to retire rather than retrofit the Hunter units, it is feasible that components or the whole of the Mona to Oquirrh transmission line could have been downsized, cancelled or deferred. To the extent that such savings exist, they should have been incorporated into the Hunter PVRR(d) analysis.

3. Environmental Requirements Facing the PacifiCorp Coal Fleet

Q Why has PacifiCorp recently retrofitted many of its coal-fired units?

A Most of the retrofit projects at issue in this proceeding appear to have been in anticipation of EPA finalizing regulations to reduce regional haze pollution in national parks and wilderness areas (Class 1 areas). The Regional Haze rules are just one of a number of regulations EPA has been working to finalize. PacifiCorp units in Wyoming and Utah are subject to regulation under EPA's Regional Haze program.

Q What are the recent and emerging EPA requirements with which PacifiCorp's coal fleet will have to comply?

A Over the course of the last seven years, EPA has promulgated rules to protect human health and the environment. Some of these rules have been in the works for decades while others are new initiatives based on new and emerging scientific evidence. There are effectively six types of environmental regulations that may have profound economic implications for coal units today:

- National Ambient Air Quality Standards (NAAQS)
- The Regional Haze Rules
- Mercury and Air Toxics Standards (MATS)
- Coal Combustion Residuals (CCR)
- Cooling Water Intake Rule; and
- Effluent limitation guidelines

Q Please briefly describe the purpose and impact of NAAQS.

A NAAQS set maximum air quality limitations that must be met at all locations across the nation. Compliance with the NAAQS can be determined through air quality monitoring stations, which are stationed in various cities throughout the U.S., or through air quality dispersion modeling. If, upon evaluation, states have areas found to be in "nonattainment" of a particular NAAQS, states are required to set enforceable requirements to reduce emissions from sources contributing to nonattainment such that the NAAQS are attained and maintained. EPA has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter (measured as particulate matter less than or equal to 10 micrometers in diameter (PM_{10}) and particulate matter less than or equal to 2.5 micrometers in diameter ($PM_{2.5}$)), and lead. EPA is required to periodically review and evaluate the need to strengthen the NAAQS if necessary to protect public health and welfare. For example, EPA is currently evaluating the NAAQS for ozone and particulate matter.

In nonattainment areas, sources must comply with emission reduction requirements known as "Reasonably Available Control Technology" (RACT) to bring the areas into attainment of the NAAQS. New major sources, including major modifications at existing sources, must comply with very strict emissions reductions consistent with "lowest achievable emissions reductions" (LAER) as well as obtain emission offsets.

Q Please briefly describe the purpose and impact of Regional Haze Rules.

A One of the Clean Air Act's national goals is to reduce existing visibility impairment from manmade air pollution in all "Class I" areas (e.g., most national parks and wilderness areas). (42 U.S.C. § 7491(a)(1)) EPA's implementing rules require states to create plans to significantly improve visibility conditions in Class 1 areas with the goal of achieving natural background visibility conditions by 2064. These requirements are implemented through state plans with enforceable reductions in haze-causing pollution from individual sources and with other measures to meet "reasonable further progress" milestones. (See generally 40 C.F.R. §51.308-309). The first reasonable progress milestone is 2018.

The Clean Air Regional Haze Rule was issued in 1999, and revised in 2005. A key component of this program is the imposition of air pollution controls on existing facilities that impact visibility in Class I areas. Specifically, the rules require installation of "best available retrofit technology" (BART) that is developed for such facilities on a case-by-case basis. In addition, EPA's BART determinations specify particular emission limits for each BART eligible facility. EPA evaluates BART for the air pollutants that impact visibility in our national parks and wilderness areas – namely sulfur dioxide (SO_2), nitrogen oxides (NO_x) and particulate matter (PM). Under the Clean Air Act, states develop regional haze requirements, but EPA approves state plans for compliance with the Clean Air Act. If EPA finds the plans are not consistent with the Clean Air Act, it adopts a federal plan with BART and reasonable progress requirements. Affected facilities must comply with the BART determinations as expeditiously as practicable but no later than five years from the date EPA approves the state plan or adopts a federal plan.

EPA's regulations allow certain states in the "Grand Canyon Visibility Transport Region" to participate in an SO_2 trading program in lieu of adopting source-specific SO_2 BART requirements, if the trading program will result in greater reasonable progress toward attaining the national visibility goal than source-specific BART.[1] Although nine states were originally eligible to participate, at this point in time, only three states are opting to participate in this program – New Mexico, Utah, and Wyoming. These states agreed to a gradually declining cap on SO_2 emissions from all emission sources in the three states. If the declining caps, or "milestones," are exceeded in any year, then even greater SO_2 emission reductions have to be achieved—although the reductions can be met through emissions trading, rather than imposition of specific emission limitations on any one facility. This program is called the Backstop Trading Program. As of the date of this testimony, EPA has not yet approved the Backstop Trading Program to meet regional haze requirements in any of the three states' regional haze plans, so the trading program is not yet federally enforceable.

Q Please briefly describe the purpose and impact of the finalized Mercury and Air Toxics Standards (MATS).

A In 2000, after a lengthy study, EPA determined it was appropriate and necessary to regulate toxic air emissions (or hazardous air pollutants, HAPs) from utility

[1] 40 C.F.R. 51.309.

steam electric generating units. As a result, EPA adopted strict emission limitations for hazardous air pollutants that are based on the emissions of the cleanest existing sources. (Clean Air Act §112(d)) These emission limitations are known as Maximum Achievable Control Technology (MACT).

The final MATS rule sets strict stack emissions limits for mercury, other metal toxins, other organic and inorganic hazardous air pollutants (HAPS), as well as acid gasses.

Q Please briefly describe the purpose and impact of the proposed Coal Combustion Residuals rule.

A Coal-fired power plants generate a tremendous amount of ash and other residual wastes, which are commonly placed in dry landfills or slurry impoundments; regulations governing the structural integrity and leakage from these installations vary. However, the risk associated with these installations was dramatically revealed in the catastrophic failure of the ash slurry containment at TVA's Kingston coal plant in Roane County, Tennessee in December 2008, releasing over a billion gallons of slurry and sending toxic sludge into tributaries of the Tennessee River.[2]

On June 21, 2010, EPA proposed regulation of ash and flue gas desulphurization (FGD) wastes, or "coal combustion residuals" (CCR) as either a Subtitle C "hazardous waste" or Subtitle D "solid waste" under the Resource Conservation and Recovery Act (RCRA). (75 Fed. Reg. 35127. (June 21, 2010)).The coal combustion rulemaking was forced by a combination of missed statutory deadlines and court orders. The current rulemaking is 30 years overdue.

If the EPA classifies CCR as hazardous waste, a cradle-to-grave regulatory system applies to CCR, requiring regulation of the entities that create, transport, and dispose of the waste. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust

[2] See TVA Kingston Ash Recovery Project at http://www.tva.com/kingston/pdf/ash_recovery_2-26.pdf (viewed June 18, 2012)

controls, and any corrective actions required; in addition, the EPA would also implement minimum requirements for dam safety at impoundments.

Under a “solid waste” Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care.

The EPA is currently evaluating which regulatory pathway will be most effective in protecting human health and the environment without resulting in unintended consequences or resulting in unnecessarily burdensome requirements.

Q Please briefly describe the purpose and impact of the proposed Cooling Water Intake Rule.

A On March 28, 2011, the EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants. [33 U.S.C. § 1326.] Section 316(b) requires "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.” Under this new rule, EPA set new standards reducing the impingement and entrainment of aquatic organisms from cooling water intake structures at new and existing electric generating facilities.

The proposed rule provides that:

- Existing facilities that withdraw more than two million gallons per day would be subject to an upper limit on fish mortality from impingement, and must implement technology to either reduce impingement or slow water intake velocities.
- Existing facilities that withdraw at least 125 million gallons per day would be required to conduct an entrainment characterization study for submission to the Director to establish a “best technology available” for the specific site.

It is unknown if final implementation of the rule will effectively require "open cycle" cooling (i.e. those that withdraw from and discharge hot water directly to rivers or lakes) to retrofit with "closed cycle" cooling towers, or if advanced fish screens will prove sufficient.

Some utilities have assumed, for forward modeling purposes, that a final rule will require closed cycle cooling.

Q Please briefly describe the purpose and impact of the expected Cooling Water Intake Rule.

A The Clean Water Act requires EPA to develop "effluent limitation guidelines" – clear rules for what large industrial sources of water pollution can discharge into nearby waters. (See 33 U.S.C. § 1311; 40 C.F.R. 423) These rules must consider what is "economically achievable" and must be updated at least once every five years to keep up with improving treatment technology. Although EPA is supposed to update its rules regularly, the power plant rules were last updated in 1982, and so are almost thirty years out of date.

On September 15, 2009, EPA announced an intent proceed with a rulemaking on effluent guidelines for wastewater discharges from steam electric plants, including nuclear and fossil-fired plants.

In May of 2010, the EPA distributed a survey to 733 steam electric facilities, including units owned by PacifiCorp, to request information about onsite waste storage and disposal (i.e. ash ponds), management of storage facilities, and leachate sampling.

The EPA has identified wastewaters from flue gas mercury control systems, regeneration of the catalysts used for SCR, wastes from FGD units, and coal combustion residual storage ponds as waste streams that warrant attention. I therefore expect that the new effluent limitation guidelines will address toxic releases from point sources or coal ash ponds.

Some utilities have assumed that such guidelines will require dewatering and wastewater treatment facilities at FGD waste ponds.

4. <u>NAUGHTON ENVIRONMENTAL RETROFITS NOT REQUIRED BY REGULATION</u>

Q Where there any final EPA rules that compelled PacifiCorp to initiate the Naughton Environmental Retrofit projects?

A No, there were not. As I explain in more detail below, at the time that the Company <u>sought</u> the attainment of the air and construction permits for the FGD retrofits at Naughton, there were no federally enforceable requirements compelling the installation of these controls.

Q Do you agree with PacifiCorp's assertion that the Naughton Environmental Retrofits were required?

A No, I do not. According to PacifiCorp witness Mr. Teply, there are three reasons that Naughton Unit 1 needed to install the flue gas desulfurization (FGD) system:

> To continue compliant operation of Naughton Unit 1, PacifiCorp must install wet FGD ("scrubber") systems described herein to control emissions of criteria pollutants as required by NAAQS, the state of Wyoming's § 309 Implementation plan, and the State of Wyoming's permit (MD-5156) dated May 2009. (PAC/500, Teply/31 at 21 – 32 at 2)

The same regulatory explanation is given for the Naughton Unit 2 facility (PAC/500, Teply/41 at 16-19). These three justifications, however, do not comport with facts on the ground at the time.

Q Did Mr. Teply provide testimony explaining why the Company moved to install retrofits prior to regulatory requirements?

A Yes. For three pages of his testimony, Mr. Teply describes the difficulties of retrofitting a large fleet, including a desire to meet pre-planned outage schedules and possible rising compliance costs. (PAC/500, Teply/25-27). Nowhere does Mr. Teply quantify the cost implications of these impacts. More importantly, nowhere does Mr. Teply discuss the potential benefits of deferral, including the realization of finalized rules and new emerging regulations or preserving the option of retiring or repowering non-compliant plants. Indeed, the Company's recent decision to withdraw an application for a Certificate of Public Convenience and Necessity (CPCN) for a series of environmental retrofits at the Naughton 3 facility is a clear example of the advantage of preserving options while rigorously examining alternatives.[3] However, neither state public utilities commissions nor interveners were given the opportunity to review the rigor of the Company's decisions at issue in this case.

Q Why is it problematic that the Company moved forward on these retrofits prior to reasonable regulatory certainty?

A Ratepayers are best served when the Company makes rational, forward-looking decisions that respond to real requirements. Unilaterally proceeding to install expensive retrofits at aging facilities serves neither ratepayers nor the environment if a lesser cost solution could otherwise be found by retiring a unit. In many cases, deferring <u>investment</u> decisions until a real requirement is apparent is in the best interest of ratepayers and allows for the greatest range of flexibility. It is incumbent on the Company to be appropriately forward-looking, but not to jump prematurely either because an investment opportunity is presented or because of an ill-conceived notion of cost effectiveness.

Q Were EPA and state rules applicable to the Naughton units at the time that the Company initiated the environmental retrofits?

A No, the regulatory requirements cited by the Company actually post-dated the decision to install the Naughton Environmental Retrofits. As I explain in more detail below, at the time that the Company <u>sought</u> the attainment of the air and construction permits for the FGD facility at Naughton: there were no NAAQS requirements targeting the plant; the Wyoming regional haze plan (§ 309) had not yet been issued by the State of Wyoming, much less approved by the EPA; and

[3] It should be noted that the CPCN process for the Naughton 3facility arose from a settlement with interveners in a 2011 Wyoming general rate case (docket 20000-384-ER-10) in which the Company was challenged on the prudence of environmental projects. The settlement requires that the Company file a CPCN application for environmental projects in Wyoming over $25 million. Settlement available at: http://wyofile.com/wp-content/uploads/2011/06/RMP-Rate-Case-Stipulation.pdf (Accessed June 18, 2012). It should also be noted that the rigor of alternatives examined in the CPCN appears to have largely been an outcome of intervener examination.

finally, the MD-5156 permit appears to have been issued at the request of the Company rather than imposed as a regulatory requirement.

Q Did Mr. Teply testify that NAAQS would have required the implementation of an FGD at Naughton?

A Yes. However, Mr. Teply did not explain the basis for this opinion in his testimony. The plant does not seem to fall under state regulations for non-haze based sulfur dioxide emissions, and his opinion clearly contradicts internal Company documents.

[redacted] The same is stated for Unit 2. These statements are repeated verbatim in the 2009 SAP (July, 2009) for both units. (see Exhibit Sierra Club 102 and Exhibit Sierra Club 103)

SO_2 NAAQS were issued in 1996 (61 FR 25566) and 2010 (75 FR 35520). No county in Wyoming was found to be in nonattainment subsequent to either standard revision.[4] The State of Wyoming has regulations for PM_{10} nonattainment in Sweetwater County, effective as of 1999, providing emissions limits for several chemical facilities, but not the Naughton power plant.[5]

Therefore, in my opinion, the NAAQS requirements did not drive the decision to retrofit the Naughton plant despite Mr. Teply's testimony.

Q How does Wyoming's § 309 Regional Haze State Implementation Plan (SIP) impact the Naughton plant?

A The §309 SIP has two major provisions that impact the Naughton plant. The first is the SO_2 Backstop Trading Program, initiated in 2003; the second is the state's BART findings from 2008, finalized in 2011. Wyoming has divided their regional

[4] See US EPA "Nonattainment Status for Each County by Year for Wyoming" (http://www.epa.gov/oaqps001/greenbk/anay_wy.html). As of March 30, 2012.
[5] Wyoming Air Quality Standards and Regulations. Chapter 8, Section 2. See http://deq.state.wy.us/aqd/stnd/chap8.pdf

haze compliance program into two nearly independent programs: SO_2 compliance via the Backstop Trading Program, and NO_x / PM compliance via BART analyses. In this case, the applicable program that could have eventually required an FGD at Naughton is the Backstop Trading Program.

The Backstop Trading Program is a voluntary SO_2 emissions reduction program, enforced by a regionally enacted penalty in the form of a trading program, hence the "backstop." Formal, government mediated trading is only initiated if declining regional milestones are exceeded; once those milestones are exceeded, a trading program is triggered and it becomes active within six years.[6]

At the start of the program in 2003, the region was already 26% under the first milestone.[7] By 2008, the region was still 30% below the adjusted milestone.[8] By 2010, the region had nearly obtained the final 2018 milestone (see **Figure 1**, below, also attached as Exhibit Sierra Club 104).

[6] Wyoming DEQ AQD Standards and Regulations. Chapter 14, Section 2 (k)(i)(A)(I)"For each source that is a WEB [Western Backstop trading] source on or before the program trigger date, the first control period is the calendar year that is six (6) years following the calendar year for which sulfur dioxide emissions exceeded the milestone…"

[7] See 2003 Regional SO_2 Emissions and Milestone Report. http://deq.state.wy.us/aqd/downloads/RegionalHaze/2003_Final_WRAP_SO2_Milestone_Report.pdf

[8] Adjusted because the State of Oregon had withdrawn from the program. See 2008 Regional SO_2 Emissions and Milestone Report. http://deq.state.wy.us/aqd/downloads/RegionalHaze/Final%20WRAP%20Milestone%20Report%202008.pdf

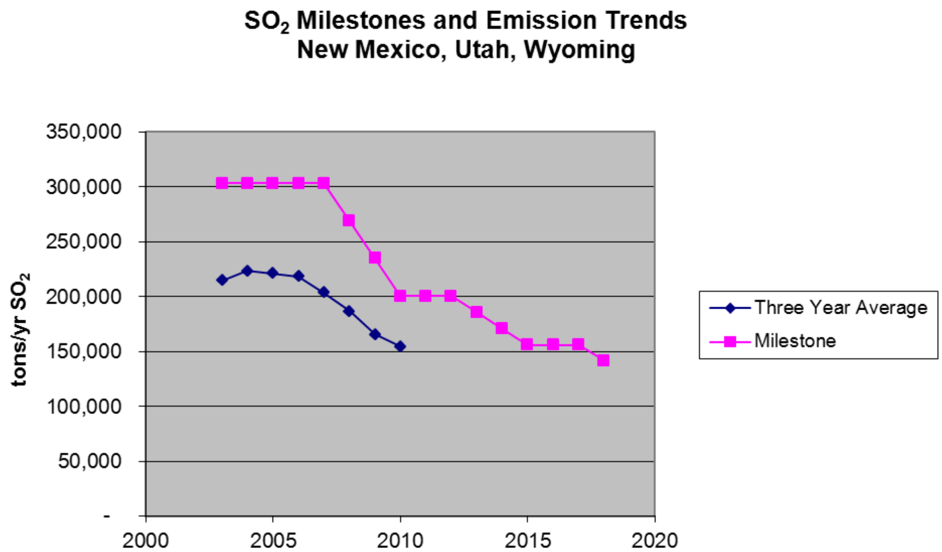

Figure 1. Regional milestones and emissions from SO_2 backstop trading program. 2010 Regional SO_2 Emissions and Milestone Report. March 22, 2012. Appendix C, pB-4.

In contrast, the Naughton FGD were not in operation until November 2011 (Unit 2) and expected May 2012 (Unit 1) (Teply Exhibit PAC/502), well after their ability to contribute substantively to the backstop program.

Q What sort of justification would you have expected from the Company if the purpose of the Naughton Environmental Retrofits was to meet the Regional SO_2 Backstop Trading Program requirements?

A Even though the pre-trigger trading program is characterized as "voluntary," clearly there could be a real economic incentive to participate in order to avoid a potentially harmful formal trading program. However, such a tradeoff, and a decision to act unilaterally, would entail a fairly intricate analysis predicting potential compliance from other sources, the likelihood of exceeding the milestones target, and likely trading prices should the milestones be exceeded. It does not appear that the Company engaged in any such analyses.[9]

[9] In Sierra Club data request 1.5, Sierra Club requested "any analyses, performed by or for PacifiCorp or any of its utility affiliates….during the past seven years that address the need for any of the Environmental Retrofit Units, the need for and cost of necessary or potentially necessary capital additions to any of the Environmental retrofit units, or the environmental effects of and risk from continued operation of any of the Environmental Retrofit Units." The Company objected, and provided only public air permits, applications

Q Is it possible that Mr. Teply meant that the Naughton Environmental Retrofits were required under the BART provisions of the Wyoming § 309 Regional Haze Plan?

A It is possible, but the Company would have been acting irrationally and very prematurely had this been the case. A timeline of events strongly indicates that the Company decided to start building an FGD before any state regulations subsequently justified this course of action. Mr. Teply implies that the Company's hand was forced by regulations, but the series of public actions leading up to the Naughton Environmental Retrofits does not support this assertion:

- **January 2007:** PacifiCorp files an application with the Wyoming DEQ Air Quality Division for a permit to construct flue gas conditioning (FGC), FGD, and low-NOx burners (LNB) at Naughton 1 & 2. (WYDEQ Permit MD-5156, see Exhibit Sierra Club 105)
- **December 2007:** PacifiCorp files first BART analysis for the Naughton units, suggesting FGD as a reasonable compliance mechanism. (see Exhibit Sierra Club 106 and Exhibit Sierra Club 107)[10]
- **March 2008:** PacifiCorp files BART analysis addendum examining SCR costs. Memo references FGD and LNB as "committed controls". (Addendum to Naughton Unit 1 BART Report, see Exhibit Sierra Club 108)[11]
- **April 22, 2009:** PacifiCorp issues internal APRs for Naughton 1 & 2 FGD systems (APRs 10003745 and 10003746, see Exhibit Sierra Club 109) and Exhibit Sierra Club 110)

to the WY DEQ, and the Wyoming Regional Haze SIP, as well as internal APRs with only basic financial analyses.

[10] Available online at:
http://deq.state.wy.us/aqd/308%20SIP/BART%20Applications%20and%20AQD%20Analyses/BART%20Applications/Revised%20Reports_Dec07/BART_Naughton1_Dec2007_Final.pdf

[11] Available online at:
http://deq.state.wy.us/aqd/308%20SIP/BART%20Applications%20and%20AQD%20Analyses/BART%20Applications/TechMemos_Mar08/BART_TMs_NaughtonUnit1_final.pdf

- **May 20, 2009:** WYDEQ Permit MD-5156 is granted. (Exhibit Sierra Club 105)
- **May 28, 2009:** WYDEQ completes BART analysis for Naughton with the statement "PacifiCorp recently received an Air Quality permit to modify the three Naughton units… New wet flue gas desulfurization systems will be installed on Naughton 1 & 2." (BART Application Analysis, AP-6042, see Exhibit Sierra Club 111)[12]
- **May 2009:** Company Notice to Proceed (NTP) on Naughton 1 & 2 (Teply Exhibit PAC/502) and contract signed (Sierra DR 1.23)
- **June 2010:** Construction begins on both units. (Sierra DR 1.23)
- **January 2011:** Wyoming submits final BART SIP to the EPA (Wyoming State Implementation Plan: Regional Haze (309(g))[13]
- **May 2012:** EPA proposes to partially approve and partially disapprove the Wyoming 309(g) SIP (77 Fed Reg 33022)
- **May 2012:** EPA clarifies that the SO_2 backstop trading program will not take effect until EPA finalizes the three participating states' Section 309 SIPs. (77 Fed Reg 30955-6)[14]

This timeline of events indicates that the Company settled on a course of action long before the regulations were issued and, in fact, initiated the permitting process for MD-5156 long before there was a regulatory requirement to do so. Indeed, Wyoming regulations require that:

[12] Available online at: http://deq.state.wy.us/aqd/308%20SIP/BART%20Applications%20and%20AQD%20Analyses/AQD%20Analyses/6042ana_BART.pdf

[13] Available online at: http://deq.state.wy.us/aqd/308%20SIP/309(g)%20SIP%201-7-11%20Clean%20Final.pdf

[14] "The 309 backstop trading program will not be effective until EPA has finalized action on all section 309 SIPs as the program is dependent on the participation of three states.… If EPA takes action approving the necessary components of the 309 backstop trading program to operate in all of the jurisdictions electing to submit 309 SIPs, the trading program will become effective."

> Each existing stationary facility located in Wyoming to which the cause of or contribution to visibility impairment in any Class I area is reasonably attributable, shall install and operate BART as expeditiously as practicable but <u>in no case later than 5 years after issuance of a compliance order by the Division</u>. (WY DEQ WAQSR Ch. 9, Sec. 2(d)(i)(B)(ii), emphasis added)

If the final compliance order was the submitted BART SIP in January 2011, Wyoming regulations would require BART to be installed by 2016, not 2012.

Q Is there other documentation showing that the Company was aware of this irrational timing?

A Yes. There is ample documentation to that effect. In Wyoming, as part of the Regional Haze documentation, the Company filed "PacifiCorp's Emissions Reduction Plan" in late 2010, listing the retrofits that the Company intended to complete through 2023 (attached as Exhibit Sierra Club 112). The plan clearly states:

> PacifiCorp began implementing its emission reduction commitments in 2005. This was well ahead of the emission reduction timelines under the regional haze rules which require BART to be installed no later than five years following approval of the applicable Regional Haze SIP…. The table above demonstrates that most of the projects to be built between 2010 and 2014, likewise, will be installed in advance of the required completion date under BART requirements.

This irrational timing is also shown in the Company's APRs and SAPs. In the Naughton Unit 1 FGD APR #10003745 (Exhibit Sierra Club 109), the Company states:

> [redacted]

[redacted] (emphasis added)

In the 2009 SAP for the Naughton plant (Exhibit Sierra Club 103), the Company further re-iterates the extended compliance deadline:

[redacted]

(emphasis added)

I conclude that Wyoming's § 309 implementation plan was not a reasonable driver to compel the Company to initiate the Naughton FGD permit in 2007 or begin construction in 2010.

Q Do you agree with Mr. Teply's statement that the MD-5156 permit compelled the Company to install FGDs at the Naughton facility by 2011/2012?

A No. This argument, if nothing else, is circular. The Company applied for the permit well before Wyoming's BART findings, and long before the EPA approved the state plan. Permit MD-5156 (Exhibit Sierra Club 105) clearly states that the "Air Quality Division received a permit application from PacifiCorp, on January 25, 2007." (Permit MD-5156, Decision: (I) Introduction) and the permit was issued in response to that application. In addition, the "Decision" section of the permit explicitly states that "installation of the pollution control equipment is expected to be completed by April 14 2014." Even if the Company had inadvertently requested the permit and even if it had no recourse to back out of the permit once issued, it had ample time to make a rational decision after the permit was issued. Instead, the time shows that the Company initiated the project within days of the issuance of the permit.

Finally, the Company's explanation that it was pursuing BART compliance with the FGD is refuted in EPA comments on the MD-5156 permit. EPA's comment letter to WYDEQ states explicitly that "the final control [requested in the permit of] (FGC+FGD) should not be considered as a BART option at currently proposed SO_3 injection rates." (US EPA letter to WY DEQ, Aug 2010, p6; see Exhibit Sierra Club 113)

5. AN EXPENSIVE AND PREMATURE CAMPAIGN OF HALF-MEASURES

Q Do you have an opinion on why the Company decided to proceed with construction of the Naughton Environmental Retrofits?

A Yes. Internal Company documentation shows that PacifiCorp implemented a large number of environmental projects across their coal fleet in the 2008-2010 timeframe with the intent [redacted] According to Mr. Teply, the Company initiated the "Comprehensive Air Initiative" in 1999 (PAC/500, Teply/5 at 15-19); however, contrary to Mr. Teply's testimony, it does not appear that the CAI was a response to Regional Haze Rules, or indeed any other specific set of rules. Instead, the CAI appears to be the Company's effort to unilaterally cement emissions controls in place with the idea that regulations would follow suit.

In 2003, the Company shared a confidential document with EPA Region 8, the Utah DEQ, and the Wyoming DEQ laying out the framework of the CAI. According to the summary:

[redacted]

> [redacted] (CAI Control Report: Comprehensive Air Initiative Analysis, Feb 2003, Exhibit Sierra Club 114)

The report contains a condition as well:

> [redacted]

By 2005, the CAI evolved into a series of specific [redacted], designed to [redacted] Indeed, in another internal document, the Company states clearly its intent to begin construction without a regulatory basis:

> [redacted]

> [redacted] (Air Quality Reference Case Investments, April 2005, Exhibit Sierra Club 115(Emphasis added))

In my opinion, it is clear that the Company decided to move forward on a number of capital investments without regard to particular regulatory requirements, which is why the Company's application for an air permit at Naughton plant preceded the Regional Haze process in Wyoming.

Q Do you object to the Company cleaning up its coal fleet?

A No. However, the Company did not even begin to contemplate the retirement of any of its units as a mechanism of providing cleaner air or water, or a method to mitigate carbon emissions. By ignoring this legitimate alternative, the Company committed itself, and subsequently its ratepayers, to decades of running aging and degrading units.

It is difficult to believe that by 2007 when the Company requested the FGD permit from the State of Wyoming that PacifiCorp was not cognizant of the mounting costs that could be faced by its coal fleet. I find it even more unlikely that by the time the Company issued the Notice to Proceed (NTP) for Naughton Units 1 & 2, in May 2009, that the Company was not aware that new EPA rules could dramatically change the economic viability of their marginal coal units. By the time the Company began construction, in June 2010, the Company should have been well aware that proceeding with this unilateral action could result in an economic loss.

Q Should the Company have been aware of these mounting regulations in May 2009?

A Yes. The Company issued an internal Strategic Asset Plan (SAP) for the Naughton plant in July of 2009, shortly after the Notice to Proceed date, but well before the start of construction. This 2009 SAP has nearly identical environmental description language to a 2009 SAP issued for the Hunter plant, dated <u>April</u> 2009. In the 2009 Hunter and Naughton SAPs (see Exhibit Sierra Club 103), the Company discusses a number of impending regulations, including:

Q [redacted] **Would additional environmental regulations impact the economic viability of the Naughton facility in the face of a large capital investment, such as the Naughton Environmental Retrofits?**

A Yes. In my opinion, had the risks and costs associated with EPA requirements been appropriately incorporated into the Naughton analysis at the time the Company decided to move forward with the retrofit, the project would not have been found to be a reasonable and economical choice. Several other factors should have been considered at the time, factors that would also have cautioned against the project.

6. THE NAUGHTON ENVIRONMENTAL RETROFIT CAPITAL COSTS WERE NOT JUSTIFIED BY THE COMPANY'S ANALYSIS AND SHOULD NOT HAVE BEEN CONSTRUCTED

Q Is the Company's request to recover capital expenditures for the Naughton Environmental Retrofits reasonable?

A No, the Company's request is not reasonable because it based the decision to install the Naughton Environmental Retrofits on a flawed and incorrect modeling analysis. The Company has requested approximately $275 million in revenue requirements to support the construction of the FGD retrofits at Naughton Units 1 & 2; in addition, the Company has requested nearly $25 million of capital to support other environmental upgrades considered and implemented after the FGDs, for a total of nearly $300 million in Naughton Environmental Retrofit capital costs. Based on my analysis, this entire slate of projects could have been avoided at a net savings to the Company had the Company properly and correctly evaluated the costs of moving forward on this project prior to the start of construction.

The Company estimated that the net benefits (what the Company refers to as the PVRR(d)) of the Naughton 1 & 2 FGD retrofits were approximately [redacted] and [redacted], respectively.

If PacifiCorp had examined the correct set of forward-going costs that were known and available at the time it conducted its PVRR(d) analysis in February of 2009, and if PacifiCorp had examined the unit with a more reasonable retirement date of 2015, instead of 2009, then the analysis would have shown that the project would result in a net liability of at least [redacted] and [redacted], respectively.

Failing this initial correction in February 2009, the Company had another opportunity to realize the problem in May 2009. If PacifiCorp had re-examined the PVRR(d) analysis of the expenditures prior to signing the contract in May of 2009, the updated results would have shown a significant net liability for the FGD retrofit at each of the Naughton units of about [redacted] and [redacted], respectively. In addition, if the Company had assessed the financial implications of the de-rate associated with the FGD and the degradation of the unit over time (according to its own assessments), the Company would have seen a liability of [redacted] and [redacted], respectively.

The Company had yet another opportunity to revisit its analysis of the Naughton expenses just prior to the start of construction in June 2010. Updating the analysis at that would have still revealed a net liability of at least [redacted] and [redacted], respectively.

Based on the information available to the Company at the time, PacifiCorp should have recognized these significant liabilities and, at a minimum, should have conducted at least a secondary review, which would certainly have raised red flags. However, the Company failed to update any information from its original analysis in February 2009, which the Company states was the final economic analysis that it conducted prior to proceeding with the Naughton 1 & 2 FGD projects (Response to Sierra Club DR 2.1).

In my opinion based on my analysis of information available to the Company at the relevant decision points, these Naughton Environmental Retrofits were not justified. At a minimum, the Company's analysis should have resulted in a delay of implementation, and better yet, the Company should have realized that the Naughton units should be considered for retirement or repowering.

7. PRESENT VALUE REVENUE REQUIREMENT DIFFERENTIAL (PVRR(D)) ANALYSES FOR NAUGHTON ENVIRONMENTAL RETROFIT PROJECTS ARE FLAWED

Q Did the Company review the cost effectiveness of pursuing the Naughton Environmental Retrofits prior to deciding to move forward with the investments?

A Yes, but this analysis was deeply flawed in timing, scope, and execution. The Company's "present value revenue requirement differential" analysis, (the PVRR(d) analysis, see PAC/500, Teply/21 at 14-19 and Attachment to OPUC 220-4) indicated that the Naughton environmental retrofit projects would result in a net benefit to ratepayers of approximately [redacted] million and [redacted] million for units 1 and 2, respectively – a narrow margin of benefit at most. Ultimately, however, the outcome of this analysis, had it been correctly executed, would have very clearly indicated to the Company that proceeding with retrofit projects at both Naughton Units 1 and 2 units would be a very poor choice for ratepayers.

Q Please describe the Company's PVRR(d) analysis.

A The analysis is a fairly simple spreadsheet cash flow model. The spreadsheet essentially evaluates the forward-going cost of operating the coal plant to the end of its depreciable life compared to the cost of obtaining the same amount of energy at market prices and returns the net present value (NPV) of this comparison. For capital expenses, the spreadsheet calculates depreciation and taxes, and returns a stream of annual revenue requirements. Operating and maintenance (O&M) expenses are input on an annual basis, as are coal prices, emissions prices, the annual average price of a "flat" (i.e. all hours) market energy product, and generation. The model uses a market energy price as a comparison against the cost of generation.

Starting in the year of the analysis (2009, in this case), the spreadsheet estimates the total cost of generation and O&M, deducts the market cost of energy, adds in amortized and depreciated capital expenses, and calculates an NPV of revenue requirement (NPVRR); the Company refers to this as the "present value of revenue requirement differential", or PVRR(d) because it is a difference relative to a market price.

Presumably, as long as the PVRR(d) is positive (i.e. the coal plant performs better than the market), the Company concludes that a project is beneficial. I would assume that should the PVRR(d) value become negative, the Company would conclude that a project would not be beneficial.

Q Does the Company's PVRR(d) analysis for the Naughton Environmental Retrofits give any indication that the projects might be a high risk proposition?

A Yes, there are several warning signs embedded in the analysis itself, even before revisions and corrections.

First, the analysis has a simple toggle that is designed to test what might happen if market prices end up being 20% above or below forecast prices. At those extremes, the PVRR(d) value (or benefit of maintaining the coal plant) quickly flips from [redacted] and [redacted] million for Naughton 1 & 2 with high prices, to [redacted] and [redacted] million with low prices. This sort of sensitivity should have quickly alerted modelers that the benefit of proceeding with the Naughton Environmental Retrofits was marginal, at best, and could quickly turn problematic if market prices fell.

Second, the analysis contains a hidden chart entitled "Accumulated NPV". This chart shows how long it takes for the unit to recover its investment. I have reproduced these charts from the basic runs performed by the Company in Exhibit Sierra Club 116). The chart for Naughton 1 indicates that, out of 21 years of remaining life, the unit requires [redacted] years to recoup its investment. The chart for Naughton 2 indicates that the unit requires [redacted] years to recoup its investment. Again, this type of risk would have been evident to Company analysts, but apparently was not part of the decision-making process.

Q What do you mean that the analysis was "flawed in <u>timing</u>"?

A The timing of the PVRR(d) analysis was flawed because the Company failed to revisit its conclusions after significant changes in the market had occurred. The analysis supporting the Naughton Environmental Retrofits was executed months before the Notice to Proceed date, and nearly a year and a half before the project broke ground. Circumstances, and particularly natural gas price outlooks, had changed markedly during that time. As the long-term outlook for natural gas fell, the Company's long-term electricity market price fell as well, substantially weakening the justification for the Naughton retrofits. As my colleague Dr. Steinhurst explains in his testimony, it is incumbent on the Company to review its decisions diligently, and in the face of new information or findings, re-assess its conclusions and act accordingly. In this case, even having pursued a flawed analysis in scope and execution, simply repeating the analysis prior to proceeding and prior to construction would have revealed a very different set of outcomes.

To explain further, a brief timeline can be illustrative. Working chronologically:

- **January 2007:** PacifiCorp files an application to modify the Naughton air permits, proposing to install flue gas conditioning (FGC), flue gas desulfurization (FGD), and low-nox burners at Naughton 1 & 2. (WDEQ permit MD-5156, Exhibit Sierra Club 105)
- **April 2008:** 2008 Strategic Asset Plan issued internally for Naughton plant characterizing strengths and weaknesses of the plant, as well as

major environmental, fuel, and operational issues facing the plant. (Exhibit Sierra Club 102)

- **February 2009 – ANALYSIS DATE:** PacifiCorp conducts PVRR(d) analysis showing marginal net benefit of FGD retrofits at Naughton 1 & 2. (PVRR(d) analysis in Attachment to OPUC 220-4; timing of PVRR(d) analysis stated in response to Sierra Club DR 1.25c).
- **April 2009:** Company files two APRs ("acquisition approvals") to MidAmerican Energy Holdings Company (MEHC) requesting funds to construct FGDs for [redacted] and [redacted], respectively at Naughton 1 & 2. (APRs 10003745 and 10003746, see Exhibit Sierra Club 109) and Exhibit Sierra Club 110)
- **May 2009 – CONTRACT DATE:** Notice to Proceed (Teply Exhibit PAC/502) and contract signed. (Response to Sierra Club DR 1.23)
- **July 2009:** 2009 Strategic Asset Plan issued internally for Naughton plant characterizing strengths and weaknesses of the plant, as well as major environmental, fuel, and operational issues facing the plant. Exhibit Sierra Club 103)
- **June 2010 – CONSTRUCTION DATE:** Construction begins. (Response to Sierra Club DR 1.23)

According to this timeline, the Company had at least three distinct decision opportunities: (1) the analysis date in February of 2009; (2) the contract date in May of 2009; and (3) the construction date in June 2010. At each of these key dates, and even beyond, the Company had the opportunity to re-assess its decision to install the environmental retrofits at the Naughton facility. Such assessments could and should have included evaluations of changing capital requirements, shifting natural gas and market prices, and up-to-date forecasts of emissions prices and environmental outlooks.

The Company's February 2009 Naughton PVRR(d) analysis utilized a December 2008 forecast of electricity market prices. By the time of the contract signing (in May of 2009), the Company's market price forecasts had changed dramatically. The forward market prices from June 2009 are about [redacted] lower over the long term than when the Naughton analysis was conducted (Response to Sierra Club DR 1.33, 2nd Supplement).

Simply substituting the June 2009 electricity prices into the Naughton analysis quickly renders the PVRR(d) value negative for both Naughton 1 & 2 ([redacted]and [redacted], respectively see Table 6 and Table 7, later in this testimony), a drop that should have caused any rational decision-maker to quickly re-assess the retrofit decision.

Q What do you mean that the analysis was "flawed in <u>scope</u>"?

A The scope of the PVRR(d) analysis was flawed because the Company failed to examine a sufficiently broad range of alternatives. PacifiCorp restricted its analysis to comparing the benefit of the coal plant upgrade against flat market prices. This narrow scope of analysis ignored potential gas replacement capacity, purchases of existing excess capacity, any form of renewable energy or demand-side management, or changes in transmission.

Of particular remark, the same tool that the Company uses to justify new generation acquisitions, the System Optimizer tool used in the 2007 and subsequent IRP, was not used for this financial analysis (Response to Sierra Club DR 2.1 and 2.11). This type of tool, if used correctly, would have analyzed whether lesser cost portfolio replacement opportunities existed among a suite of options, rather than simply relying on a calculation of replacing each and every MWh of generation with a market purchase. (In fact, in 2009 and 2010, the Company generated about 9-10% more than retail sales (EIA Form 861), suggesting that PacifiCorp would not have needed to replace each and every MWh of lost generation.)

Q What do you mean that the analysis was "flawed in <u>execution</u>"?

A Overall, the PVRR(d) analysis was poorly designed and contained several errors or omissions. The February 2009 analysis was the final financial model used by the Company prior to deciding to move ahead with the FGD upgrade (Response to Sierra Club DR 2.1), and yet it is no more than a "tabletop" cash-flow spreadsheet with faulty formulae, incorrect assumptions and timestamps, inconsistent assumptions, and a critical fundamental bias favoring coal plant continuation. By way of comparison, the Company provided interveners in the 2011 Oregon IRP proceeding a screening tool that handled capital expenses, generation assumptions, replacement capacity assumptions, and market costs in a superior construct to the PVRR(d) analyses, yet the IRP screening tool was produced by the Company in under two months.[15]

Flaws in the execution of the PVRR(d) analysis can be clustered into four basic groups:

1. Capital assumptions do not reflect anticipated future investments or known and cited regulatory risks;
2. The output of the coal units does not reflect the parasitic load from environmental retrofits or anticipated degradation in unit availability due to aging boilers;
3. Emissions prices do not reflect a range of carbon dioxide price risk that were considered reasonable at the time;
4. The model erroneously assumes that a market replacement would occur at the start of the analysis period, in 2009, rather than when a regulation would require either action or retirement, in the 2013-2018 timeframe.

Each of these flaws has a distinct financial impact on the outcome of the PVRR(d) analysis, and nearly each one (independently), if reasonably assessed, would have caused the PVRR(d) analysis to show a significant loss. Singly or in combination,

[15] Requested on 12/6/2011, provided on 1/31/2011

consideration of those flaws makes it clear that the Naughton plant should not have been retrofit from a least cost perspective.

Q Did the Company have information that would have allowed it to perform a more accurate analysis at the time it made the decision to proceed with the Naughton Environmental Retrofits?

A Yes. In my opinion and based on discovery in this proceeding, at the time the Company performed the PVRR(d) analysis (in February 2009), it possessed more detailed and accurate information than what was used in the model. The Company also should have incorporated critical updated information just prior to the contract date in May 2009, and again at the construction date in June 2010.

To demonstrate the impact of this improved information and the Company's failure to correctly assess important conditions at the time, I will walk through both capital and market price assumptions for:

- information used in the PVRR(d) analysis,
- additional information known at the time of the February 2009 analysis date but which was not used in the PVRR(d) analysis,
- substantively changed information as of the contract date that should have informed a new PVRR(d) analysis and caused the Company to refrain from entering into the contract, and
- substantively changed information as of the construction date that should have triggered review or cancelation of the work.

a. ADDITIONAL INFORMATION KNOWN ON THE ANALYSIS DATE (FEB. 2009)

Q What does the Naughton PVRR(d) analysis assume for forward-going capital expenses?

A The PVRR(d) analysis for the Naughton 1 & 2 units draws on environmental capital expenditures (termed here "CAI expenditures") and non-environmental capital expenditures, which presumably includes periodic work on the turbine, boilers, and other generation components. Both categories are supplemented with AFUDC costs.

Within the CAI expenditures category, there are costs incurred from 2009 through 2012, stated in 2009$. These costs are broken down in OPUC DR 138, 1st Supplement (in nominal dollars), and share identical descriptors between Naughton 1 & 2, as follows in Table 1below.

Table 1. Capital expenditures in the Naughton PVRR(d) analysis in millions of nominal dollars and 2009$

(in millions)	**Naughton 1**		**Naughton 2**	
CAI Project	**Nominal $**	**2009$**	**Nominal $**	**2009$**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]

Q Are there additional capital expenditures that the Company did not consider in the PVRR(d) analysis on the analysis date?

A Yes there are. First, the analysis should have used the proposed APR cost estimates for the FGD.[16] Even though these APRs were issued two months later, the Company would have had a reasonable idea of the final cost stream of the FGD that would be required. This resulted in a cost reduction at Naughton 1 and small increase at Naughton 2.

Second, the same APRs explain that the Naughton units will be faced with additional FGD waste pond construction and closure costs once the FGD is put in place; these costs are laid out explicitly and should have been part of the PVRR(d) analysis.[17]

Third, the same APRs reference new chimney construction for the FGD, a cost that should have been considered avoidable along with the remainder of the FGD.

[16] In Naughton 1 APR #10003745 [redacted] and Naughton 2APR #10003746 [redacted]
[17] In Naughton 1 APR #10003745 Table 1-2 [redacted] and Naughton 2 APR #10003746 Table 1-2 [redacted]

The cost of this chimney is [redacted] nominal, split 50/50 between Naughton 1 & Naughton 2.[18]

Fourth, in 2008, prior to the analysis, there was still considerable uncertainty as to whether the EPA would require Selective Catalytic Reduction (SCR) at the unit for Regional Haze compliance, and so there was a reasonable risk that the Company could incur the cost of an SCR in the next seven years (i.e. ~2015).[19] Interestingly, the 2008 SAP for the Naughton plant clearly lays out that the Company expected and intended to place an [redacted] in service in the [redacted] to [redacted] range, no specific reason given. Further, the Company explores the risk of [redacted] compliance obligation in the 2008 SAP:

> [redacted] (2008 Naughton SAP, pages 28-29, Exhibit Sierra Club 102) (emphasis added)

Based on this information, it is evident that the Company had reasonable expectations that an [redacted] could be required at some point in the future, and possibly in the near future; regardless, the costs of an [redacted] ([redacted] and [redacted]

[18] APR #10003745 references to APR #10010143 with chimney costs, not supplied in discovery. The date of this expense was not specified, and I have therefore assumed this cost would be incurred in 2012.

[19] An SCR could have reasonably been required up to five years after EPA's SIP approval, expected within two years at the time.

[redacted], respectively for Naughton 1 and 2, presumed nominal) were not included in the Company's PVRR(d) analysis in any timeframe.

Q Did the Company's PVRR(d) analysis accurately assess the expected output of the Naughton units?

A No, the PVRR(d) analysis did not consider the parasitic load from environmental retrofits or the anticipated degradation in unit availability. First, the expected output from the Naughton units does not show the effect of a de-rate associated with the FGD and other plant changes. According to the Company's response to Sierra Club DR 1.22, Naughton 1 will reduce its net dependable capacity by 4 MW, while Naughton 2 will reduce capacity by 9 MW. I estimated the effect of reduced output on total annual generation in the PVRR(d) analysis: such a de-rate would reduce the PVRR(d) benefit of Naughton 1 and 2 by about one-half and one-third, respectively.

Second, both the 2008 and 2009 SAPs include "Unit Age and Condition Charts" which show that, based on historical experience, the utility could expect to see increasing losses each year. The Company also assumes that, although the trend is towards increasing losses, "[redacted]" (See Exhibits Sierra Club 102 and Sierra Club 103) It remains uncertain whether the plant is likely to experience increased losses along this trajectory over time; however, the Company clearly recognized this risk in 2008 and 2009 and should have examined implications of this risk in reviewing the economics of the plant. I extracted information from these charts and estimated the annual new losses. Overall, these losses reduce output from the plant by about [redacted] by the end of the plant's depreciable life in 2029.

Q Would this additional capital and outage information have changed the outcome of the PVRR(d) analysis?

A Yes. The Company found in their basic analysis that the net benefit of the Naughton Unit 1 retrofit at the time of the February 2009 PVRR(d) analysis date was [redacted]. The table below shows that the benefit decreases to [redacted]

[redacted] with the addition of SCR and ACI costs as well as the baseline FGD and LNB costs. Including the FGD unit de-rate reduces the benefit still further to just [redacted], and if we include plant degradation, the benefit flips to a liability of [redacted].

Table 2. Present value revenue requirement difference (PVRR(d)) of the Naughton 1 retrofit relative to market replacement, in thousands of 2009$ (original retirement date). The * indicates the Company's estimated net benefit.

	Original Generation	FGD De-rate	De-rate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR & ACI	[redacted]	[redacted]	[redacted]

Similarly, the Company assigned the Naughton Unit 2 retrofit a positive benefit of [redacted] However, after similar considerations, the benefit of the retrofit shrinks to just [redacted] with known capital expenses and the expected FGD de-rate. Including plant degradation drives this value to a liability of [redacted].

Table 3. Present value revenue requirement difference (PVRR(d)) of the Naughton 2 retrofit relative to market replacement, in thousands of 2009$ (original retirement date). The * indicates the Company's estimated net benefit.

	Original Generation	FGD De-rate	De-rate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR & ACI	[redacted]	[redacted]	[redacted]

Q Where there other errors made in the original PVRR(d) analysis of the Naughton Environmental Retrofits?

A Yes. There is a subtle but very significant error in the embedded assumed retirement date of the Naughton units for market replacement. The analysis tests the net benefit of a retrofit relative to market prices as of the year 2009. Fundamentally, this means that the analysis measures the net benefit as if the unit would otherwise be retired <u>in the year 2009.</u> There are no likely circumstances in which the Naughton units should have been actively considered for retirement in 2009, regardless of the status of the retrofits. Indeed, the FGDs at Naughton were only in service at the end of 2011 and mid-2012, meaning that there was clearly no restriction on operating the plant, uncontrolled, through at least 2012.

The permit authorizing the FGD (MD-5156, Exhibit Sierra Club 105) explicitly expects the retrofits to be installed around 2014, and the Regional Haze regulations issued by the State of Wyoming do not actually set a deadline for installing FGD at any given facility.[20] The current deadlines for MATS (not contemplated as a specific deadline in 2009) ultimately require implementation of SO_2 controls by December 2015. Therefore, I based my analysis on the assumption that the plant could have continued running, uncontrolled, through the year 2015.

Q How did you correct the retirement year error?

To correctly analyze a 2015 retirement in the Company's PVRR(d) analysis, I created two scenarios that can be compared against each other:

- **Run to 2029:** The units incur CAI costs, but run until 2029. The units receive no market benefit.
- **Retire in 2015:** The units do not incur CAI costs, and incur no new capital, fuel, or O&M costs past the year 2015. From 2016 to 2029, the scenario incurs the cost of market power equal to the foregone generation of the unit. [21]

Overall the outcome of these two scenarios is a simple NPVRR. The difference between the cost of running to 2029 and the cost of retiring in 2015 becomes the PVRR(d).

[20] Under the Wyoming Regional Haze regulations on SO_2 (the 309 SIP), Wyoming created the voluntary SO_2 Regional Backstop Trading Program, therefore not explicitly requiring FGD at any given unit. The Wyoming Regional Haze regulations (the 309(g) SIP) on PM and NOx do not stipulate a requirement for an FGD either.

[21] At this point, it is worth reiterating that the overly simple spreadsheet model used by the Company in its 2009 Naughton analysis would have inflated the costs of the replacement power costs during 2016 through 2029 and that the adjusted result shown here does not remedy that flaw and therefore is conservative in favor of the retrofit.

Q Does the shift in the retirement date change the outcome of the PVRR(d) analysis?

A Yes, it does. Because the plant does not incur a special benefit simply for operating from 2009 to 2015 (a foregone conclusion), the actual net result is, <u>in all cases</u>, a liability. The tables below are similar in nature to Table 2 and Table 3, above, but they examine the net benefit (or in the case of a negative, net liability) of the retrofits <u>based on information that was readily available in early 2009.</u>

Table 4. Present value revenue requirement difference (PVRR(d)) of the Naughton 1 retrofit relative to market replacement, in thousands of 2009$ (2015 retirement date). The ** marks the most conservative value that the Company should have estimated as of the February 2009 analysis date.

	Original Generation	FGD De-rate	Derate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR & ACI	[redacted]	[redacted]	[redacted]

Table 5. Present value revenue requirement difference (PVRR(d)) of the Naughton 2 retrofit relative to market replacement, in thousands of 2009$ (2015 retirement date). The The ** marks the most conservative value that the Company should have estimated as of the February 2009 analysis date.

	Original Generation	FGD De-rate	Derate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR & ACI	[redacted]	[redacted]	[redacted]

In the best case, the retrofits posed liabilities of [redacted] and [redacted], respectively for Naughton 1 & 2. In the worst case, these units would incur present value costs of [redacted] and [redacted], respectively.

b. <u>ADDITIONAL INFORMATION KNOWN ON THE CONTRACT DATE (MAY 2009)</u>

Q What additional information would have been available to the Company around the May 2009 contract date?

A There are several important new pieces of information that would have been available to the Company around the May 2009 contract date, including:

- New estimated costs for the SCR
- Knowledge of impending regulations for mercury, carbon dioxide, effluent and coal ash
- Falling gas price futures and changing market prices for electricity

Q Did the Company have an updated cost estimate for the future SCR as of the contract date?

A Yes, they should have. The contract date is May 2009. According to its own schedule, the Company would have issued the 2009 SAP for the Naughton unit in the first quarter of 2009,[22] which means that the updated SAP would have been available at the time.[23] This 2009 SAP also assumes that an [redacted] will be required by [redacted] at Naughton 1 and in [redacted] at Naughton 2. The estimated costs for these units had been updated by the Company at this point, nearly doubling from the 2008 SAP.[24]

Q Did the Company have knowledge of new impending regulations as of the contract date?

A The 2009 SAP explicitly lays out the risks of new impending regulations for mercury and the series of lawsuits that rendered the pollutant [redacted][25] the potential for [redacted] on in the near term,[26] the likelihood of new [redacted]

[22] 2009 Naughton SAP, p3: [redacted] See Exhibit Sierra Club 103)

[23] The 2009 Naughton SAP does not have a specific date written on it, but the file has an origination timestamp of July 2009. Other 2009 SAPs issued by the Company (Hunter, Huntington, Wyodak, Carbon, Dave Johnston, and Jim Bridger) all have origination timestamps of mid-April to early May 2009, and share similar general content.

[24] [redacted] respectively, assumed in nominal dollars.

[25] 2009 Naughton SAP, p12. The Company, while aware of the new impending regulations, apparently decided to downplay the risk of this regulation internally as well: [redacted]

[26] 2009 Naughton SAP, p13.

[redacted],[27] and the likelihood of regulation controlling [redacted].[28]

Q Should the Company have considered updated gas and electric market price information at the time of the May 2009 contract date?

A Yes, the updated gas and electric market prices would have provided critically important information. The PVRR(d) analysis is structured to review the relative benefit of maintaining a coal unit against the cost of obtaining energy at the equivalent of a wholesale price. The wholesale price of energy is closely tied to natural gas prices, and in the PacifiCorp region, changes in the annual average flat price of electricity are closely tied to changes in natural gas prices as well.

Natural gas prices reached near historic highs in mid-2008 at around $13/MMBtu; in December 2008, prices had returned back to $6/MMBtu, but would continue to generally decline over the next few years. Similarly, the long-term outlook for natural gas prices fell with the spot price, and at the time of the May 2009 contract date, had changed dramatically from the data used by the Company in their PVRR(d) analysis. The long-term outlook for natural gas prices was predicted by the Company to [redacted] (nominal dollars) over the next two decades (see **Figure 2**).

[27] 2009 Naughton SAP, p14-15
[28] 2009 Naughton SAP, p15

[redacted]

Figure 2. Historic and natural gas forecast prices used for the analysis (Dec. 2008 prices for Feb. 2009 analysis) and available near the contract date (June 2009 near May 2009 signing date). (Source: Historic prices from EIA. Forecast prices from Sierra DR 1.33, 2nd Supplemental)

Similarly, the Company's long-term electricity market prices fell during this time, and by the contract date were, on average 14% lower from 2016 through 2029 (see **Figure 3**, below).

[redacted]

Figure 3. Annual average forecast flat energy prices at Mona hub used on the analysis date (Dec 2008) and available near the contract date (June 2009) (Source: Sierra DR 1.33 2nd Supplemental)

Q Would the analysis conclusions have changed if the Company had used updated capital and market prices on the contract date?

A Yes. The change in the net benefit of the retrofits at Naughton 1 and Naughton 2 would have been dramatic. Just changing the market price of electricity in the PVRR(d) analysis, but still using the Company's flawed impression of a 2009 retirement date, the net benefit of the Naughton 1 FGD shifts from [redacted] to a liability of [redacted] (see **Table 6**). Similarly, the net benefit of the Naughton 2 FGD shifts from [redacted] to a liability of [redacted] (see **Table 7**). Including the known costs of the SCR and ACI units, plus accounting for de-rates and unit degradation, the units both become significant liabilities with an upgrade "benefit" of [redacted] and [redacted], respectively.

Table 6. Present value revenue requirement difference (PVRR(d)) of the Naughton 1 retrofit relative to market replacement (at June 2009 market prices), in thousands of 2009$ (<u>2009</u> retirement date)

	Original Generation	FGD De-rate	Derate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR, ACI			

Table 7. Present value revenue requirement difference (PVRR(d)) of the Naughton 1 retrofit relative to market replacement (at June 2009 market prices), in thousands of 2009$ (<u>2009</u> retirement date)

	Original Generation	FGD De-rate	Derate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR, ACI	[redacted]	[redacted]	[redacted]

Finally, if the Company had appropriately evaluated the retrofit considering a unit retirement date of 2015 instead of 2009, the net benefit of building an FGD at Naughton units 1 and 2 would have clearly shown a problem. At best, the units would have appeared to be forward-going liabilities of [redacted] and [redacted], respectively (see **Table 8 and Table 9,** below). At worst, the "benefit" would be closer to liabilities of [redacted] and [redacted] million, respectively.

Table 8. Present value revenue requirement difference (PVRR(d)) of the Naughton 1 retrofit relative to market replacement (at June 2009 market prices), in thousands of 2009$ (2015 retirement date). The ** marks the most conservative value that the Company should have estimated as of the Contract Date.

	Original Generation	FGD De-rate	Derate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR, ACI	[redacted]	[redacted]	[redacted]

Table 9. Present value revenue requirement difference (PVRR(d)) of the Naughton 2 retrofit relative to market replacement (at June 2009 market prices), in thousands of 2009$ (2015 retirement date). The ** marks the most conservative value that the Company should have estimated as of the Contract Date.

	Original Generation	FGD De-rate	Derate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR, ACI	[redacted]	[redacted]	[redacted]

If the Company had assessed the value of moving forward on this project on the contract date, it would have recognized that moving forward with the project would have created a significant liability. Based on the information available to it at the time of contract date, the Company should have halted the project.

c. ADDITIONAL INFORMATION KNOWN AT THE START OF CONSTRUCTION (JUNE, 2010)

Q Was there additional information that would have been available to the Company around the June 2010 construction date?

A Yes. According to the Company's response to Sierra Club DR 1.23, construction did not being on the Naughton 1 & 2 FGD units until June of 2010. Presuming the Company had completely missed the opportunity to re-evaluate the Naughton projects prior to signing contracts in May of 2009, this additional year of time would have allowed ample opportunity to re-evaluate the Company's decision prior to moving forward on the projects. By June 2010, the Company would have had access to both the newly proposed coal combustion residuals rule (released May 4th, 2010), which has the potential to impose high incremental costs at existing coal-fired power plants, as well as new forecasts for gas and market prices and increasing certainty about the impending mercury emissions standards.[29]

Q Would consideration of potential costs and risks related to the proposed coal residuals rule, the mercury regulations, and changed market price forecasts impacted the Company's PVRR(d) analysis?

A Yes, these costs and risks would have had a significant impact on the PVRR(d) analysis. The Company was aware that the EPA was interested in regulating coal combustion residuals; the [redacted] explicitly discusses this risk. While it is unclear whether the Company developed estimates for coal ash waste by June 2010, it certainly could have developed order-of-magnitude proxy costs for testing forward-looking estimates. In my analysis for this testimony, I use proxy costs from the 2011 Screening Analysis provided to Oregon stakeholders in the 2011 IRP coal study review.[30] For purposes of this analysis, I assumed that these costs amounted to about [redacted] (nominal) between the two units, These costs are most likely purely incremental in nature (i.e. required for future operation, but not for retirement) otherwise the Company would not have included them in the Screening Analysis. It should be noted that the costs used in my analysis are <u>significantly</u> less than the order of magnitude costs provided to the Company by Sargent & Lundy in a May 2011 estimate [redacted] for the Naughton station).[31]

For the mercury regulations, my analysis assumed that the Company's incremental costs for an ACI as contemplated in the 2008 SAP were still

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[29] See, for example, EPA News Release dated 4/30/2010: "EPA to Cut Mercury, Other Toxic Emissions from Boilers, Solid Waste Incinerators / Cost-effective proposals would reduce harmful air pollution in communities across the United States." (http://yosemite.epa.gov/opa/admpress.nsf/0/74EF19CE603F20548525771500507938) Accessed June 13, 2012.

[30] Screening Analysis provided in response to Sierra DR 1.30. CCB costs in tab "Upfront Coal Capital", tables 1f-1-5

[31] Table 13 in "Naughton Station Subtitle D Coal Combustion Residue Disposal Evaluation" from Sargent and Lundy. May 6, 2011. Provided as Sierra DR 1.6-3.

approximately accurate. These costs roughly comport with values shown in the 2011 Screening Analysis.

In 2010, long-term forecasts for natural gas (and hence market prices) had shifted again. I used electricity market prices from the Company's June 2010 official forward price curve.[32] Prices had shifted upwards again slightly, but still remained below the December 2008 forecast prices used in the original analysis.

The outcome of this revised analysis with a 2009 retirement date, despite the higher market prices, is still a net liability under almost all circumstances for Naughton Units 1 & 2, as shown in **Table 10** and **Table 11,** below.

Table 10. Present value revenue requirement difference (PVRR(d)) of the Naughton 1 retrofit relative to market replacement (at June 2010 market prices), in thousands of 2009$ (2009 retirement date)

	Original Generation	FGD De-rate	Derate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR, ACI	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR, ACI & RCRA	[redacted]	[redacted]	[redacted]

Table 11. Present value revenue requirement difference (PVRR(d)) of the Naughton 2 retrofit relative to market replacement (at June 2010 market prices), in thousands of 2009$ (2009 retirement date)

	Original Generation	FGD De-rate	Derate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR, ACI	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR, ACI & RCRA	[redacted]	[redacted]	[redacted]

Finally, had the Company tested the 2015 retirement deadline rather than the now-impossible 2009 deadline, the results would have continued to clearly indicate that the Naughton FGD should not be constructed. The results of a 2015 retirement study performed around the time of the June 2010 construction date are in **Table 12** and **Table 13** below.

[32] Response to Sierra Club DR 1.33, 2nd Supplemental

Table 12. Present value revenue requirement difference (PVRR(d)) of the Naughton 1 retrofit relative to market replacement (at June 2010 market prices), in thousands of 2009$ (2015 retirement date). The ** marks the most conservative value that the Company should have estimated as of the Construction Date.

	Original Generation	FGD De-rate	Derate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR, ACI	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR, ACI & RCRA	[redacted]	[redacted]	[redacted]

Table 13. Present value revenue requirement difference (PVRR(d)) of the Naughton 2 retrofit relative to market replacement (at June 2010 market prices), in thousands of 2009$ (2015 retirement date). The ** marks the most conservative value that the Company should have estimated as of the Construction Date.

	Original Generation	FGD De-rate	Derate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR, ACI	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR, ACI & RCRA	[redacted]	[redacted]	[redacted]

If the Company had assessed the value of moving forward on this project at the time of the June 2010 construction date, it would have recognized that the project would result in a significant liability. Based on the information available to the Company at the time of construction date, the Company should have halted the project.

Q Does your re-analysis of the PVRR(d) address all of the flaws in the Company's analysis?

A No. I have attempted to identify and quantify the most egregious errors, but there are several additional problems that could not be addressed with the data and resources available for this testimony. My additional concerns are as follows:

First, I am concerned that the Company's assessment of carbon dioxide (CO_2) price forecasts in 2009 was significantly below those predicted by other utilities, the federal government, and third-party analysts. The $8/ton flat (real 2009$) price used in the business plan did not appropriately reflect the risk that could be imposed on the utility. I have not been able to make this correction as I do not have access to the Company's market price model, and such a price difference would have to be reflected as both a carbon price adder and in market prices.

Second, I do not believe that the Company's analysis accurately reflects the cost of purchasing market power as required to meet load requirements. The Company assumes that each MWh of power lost at a generator would need to be made up in full. PacifiCorp is a net exporter of power; it would be irrational to think that the Company would purchase market power just to make up off-system sales. The model should, instead, reflect the cost of making up power requirements rather than just lost generation.

Third, the model cannot accurately predict how different generators in the PacifiCorp fleet might make up for lost power. There is a reasonable expectation that other generators in the Company's fleet might increase their output at lower-than-market prices if another generator were taken offline; such dynamics are not reflected in the Company's model.

Fourth, the model fails to assess the cost of makeup generation for the weeks or months that the generator is taken offline to tie in various retrofits. Instead, the model simply shows a lower capacity factor, and hence a slightly lower margin against market prices – but not the cost of replacement power as required.

Fifth, the model as used here denies the opportunity to look for more cost effective mechanisms of supplying power to customers, except through market purchases. The Company did not examine renewable energy, demand side management, new natural gas generation, purchasing power from existing underutilized natural gas generators, changes in transmission, or any other combination of resources that could have resulted in a lower cost solution (Response to Sierra Club DR 1.24a-g). Although the Company had access to (and was actively using) the System Optimizer model to make resource choices in the IRP, this model was not used to examine coal retirement opportunities until the

2011 IRP,[33] and was not used to examine the opportunity to avoid environmental upgrades until the most recent coal retirement study, issued in 2012.

Finally, at the time the model was constructed, the Company was already planning large-scale transmission projects expanding its ability to move energy from its existing generating resources to load centers.[34] It is reasonable to assume that some of the six billion dollar cost associated with the Energy Gateway transmission project[35] might have been avoidable with the retirement of one or more of the Company's existing assets, yet such avoided costs are neither contemplated nor quantified in the PVRR(d) analyses.

8. Questionable Economics of Hunter Environmental Retrofits

Q Would you please summarize your concerns with the Hunter Environmental Retrofits?

A In this rate case, there are at least four retrofits at Hunter units 1 & 2 for which the Company is requesting rate recovery that could have reasonably been avoided through a comprehensive accounting of reasonable forward-going costs, rather than the use of the Company's flawed PVRR(d) analysis tool. These upgrades, amounting to **$79** million of capital investments, include:

- Hunter U1 SO2 Upgrades at $51,918,028
- 302 – Hunter U2 SO2 Project at $25,068,777
- Hunter 302 Clean Air – PM at $1,503,979
- Hunter U1 Turbine Upgrade – Interconnection at $1,176,775

It is my belief that the Company's analysis justifying these upgrades, conducted in November of 2009, inadequately captured either the forward-going costs of

[33] System Optimizer obtained in April 2005 (Sierra DR 2.11a), used in commercial production as of August 2006.
[34] Sierra 1.38: "PacifiCorp announced the decision to proceed with the Energy Gateway project in June 2007."
[35] Sierra 1.40

operation known in 2009 or the opportunities to avoid capital expenditures assuming a reasonable retirement date in 2015.

For the purposes of the Hunter Analysis, the analysis date was November of 2009, and the contract date was in December of 2009 (Sierra DR 1.23 and Sierra 1.25).

Q What was the outcome of the Company's PVRR(d) analysis?

A The Company's PVRR(d) analysis, as provided in OPUC 220-2, suggested that at \$8 CO_2 prices, the retrofits would result in a net benefit of [redacted] and [redacted] respectively for Hunter 1 & 2. This analysis was the only model supplied to interveners that reviewed other CO2 price trajectories <u>aside</u> from a flat \$8 price (in real 2009\$). At higher CO_2 prices, the upgrade, in the Company's original analysis became marginal at mid-CO2 prices, and then became a significant liability at high-CO2 prices, as shown in **Table 14,** below.

Table 14. Present value revenue requirement difference (PVRR(d)) of the Hunter 1 & 2 retrofits relative to market replacement, in thousands of 2009\$ (~2013 retirement date). The * marks the value used by the Company.

	\$8 CO_2	**\$45 CO_2**	**\$70 CO_2**	**\$100 CO_2**
Hunter U1	[redacted]	[redacted]	[redacted]	[redacted]
Hunter U2				

Based on this analysis, the Company decided that the Hunter Environmental Retrofits were financially viable. The Company has stated that "the alternative CO2 price trajectories presented in this model were used as a sensitivity analysis. The sensitivity results were not assigned a specific weighting." (Sierra 2.4c)

Indeed, at these values, it would have required a fairly high probability of a high CO_2 price to have changed the perception of the economic viability of this project. I do not agree, however, that this analysis was conducted correctly, and the outcome of my revised analysis, based on what the Company reasonably should have known at the contract date, indicates that the Hunter Environmental Retrofits were far less favorable than the Company concluded.

Q Does your revised NVRR(d) analysis change the expected net benefit of the Hunter Environmental Retrofits?

A Yes, my analysis shows a substantial decrease in net benefits. After a number of revisions based on other documentation provided by the Company, and using the same analytical platform provided by the Company with some structural modifications to correctly examine a 2015 retirement date, I determined that the maximum net benefit of the retrofits would have been on the order of just [redacted] and [redacted], respectively, as shown in **Table 15**, below.

Table 15. Revised present value revenue requirement difference (PVRR(d)) of the Hunter 1 & 2 retrofits relative to market replacement, in thousands of 2009$ (2015 retirement date, revised capacity factor & O&M, advanced SCR date and RCRA, avoided turbine costs, increased coal costs in 2012, and unit degradation). The ** marks the best possible outcome that should have been realized by the Company.

	\$8 CO_2	**\$45 CO_2**	**\$70 CO_2**	**\$100 CO_2**
Hunter U1 **Hunter U2**	[redacted]	[redacted]	[redacted]	[redacted]

These revised results show that the significant net liabilities at any alternate carbon price other than the low-CO2 price assumed by the Company are so large that, had the Company run this analysis, the results would have suggested that the retrofits would be extremely risky – any uptick in capital requirements, reduced gas prices, higher carbon prices, or increased O&M expenditures could easily have resulted in a net liability.

In my opinion, based on the marginal economic benefit evident in the corrected PVRR(d) analysis, the risk of higher CO2 prices, and the fact, discussed in my testimony above, that there was no regulatory requirement to begin the FGD projects at Hunter by 2010,[36] the Company should have deferred the construction of this upgrade until it had better resolution on future likely costs and risks.

[36] Similar to the Naughton plant, the requirements stipulated by Mr. Teply (p63 at 6-10) are not causal for the FGDs. The 2008 version of Utah's Regional Haze SIP simply assumes that the FGD will have been installed because the Company had already received a permit (2008 SIP, p24; also 2011 SIP, p24), the same permit cited by Mr. Teply on p63 line 10 of his direct testimony. The permit cited by Mr. Teply is simply an approval by the State to build an FGD for which the Company had requested a permit in 2007, long before Utah BART findings. Again, there is no regulatory reason that the Company had to move

Q What modifications did you make to the Hunter analysis?

A The changes are similar to those discussed previously and in more detail in my testimony with respect to the Naughton analysis. Those changes are summarized as follows:

- To correctly evaluate a 2015 retirement date, the analysis was broken into two separate parts. The first part estimated the total cost of generating through 2042, including environmental and standard capital investments, fuel costs, and O&M expenses, but no benefit for equivalent market revenues. The second part evaluated the total cost of operating until 2015 with no environmental investments, and no additional coal expenses (fuel, capital or O&M) after 2015, but costs for replacement energy in-kind from 2016-2042;
- Included O&M expenses for the years 2010-2013, left out of the original analysis;
- Included “forced outage benefit and risk” from 2010-2012, left blank in original;
- Added expected run-rate capital from 2010-2012, and corrected formulas to pass information correctly from data to analysis;
- Extracted expected future capacity factors from visual chart in 2009 Hunter SAP and replaced $8 CO2 capacity factor trajectory;
- Included unit degradation in Hunter Unit 1 from projected curve in 2009 Hunter SAP, and reduced capacity factor according to degradation schedule;
- Included SCR costs for Hunter Unit 1 from 2009 SAP and moved costs to 2017 instead of 2025 (explanation below);

forward with this upgrade in 2007, or could not have waited longer to actually implement the FGD once permitted.

- Replaced coal fuel costs with trajectory used in 2011 Screening Analysis (explanation below);
- Added costs of coal combustion residuals management from 2011 Screening Analysis as "proxy costs", order of magnitude available to the Company in 2009;
- Added total O&M costs from 2011 Screening Analysis, consistent with data issued internally to Company;[37] and
- Removed capital expenses of Hunter 1 turbine upgrade in 2010 as an "avoidable expense" in 2015 retirement case.

Q Is it appropriate to include SCR costs in 2017 for the Hunter 1 analysis?

A Yes, the Company should have at least considered the risk the SCR would be required by 2017. [redacted] The Company would have known, based on its experience in the Wyoming Regional Haze process that the EPA would be reviewing how the Company and Utah DEQ decided on particular regional haze (BART) findings. For example, the Company had made explicit arguments in Wyoming that an SCR was not required because the "presumptive BART" NOx emissions rate was higher than would be achieved with an SCR.[38] Despite the Company's arguments, ultimately the choice of BART is in the hands of the states and EPA, not the Company. Based on this information, it is evident that the Company was explicitly aware that the EPA could require an SCR at the Hunter unit in the next 5-7 years.

[37] Total plant O&M costs shown in Exhibit 5 of Huntsman deposition in Deseret arbitration case, provided to interveners in this case as Sierra DR 1.9.

[38] The Company recognized internally that, despite their arguments in Wyoming, the state could still find that SCR was BART. [redacted]

Indeed, the EPA recently disapproved significant portions of the Utah SIP, particularly pertaining to NOx requirements on the PacifiCorp units, explaining that:

> "neither the State nor PacifiCorp, conducted a BART analyses for each of the units that took into account the five BART factors… For these reasons, we are proposing to disapprove the State's determination that BART for NOX for PacifiCorp Hunter Unit 1 and Unit 2 and PacifiCorp Huntington Unit 1 and Unit 2 is a NOX emission limit of 0.26 lb/MMBtu (30-day rolling average) (assumed to be achieved by LNBs plus SOFA)." (77 Fed Reg 28842, May 16 2012)

The Company was well aware of the risk that the EPA might disapprove the Utah SIP and require SCR within five years of a final BART determination, which in this case would have been 2017. To test this risk, I moved the SCR implementation date to 2017 and shifted its cost along a nominal trajectory accordingly.

Q Is it appropriate to change the coal fuel costs in the Hunter PVRR(d) analysis?

A Yes, the Company should have updated its coal fuel cost assumptions to reflect higher prices. The Company explains in its 2009 SAP (issued several months before the PVRR(d) analysis) that the cost of coal at Hunter 2 is expected to increase in the [redacted]. The 2009 SAP shows the source of the coal [redacted], and explains in the text that "[redacted]." (2009 Hunter SAP, p27, Exhibit Sierra Club 117) This change in coal prices is not reflected in the PVRR(d) analysis, but <u>is</u> reflected in the 2011 Screening Analysis. I assume that, even for proxy purposes, such an increase could have been modeled in the PVRR(d) analysis.

It is notable that the 2009 Hunter SAP also explains that [redacted] (2009 Hunter SAP, p9) This potentially dramatic price increase is not reflected in the 2011 Screening Analysis or 2009 SAP.

Q Are there additional costs should be considered in the Hunter analysis?

A Yes, there are two important areas of costs that I think should have been in the analysis, but for which I do not have proxy costs available today.

First, the 2009 Hunter SAP is explicit where it discusses [redacted] This emerging regulation has the potential to impose high costs at coal plants across the country, and I believe it would have been incumbent on PacifiCorp to roughly estimate proxy costs as part of this analysis.

Second, Company witness Mr. Gerrard discusses the need for the Mona-to-Oqirrh transmission project as essentially buffering transmission capacity from southern Utah power plants to the greater Salt Lake area. Amongst these southern plants, he includes “Carbon, Hunter, Huntington, and Currant Creek Power Plants” (PAC/700, Gerrard/21 at 4-5). The Company should have considered whether a new transmission line would still be required if both the Carbon and Hunter 1 & 2 units were not in operation.

The Carbon unit is likely to be taken out of service (see Mr. Teply’s testimony, PAC/500, Teply/4 at 21 to 5 at 8), and evidence suggests that the Company has known about this feasible retirement since at least early 2009.[39]

[39] PacifiCorp’s response to Sierra Club DR 1.36 suggests that the Company did not contemplate removing this unit until recently in March 2011, but the 2009 Carbon SAP is explicit that the net benefit of operating the plant through 2020 is marginal at best, and likely to be reversed if there are any environmental requirements imposed at the plant: [redacted]

If the retirement of either or both of the Hunter 1 & 2 units (together 687 MW of PacifiCorp share) could have prevented some or all of the $406.9 million Mona-to-Oqirrh transmission project costs (a 1,500 MW capacity project),[40] then these costs (or the avoidable portion) should have been included as part of the Hunter analysis.

Q Was the Company's decision to install the Hunter Environmental Retrofits reasonable?

A Based on the output of the corrected Hunter PVRR(d) analysis, the Company should have recognized the high level of risk and uncertainty associated with the plant and deferred the decision to implement the Hunter environmental retrofits.

9. Environmental Retrofits Would be Non-Economic Today

Q Should PacifiCorp have examined the costs of compliance with the Regional Haze rule and other regulations in 2008 and 2009?

A Yes. The Company must stay appraised of the costs of regulatory compliance as soon as there is evidence that a significant cost may be incurred in a future year. There are numerous ways of examining the probability that such a cost will need to be incurred, and the impact that regulations would have on the Company's assets; utilities across the country are actively examining the forward-going costs of generation against finalized, proposed, and emerging regulations.

Q Should PacifiCorp have invested in environmental retrofits in 2008 - 2010?

A No. The Company should not have moved forward with regulatory compliance action until there was both reasonable certainty about the final form of the rule and regulatory requirements, as well as reasonable certainty about other obligations and costs. It would have been incumbent on the Company to examine their existing fleet comprehensively prior to moving forward with these large investments; such an examination might have included using technology available

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[redacted] (Sierra 1.36a attached as Exhibit [redacted]); 2009 Carbon SAP attached as Exhibit Sierra Club 119))

[40] See Sierra DR 1.40-l and Sierra DR 1.40-I, respectively.

to the Company, such as the System Optimizer tool used in Integrated Resource Planning (IRP).

Q When should the Company have moved forward on environmental compliance investments?

A Other major utilities have been making final environmental investment decisions in late 2011 and 2012, including filing CPCN and other notice. In these cases, commissions have been able to either verify or challenge whether such investments are necessary and required under current regulation, and if installing retrofits are the most efficient mechanism to meet regulatory requirements. Until the mandatory Naughton 3 CPCN in Wyoming, no PacifiCorp commission has been able to review the Company's decisions.

Q If the Company had waited until 2011 or 2012 to make environmental investments at issue in this case, would they have moved forward on the projects?

A No. It is my assessment that the Company would have refrained from moving forward on at least Naughton 1 or 2, Hunter 1 or 2, or Dave Johnston 4 if they were making the same decisions today. In a brief check, I used the Screening Analysis provided by the Company to Oregon interveners in the 2011 IRP case and included the install-year capital costs for projects used in the 2008/2009 PVRR(d) analyses that were not already included in the Screening Analysis, cross checking against costs broken down in OPUC 138. Using the same criteria as in the PVRR(d) analyses (net margin relative to market electricity prices), I found that these five units all returned [redacted] PVRR(d) results in the base case:

Table 16. PVRR(d) Results from running IRP Screening Analysis as if current retrofit costs were avoidable today; benefits relative to market.

Unit	PVRR(d) Result: Benefit / (Cost) of Coal investments relative to market (Net PVRR) (million 2011 $)
Naughton 1	[redacted]
Naughton 2	[redacted]
Hunter 1	[redacted]
Hunter 2	[redacted]
Dave Johnston 4	[redacted]

I would have expected the Company to have obtained roughly these model results if they had waited until regulations were reasonably certain and had included the risk of additional forward-going investments in the PVRR(d) analysis.

Based on this analysis, it is my assessment that the decision to move forward on these three retrofits did cause substantive damage to ratepayers.

10. <u>Wyodak Revenue Requirement is a Small Fraction of Baghouse Cost</u>

Q Do you have additional concerns with any other retrofits noted in this case?

A I do. I have a significant concern with the recovery requested for the Wyodak baghouse (called Wyodak U1 SO2 and PM Emiss Control Upgrade in Dalley 8.6.5). In this case, the Company is requesting $1,759,942 in rate recovery. However, the project has, according to the Company, already incurred a far higher cost and is in-service. According to the Company's response to Sierra Club DR 1.19, the total project cost is [redacted]; thus the recovery requested here is less than [redacted]% of the total cost.

Q Why is the recovery requested by the Company in this proceeding so small relative to the overall cost of the project?

A It is unclear why the Company included only a fraction of the Wyodak baghouse costs in this proceeding. However, it raises the concern that the Company would obtain a determination of prudence on the Wyodak retrofit without alerting the

Commission and other parties to the magnitude of total costs that could be expected in future rate cases. The Company should include all of the known and measurable costs that it considers are used and useful in this proceeding so that the Commission and other parties can fully evaluate the impact of this project.

Q Does this conclude your testimony?

A It does.

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SIERRA CLUB EXHIBIT 101

Curriculum Vitae
of Jeremy I. Fisher, PhD

Jeremy I. Fisher, PhD

Curriculum Vitae

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EMPLOYMENT

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Synapse Energy Economics

Postdoctoral Research Scientist **2006 - 2007**
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University of New Hampshire, Institute for the Study of Earth, Oceans, and Space

Visiting Fellow **2007 - 2008**
Brown University, Watson Institute for International Studies

Research Assistant **2001 - 2006**
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Remote Sensing Analyst **2005 - 2006**
Consultant for Geosyntec. in Acton, Massachusetts

Remote Sensing Specialist **2000**
3Di, LLC. Remote Sensing Department. Easton, Maryland

Research Assistant **1999 - 2001**
University of Maryland, Laboratory for Global Remote Sensing Studies

EDUCATION

Ph.D. Geological Sciences	**2006**	Brown University, Providence, Rhode Island
M.Sc. Geological Sciences	**2003**	Brown University, Providence Rhode Island
B.S. Geography	**2001**	University of Maryland, College Park, Maryland
B.S. Geology *(honors)*	**2001**	University of Maryland, College Park, Maryland

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TEACHING

Teaching Assistant	**2005**	Global Environmental Remote Sensing, Brown University
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PUBLIC UTILITY COMMISSION OF OREGON

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SIERRA CLUB EXHIBIT 102

CONFIDENTIAL
2008 Strategic Asset Plan:
Naughton Power Plant

This exhibit is confidential and is provided under separate cover.

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SIERRA CLUB EXHIBIT 103

CONFIDENTIAL
2009 Strategic Asset Plan:
Naughton Power Plant

This exhibit is confidential and is provided under separate cover.

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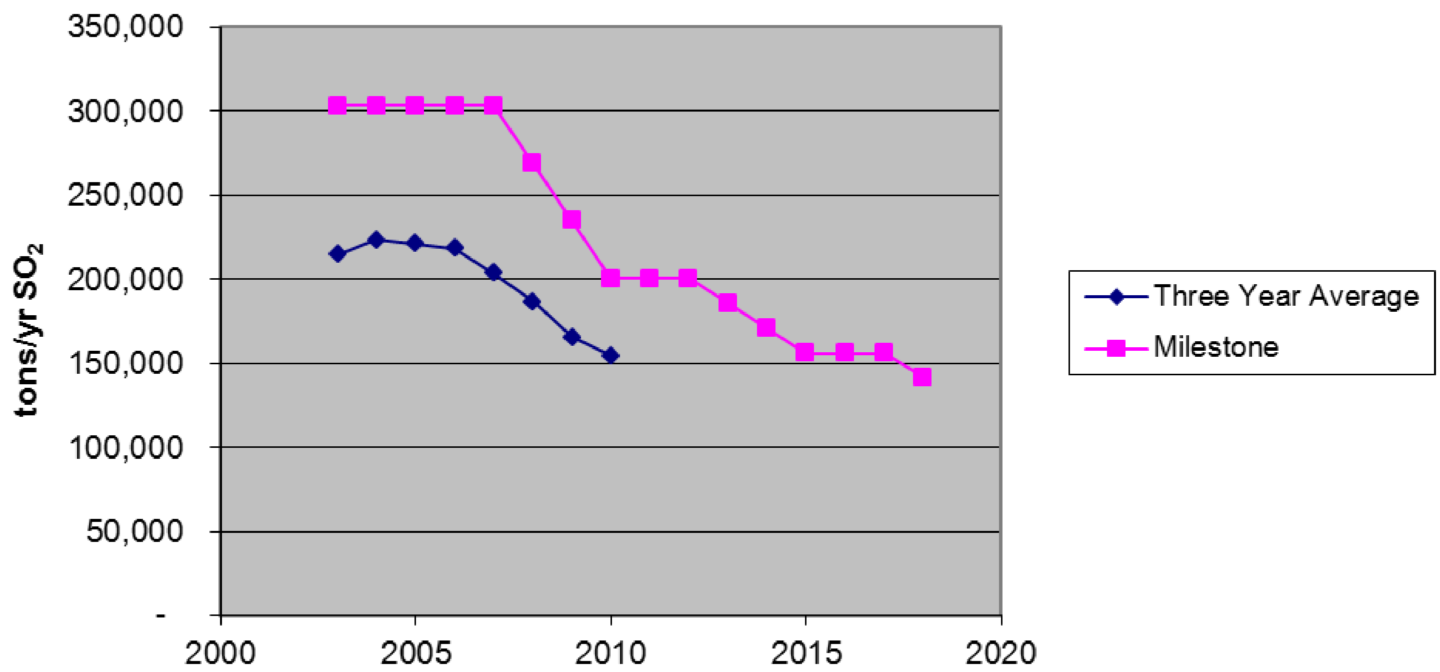
SIERRA CLUB EXHIBIT 104

SO_2 Milestones and Emission Trends
New Mexico, Utah, Wyoming

SO_2 Milestones and Emission Trends
New Mexico, Utah, Wyoming



2010 Regional SO2 Emissions and Milestone Report. March 22, 2012
Appendix C, pB-4.

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SIERRA CLUB EXHIBIT 105

CONFIDENTIAL
Naughton Permit No. MD-5156

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SIERRA CLUB EXHIBIT 106

BART Analysis for Naughton Unit 1
2007

Final Report

BART Analysis for Naughton Unit 1

Prepared For:

PacifiCorp
1407 West North Temple
Salt Lake City, Utah 84116

December 2007

Prepared By:

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Final Report

BART Analysis for Naughton Unit 1

Submitted to

PacifiCorp

Decmeber 2007

CH2MHILL

Executive Summary

Background

In response to the Regional Haze Rule and Best Available Retrofit Technology (BART) regulations and guidelines, CH2M HILL was requested to perform a BART analysis for PacifiCorp's Naughton Unit 1 (hereafter referred to as Naughton 1). A BART analysis has been conducted for the following criteria pollutants: oxides of nitrogen (NO_x), sulfur dioxide (SO_2), and particulate matter less than 10 micrometers in aerodynamic diameter (PM_{10}). The Naughton Station consists of three units with a total generating capacity of 710 megawatts (MW). Because the total generating capacity of the Naughton Station does not exceed 750 MW, presumptive BART limits do not directly apply to Naughton 1, based on the United States Environmental Protection Agency's (EPA) guidelines. Presumptive BART limits are a goal unless it is determined that an alternative control level is justified based on a careful consideration of the statutory factors. BART emissions limits must be achieved within 5 years after the State Implementation Plan (SIP) is approved by the EPA. A compliance date of 2014 was assumed for this analysis.

In completing the BART analysis, technology alternatives were investigated and potential reductions in NO_x, SO_2, and PM_{10} emissions rates were identified. The following technology alternatives were investigated, listed below by pollutant:

- NO_x emission controls:
  - Low NO_x burners (LNBs) with over-fire air(OFA)
  - Rotating opposed fire air (ROFA)
  - LNBs with selective non-catalytic reduction system (SNCR)
  - LNBs with selective catalytic reduction (SCR) system
- SO_2 emission controls:
  - Dry flue gas desulfurization (FGD) system with existing electrostatic precipitator (ESP)
  - Dry FGD system with new fabric filter
  - Wet FGD system with existing ESP
- PM_{10} emission controls:
  - Sulfur trioxide (SO_3) injection flue gas conditioning (FGC) system on existing ESP
  - Polishing fabric filter
  - Replacement fabric filter

BART Engineering Analysis

The specific steps in a BART engineering analysis are identified in the *Code of Federal Regulations* (CFR) at 40 CFR 51, Appendix Y, Section IV. The evaluation must include:

- The identification of available, technically feasible, retrofit control options
- Consideration of any pollution control equipment in use at the source (which affects the availability of options and their impacts)
- The costs of compliance with the control options
- The remaining useful life of the facility
- The energy and non-air quality environmental impacts of compliance
- The degree of visibility improvement that may reasonably be anticipated from the use of BART

The following steps are incorporated into the BART analysis:

- Step 1 – Identify All Available Retrofit Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
  - The identification of available, technically feasible, retrofit control options
  - Consideration of any pollution control equipment in use at the source (which affects the applicability of options and their impacts)
- Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies
- Step 4 – Evaluate Impacts and Document the Results
  - The costs of compliance with the control options
  - The remaining useful life of the facility
  - The energy and non-air quality environmental impacts of compliance
- Step 5 – Evaluate Visibility Impacts
  - The degree of visibility improvement that may reasonably be anticipated from the use of BART

Separate analyses have been conducted for NO_x, SO_2, and PM_{10} emissions. All costs included in the BART analyses are in 2006 dollars, and costs have not been escalated to the assumed 2014 BART implementation date.

Coal Characteristics

The main source of coal burned at Naughton 1 will be the low sulfur and high sulfur P&M Kemmerer Mines (P&M). These coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. These coals have higher nitrogen content than coals from the Powder River Basin (PRB), which represent the bulk of sub-bituminous coal use in the U.S. This BART analysis has considered the higher nitrogen content and different combustion characteristics of PRB coals, as compared to those coals used at Naughton 1, and has evaluated the effect of these qualities on NO_x formation and achievable emission rates.

Recommendations

CH2M HILL recommends installing the following control devices, which include LNBs with OFA, dry FGD system, and the existing ESP. This combination of control devices is identified as Scenario 1 throughout this report.

NO_x Emission Control

Naughton 1 burns coal from P&M. As documented in this analysis, the characteristics of the P&M coals are more closely aligned with bituminous coals.

CH2M HILL recommends LNBs with OFA as BART for Naughton 1, based on the projected significant reduction in NO_x emissions, reasonable control costs, and the advantages of no additional power requirements or non-air quality environmental impacts. NO_x reductions are expected to be similar to those realized at the Jim Bridger plant where these devices have been installed on Unit 2. This selection of new LNBs with OFA at Naughton 1 is projected to attain an emission rate at or below 0.26 pound (lb) per million British thermal units (MMBtu).

SO_2 Emission Control

CH2M HILL recommends a dry lime FGD system with the existing ESP as BART for Naughton 1, assuming use of coal containing no more than 1.02 percent sulfur by weight, based on the significant reduction in SO_2 emissions, reasonable control costs, and the advantages of minimal additional power requirements and minimal non-air quality environmental impacts. This approach is projected to have a SO_2 emission rate of 0.41 lb per MMBtu.

PM_{10} Emission Control

CH2M HILL recommends the addition of a flue gas conditioning system to enhance the performance of the existing ESP as BART for Naughton 1, based on the significant reduction in PM_{10} emissions, reasonable control costs, and the advantages of minimal additional power requirements and no non-air quality environmental impacts.

BART Modeling Analysis

CH2M HILL used the CALPUFF modeling system to assess the visibility impacts of emissions from Naughton 1 at Class I areas. The Class I areas potentially affected are located more than 50 kilometers, but less than 300 kilometers, from the Naughton Plant.

The Class I areas include the following wilderness areas:

- Bridger Wilderness Area
- Fitzpatrick Wilderness Area

Because Naughton 1 will simultaneously control NO_x, SO_2, and PM_{10} emissions, four post-control atmospheric dispersion modeling scenarios were developed to cover the range of effectiveness for combining the individual NO_x, SO_2, and PM_{10} control technologies under evaluation. These modeling scenarios, and the controls assumed, are as follows:

- **Scenario 1**: New LNB with OFA modifications, a dry FGD system, and flue gas conditioning for enhanced ESP performance and higher sulfur coal. As indicated previously, this scenario represents CH2M HILL's preliminary BART recommendation.
- **Scenario 2**: New LNB with OFA modifications, a dry FGD system, and new fabric filter.
- **Scenario 3**: New LNB with OFA modifications and SCR, dry FGD system, and new fabric filter.
- **Scenario 4**: New LNB with OFA modifications and SCR, wet FGD system, flue gas conditioning for enhanced ESP performance, and a new stack.

Visibility improvements for all emission control scenarios were analyzed, and the results were compared using a least-cost envelope, as outlined in the draft EPA 1990 *New Source Review Workshop Manual*.[1]

Least-cost Envelope Analysis

EPA has adopted the least-cost envelope analysis methodology as an accepted methodology for selecting the most reasonable, cost-effective controls. Incremental cost-effectiveness comparisons focus on annualized cost and emission reduction differences between dominant alternatives. The dominant set of control alternatives is determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for a total emissions reductions for all control alternatives identified in the BART analysis.

To evaluate the impacts of the modeled control scenarios on the three Class I areas, the total annualized cost, cost per deciview (dV) reduction, and cost per reduction in number of days above 0.5 dV were analyzed. This report provides a comparison of the average incremental costs between relevant scenarios for the three Class I areas; the total annualized cost versus number of days above 0.5 dV, and the total annualized cost versus 98th percentile delta deciview (ΔdV) reduction.

Results of the least-cost envelope analysis validate the selection of Scenario 1, based on incremental cost and visibility improvements. The other scenarios were eliminated for the following reasons:

- Scenario 2 (LNB with OFA, dry FGD, and fabric filter) is to the left of the curve formed by the dominant control alternative scenario, which indicates a scenario with lower improvement and/or higher costs.

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[1] EPA, 1990. *New Source Review Workshop Manual*. Draft. Environmental Protection Agency. October, 1990.

- Scenario 3 (LNB with OFA and SCR, dry FGD, and new fabric filter) has very high incremental costs, on the basis of both a cost per day of improvement and cost per dV reduction.
- While Scenario 4 (LNB with OFA and SCR, wet FGD, ESP with SO_3 injection and new stack) provides some potential visibility advantage over Scenario 1, the projected improvement is less than half a dV, and the projected costs are excessive. Therefore, Scenario 1 represents BART for Naughton 1.

Just-Noticeable Differences in Atmospheric Haze

Studies have been conducted that demonstrate dV differences of only approximately 1.5 to 2.0 dV or more are perceptible by the human eye. Deciview changes of less than 1.5 cannot be distinguished by the average person. Therefore, the modeling analysis results indicate that only minimal, if any, observable visibility improvements at the Class I areas studied would be expected under any of the control scenarios. Thus, the results indicate that only minimal discernable visibility improvements may result, even though PacifiCorp will spend many millions of dollars at this single unit, and over $1 billion when considering its entire fleet of coal-fired power plants.

Contents

Tables

Figures

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Acronyms and Abbreviations

acfm	Actual Cubic Feet per Minute
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CALDESK	Program to display data and results
CALMET	Meteorological data preprocessing program for CALPUFF
CALPOST	Post-processing program for calculating visibility impacts
CALPUFF	Gaussian puff dispersion model
CFR	*Code of Federal Regulations*
COHPAC	Compact Hybrid Particulate Collector
dV	Deciview
ΔdV	Delta Deciview, Change in Deciview
ESP	Electrostatic Precipitator
EPA	United States Environmental Protection Agency
FGC	Flue Gas Conditioning
FGD	Flue Gas Desulfurization
kWh	Kilowatt-hour
LAER	Lowest Achievable Emission Rate
lb	Pound
LNB	Low-NO_x burner
LOI	Loss on Ignition
MMBtu	Million British Thermal Units
MM5	Mesoscale Meteorological Model, Version 5
MW	Megawatt
N_2	Nitrogen
NO_x	Nitrogen Oxide
$(NH_4)_2SO_4$	Ammonium Sulfate
OFA	Over-fire Air
P&M	P&M Kemmerer Mine
PM_{10}	Particulate Matter less than 10 Micrometers in Aerodynamic Diameter
PRB	Powder River Basin
ROFA	Rotating Opposed Fire Air
S&L	Sargent & Lundy

S&L Study	*Multi-Pollutant Control Report* dated October, 2002
SCR	Selective Catalytic Reduction System
SIP	State Implementation Plan
SNCR	Selective Non-catalytic Reduction System
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
TRC	TRC Companies, Inc.
USGS	United States Geological Survey
WA	Wilderness Area
WDEQ	Wyoming Department of Environmental Quality
WDEQ-AQD	Wyoming Department of Environmental Quality – Air Quality Division

1.0 Introduction

Best Available Retrofit Technology (BART) guidelines were established as a result of United States Environmental Protection Agency (EPA) regulations intended to reduce the occurrence of regional haze in national parks and other Class I-protected air quality areas in the United States. These guidelines provide guidance for states when determining which facilities must install additional controls, and the type of controls that must be used. Facilities eligible for BART installation were built between 1962 and 1977, and have the potential to emit more than 250 tons per year of visibility-impairing pollutants.

The Wyoming Department of Environmental Quality (WDEQ) BART regulations state that each source subject to BART must submit a BART application for a construction permit by December 15, 2006. PacifiCorp received an extension from the WDEQ to submit the BART report for Naughton 1 by February 9, 2007. The BART Report that was submitted to WDEQ in February 2007 included a BART analysis, and a proposal and justification for BART at the source. This revised report—submitted in October 2007—incorporates editorial revisions and new model revisions since the January 2007 version.

The State of Wyoming has identified those eligible in-state facilities that are required to reduce emissions under BART, and will set BART emissions limits for those facilities. This information will be included in the State of Wyoming State Implementation Plan (SIP), which the State has estimated will be formally submitted to the EPA by early 2008. The EPA BART guidelines also state that the BART emission limits must be fully implemented within 5 years of EPA's approval of the SIP.

There are five basic elements related to BART, when addressing the issue of emissions for the identified facilities:

- The cost of the controls
- The energy and non-air quality environmental impacts of compliance
- Any existing pollution control technology in use at the source
- The remaining useful life of the source
- The degree of improvement in visibility that may reasonably be anticipated from the use of such technology

This report documents the BART analysis that was performed on Naughton 1 by CH2M HILL for PacifiCorp. The analysis was performed for the pollutants NO_x, sulfur dioxide (SO_2), and particulate matter less than 10 micrometers in aerodynamic diameter (PM_{10}), because they are the primary criteria pollutants that affect visibility.

Section 2 of this report provides a description of the present unit operation, including a discussion of coal sources and characteristics. The BART Engineering Analysis is provided in Section 3 by pollutant type. Section 4 provides the methodology and results of the BART Modeling Analysis, followed by recommendations in Section 5 and references are provided in Section 6. Appendices provide more detail on the economic analysis and the 2006 Wyoming BART Protocol.

2.0 Present Unit Operation

Naughton 1 is a nominal 160-megawatts (MW) unit located approximately 6 miles southwest of Kemmerer, Wyoming. The unit is equipped with a tangentially fired boiler manufactured by Combustion Engineering (now Alstom). The unit was constructed with a Research Cottrell mechanical dust collector for particulate matter control, and a Lodge Cottrell electrostatic precipitator (ESP) was added in 1974. The unit presently uses low sulfur coal to control SO_x below 1.2 pounds (lb) per million British thermal units (MMBtu) and an ESP to control particulate matter. The unit uses good combustion practices for NO_x control.

Naughton 1 began operation in 1963. Its current economic depreciation life is through 2032; however, this analysis is based on a 20-year life for BART control technologies. Assuming a BART implementation date of 2014, this will result in an approximate remaining useful life for Naughton 1 of 20 years from the installation date of any new or modified BART-related equipment. This report does not attempt to quantify any additional life extension costs needed to allow the unit at Naughton 1 to operate until 2034.

Table 2-1 lists additional unit information and study assumptions for this analysis.

The main source of coal burned at Naughton 1 is the P&M Kemmerer Mine (P&M). This coal is ranked as sub-bituminous, but is closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. This coal has higher nitrogen content than coals from the Powder River Basin (PRB), which represent the bulk of sub-bituminous coal use in the U.S.

This BART analysis has considered the higher nitrogen content and different combustion characteristics of PRB coals, as compared to those coals used Naughton 1 and the effect of these qualities on NO_x formation. Coal sources and characteristics are summarized in Table 2-2. The primary source of coal will be the P&M mine, and data on coal from this source were used in the modeling analysis.

TABLE 2-1
Present Unit Operation
Naughton 1

General Plant Data	
Site Elevation (feet above mean sea level)	6939
Stack Height (feet)	200
Stack Exit Internal Diameter (feet) /Exit Area (square feet).	14 / 153.9
Stack Exit Temperature (degrees Fahrenheit)	280
Stack Exit Velocity (feet/second)	76
Stack Flow actual cubic feet per minute (actual cubic feet per minute)	701,784
Latitude (deg: min : sec)	41:45:26.84
Longitude (deg: min : sec)	110:35:54.01
Annual Unit Capacity Factor (percentage)	90
Net Unit Output (megawatts)	160
Net Unit Heat Rate (British thermal units [Btu] per kilowatt hour [kWh])(100% load)	10,680 (as measured by fuel throughput)
Boiler Heat Input (million Btu [MMBtu] per hour)(100% load)	1,850 (as measured by CEM)
Type of Boiler	Tangentially fired
Boiler Fuel	Coal
Coal Sources	P & M Kemmerer Mine
Coal Heating Value (Btu per lb) [(a)]	9,800
Coal Sulfur Content (wt. percentage)[(a)]	0.58
Coal Ash Content (wt. percentage)[(a)]	5.00
Coal Moisture Content (wt. %)[(a)]	21.0
Coal Nitrogen Content (wt. %)	1.3
Current NO_x Controls	Good combustion practices
Pre-project NO_x Emission Rate (lb per MMBtu)	0.58
Current Sulfur Dioxide Controls	Use of low sulfur coal
Pre-project Sulfur Dioxide Emission Rate (lb per MMBtu)	1.20
Current PM_{10} Controls[(b)]	Electrostatic precipitator
Pre-project particulate matter Emission Rate (lb per MMBtu)	0.056

NOTES:
[(a)]Coal characteristics vary between coal sources
[(b)]PM_{10} refers to particulate matter less than 10 micrometers in aerodynamic diameter

TABLE 2-2
Coal Sources and Characteristics
Naughton 1

							Ultimate Analysis (% dry basis)					
Mines	Moist. (%)	Ash (%)	Volatile Matter (%)	Fixed Carbon (%)	British thermal units per pound	Sulfur (%)	Hydrogen	Carbon	Sulfur	Nitrogen	Oxygen	Ash
Low Sulfur P&M Mine												
Average	20.90	4.49	33.46	41.17	9970	0.59	5.06	71.67	0.73	1.33	15.35	5.86
Standard Deviation *	0.97	1.11	0.57	1.18	303	0.05	0.19	1.43	0.06	0.16	0.97	1.04
High Sulfur P&M Mine												
Average	20.26	5.50	33.77	40.48	9965	1.29	5.02	70.87	1.68	1.22	14.57	6.64
Standard Deviation *	0.84	1.41	0.50	1.44	232	0.29	0.20	1.34	0.33	0.17	0.92	1.08

NOTES:
* Statistics are based on daily delivered samples except for ultimate analysis, which is based on weekly composites of daily samples

3.0 BART Engineering Analysis

This section presents the required BART engineering analysis.

3.1 Applicability

In compliance with regional haze requirements, the State of Wyoming must prepare and submit visibility SIPs to the EPA for Class I areas. The State has estimated that the formal submittal of the SIPs will occur by early 2008. The first phase of the regional haze program is the implementation of BART emission controls on all BART eligible units, within 5 years after EPA approval of the SIP.

3.2 BART Process

The specific steps in a BART engineering analysis are identified in the *Code of Federal Regulations* (CFR) at 40 CFR 51, Appendix Y, Section IV. The evaluation must include:

- The identification of available, technically feasible, retrofit control options
- Consideration of any pollution control equipment in use at the source (which affects the availability of options and their impacts)
- The costs of compliance with the control options
- The remaining useful life of the facility
- The energy and non-air quality environmental impacts of compliance
- The degree of visibility improvement that may reasonably be anticipated from the use of BART

The following steps are incorporated into the BART analysis:

- Step 1 – Identify All Available Retrofit Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
  - The identification of available, technically feasible, retrofit control options
  - Consideration of any pollution control equipment in use at the source (which affects the applicability of options and their impacts)
- Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies
- Step 4 – Evaluate Impacts and Document the Results
  - The costs of compliance with the control options
  - The remaining useful life of the facility
  - The energy and non-air quality environmental impacts of compliance

- Step 5 – Evaluate Visibility Impacts
  - The degree of visibility improvement that may reasonably be anticipated from the use of BART

To minimize costs in the BART analysis, consideration was made of any pollution control equipment in use at the source, the costs of compliance associated with the control options, and the energy and non-air quality environmental impacts of compliance using these existing control devices. In some cases, enhancing the performance of the existing control equipment was considered. Other scenarios with new control equipment were also developed.

All costs included in the BART analysis are in 2006 dollars (not escalated to a 2014 BART implementation date).

3.2.1 BART NO_x Analysis

NO_x formation in coal-fired boilers is a complex process depends on a number of variables, including operating conditions, equipment design, and coal characteristics.

Formation of NO_x

During coal combustion, NO_x forms in three ways. The dominant source of NO_x formation is the oxidation of fuel-bound nitrogen (fuel NO_x). During combustion, part of the fuel-bound nitrogen is released from the coal with the volatile matter, and part is retained in the solid portion (char). The nitrogen chemically bound in the coal is partially oxidized to nitrogen oxides (nitric oxide and nitrogen dioxide) and partially reduced to molecular nitrogen (N_2). A smaller part of NO_x formation is caused by high temperature fixation of atmospheric nitrogen in the combustion air (thermal NO_x). A very small amount of NO_x is called “prompt” NO_x. Prompt NO_x results from an interaction of hydrocarbon radicals, nitrogen, and oxygen.

In a conventional pulverized coal burner, air is introduced with turbulence to promote good mixing of fuel and air, which provides stable combustion. However, not all of the oxygen in the air is used for combustion. Some of the oxygen combines with the fuel nitrogen to form NO_x.

Coal characteristics directly and significantly affect NO_x emissions from coal combustion. Coal ranking is a means of classifying coals according to their degree of metamorphism in the natural series, from lignite to sub-bituminous to bituminous and on to anthracite. Lower rank coals, such as the sub-bituminous coals from the PRB, produce lower NO_x emissions than higher rank bituminous coals because of their higher reactivity and lower nitrogen content. The fixed carbon to volatile matter ratio (fuel ratio), coal oxygen content, and rank are good relative indices of the reactivity of a coal. Lower rank coals release more organically bound nitrogen earlier in the combustion process than do higher rank bituminous coals. When used with low-NO_x burners (LNBs), sub-bituminous coals create a longer time for the kinetics to promote more stable molecular nitrogen, and hence result in lower NO_x emissions.

Coals from the PRB are classified as sub-bituminous C and demonstrate the high reactivity and low NO_x production characteristics previously described. Based on data from the Energy Information Administration, PRB coals currently represent 88 percent of total U.S. sub-bituminous production and 73 percent of western coal production (Energy Information Administration, 2006). Most references to western coal and sub-bituminous coal infer PRB origin and characteristics. Emissions standards differentiating between bituminous and sub-bituminous coals are presumed to use PRB coal as the basis for the sub-bituminous standards, due to its dominant market presence and unique characteristics.

There are a number of western coals that are classified as sub-bituminous; however, they border on being ranked as bituminous and do not display many of the qualities of PRB coals, including most of the low NO_x forming characteristics. Coals from the P&M mine fall into this category.

One distinguishing characteristic that classifies a sub-bituminous from a bituminous coal is whether it is "agglomerating" or "non-agglomerating." Agglomerating as applied to coal has "the property of softening when it is heated to above about 400 degrees Celsius (°C) in a non-oxidizing atmosphere, and then appearing as a coherent mass after cooling to room temperature." Because the agglomerating property of coals is the result of particles transforming into a plastic or semi-liquid state when heated, it reflects a change in surface area of the particle. Thus, with the application of heat, agglomerating coals would tend to develop a non-porous surface while the surface of non-agglomerating coals would become even more porous with combustion. As shown by Figure 3-1, the increased porosity provides more particle surface area resulting in more favorable combustion conditions. This non-agglomerating property assists in making sub-bituminous coals more amenable to controlling NO_x by allowing less air to be introduced during the initial ignition portion of the combustion process. The coals from the P&M mine just barely fall into the category of non-agglomerating coals. While each of these coals is considered non-agglomerating, they either do not exhibit the properties of non-agglomerating coals or exhibit them to only a minor degree. The conditions during combustion of typical non-agglomerating coals that make it easier to control NO_x emissions do not exist for the coal used at Naughton 1.

FIGURE 3-1
Illustration of the Effect of Agglomeration on the Speed of Coal Combustion
Naughton 1

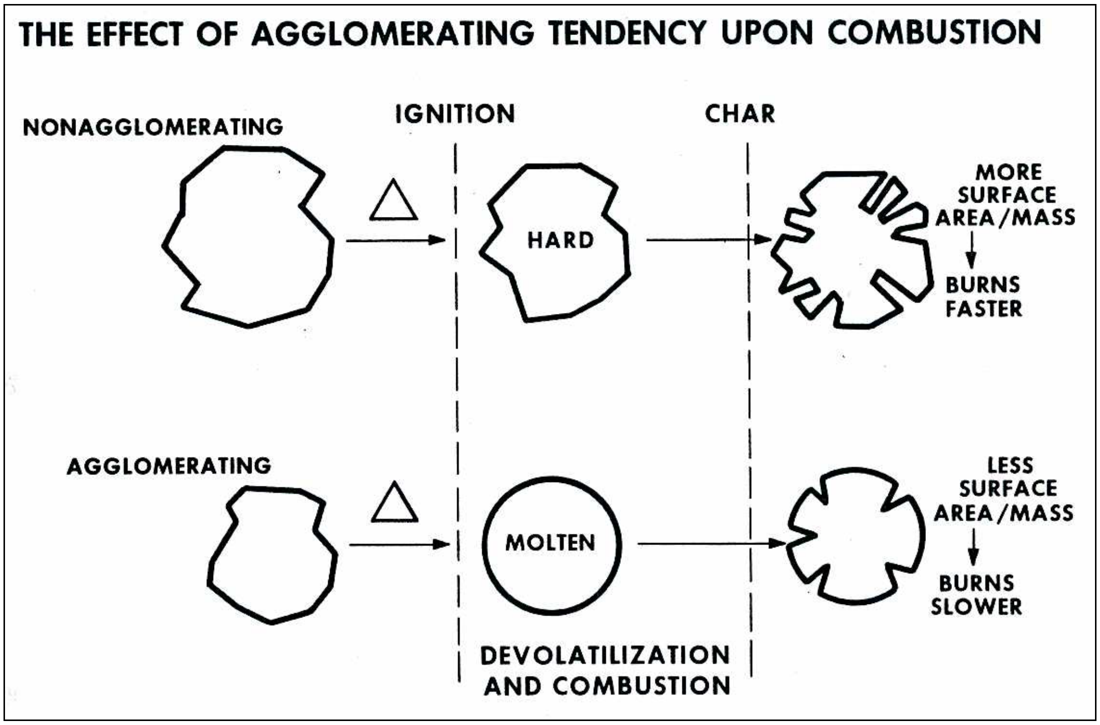


Table 3-1 shows key NO_x forming characteristics of a typical PRB coal compared to low sulfur and high sulfur coals from the P&M mine, and coals from Twentymile, which is a representative western bituminous coal.

TABLE 3-1
Coal Characteristics Comparison
Naughton 1

Parameter	PRB	P&M Low Sulfur	P&M High Sulfur	Twentymile
Nitrogen (% dry)	1.10	1.33	1.22	1.85
Oxygen (% dry)	16.2	15.35	14.57	7.19
Coal rank	Sub C	Sub B	Sub B	Bitum. high volatility B

As shown in Table 3-1, although P&M is classified as sub-bituminous, it exhibits higher nitrogen content and lower oxygen content than the PRB coal. The higher nitrogen content is an indication that more nitrogen is available to the combustion process and higher NO_x emissions are likely. Oxygen content can be correlated to the reactivity of the coal with more reactive coals—generally containing higher levels of oxygen. More reactive coals tend to produce lower NO_x emissions, and they are also more conducive to reduction of NO_x emissions, through use of combustion control measures such as LNBs and over fire air (OFA). These characteristics indicate that higher NO_x formation is likely with coal from the P&M mine, rather than with PRB coal. The P&M coal contains quality characteristics that fall between a typical PRB coal and Twentymile, a clearly bituminous coal that produces higher NO_x—as has been demonstrated at power plants burning this fuel.

Figures 3-2 and 3-3 graphically illustrate the relationship of nitrogen and oxygen content to related BART-presumptive NO_x limits for the coals listed in Table 3-1. Each chart identifies the presumptive BART limit associated with a typical bituminous and sub-bituminous coal, and demonstrates how the P&M mine coal falls between these two general coal classifications. Twentymile is used to graphically illustrate achievement of the BART-presumptive NO_x limit for a bituminous coal and the PRB coal corresponds to the sub-bituminous BART-presumptive NO_x limit. The "Present" data point represents coal from the P&M mine that is used at Naughton 1, and indicates the average NO_x emission rate of 0.57 lb per MMBtu achieved during 2005. The "LNB with OFA" data point indicates the projected NO_x emission rate of 0.24 after installation of new LNBs and OFA.

Figures 3-2 and 3-3 both demonstrate that for Naughton 1 with a TFS2000 low NO_x emission system installed and burning P&M coal. The likely NO_x emission rate will be closer to the bituminous end (0.28) of the BART presumptive NO_x limit range than to the sub-bituminous BART-presumptive NO_x limit of 0.15 lb per MMBtu.

All these factors are consistent with the observed sustainable emission rate of 0.24 lb per MMBtu for the control device that has been installed at Jim Bridger 2.

FIGURE 3-2
Plot of Typical Nitrogen Content of Various Coals and Applicable Presumptive BART NO_x Limits
Naughton 1

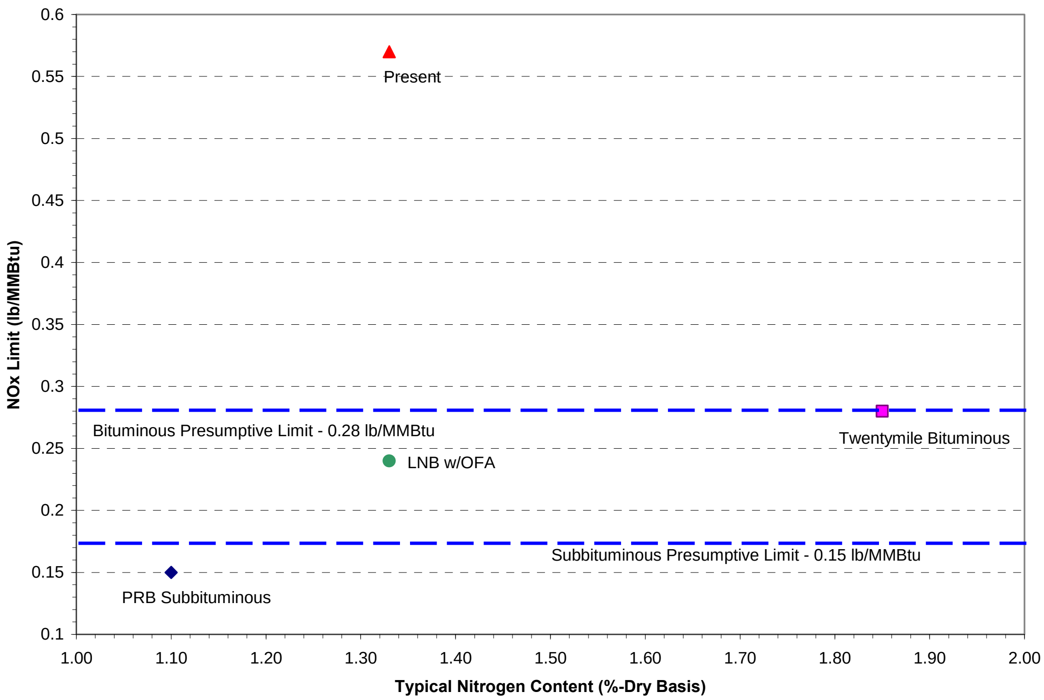
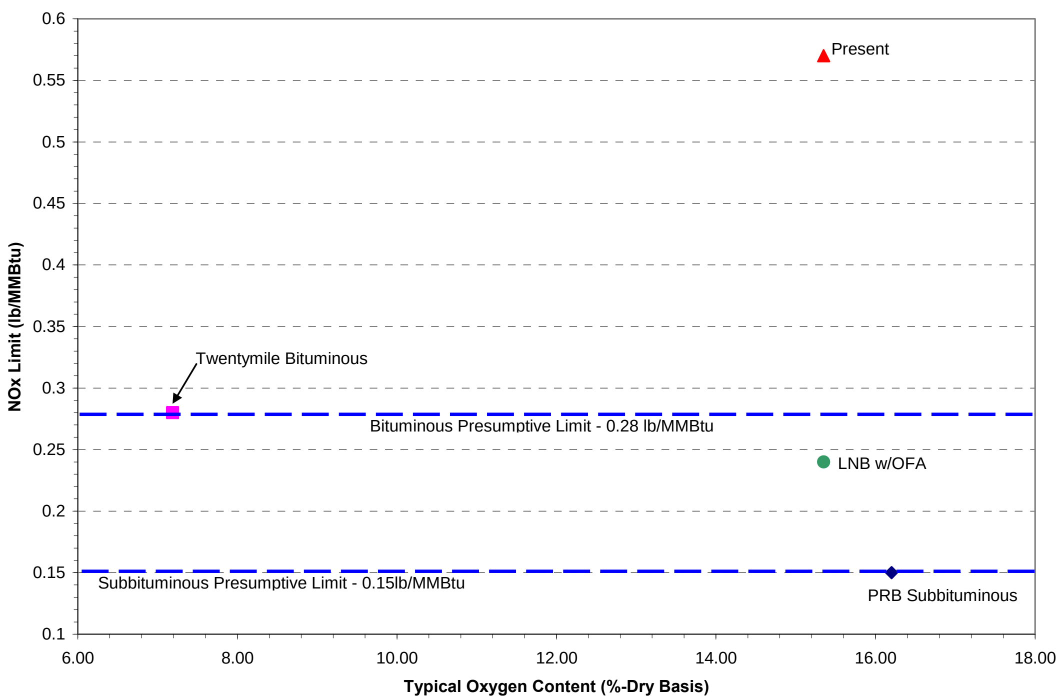


FIGURE 3-3
Plot of Typical Oxygen Content of Various Coals and Applicable Presumptive BART NO_x Limits
Naughton 1



Coal quality characteristics also impact the design and operation of the boiler and associated auxiliary equipment. Minor changes in quality can sometimes be accommodated through operational adjustments or changes to equipment. It is important to note, however, that consistent variations in quality or assumptions of "average" quality for performance projections can be problematic. This is particularly troublesome when dealing with performance issues that are very sensitive to both coal quality and combustion conditions, such as NO_x formation. There can be significant variability in the quality of coals at mines, such as the P&M mine that is burned at Naughton 1.

Several of the coal quality characteristics and their effect on NO_x formation have been previously discussed. There are some additional considerations that illustrate the complexity of achieving and maintaining low NO_x emissions with pulverized coal on a consistently shorter term, such as a 30-day rolling average basis.

Good combustion is based on the "three Ts": time, temperature, and turbulence. These parameters, along with a "design" coal, are taken into consideration when designing a boiler and associated firing equipment such as fans, burners, and pulverizers. If a performance requirement such as NO_x emission limits is subsequently changed, conflicts with and between other performance issues can result.

Naughton 1 is located at an altitude of 6,936 feet above sea level. At this elevation, atmospheric pressure is lower (11.3 lbs per square inch) as compared with sea level pressure of 14.7 lbs per square inch. This lower pressure means that less oxygen is available for combustion for each volume of air. In order to provide adequate oxygen to meet the requirements for efficient combustion, larger volumes of air are required. When adjusting air flows and distribution to reduce NO_x emissions using LNBs and OFA, original boiler design restrictions again limit the modifications that can be made and still achieve satisfactory combustion performance.

Another significant factor in controlling NO_x emissions is the fineness of the coal entering the burners. Fineness is influenced by the grindability index (Hardgrove) of the coal. Finer coal particles promote release of volatiles and assist char burnout due to more surface area exposed to air. NO_x reduction with high-volatile coals is improved with greater fineness and with proper air staging. Coal fineness can deteriorate over time periods between pulverizer maintenance and service as pulverizer grinding surfaces wear.

When all the factors—of agglomeration versus non-agglomeration, nitrogen and oxygen content of the coals, and the grindability index—are taken into account, this analysis demonstrates that for the coal used at Naughton 1, LNB technology referred to in the EPA's presumptive BART analysis will achieve NO_x reductions similar the rates identified for tangentially fired boilers that burn bituminous coals. The current NO_x emission rate at Naughton 1 is 0.58 lb per MMBtu.

Step 1: Identify All Available Retrofit Control Technologies

The first step of the BART process is to evaluate NO_x control technologies with practical potential for application to Naughton 1, including those control technologies identified as Best Available Control Technology (BACT) or lowest achievable emission rate by permitting agencies across the United States. A broad range of information sources have been reviewed in an effort to identify potentially applicable emission control technologies. NO_x emissions from Naughton 1 are currently controlled through the use of good combustion practices and OFA.

The following potential NO_x control technology options were considered:

- New/modified LNB with advanced OFA
- Mobotec rotating opposed fire air (ROFA)
- Conventional selective non-catalytic reduction (SNCR) system
- Selective catalytic reduction (SCR) system

Step 2: Eliminate Technically Infeasible Options

For Naughton 1 technical feasibility will primarily be determined by physical constraints and boiler configuration. Naughton 1 has an uncontrolled NO_x emission rate of 0.58 lb per MMBtu.

For this BART analysis, information pertaining to LNBs, OFA, SNCR, and SCR were based on the *Multi-Pollutant Control Report* (Sargent and Lundy, 2002, hereafter referred to as the S&L Study). Updated cost estimates for SCR and SNCR were used (Sargent & Lundy, 2006). PacifiCorp provided additional emissions data and costs developed by boiler vendors for LNBs and OFA. Also, CH2M HILL solicited a proposal from Mobotec for their ROFA technology.

With SNCR, an amine-based reagent such as ammonia, or more commonly urea, is injected into the furnace within a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 40 to 60 percent have been achieved, although 15 to 30 percent is more realistic for most applications. SNCR is typically applied on smaller units. Adequate reagent distribution in the furnaces of large units can be problematic.

Table 3-2 summarizes the control technology options evaluated in this BART analysis, along with projected NO_x emission rates.

TABLE 3-2
NO_x Control Technology Projected Emission Rates
Naughton 1

Technology	Projected Emission Rate (pounds per million British thermal units)
Bituminous Presumptive Limit	0.28
Low-NO_x Burner (LNB) with Over-fire Air (OFA)	0.24
Rotating Opposed Fire Air	0.26
LNB with OFA and Selective Non-catalytic Reduction System	0.19
LNB with OFA and Selective Catalytic Reduction System	0.07

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Preliminary vendor proposals, such as those used to support portions of this BART analysis, may be technically feasible and provide expected or guaranteed emission rates; however, the proposals include inherent uncertainties. These proposals are usually prepared in a limited timeframe, may be based on incomplete information, may contain over-optimistic conclusions, and are non-binding. Therefore, emission rate values obtained in such preliminary proposals must be qualified, and it must be recognized that contractual guarantees are established only after more detailed analysis has been completed. The following subsections describe the control technologies and the control effectiveness evaluated in this BART analysis.

New LNBs with OFA System. The mechanism used to lower NO_x with LNBs is to stage the combustion process and provide a fuel-rich condition initially; this is so oxygen needed for combustion is not diverted to combine with nitrogen and form NO_x. Fuel-rich conditions favor the conversion of fuel nitrogen to N_2 instead of NO_x. Additional air (or OFA) is then introduced downstream in a lower temperature zone to burn out the char.

Both LNBs and OFA are considered to be capital cost, combustion technology retrofits. Information provided to CH2M HILL by PacifiCorp—based on the S&L Study and data from boiler vendors—indicates that new LNB and OFA retrofit at Naughton 1 would result in an expected NO_x emission rate of 0.24 lb per MMBtu. PacifiCorp has indicated that this rate corresponds to a vendor guarantee plus an added operating margin, not a vendor prediction, and they believe that this emission rate can be sustained as an average between overhauls. This emission rate represents a significant reduction from the NO_x emission rate of 0.58 lb per MMBtu.

ROFA. Mobotec markets ROFA as an improved second-generation OFA system. Mobotec states that "the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles. Rotation is reported to prevent laminar flow, so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. The combustion air is also mixed more effectively." A typical ROFA installation would have a booster fan(s) to supply the high-velocity air to the ROFA boxes, and Mobotec would propose one 1,900-horsepower fan for Naughton 1.

Mobotec expects to achieve a NO_x emission rate of 0.24 lb per MMBtu using ROFA technology. An operating margin of 0.02 lb per MMBtu was added to the expected rate due to Mobotec's limited ROFA experience with western sub-bituminous coals. Under the Mobotec proposal, primarily based on ROFA equipment, the operation of existing burners was analyzed. While a typical installation does not require modification to the existing burner system, results of computational fluid dynamics modeling will determine the quantity and location of new ROFA ports. The Mobotec proposal includes bent tube assemblies for ROFA port installation.

Mobotec does not provide installation services, because they believe that the Owner can more cost-effectively contract for these services. However, they do provide one onsite construction supervisor during installation and startup.

Because of the expected marginal emission rate improvement, the burden of significant ongoing parasitic costs, the operating difficulties and the lack of vendor experience with sub-bituminous coals, ROFA was not considered in the post-control modeling scenarios.

SNCR. Selective non-catalytic reduction is generally used to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia—or more commonly urea—is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60 percent have been achieved, although 20 to 40 percent is more realistic for most applications.

Reagent utilization, which is a measure of the efficiency with which the reagent reduces NO_x, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create problems downstream. The ammonia may render fly ash unsaleable, react with sulfur to foul heat exchange surfaces, and/or create a visible stack plume. Reagent utilization can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost.

Reductions from higher baseline concentrations (inlet NO_x) are lower in cost per ton, but result in higher operating costs because of greater reagent consumption. To reduce reagent costs, S&L has assumed that combustion modifications including LNBs and advanced OFA, capable of achieving a projected NO_x emission rate of 0.24 lb per MMBtu. At a further reduction of 20 percent in NO_x emission rates for SNCR would result in a projected emission rate of 0.19 lb per MMBtu.

Because of the expected marginal emission rate improvement, the burden of significant ongoing parasitic costs, the operating difficulties and the potential ammonia slip emission problems; SNCR was not considered in the post-control modeling scenarios.

SCR. SCR works on the same principle as SNCR but it uses a catalyst to promote the reaction. Ammonia is injected into the flue-gas stream, where it reduces NO_x to nitrogen and water. Unlike the high temperatures required for SNCR, the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580°F to 750°F. As a result of the catalyst, the SCR process is more efficient than SNCR. The most common type of SCR is the high-dust configuration where the catalyst is located downstream from the boiler economizer and upstream of the air heater and any 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. The high-dust configuration is assumed for Naughton 1. In a full-scale SCR, the flue ducts are routed to a separate large reactor containing the catalyst. With in-duct SCR, the catalyst is located in the existing gas duct, which may be expanded in the area of the catalyst to increase flue gas residence time. Due to the higher removal rate, a full-scale SCR was used as the basis for analysis at Naughton 1.

S&L prepared the design conditions and cost estimates for SCR at Naughton 1. As with SNCR, it is generally more cost effective to reduce NO_x emission levels as much as possible through combustion modifications to minimize the catalyst surface area and ammonia requirements of the SCR. To reduce reagent costs, S&L has assumed that combustion modifications, including LNBs and OFA, providing a NO_x emission rate of 0.24 lb per MMBtu, would be installed in conjunction with the SCR. The S&L design basis results in a projected NO_x emission rate of 0.07 lb per MMBtu. Additional catalyst surface was included in the SCR design to accommodate the characteristics of the coal used at Naughton 1.

Level of Confidence for Vendor Post-Control Emissions Estimates. To determine the level of NO_x emissions needed to consistently achieve compliance with an established goal, a review of typical NO_x emissions from coal-fired generating units was completed. As a result of this review, it was noted that NO_x emissions can vary significantly around an average emissions level. Variations may result for many reasons, including coal characteristics, unit load, boiler operation including excess air, boiler slagging, burner equipment condition, coal mill fineness, and so forth.

The steps used for determining a level of confidence for the vendor expected values are as follows:

1. Establish expected NO_x emissions value from vendor.
2. Evaluate vendor experience and historical basis for meeting expected values.
3. Review and evaluate unit physical and operational characteristics and restrictions. The fewer variations in operations, coal supply, etc., the more predictable and less variant the NO_x emissions are.
4. For each technology expected value, there is a corresponding potential for actual NO_x emissions to vary from this expected value. From the vendor information presented, along with anticipated unit operational data, an adjustment to the expected value can be made.

Step 4: Evaluate Impacts and Document the Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. Installation of LNBs with OFA is not expected to significantly impact the boiler efficiency or forced-draft fan power usage. Therefore, these technologies will not have energy impacts.

The Mobotec ROFA system would require installation and operation of one 1,900 horsepower ROFA fan.

SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch increase. Total additional power requirements for SCR installation at Naughton 1 are estimated at approximately 980 kilowatts, based on the S&L Study.

Environmental Impacts. Mobotec has predicted that the ROFA system may result in an increase in CO emissions and unburned carbon in the ash, commonly referred to as loss on ignition would be the same or lower than previous levels. Installation of LNBs with OFA may also result in higher carbon monoxide emissions and loss on ignition, which will result in unburned carbon in the ash.

SCR installation could impact the saleability and disposal of fly ash due to ammonia levels, and could potentially create a visible stack plume, which may negate other visibility improvements. Other environmental impacts involve the storage of ammonia, especially if anhydrous ammonia is used, and the transportation of the ammonia to the power plant site.

Economic Impacts. Costs and schedules for the LNBs, OFA, SNCR, and SCR were furnished to CH2M HILL by PacifiCorp, developed using S&L's internal proprietary database, and supplemented (as needed) by vendor-obtained price quotes. The relative accuracy of these cost estimates is stated by S&L to be in the range of plus or minus 20 percent. Cost for the ROFA system was obtained from Mobotec to which construction and other costs were added to make a comparable estimate.

A comparison of the technologies on the basis of costs, design control efficiencies, and tons of NO_x removed is summarized in Table 3-3, and the first year control costs are presented in Figure 3-4. The complete economic analysis is contained in Appendix A.

TABLE 3-3
NO_x Control Cost Comparison
Naughton 1

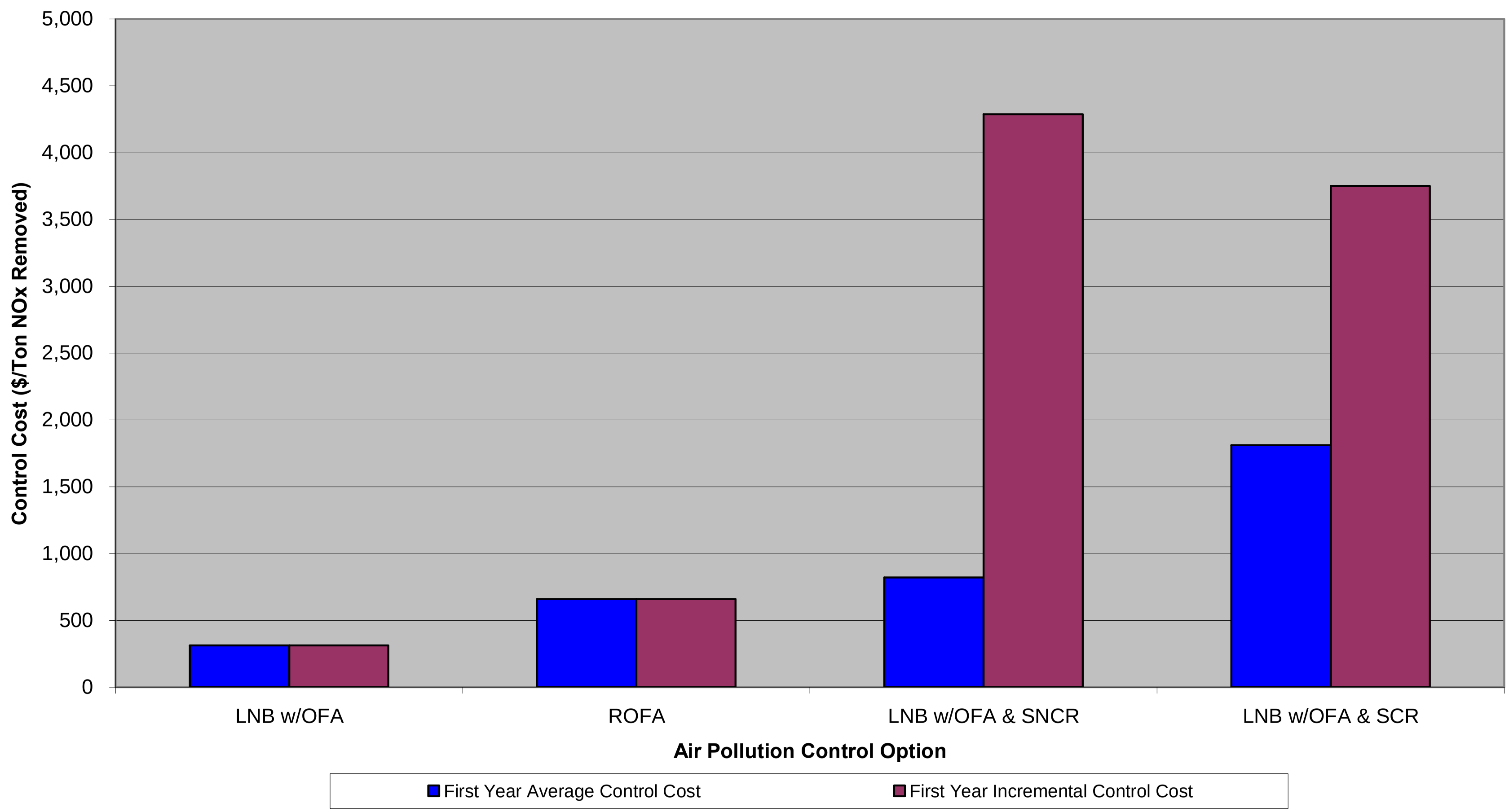
Factor	Low NOx Burner with (LNB) with Over-fire Air (OFA)	Rotating Opposed Fire Air	LNB with OFA and Selective Non-catalytic Reduction System	LNB with OFA and Selective Catalytic Reduction System
Total Installed Capital Costs	$7.3 million	$9.1 million	$17.5 million	$58.2 million
Total First Year Fixed & Variable Operation and Maintenance Costs	$0.1 million	$0.7 million	$0.7 million	$1.2 million
Total First Year Annualized Cost	$0.8 million	$1.5 million	$2.3 million	$6.7 million
Power Consumption (megawatts)	--	1.4	0.2	1.0
Annual Power Usage (1000 megawatt-hours per year)	--	11.2	1.3	7.7
NO_x Design Control Efficiency	58.6%	55.2%	67.2%	87.9%
Tons NO_x Removed per Year	2,480	2,334	2,844	3,719
First Year Average Control Cost ($ per Ton of Nitrogen Oxides Removed)	312	660	822	1,812
Incremental Control Cost ($ per Ton of Nitrogen Oxides Removed)	312	660	4,287	3,751

Preliminary BART Selection. CH2M HILL recommends selection of LNBs with OFA as BART for Naughton 1, based on its significant reduction in NO_x emissions, reasonable control cost, and no additional power requirements or environmental impacts. As discussed in the section on coal quality, the recommended technology and the achieved emission rate are deemed appropriate as BART for NO_x emissions from the coals combusted at Naughton 1.

Step 5: Evaluate Visibility Impacts

Please see Section 4, BART Modeling Analysis.

FIGURE 3-4
First Year Control Cost for NO_x Air Pollution Control Options
Naughton 1



3.2.2 BART SO_2 Analysis

Sulfur dioxide forms in the boiler during the combustion process, and is primarily dependent on coal sulfur content. The BART analysis for SO_2 emissions on Naughton 1 is described in this section.

Step 1: Identify All Available Retrofit Control Technologies

A broad range of information sources were reviewed in an effort to identify potentially applicable emission control technologies for SO_2 at Naughton 1, including control technologies identified as BACT or lowest achievable emission rate by permitting agencies across the United States.

The following potential SO_2 control technology options were considered:

- Dry flue gas desulfurization (FGD) with existing ESP
- Dry FGD with new fabric filter
- Wet lime/limestone FGD with existing ESP and new stack

Step 2: Eliminate Technically Infeasible Options

Naughton 1 currently has an uncontrolled SO_2 emission rate of approximately 1.20 lb per MMBtu.

Dry FGD with Existing ESP. The lime spray dryer typically injects lime slurry in the top of the absorber vessel with a rapidly rotating atomizer wheel. The rapid speed of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas. The SO_2 in the flue gas reacts with the calcium in the lime slurry to form calcium sulfate in the form of particulate matter. At Naughton 1, this dry particulate matter would be captured in the downstream existing ESP, along with the fly ash. A lime spray dryer system typically produces a dry waste product suitable for landfill disposal.

Dry FGD with the existing ESP is projected to achieve 85 percent SO_2 removal using the lower sulfur coal. This would result in a controlled SO_2 emission rate from Naughton 1 equal to 0.18 lb per MMBtu, based on an average coal sulfur content of 0.58 percent by weight. Therefore, this option cannot meet a limit of 0.15 lb per MMBtu.

Similarly, with coal having a higher sulfur content of 1.02 percent, the controlled SO_2 emission rate is projected to be 0.41 lb per MMBtu. Therefore, this option cannot meet a limit of 0.15 lb per MMBtu.

Lime Spray Drying FGD with New Fabric Filter. If the existing ESP is replaced with a fabric filter located downstream of the lime spray dryer; by using the lower sulfur coal, an 87.5 percent SO_2 removal is projected, allowing the facility to meet a limit of 0.15 lb per MMBtu.

However, if higher sulfur coal at 1.02 percent sulfur is used, the controlled SO_2 emission rate is projected to be 0.21 lb per MMBtu. Therefore, this option cannot meet a limit of 0.15 lb per MMBtu.

Wet Lime/Limestone FGD. Wet SO_2 scrubbers operate by flowing the flue gas upward through a large reactor vessel that has an alkaline reagent (typically a lime or limestone slurry) flowing down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to distribute the reagent across the scrubber vessel. The calcium in the reagent reacts with the SO_2 in the flue gas to form calcium sulfite and/or calcium sulfate, which are removed from the scrubber with the sludge, and disposed. Most wet FGD systems use forced oxidation to assure that only calcium sulfate sludge is produced. The wet lime/limestone forced oxidation process is used in most new wet FGD installations. Several variations on wet FGD technology are offered by various process developers. These variations include using a jet bubbling reactor as a combination SO_2 absorber and calcium sulfite oxidation vessel, and using magnesium enhanced lime as the alkaline reagent.

Wet lime/limestone scrubbing is projected to achieve 90 to 95 percent SO_2 removal. At Naughton 1, this removal efficiency is projected to meet a limit of 0.15 lb per MMBtu if low or high sulfur coal is used with the existing ESP.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Table 3-4 summarizes the projected emission rates for the FGD technologies being evaluated for Naughton 1.

TABLE 3-4
SO_2 Control Technology Emission Rates
Naughton 1

Control Technology	Projected Sulfur Dioxide Emission Rate (pounds per million British thermal units)
Bituminous Presumptive Limit	0.15
Dry Flue Gas Desulfurization (FGD) with existing Electrostatic Precipitator (ESP)	0.41
Dry FGD with fabric filter	0.15
Wet FGD with existing ESP and new stack	0.10

Step 4: Evaluate Impacts and Document the Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. A dry FGD system with the existing ESP has the advantage of requiring less electric power for its operation, compared to a wet FGD system. A dry FGD system at Naughton 1 using the existing ESP would require approximately 1.6 MW of power, compared to approximately 2.4 MW for wet FGD. Based on a 90 percent annual plant capacity factor, this would equate to an annual power savings of approximately 5.9 million kilowatt-hours (kWh) for dry FGD versus wet FGD.

Environmental Impacts. The dry FGD system has the following environmental advantages when compared to wet FGD technology:

- **Sulfuric Acid Mist.** Sulfur trioxide (SO_3) in the flue gas, which condenses to liquid sulfuric acid at temperatures below the acid dew point, is removed efficiently with a lime spray dryer system. Wet scrubbers capture less than 40 to 60 percent of SO_3 and may require the addition of a wet ESP or hydrated lime injection when medium to high sulfur coal is burned in a unit to remove the balance of SO_3. Otherwise, the emission rate rankings are shown in Table 3-4 of sulfuric acid mist, if above a threshold value, may result in a visible plume after the vapor plume dissipates.
- **Plume Buoyancy.** Flue gas following a dry FGD system is not saturated with water (30°F to 50°F above dew point), which reduces or eliminates a visible moisture plume. Wet FGD scrubbers produce flue gas that is saturated with water, which would require a gas-gas heat exchanger to reheat the flue gas if it were to operate as a dry stack. Due to the high capital and operating costs associated with heating the flue gas, all recent wet FGD systems in the United States have used wet stack operation.
- **Liquid Waste Disposal.** There is no liquid waste from a dry FGD system. However, wet FGD systems produce a wastewater blowdown stream that must be treated to limit chloride buildup in the absorber scrubbing loop. In some cases, a wastewater treatment plant must be installed to treat the liquid waste prior to disposal. The wastewater treatment plant would produce a small volume of solid waste, which may contain toxic metals and may require special considerations for disposal.
- **Solid Waste Disposal.** The creation of a wet sludge from the wet FGD process creates a solid waste handling and disposal challenge. This sludge needs to be handled properly to prevent groundwater contamination. Wet FGD systems can produce saleable gypsum if a gypsum market is available, reducing the quantity of solid waste from the power plant that needs to be disposed.
- **Makeup Water Requirements.** Dry FGD has advantages over a wet scrubber, producing a dry waste material and requiring less makeup water in the absorber. Given that water is a valuable commodity in Wyoming, the reduced water consumption required for dry FGD is major advantage for this technology.

Economic Impacts. A summary of the costs and amount of SO_2 removed for each technology option is provided in Table 3-5, and a comparison of the first year control cost (dollars per ton removed) is shown in Figure 3-5. The complete Economic Analysis is contained in Appendix A.

TABLE 3-5
SO_2 Control Cost Comparison (Incremental to Existing FGD System)
Naughton 1

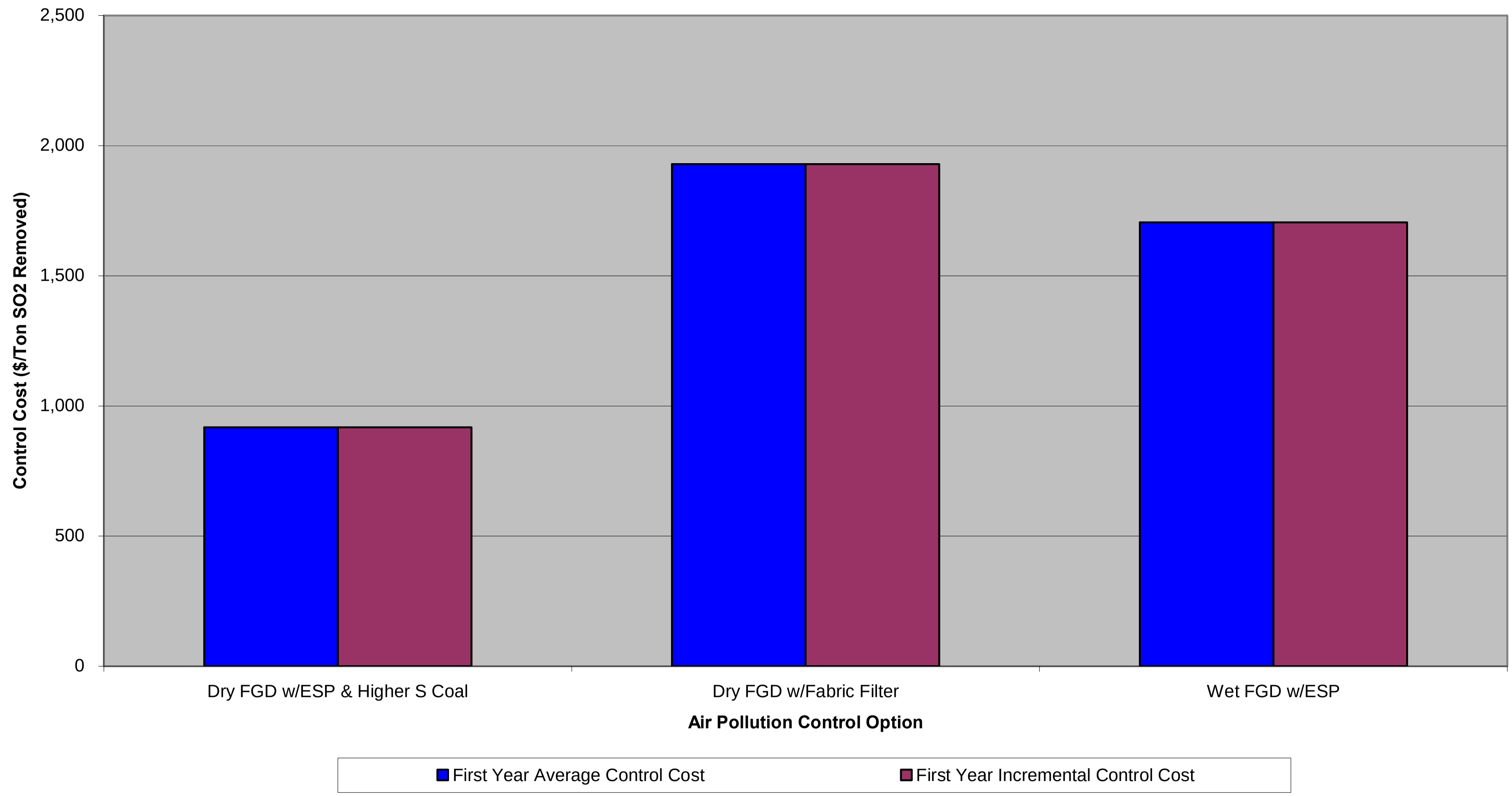
Factor	Dry Flue Gas Desulfurization (FGD) with Electrostatic precipitator (ESP)	Dry FGD with Fabric Filter	Wet FGD
Total Installed Capital Costs	$64.3 million	$109.0 million	$91.7 million
Total First Year Fixed & Variable Operation and Maintenance Costs	$5.0 million	$4.2 million	$4.7 million
Total First Year Annualized Cost	$11.1 million	$14.5 million	$13.5 million
Power Consumption (megawatts)	1.6	2.7	2.4
Annual Power Usage (1000 megawatt-hours per year)	13.0	20.9	18.9
Sulfur Dioxide Design Control Efficiency	80.1%	87.3%	91.5%
Tons Sulfur Dioxide Removed per Year	12,061	7,530	7,895
First Year Average Control Cost ($ per ton of Sulfur Dioxide Removed)	918	1,929	1,705
Incremental Control Cost ($ per ton of Sulfur Dioxide Removed)	918	1,929	1,705

Preliminary BART Selection. CH2M HILL recommends the combination of using a dry FGD system with the existing ESP, and using a coal with a sulfur content that does not exceed 1.02 percent by weight, as BART for Naughton 1 based on its significant reduction in SO_2 emissions, reasonable control costs, and the advantages of minimal additional power requirements and environmental impacts.

Step 5: Evaluate Visibility Impacts

Please see Section 4, BART Modeling Analysis.

FIGURE 3-5
First Year Control Cost for SO_2 Air Pollution Control Options
Naughton 1



3.2.3 BART PM_{10} Analysis

Naughton 1 is currently equipped with a mechanical dust collector and an ESP. ESPs remove particulate matter from the flue gas stream by charging fly ash particles with a very high direct current voltage, and attracting these particles to grounded collection plates. A layer of collected particulate matter forms on the collecting plates and is removed by periodically rapping the plates. The collected ash particles drop into hoppers below the precipitator and are removed periodically by the fly ash-handling system. Historically, the ESP at Naughton 1 has controlled PM_{10} emissions to levels of 0.056 lb per MMBtu.

The BART analysis for PM_{10} emissions from Naughton 1 is described in this section. For the modeling analysis in Section 4, PM_{10} was used as an indicator for particulate matter, and PM_{10} includes $PM_{2.5}$ as a subset.

Step 1: Identify All Available Retrofit Control Technologies

Three retrofit control technologies have been identified for additional particulate matter control:

- Flue gas conditioning (FGC)
- Polishing fabric filter
- Replacement fabric filter

Step 2: Eliminate Technically Infeasible Options

FGC. If the fly ash from coal has high resistivity, such as fly ash from sub-bituminous coal, the ash is not collected effectively in a small ESP. This is because the high resistivity makes the particles less willing to accept an electrical charge. Adding FGC, which is typically accomplished by injection of SO_3, will lower the resistivity of the particles so that they will accept more charge and allow the ESP to collect the ash more effectively. Adding FGC can account for large improvements in collection efficiency for small ESPs.

Polishing Fabric Filter. A polishing fabric filter could be added downstream of the existing ESP at Naughton 1. One such technology is licensed by the Electric Power Research Institute, and referred to as a Compact Hybrid Particulate Collector (COHPAC). The COHPAC collects the ash that is not collected by the ESP, thus acting as a polishing device. The ESP needs to be kept in service for the COHPAC fabric filter to operate effectively.

The COHPAC fabric filter is about one-half to two-thirds the size of a full size fabric filter, because the COHPAC has a higher air-to-cloth ratio (7 to 9:1), compared to a full size pulse jet fabric filter (3.5 to 4:1).

Replacement Fabric Filter. Another available control technology is replacing the existing ESP with a new fabric filter. However, because the environmental benefits that would be achieved by a replacement fabric filter are also achieved by installing a polishing fabric filter downstream of the existing ESP at lower costs, installation of a full fabric filter was not considered to be cost-effective in the analysis.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

The existing ESP at Naughton 1 is achieving a controlled particulate matter emission rate of 0.056 lb per MMBtu. Adding FGC upstream of the existing ESP is projected to reduce particulate matter emissions to approximately 0.040 lb per MMBtu. Adding a COHPAC fabric filter downstream of the existing ESP is projected to reduce particulate matter emissions to approximately 0.015 lb per MMBtu. A replacement fabric filter is also projected to reduce particulate matter emissions to approximately 0.015 lb per MMBtu.

The PM_{10} control technology emission rates are summarized in Table 3-6.

TABLE 3-6
PM_{10} Control Technology Emission Rates
Naughton 1

Control Technology	Projected PM_{10} Emission Rate (pounds per million British thermal units)
Flue Gas Conditioning	0.040
Polishing Fabric Filter	0.015
Replacement Fabric Filter	0.015

Step 4: Evaluate Impacts and Document the Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. Energy is required to overcome the additional pressure drop from the COHPAC fabric filter and associated ductwork. Therefore, a COHPAC retrofit will require an induced draft fan upgrade and upgrade of the auxiliary power supply system.

A COHPAC fabric filter at Naughton 1 would require approximately 1.0 MW of power, equating to an annual power usage of approximately 8.0 million kWh, based on a 90 percent annual plant capacity factor.

There are no negative environmental impacts from the addition of an FGC system.

Environmental Impacts. There are no negative environmental impacts from the addition of a COHPAC polishing fabric filter or FGC system.

Economic Impacts. A summary of the costs and particulate matter removed for COHPAC and FGCs are recorded in Table 3-7, and the first-year control costs for FGC and fabric filters are shown in Figure 3-6. The complete economic analysis is contained in Appendix A.

TABLE 3-7
PM_{10} Control Cost Comparison
Naughton 1

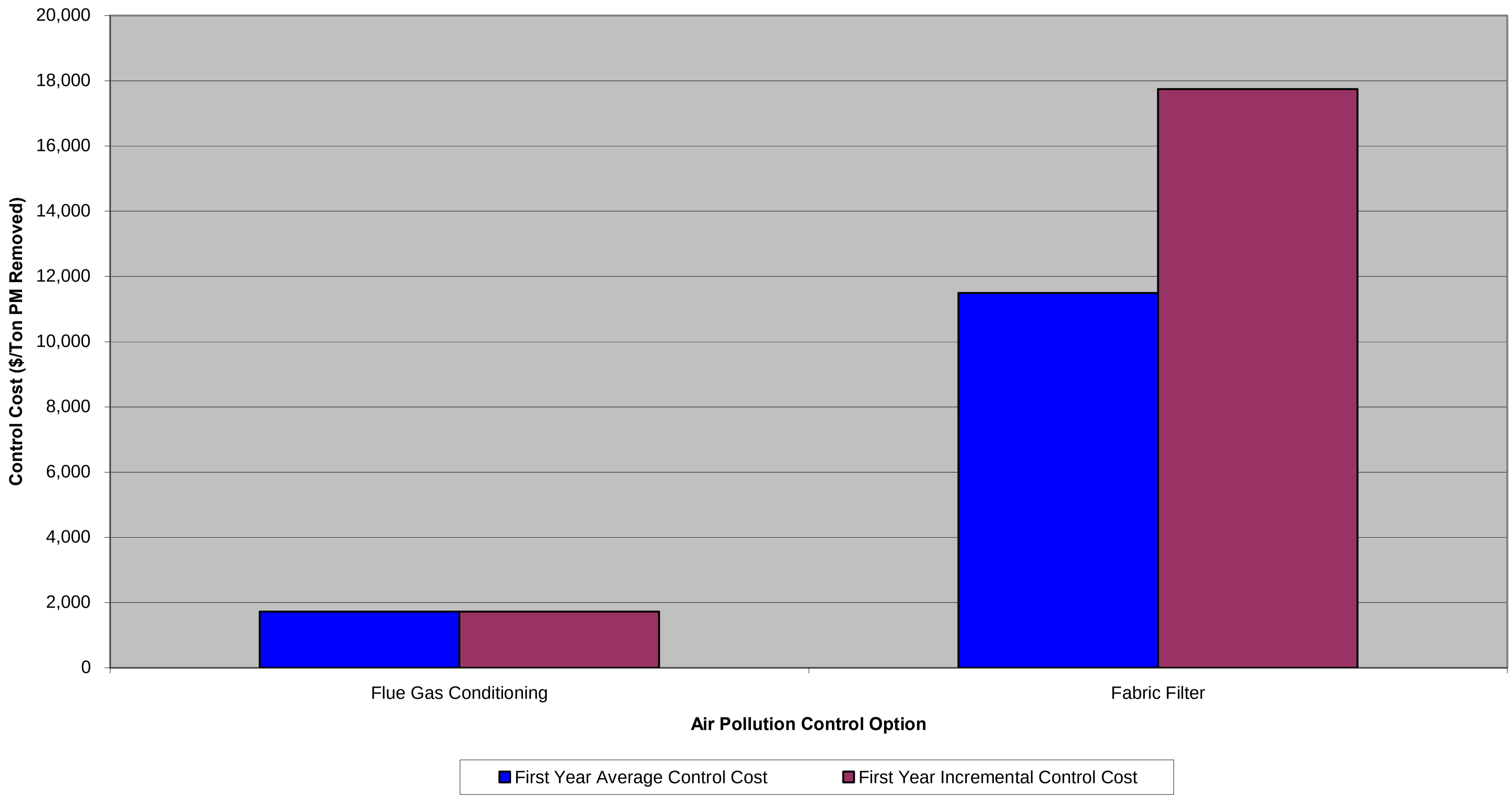
Factor	Flue Gas Conditioning	Polishing Fabric Filter
Total Installed Capital Costs	$1.3 million	$29.8 million
Total First Year Fixed & Variable O&M Costs	$0.1 million	$0.6 million
Total First Year Annualized Cost	$0.2 million	$3.4 million
Power Consumption (megawatts)	0.1	1.01
Annual Power Usage (kilowatt-hours per year)	0.4	8.0
Particulate Matter Design Control Efficiency	28.6%	73.2%
Tons PM Removed per Year	117	299
First Year Average Control Cost ($ per Ton of Particulate Matter Removed)	1,721	11,493
Incremental Control Cost ($ per Ton of Sulfur Dioxide Removed)	1,721	17,747

Preliminary BART Selection. CH2M HILL recommends adding FCG to the existing ESP as BART for Naughton 1, based on the significant reduction in PM_{10} emissions, reasonable control costs, and the advantages that both do not create additional power requirements or non-air quality environmental impacts.

Step 5: Evaluate Visibility Impacts

Please see Section 4, BART Modeling Analysis.

FIGURE 3-6
First Year Control Cost for PM Air Pollution Control Options
Naughton 1



4.0 BART Modeling Analysis

4.1 Model Selection

CH2M HILL used a Gaussian puff dispersion modeling system (CALPUFF) to assess the visibility impacts of emissions from Naughton 1 at Class I areas. The Class I areas potentially affected are located more than 50 kilometers but less than 300 kilometers from the Naughton 1 Plant. These wilderness areas include the following:

- Bridger Wilderness Area
- Fitzpatrick Wilderness Area

The CALPUFF modeling system includes the CALMET meteorological model, CALPUFF with algorithms for chemical transformation and deposition, and a post processor capable of calculating concentrations, visibility impacts, and deposition (CALPOST). The CALPUFF modeling system was applied in a full, refined mode. The following version numbers of the various programs in the CALPUFF system were used by CH2M HILL:

- CALMET Version 5.53a, Level 040716
- CALPUFF Version 5.711a, Level 040716
- CALPOST Version 5.51, Level 030709

4.2 CALMET Methodology

4.2.1 Dimensions of the Modeling Domain

CH2M HILL used the CALMET model to generate a three-dimensional wind field and other meteorological parameters suitable for use by the CALPUFF model. A modeling domain was established to encompass the Naughton 1 facility and allow for a 50-kilometer buffer around the Class I areas that were within 300 kilometers of the facility. Grid resolution was 4 kilometers. Figure 4-1 shows the extent of the modeling domain. Except when specifically instructed otherwise by the Wyoming Department of Environmental Quality—Air Quality Division (WDEQ-AQD), CH2M HILL followed the methodology spelled out in the BART Modeling Protocol, which is included in this report as Appendix B. This protocol was prepared by the WDEQ-AQD.

CH2M HILL used the Lambert Conformal Conic map projection for the analysis due to the large extent of the domain. The latitude of the projection origin and the longitude of the central meridian were chosen at the approximate center of the domain. Standard parallels were drawn to represent one-sixth and five-sixths of the north-south extent of the domain to minimize distortion in the north-south direction.

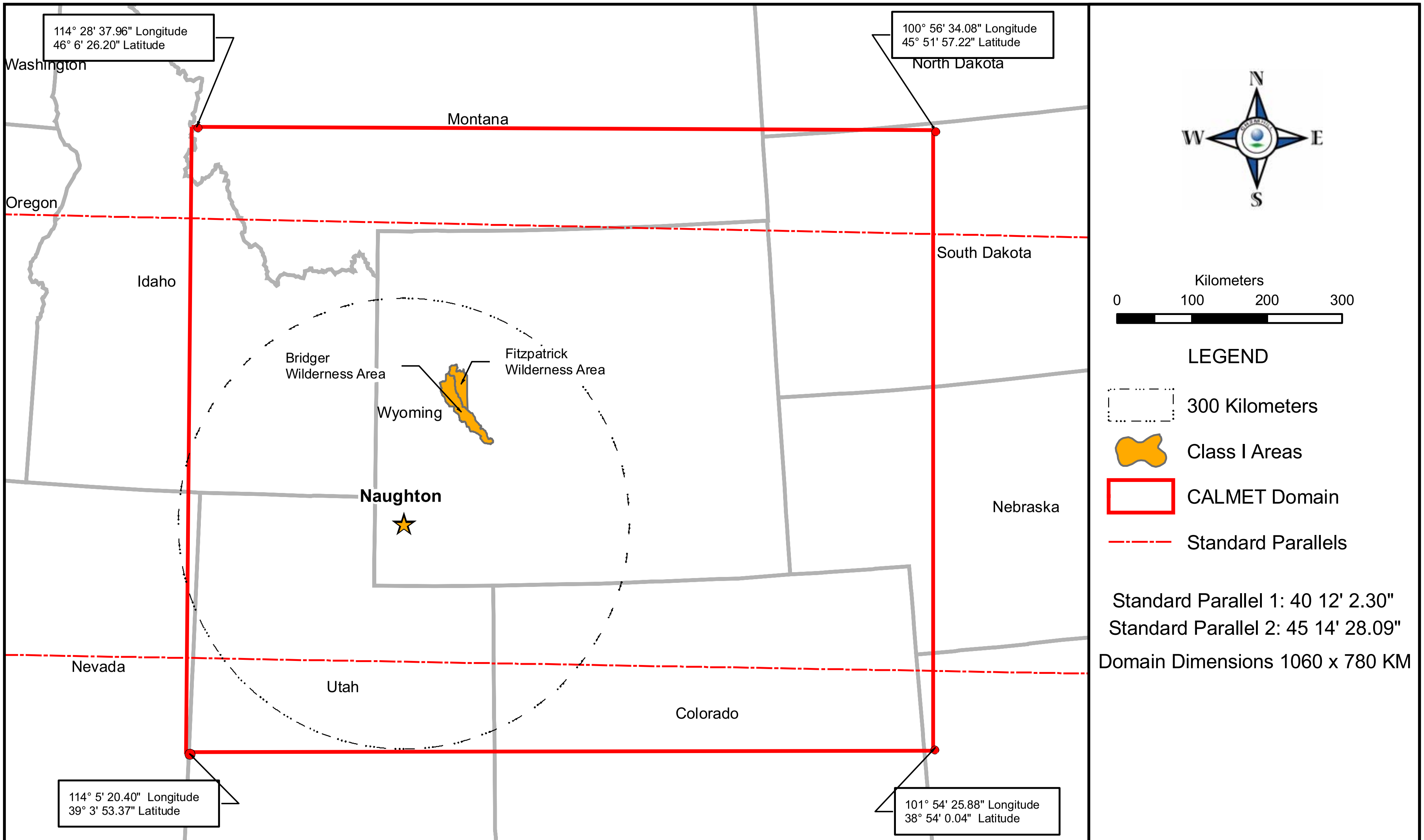


Figure 4-1
Naughton Source-Specific
Class I Areas to be Addressed

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The default technical options listed in TRC Companies, Inc.'s (TRC) current example CALMET.inp file were used for CALMET. Vertical resolution of the wind field included 10 layers, with vertical face heights as follows (in meters):

- 0, 20, 40, 100, 140, 320, 580, 1020, 1480, 2220, 3500

Other user-specified model options were set to values established by WDEQ-AQD that appear in Table 3 of Appendix B. Table 4-1 lists the key user-specified options used for this analysis.

TABLE 4-1
User-specified CALMET Options
Naughton 1

CALMET Input Parameter	Value
CALMET Input Group 2	
Map projection (PMAP)	Lambert Conformal
Grid spacing (DGRIDKM)	4
Number vertical layers (NZ)	10
Top of lowest layer (m)	20
Top of highest layer (m)	3500
CALMET Input Group 4	
Observation mode (NOOBS)	0
CALMET Input Group 5	
Prog. Wind data (IPROG)	14
(RMAX1)	30
(RMAX2)	50
Terrain influence (TERRAD)	15
(R1)	5
(R2)	25
CALMET Input Group 6	
Max mixing ht (ZIMAX)	3500

4.2.2 CALMET Input Data

CH2M HILL ran the CALMET model to produce 3 years of analysis: 2001, 2002, and 2003. WDEQ-AQD provided 12-kilometers resolution Mesoscale Meteorological Model, Version 5 (MM5) meteorological data fields for each year that covered the entire modeling domain.

These three data sets were chosen because they are current and have been evaluated for quality. The MM5 data were used as input to CALMET as the "initial guess" wind field. The initial guess wind field was adjusted by CALMET for local terrain and land use effects to generate a Step 1 wind field, and further refined using local surface observations to create a final Step 2 wind field.

Surface data for 2001 through 2003 were obtained from the National Climatic Data Center. CH2M HILL processed the data for all stations from the National Weather Service's Automated Surface Observing System network that are in the domain. The surface data were obtained in abbreviated DATSAV3 format. A conversion routine available from the TRC website was used to convert the DATSAV3 files to CD-144 format for input into the SMERGE preprocessor and CALMET.

Land use and terrain data were obtained from the United States Geological Survey (USGS). Land use data were obtained in Composite Theme Grid format from the USGS, and the Level I USGS land use categories were mapped into the 14 primary CALMET land use categories. Surface properties such as albedo, Bowen ratio, roughness length, and leaf area index were computed from the land use values. Terrain data were taken from USGS 1-degree Digital Elevation Model data, which primarily derive from USGS 1:250,000 scale topographic maps. Missing land use data were filled with values that were appropriate for the missing area.

Precipitation data were ordered from the National Climatic Data Center. All available data in fixed-length, TD-3240 format were ordered for the modeling domain. The list of available stations that have collected complete data varies by year, but CH2M HILL processed all available stations/data within the domain for each year. Precipitation data were prepared with the PXTRACT/PMERGE processors in preparation for use within CALMET.

Upper-air data were prepared for the CALMET model with the READ62 preprocessor for the following stations:

- Denver, Colorado
- Salt Lake City, Utah
- Riverton, Wyoming
- Rapid City, South Dakota

Figure 4-2 shows the locations of surface and upper air stations within the MM5 modeling domain.

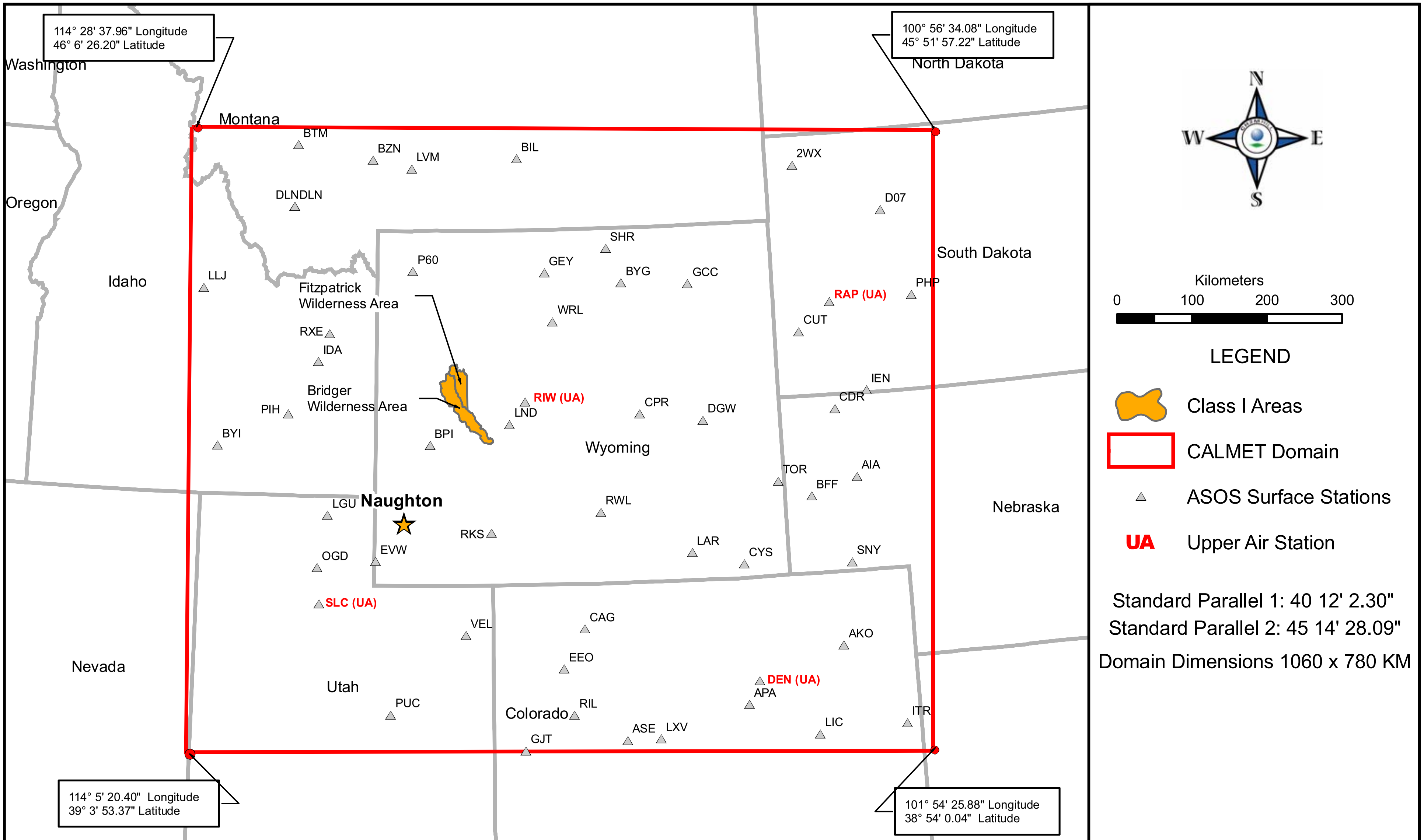

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Figure 4-2
Surface and Upper Air Stations Used in the Naughton BART Analysis

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4.2.3 Validation of CALMET Wind Field

CH2M HILL used the CALDESK data display and analysis system (v2.97, Enviromodeling Ltd.) to view plots of wind vectors and other meteorological parameters to evaluate the CALMET wind fields. The CALDESK displays were compared to observed weather conditions, as depicted in surface and upper-air weather maps (National Oceanic and Atmospheric Administration, 2006).

4.3 CALPUFF Modeling Approach

For the BART control technology visibility improvement modeling, CH2M HILL followed WDEQ-AQD guidance provided (WDEQ-AQD, 2006).

CH2M HILL drove the CALPUFF model with the meteorological output from CALMET over the modeling domain described earlier. The CALPUFF model was used to predict visibility impacts for the pre-control (baseline) scenario for comparison to the predicted impacts for post-control scenarios for Naughton 1.

4.3.1 Background Ozone and Ammonia

Hourly values of background ozone concentrations were used by CALPUFF for the calculation of SO_2 and NO_x transformation with the MESOPUFF II chemical transformation scheme. CH2M HILL obtained hourly ozone data from the following stations located within the modeling domain for 2001, 2002, and 2003:

- Rocky Mountain National Park, Colorado
- Craters of the Moon National Park, Idaho
- Highland, Utah
- Thunder Basin National Grasslands, Wyoming
- Yellowstone National Park, Wyoming
- Centennial, Wyoming
- Pinedale, Wyoming

For periods of missing hourly ozone data, the chemical transformation relied on a monthly default value of 44 parts per billion. Background ammonia was set to 2 parts per billion. Both of these background values were taken from the guidance document (WDEQ-AQD, 2006).

4.3.2 Stack Parameters

The stack parameters used for the baseline modeling reflect those that are in place under the current permit for Naughton 1. Post-control stack parameters reflect the anticipated changes associated with installation of the control technology alternatives that are being evaluated.

4.3.3 Emission Rates

Pre-control emission rates for Dave Johnston 3 reflect peak 24-hour average emissions that may occur under the source's current permit. The emission rates reflect actual emissions under normal operating conditions, as described by the EPA in the *Regional Haze*

Regulations and Guidelines for Best Available Retrofit Technology Determinations; Final Rule (40 CFR Part 51).

CH2M HILL used available continuous emission monitoring data to determine peak 24-hour emission rates. Data reflected operations from the most recent 3- to 5-year period unless a more recent period was more representative. Allowable short-term (24-hour or shorter period) emissions or short-term emission limits were used if continuous emission monitoring data were not available.

Emissions were modeled for the following pollutants:

- SO_2
- NO_x
- Coarse particulate ($PM_{2.5}$<diameter<PM_{10})
- Fine particulate (diameter<$PM_{2.5}$)
- Sulfates

Post-control emission rates reflect the effects of the emissions control scenario under consideration. Modeled pollutants were the same as those listed for the pre-control scenario.

4.3.4 Post-control Scenarios

Four post-control modeling scenarios were developed to cover the range of effectiveness for the combination of the individual NO_x, SO_2, and particulate matter control technologies being evaluated. The selection of each control device was made, based on the engineering analyses performed in Section 3 for reasonable technologies that would meet or exceed the presumptive BART levels for each pollutant—unless it was determined that an alternative control level is justified, based on a careful consideration of the statutory factors evaluated in Sections 3, 4, and 5.

- **Scenario 1**: New LNB with OFA modifications, a dry FGD system, and flue gas conditioning for enhanced ESP performance. As indicated previously, this scenario represents CH2M HILL's preliminary BART recommendation.
- **Scenario 2**: New LNB with OFA modifications, a dry FGD system, and new fabric filter.
- **Scenario 3**: New LNB with OFA modifications and SCR, dry FGD system, and new fabric filter.
- **Scenario 4**: New LNB with OFA modifications and SCR, wet FGD system, flue gas conditioning for enhanced ESP performance, and a new stack.

Table 4-2 presents the stack parameters and emission rates used for the Naughton 1 analysis for baseline and post-control modeling. In accordance with the WDEQ BART modeling protocol, elemental carbon stack emissions and organic aerosol emissions were not modeled.

TABLE 4-2
BART Model Input Data
Naughton 1

	Baseline	Post-control Scenario 1	Post-control Scenario 2	Post-control Scenario 3	Post-control Scenario 4
Model Input Data	**Current Operations with Electrostatic Precipitator (ESP)**	**Low-NO_x Burner (LNB) with Over-fire air (OFA), Dry Flue Gas Desulfurization (FGD), ESP**	**LNB with OFA, Dry FGD, New Fabric Filter**	**LNB with OFA and Selective Catalytic Reduction System (SCR), Dry FGD, New Fabric Filter**	**LNB with OFA and SCR, Wet FGD, ESP with Sulfur Trioxide Injection, New Stack**
Sulfur Dioxide (SO_2) Stack Emissions (pounds per hour [lb/hr])	2,220	759	278	278	185
Nitrogen Oxide (NO_x) Stack Emissions (lb/hr)	1,073	444	444	130	130
PM_{10} Stack Emissions (lb/hr)	104	74.0	27.8	27.8	74.0
Coarse Particulate ($PM_{2.5}$ <diameter< PM_{10}) Stack Emissions (lb/hr)[(a)]	44.5	31.8	15.8	15.8	31.8
Fine Particulate (diameter<$PM_{2.5}$) Stack Emissions (lb/hr)[(b)]	59.1	42.2	11.9	11.9	42.2
Sulfuric Acid (H_2SO_4) Stack Emissions (lb/hr)	34.0	1.67	1.67	2.41	29.2
H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr)	33.3	1.63	1.63	2.36	28.6
Ammonium Sulfate [$(NH_4)_2SO_4$] Stack Emissions (lb/hr)				0.43	2.13
$(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr)				0.31	1.55
$(NH_4)HSO_4$ Stack Emissions (lb/hr)				0.74	3.70
$(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)				0.62	3.09
Total Sulfate (SO_4) (lb/hr)	33.3	1.63	1.63	3.28	33.3
Stack Conditions					
Stack Height (meters)	61	61	61	61	152
Stack Exit Diameter (meters)	4.27	4.27	4.27	4.27	4.88
Stack Exit Temperature (Kelvin)	411	350	342.6	342.6	323
Stack Exit Velocity (meters per second)	28.1	19.69	24.6	24.6	18.1

NOTES:
[(a)]Based on AP-42, Table 1.1-6, the coarse particulates are counted as a percentage of PM_{10}. This equates to 43 percent ESP and 57 percent Baghouse.
[(b)]Based on AP-42, Table 1.1-6, the fine particulates are counted as a percentage of PM_{10}. This equates to 57 percent ESP and 43 percent Baghouse.

Total Sulfate (SO_4) (lb/hr) = H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr) + $(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr) + $(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)

4.3.5 Modeling Process

The CALPUFF modeling for the control technology options for Naughton 1 followed this sequence:

- Model pre-control (baseline) emissions
- Model preferred post-control scenario (if applicable)
- Determine degree of visibility improvement
- Model other control scenarios
- Determine degree of visibility improvement
- Factor visibility results into the BART five-step evaluation

4.3.6 Receptor Grids

Discrete receptors for the CALPUFF modeling were placed at uniform receptor spacing along the boundary and in the interior of each area of concern. Class I area receptors were taken from the National Park Service database for Class I area modeling receptors. The TRC COORDS program was used to convert all latitude/longitude coordinates to Lambert Conformal Conic coordinates, including receptors, meteorological stations, and source locations.

4.4 CALPOST

The CALPOST processor was used to determine 24-hour average visibility results with output specified in deciview (dV) units. Calculations of light extinction were made for each pollutant modeled. The sum of all extinction values were used to calculate the delta deciview (ΔdV) change relative to natural background. The following default extinction coefficients for each pollutant were used:

- Ammonium sulfate 3.0
- Ammonium nitrate 3.0
- PM coarse (PM_{10}) 0.6
- PM fine ($PM_{2.5}$) 1.0
- Organic carbon 4.0
- Elemental carbon 10.0

CALPOST Visibility Method 6 was used to determine the visibility impacts. Monthly relative humidity factors were used in the light extinction calculations to account for the hygroscopic characteristics of nitrate and sulfate particles. Table 5 of the Wyoming BART Air Modeling Protocol (Appendix B) lists the monthly relative humidity factors for the Class I areas. These values were used for the particular Class I area being modeled.

The natural background conditions as a reference for determining the ΔdV change represented the 20 percent best natural visibility days. The EPA BART guidance document provided deciview values for the 10 percent best days for each Class I area, but did not provide individual species concentration data for the 20 percent best background conditions. Species concentrations corresponding to the 20 percent best days were calculated for each Class I area by scaling back the annual average species concentrations given in Table 2-1 of

Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (EPA, 2003). A separate scaling factor was derived for each Class I area such that, when multiplied by the guidance table annual concentrations, the 20 percent best days dV value for that area would be calculated. This procedure was taken from *Protocol for BART-Related Visibility Improvement Modeling Analysis in North Dakota* (North Dakota Department of Health, 2005). However, the Wyoming BART Air Modeling Protocol (see Appendix B) provided natural background concentrations of aerosol components to use in the BART analysis. Table 4-3 lists the annual average species concentrations from the BART protocol.

TABLE 4-3
Average Natural Levels of Aerosol Components
Naughton 1

Aerosol Component	**Average Natural Concentration (micrograms per cubic meter) for Fitzpatrick and Bridger Class I Wilderness Areas**
Ammonium Sulfate	0.045
Ammonium Nitrate	0.038
Organic Carbon	0.178
Elemental Carbon	0.008
Soil	0.189
Coarse Mass	1.136

NOTE:
Taken from Table 6 of the Wyoming BART Air Modeling Protocol

4.5 Presentation of Modeling Results

This section presents the results of the CALPUFF visibility improvement modeling analysis for Naughton 1.

4.5.1 Visibility Changes for Baseline vs. Preferred Scenario

CH2M HILL modeled Naughton 1 for the baseline and its post-control Scenario 1. In addition, three other scenarios were modeled. The post-control scenarios included emission rates for SO_2, NO_x, and PM_{10} that would be achieved if BART state-of-the-art technology were installed on Naughton 1. Some scenarios included controls that would not be able to meet presumptive BART limits where it was determined—based on the statutory factors—that the selection of an alternative control device may be warranted.

Baseline and post-control 98th percentile results were greater than 0.5 ΔdV for the Bridger Wilderness Area, and Fitzpatrick Wilderness Area. The 98th percentile results for each Class I area are presented in Table 4-4.

TABLE 4-4
Costs and Visibility Modeling Results for Baseline vs. Post-Control Scenarios at Class I Areas
Naughton 1

Scenario	Total First Year Annualized Cost	Class I Area	Highest Delta-Deciview (ΔdV)	98th Percentile Delta-Deciview (ΔdV)	No. of Days Above 0.5 Deciview (dV)	Cost per dV Reduction	Cost per Reduction in No. of Days Above 0.5 dV	Incremental Cost per dV Reduction	Incremental Cost per Reduction in No. of Days Above 0.5 dV
2001									
Baseline: current operation with Electrostatic Precipitator (ESP)		Bridger Wilderness Area (WA)	4.649	1.777	48	--	--		
		Fitzpatrick WA	2.769	0.966	23	--	--		
Scenario 1: Low-NO_x Burner (LNB) with Over-fire Air (OFA), dry Flue Gas Desulfurization (FGD), ESP	$12,042,621	Bridger WA	2.015	0.644	14	$10,628,968	$354,195		
	$12,042,621	Fitzpatrick WA	1.192	0.357	3	$19,774,419	$602,131		
Scenario 2: LNB with OFA, dry FGD, fabric filter	$15,299,091	Bridger WA	1.519	0.479	7	$11,786,665	$373,149	$19,736,182	$465,210
	$15,299,091	Fitzpatrick WA	0.864	0.235	2	$20,928,989	$728,528	$26,692,377	$3,256,470
Scenario 3: LNB with OFA and Selective Catalytic Reduction (SCR) System, dry FGD, fabric filter	$21,262,911	Bridger WA	0.692	0.217	1	$13,630,071	$452,402	$22,762,672	$993,970
	$21,262,911	Fitzpatrick WA	0.399	0.119	0	$25,103,791	$924,474	$51,412,241	$2,981,910
Scenario 4: LNB with OFA and SCR, wet FGD, ESP, new stack	$20,399,907	Bridger WA	1.292	0.387	4	$14,676,192	$463,634	NA	NA
	$20,399,907	Fitzpatrick WA	0.597	0.153	1	$25,092,137	$927,269	NA	NA
2002									
Baseline: current operation with ESP		Bridger WA	3.575	1.763	41	--	--		
		Fitzpatrick WA	3.190	0.881	18	--	--		
Scenario 1: LNB with OFA, dry FGD, ESP	$12,042,621	Bridger WA	1.424	0.741	14	$11,783,386	$446,023		
	$12,042,621	Fitzpatrick WA	1.124	0.314	5	$21,239,190	$926,355		
Scenario 2: LNB with OFA, dry FGD, fabric filter	$15,299,091	Bridger WA	1.034	0.635	9	$13,563,024	$478,097	$30,721,415	$651,294
	$15,299,091	Fitzpatrick WA	0.834	0.205	2	$22,631,791	$956,193	$29,875,872	$1,085,490
Scenario 3: LNB with OFA and SCR, dry FGD, fabric filter	$21,262,911	Bridger WA	0.505	0.274	1	$14,279,994	$531,573	$16,520,277	$745,478
	$21,262,911	Fitzpatrick WA	0.389	0.105	0	$27,400,659	$1,181,273	$59,638,200	$2,981,910
Scenario 4: LNB with OFA and SCR, wet FGD, ESP, new stack	$20,399,907	Bridger WA	0.775	0.288	3	$13,830,445	$536,840	NA	NA
	$20,399,907	Fitzpatrick WA	0.591	0.108	1	$26,390,565	$1,199,995	NA	NA

TABLE 4-4
Costs and Visibility Modeling Results for Baseline vs. Post-Control Scenarios at Class I Areas
Naughton 1

Scenario	Total First Year Annualized Cost	Class I Area	Highest Delta-Deciview (ΔdV)	98th Percentile Delta-Deciview (ΔdV)	No. of Days Above 0.5 Deciview (dV)	Cost per dV Reduction	Cost per Reduction in No. of Days Above 0.5 dV	Incremental Cost per dV Reduction	Incremental Cost per Reduction in No. of Days Above 0.5 dV
2003									
Baseline: current operation with ESP		Bridger WA	4.014	1.797	45	--	--		
		Fitzpatrick WA	2.387	0.840	20	--	--		
Scenario 1: LNB with OFA, dry FGD, ESP	$12,042,621	Bridger WA	1.559	0.694	16	$10,918,061	$415,263		
	$12,042,621	Fitzpatrick WA	0.927	0.361	5	$25,141,171	$802,841		
Scenario 2: LNB with OFA, dry FGD, fabric filter	$15,299,091	Bridger WA	1.306	0.493	7	$11,732,432	$402,608	$16,201,343	$361,830
	$15,299,091	Fitzpatrick WA	0.634	0.266	3	$26,653,469	$899,947	$34,278,632	$1,628,235
Scenario 3: LNB with OFA and SCR, dry FGD, fabric filter	$21,262,911	Bridger WA	0.572	0.234	3	$13,603,910	$506,260	$23,026,332	$1,490,955
	$21,262,911	Fitzpatrick WA	0.344	0.123	0	$29,655,385	$1,063,146	$41,705,035	$1,987,940
Scenario 4: LNB with OFA and SCR, wet FGD, ESP, new stack	$20,399,907	Bridger WA	0.964	0.397	4	$14,571,362	$497,559	NA	NA
	$20,399,907	Fitzpatrick WA	0.309	0.135	0	$28,936,038	$1,019,995	NA	NA
3-Year Averages									
Baseline: current operation with ESP		Bridger WA		1.779	44.7				
		Fitzpatrick WA		0.896	20.3				
Scenario 1: LNB with OFA, dry FGD, ESP	$12,042,621	Bridger WA		0.693	14.7	$11,088,970	$401,421		
	$12,042,621	Fitzpatrick WA		0.344	4.3	$21,829,524	$752,664		
Scenario 2: LNB with OFA, dry FGD, fabric filter	$15,299,091	Bridger WA		0.536	7.7	$12,304,899	$413,489	$20,697,903	$465,210
	$15,299,091	Fitzpatrick WA		0.235	2.3	$23,168,740	$849,950	$29,967,515	$1,628,235
Scenario 3: LNB with OFA and SCR, dry FGD, fabric filter	$21,262,911	Bridger WA		0.242	1.7	$13,831,035	$494,486	$20,285,102	$993,970
	$21,262,911	Fitzpatrick WA		0.116	0.0	$27,260,142	$1,045,717	$49,836,936	$2,555,923
Scenario 4: LNB with OFA and SCR, wet FGD, ESP, new stack	$20,399,907	Bridger WA		0.357	3.7	$14,349,290	$497,559	NA	NA
	$20,399,907	Fitzpatrick WA		0.132	0.7	$26,713,104	$1,037,283	NA	NA

NOTES:
Scenario 4 produces worse results than Scenario 3.
Sample Calculations: Cost per dV Reduction for Scenario 1 for 2001: = $12,042,621 / (1.910 - 0.695) = $9,911,622
Sample Calculations: Cost per Reduction in No. of Days Exceeding 0.5 dV for 2001: = $12,042,621 / (58 - 19) = $308,785

5.0 Preliminary Assessment and Recommendations

As a result of the completed technical and economic evaluations, and in consideration of the modeling analysis completed for Naughton 1, the preliminary recommended BART controls for NO_x, SO_2, and PM are as follows:

- New LNBs OFA system for NO_x control
- Lime spray dryer FGD for SO_2 control and a coal sulfur limit of 1.02 weight percent
- Addition of FGC ahead of the existing ESP for particulate matter control

These recommendations were identified as Scenario 1 for the modeling analysis described in Section 4. Visibility improvements for all emission control scenarios were analyzed, and the results are compared below, utilizing a least-cost envelope, as outlined in the *New Source Review Workshop Manual* (EPA, 1990, hereafter referred to as NSR Manual).

5.1 Least-cost Envelope Analysis

The total annualized cost, cost per dV reduction, and cost per reduction in number of days above 0.5 dV for the scenarios modeled in Section 4 to determine the impact on the two Class I areas are listed in Tables 5-1 and 5-2. A comparison of the incremental costs between relevant scenarios is shown in Tables 5-3 and 5-4. The total annualized cost versus number of days above 0.5 dV, and the total annualized cost versus 98th percentile ΔdV reduction are shown in Figures 5-1 through 5-4 for the two Class I areas.

5.1.1 Analysis Methodology

On page B-41 of the New Source Review Manual, the EPA states that "Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between dominant alternatives. Dominant set of control alternatives are determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for a total emissions reductions for all control alternatives identified in the BACT analysis..."

An analysis of incremental cost effectiveness has been conducted. This analysis was performed in the following way:

- First, the control option scenarios are ranked in ascending order of annualized total costs as shown in Tables 5-1 and 5-2. The incremental cost effectiveness data, expressed per day and per dV reduction, represents a comparison of the different scenarios, and is summarized in Tables 5-3 and 5-4 for each of the two Class I areas.
- Then the most reasonable smooth curve of least-cost control option scenarios is plotted for each analysis. Figures 5-1 through 5-4 present the two analyses (cost per dV reduction

and cost per reduction in number of days above 0.5 dV) for each of the two Class I areas impacted by the operation of Naughton 1.

In Figure 5-1, the four scenarios are compared as a graph of total annualized cost versus number of days above 0.5 dV. The EPA states that "In calculating incremental costs, the analysis should only be conducted for control options that are dominant among all possible options." In Figure 5-1, the dominant set of control options (Scenarios 1 and 3) represent the least-cost envelope depicted by the curvilinear line connecting them. Scenarios 2 and 4 are inferior options and should not be considered in the derivation of incremental cost effectiveness. Scenarios 2 and 4 represent inferior controls because Scenario 1 provides approximately the same amount of visibility impact reduction for less cost than Scenario 2, and similarly, Scenario 3 will provide approximately the same amount of visibility impact reduction for less cost than Scenario 4. The incremental cost effectiveness is determined by the difference in total annual costs between two contiguous scenarios, divided by the difference in emissions reduction.

TABLE 5-1
Bridger Wilderness Area Class I Agent Control Data
Naughton 1

Scenario	Controls	98th Percentile Deciview (dV) Reduction	Reduction in Average Number of Days Above 0.5 dV (Days)	Total Annualized Cost (Million$)	Cost per dV Reduction (Million$/dV Reduced)	Cost per Reduction in No. of Days Above 0.5 dV (Million$/Day Reduced)
Base	Current Operation with Electrostatic Precipitator (ESP)	0.00	0.0	$0.0	$0.0	$0.0
1	Low-NO_x Burner (LNB) with Over-fire Air (OFA), Dry Flue Gas Conditioning (FGD), ESP	1.09	30.0	$12.0	$11.1	$0.4
2	LNB with OFA, Dry FGD, New Fabric Filter	1.24	37.0	$15.3	$12.3	$0.4
3	LNB with OFA and Selective Catalytic Reduction (SCR) System, Dry FGD, Fabric Filter	1.54	43.0	$21.3	$13.8	$0.5
4	LNB with OFA and SCR, Wet FGD, New stack	1.42	41.0	$20.4	$14.3	$0.5

TABLE 5-2
Fitzpatrick Wilderness Area Class I Area Control Data
Naughton 1

Scenario	Controls	98th Percentile Deciview (dV) Reduction	Reduction in Average Number of Days Above 0.5 dV (Days)	Total Annualized Cost (Million$)	Cost per dV Reduction (Million$ per dV Reduced)	Cost per Reduction in No. of Days Above 0.5 dV (Million$ per Day Reduced)
Base	Current Operation with Electrostatic Precipitator (ESP)	0.00	0.0	$0.0	$0.0	$0.0
1	Low-NO_x Burner (LNB) with Over-fire Air (OFA), Dry Flue Gas Conditioning (FGD), ESP	0.55	16.0	$12.0	$21.8	$0.8
2	LNB with OFA, Dry FGD, New Fabric Filter	0.66	18.0	$15.3	$23.2	$0.8
3	LNB with OFA and Selective Catalytic Reduction (SCR) System, Dry FGD, Fabric Filter	0.78	20.3	$21.3	$27.3	$1.0
4	LNB with OFA & SCR, Wet FGD, New stack	0.76	19.7	$20.4	$26.7	$1.0

TABLE 5-3
Bridger Wilderness Area Class I Agent Incremental Data
Naughton 1

Options Compared	Incremental Reduction in Days Above 0.5 Deciview (dV) (Days)	Incremental dV Reductions (dV)	Incremental Cost Effectiveness (Million$ per Day)	Incremental Cost Effectiveness (Million$ per dV)
Baseline and Scenario 1	30.00	1.09	$0.40	$11.1
Scenario 1 and Scenario 2	7.0	0.16	$0.5	$20.7
Scenario 1 and Scenario 3	13.0	0.45	$0.7	$20.4
Scenario 1 and Scenario 4	11.0	0.34	$0.8	$24.9

TABLE 5-4
Fitzpatrick Wilderness Area Class I Area Incremental Data
Naughton 1

Options Compared	Incremental Reduction in Days Above 0.5 Deciview (dV) (Days)	Incremental dV Reductions (dV)	Incremental Cost Effectiveness (Million$ per Day)	Incremental Cost Effectiveness (Million$ per dV)
Baseline and Scenario 1	16.00	0.55	$0.75	$21.8
Scenario 1 and Scenario 2	2.0	0.11	$1.6	$30.0
Scenario 1 and Scenario 3	4.3	0.23	$2.1	$40.4
Scenario 1 and Scenario 4	3.7	0.21	$2.3	$39.4

FIGURE 5-1
Least-cost Envelope Bridger Wilderness Area Class I Area Days Reduction
Naughton 1

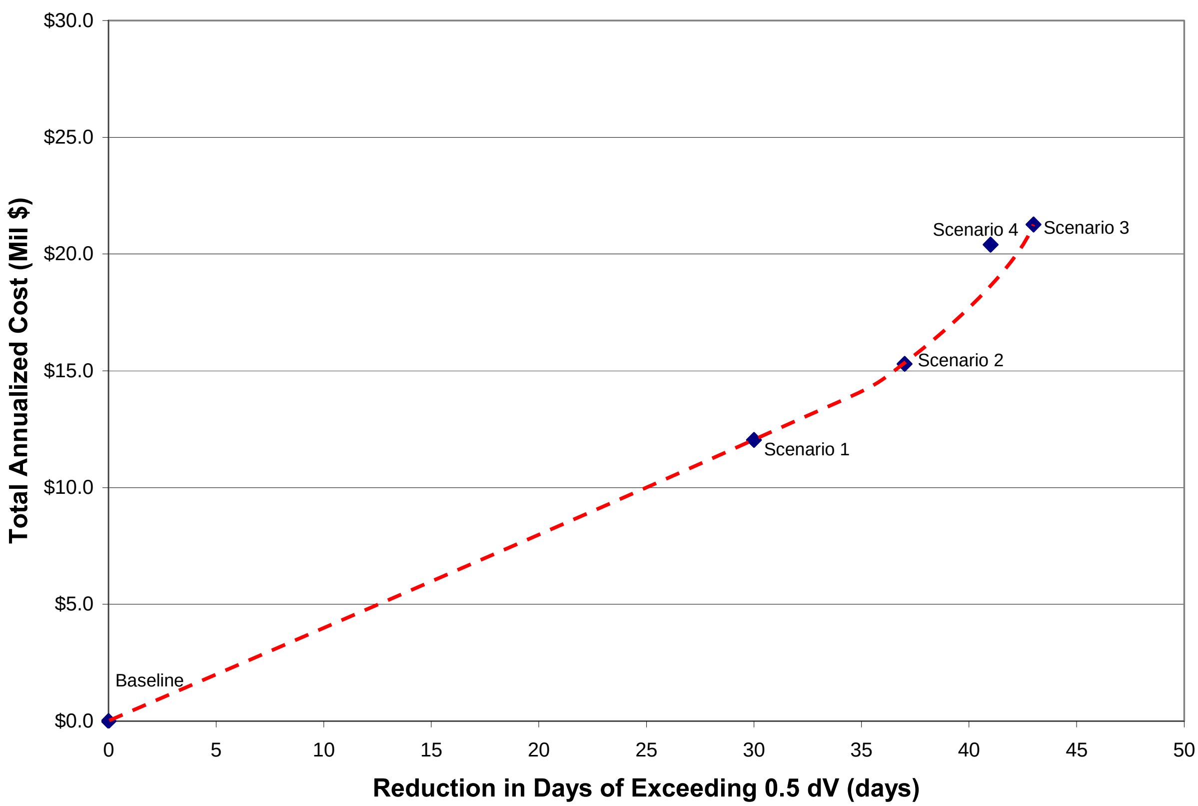


FIGURE 5-2
Least-cost Envelope Bridger Wilderness Area Class I Area 98th Percentile dV Reduction
Naughton 1

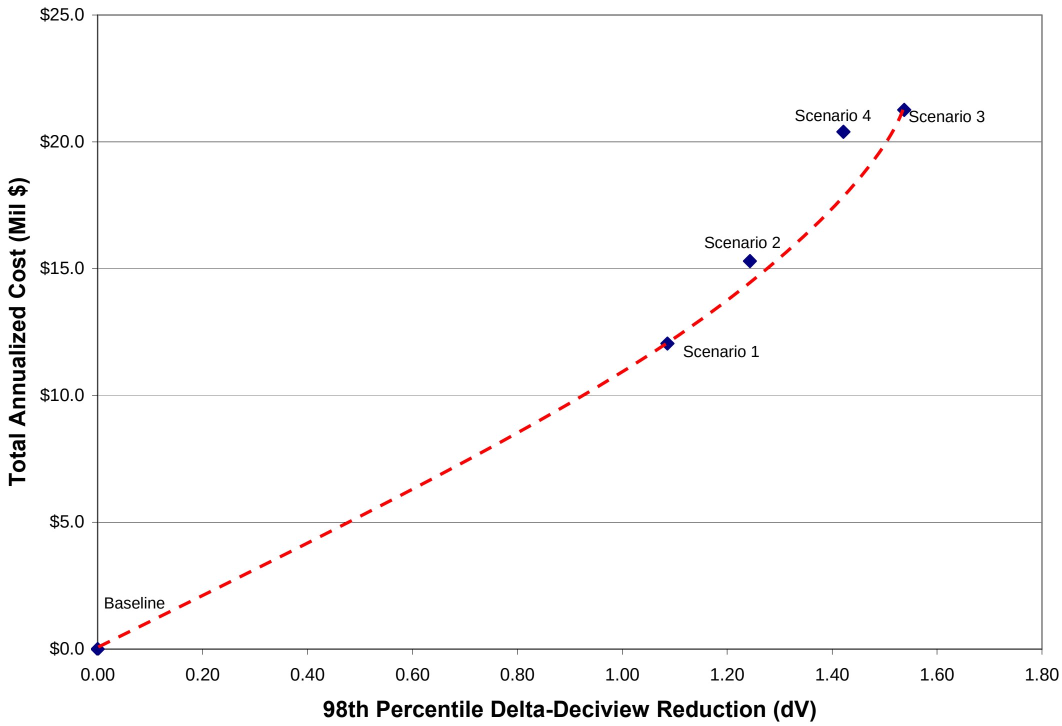


FIGURE 5-3
Least-cost Envelope Fitzpatrick Wilderness Area Class I Area Days Reduction
Naughton 1

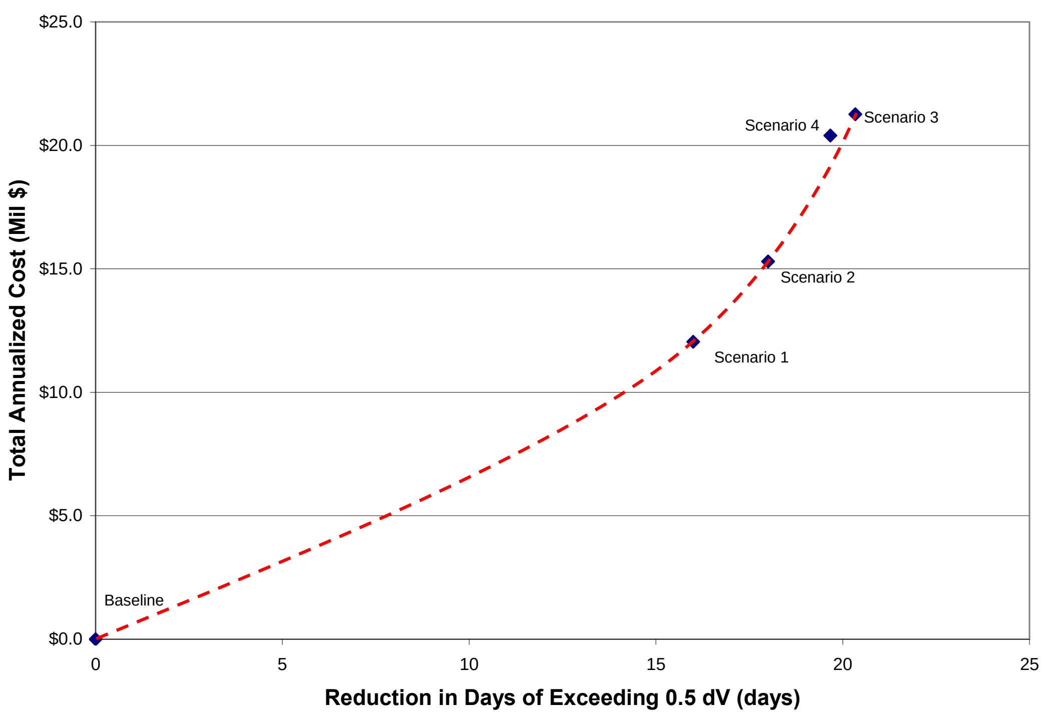
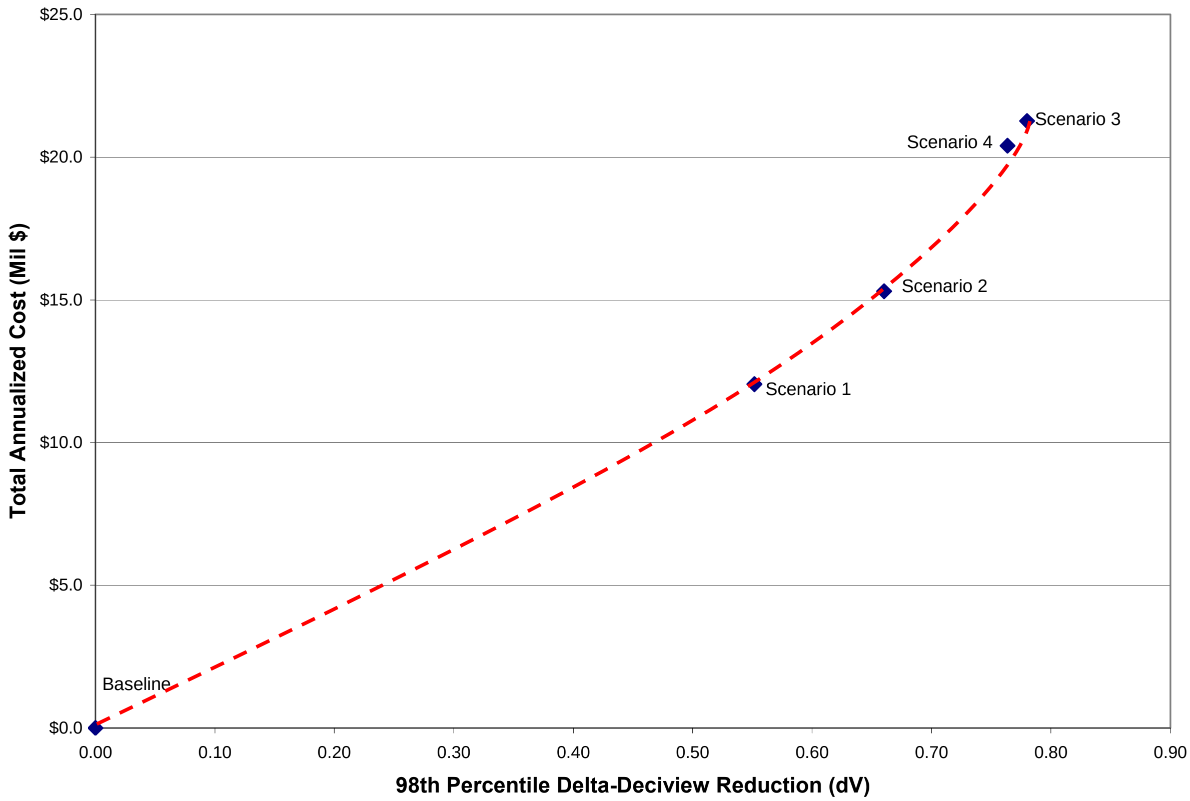


FIGURE 5-4
Least-cost Envelope Fitzpatrick Wilderness Area Class I Area 98th Percentile dV Reduction
Naughton 1



5.1.2 Analysis of Results

Results of the least-cost analysis, shown in Tables 5-1 to 5-4 and Figures 5-1 to 5-4 (on the following pages), confirm the selection of Scenario 1, based on incremental cost and visibility improvements.

The other scenarios were eliminated because of the following reasons:

- Scenario 2 is to the left of one of the four curves formed by the dominant control alternative scenarios; this indicates lower improvement and/or higher costs.
- Scenario 3 has very high incremental costs, on the basis of both a cost per day of improvement and a cost per dV reduction.
- While Scenario 4 provides some potential visibility advantage over Scenario 1, the projected improvement is less than 0.5 dV, and the cost increment is excessive. It is also to the left of the curves indicating a scenario with lower improvement or higher costs.

Analysis of the results for the Bridger Class I Wilderness Area in Tables 5-1 and 5-3 and Figures 5-1 and 5-2 illustrates these conclusions. The greatest reduction in 98th percentile dV—and number of days above 0.5 dV—is between the Baseline and Scenario 1. For example, Table 5-3 shows that the incremental cost effectiveness for Scenario 1 compared to the Baseline is reasonable at $400,000 per day and $11.1 million per dV to improve visibility at the Bridger WA. However, the incremental cost effectiveness for Scenario 2 compared to Scenario 1 is excessive at $500,000 per day and $20.7 million per dV. The incremental cost effectiveness for Scenario 3 compared to Scenario 1 is equally excessive at $700,000 per day and $20.4 million per dV. Using Table 5-4, a similar conclusion is reached for improving visibility at the Fitzpatrick Wilderness Area. Therefore, the EPA's Least Cost Analysis confirms that Scenario 1 represents the proper BART control technology for Naughton 1; Scenario 2's incremental cost effectiveness, compared to Scenario 1, is excessive.

5.2 Recommendations

5.2.1 NO_x Emission Control

CH2M HILL recommends LNB with OFA as BART for Naughton 1, based on the projected significant reduction in NO_x emissions, reasonable control costs, and the advantages of no additional power requirements or non-air quality environmental impacts. NO_x reductions are expected to be similar to those realized at the Jim Bridger plant where these devices have been installed on Unit 2. This selection of new LNBs with OFA at Naughton 1 is projected to attain an emission rate below 0.26 lb per MMBtu.

5.2.2 SO_2 Emission Control

CH2M HILL recommends a dry lime FGD system as BART for Naughton 1, assuming use of coal containing no more than 1.02 percent sulfur by weight, based on the significant reduction in SO_2 emissions, reasonable control costs, and the advantages of minimal additional power requirements and minimal non-air quality environmental impacts.

5.2.3 PM_{10} Emission Control

CH2M HILL recommends the addition of FGC system to enhance the performance of the existing ESP as BART for Naughton 1, based on the significant reduction in PM_{10} emissions, reasonable control costs, and the advantages of minimal additional power requirements and no non-air quality environmental impacts.

5.3 Just-Noticeable Differences in Atmospheric Haze

Conclusions reached in the reference document "Just-Noticeable Differences in Atmospheric Haze" by Dr. Ronald Henry (Henry, 2002), state that only dV differences of approximately 1.5 to 2.0 dV or more are perceivable by the human eye. Deciview changes of less than 1.5 cannot be distinguished by the average person. Therefore, the modeling analysis results indicate that only minimal, if any, visibility improvements at the Class I areas studied would be expected under any of the scenarios. Thus, the results indicate that even though many millions of dollars will be spent, only minimal visibility improvements may result.

Finally, it should be noted that none of the data were corrected for natural obscuration. During the period of 2001 through 2003, there were several mega-wildfires that lasted for several days and could have had a significant impact of visibility in these Class I areas. If natural obscuration were to reduce the visibility impacts modeled for the Naughton 1 facility, it would increase the costs per dV reduction that are presented in this report.

6.0 References

40 CFR Part 51. *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations; Final Rule.* July 6, 2005.

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APPENDIX A

Economic Analysis

PacifiCorp BART Analysis Scenarios

Select Unit:	7	Naughton Unit 1
Index No.	**Name of Unit**	
1	Dave Johnston Unit 3	
2	Dave Johnston Unit 4	
3	Jim Bridger Unit 1	
4	Jim Bridger Unit 2	
5	Jim Bridger Unit 3	
6	Jim Bridger Unit 4	
7	Naughton Unit 1	
8	Naughton Unit 2	
9	Naughton Unit 3	
10	Wyodak	

Dave Johnston

DJ Unit 3

Scenario	First Year Cost
Baseline - Current Operation with ESP	
Scenario 1 - LNB with OFA, Dry FGD, Existing ESP	N/A N/A
Scenario 2 - LNB with OFA, Dry FGD, New Fabric Filter	N/A N/A
Scenario 3 - LNB with OFA and SCR, Dry FGD, New Fabric Filter	N/A N/A
Scenario 4 - LNB with OFA and SCR, Wet FGD, Existing ESP, New Stack	N/A N/A

DJ Unit 4

Scenario	First Year Cost
Baseline - Current Operation with Venturi Scrubber	
Scenario 1 - LNB with OFA, Dry FGD, Fabric Filter	N/A N/A
Scenario 2 - LNB with OFA, Wet FGD, New Fabric Filter	N/A N/A
Scenario 3 - LNB with OFA and SCR, Dry FGD, New Fabric Filter	N/A N/A
Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	N/A N/A

Naughton

NTN Unit 1

Scenario	First Year Cost
Baseline - Current Operation with ESP	
Scenario 1 - LNB with OFA, Dry FGD, ESP and Higher Sulfur Coal	$ 12,042,621 $ 12,042,621
Scenario 2 - LNB with OFA, Dry FGD, New Fabric Filter	$ 15,299,091 $ 15,299,091
Scenario 3 - LNB with OFA and SCR, Dry FGD, New Fabric Filter	$ 21,262,911 $ 21,262,911
Scenario 4 - LNB with OFA and SCR, Wet FGD, ESP, New Stack	$ 20,399,907 $ 20,399,907

NTN Unit 2

Scenario	First Year Cost
Baseline - Current Operation with ESP	
Scenario 1 - LNB with OFA, Dry FGD, ESP	N/A N/A
Scenario 2 - LNB with OFA, Dry FGD, New Fabric Filter	N/A N/A
Scenario 3 - LNB with OFA and SCR, Dry FGD, New Fabric Filter	N/A N/A
Scenario 4 - LNB with OFA and SCR, Wet FGD, ESP, New Stack	N/A N/A

NTN Unit 3

Scenario	First Year Cost
Baseline - Current Operation with Wet FGD and ESP	
Scenario 1 - LNB with OFA, Waste Liquor FGD, Enhance ESP	N/A N/A
Scenario 2 - LNB with OFA and SCR, Waste Liquor FGD, Enhance ESP	N/A N/A
Scenario 3 - LNB with OFA and SCR, Waste Liquor FGD, New Fabric Filter	N/A N/A
Scenario 4 - LNB with OFA and SCR, Soda Ash FGD, New Fabric Filter	N/A N/A

Jim Bridger

JB Unit 1

Scenario	First Year Cost
Baseline - Current Operation with Wet FGD and ESP	
Scenario 1 - LNB with OFA, Wet FGD, ESP	N/A N/A N/A
Scenario 2 - LNB with OFA, Wet FGD, New Fabric Filter	N/A N/A N/A
Scenario 3 - LNB with OFA and SCR, Wet FGD, ESP	N/A N/A N/A
Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	N/A N/A N/A

JB Unit 2

Scenario	First Year
Baseline - Current Operation with Wet FGD and ESP	
Scenario 1 - LNB with OFA, Wet FGD, ESP	N/A N/A N/A
Scenario 2 - LNB with OFA, Wet FGD, New Fabric Filter	N/A N/A N/A
Scenario 3 - LNB with OFA and SCR, Wet FGD, ESP	N/A N/A N/A
Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	N/A N/A N/A

JB Unit 3

Scenario	First Year Cost
Baseline - Current Operation with Wet FGD and ESP	
Scenario 1 - LNB with OFA, Wet FGD, ESP	N/A N/A N/A
Scenario 2 - LNB with OFA, Wet FGD, New Fabric Filter	N/A N/A N/A
Scenario 3 - LNB with OFA and SCR, Wet FGD, ESP	N/A N/A N/A
Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	N/A N/A N/A

JB Unit 4

Scenario	First Year Cost
Baseline - Current Operation with Wet FGD and ESP	
Scenario 1 - LNB with OFA, Wet FGD, ESP	N/A N/A N/A
Scenario 2 - LNB with OFA, Wet FGD, Fabric Filter	N/A N/A N/A
Scenario 3 - LNB with OFA and SCR, Wet FGD, ESP	N/A N/A N/A
Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	N/A N/A N/A

Wyodak

Wyodak

Scenario	First Year Cost
Baseline - Current Operation with Dry FGD, ESP	
Scenario 1 - LNB with OFA, Dry FGD, ESP	N/A N/A
Scenario 2 - LNB with OFA, Dry FGD, Fabric Filter	N/A N/A
Scenario 3 - LNB with OFA and SCR, Dry FGD, Fabric Filter	N/A N/A
Scenario 4 - LNB with OFA and SCR, Wet FGD, ESP	N/A N/A

Sierra Club/106
Fisher/60

ECONOMIC ANALYSIS SUMMARY

Naughton Unit 1 | **Boiler Design:** **Tangential-Fired PC**

Parameter	Current Operation	NOx Control				SO2 Control			PM Control	
		LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Dry FGD w/ESP & Higher S Coal	Dry FGD w/Fabric Filter	Wet FGD w/ESP	Flue Gas Conditioning	Fabric Filter
Case	1	2	3	4	5	6	7	8	9	10
NOx Emission Control System	None	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	None	None	None	None	None
SO2 Emission Control System	None	None	None	None	None	Dry FGD w/ESP & Higher S Coal	Dry FGD w/Fabric Filter	Wet FGD w/ESP	None	None
PM Emission Control System	ESP	ESP	ESP	ESP	ESP	ESP	ESP	ESP	Flue Gas Conditioning	Fabric Filter
TOTAL INSTALLED CAPITAL COST ($)	0	7,300,000	9,068,746	17,526,855	58,227,447	64,297,623	108,995,970	91,696,610	1,298,352	29,798,898
FIRST YEAR O&M COST ($)										
Operating Labor ($)	0	0	0	0	0	506,128	506,128	809,804	0	0
Maintenance Material ($)	0	32,000	48,000	83,000	132,000	587,643	632,660	963,589	0	45,016
Maintenance Labor ($)	0	48,000	72,000	124,500	198,000	391,762	459,286	642,393	10,000	67,524
Administrative Labor ($)	0	0	0	0	0	0	0	0	0	0
TOTAL FIXED O&M COST	0	80,000	120,000	207,500	330,000	1,485,533	1,598,074	2,415,786	10,000	112,540
Makeup Water Cost	0	0	0	0	0	69,063	69,063	92,084	0	0
Reagent Cost	0	0	0	399,761	281,492	1,870,139	880,203	735,700	47,609	0
SCR Catalyst / FF Bag Cost	0	0	0	0	201,000	0	89,960	0	0	89,960
Waste Disposal Cost	0	0	0	0	0	878,461	471,814	548,278	0	0
Electric Power Cost	0	0	558,514	63,072	386,710	647,671	1,046,995	946,080	19,710	399,325
TOTAL VARIABLE O&M COST	0	0	558,514	462,833	869,203	3,465,334	2,558,035	2,322,141	67,319	489,285
TOTAL FIRST YEAR O&M COST	0	80,000	678,514	670,333	1,199,203	4,950,867	4,156,109	4,737,927	77,319	601,825
FIRST YEAR DEBT SERVICE ($)	0	694,433	862,690	1,667,292	5,539,050	6,116,493	10,368,549	8,722,899	123,509	2,834,704
TOTAL FIRST YEAR COST ($)	0	774,433	1,541,204	2,337,624	6,738,253	11,067,360	14,524,658	13,460,826	200,828	3,436,529
Power Consumption (MW)	0.0	0.0	1.4	0.2	1.0	1.6	2.7	2.4	0.1	1.0
Annual Power Usage (Million kW-Hr/Yr)	0.0	0.0	11.2	1.3	7.7	13.0	20.9	18.9	0.4	8.0
CONTROL COST ($/Ton Removed)										
NOx Removal Rate (%)	0.0%	58.6%	55.2%	67.2%	87.9%	0.0%	0.0%	0.0%	0.0%	0.0%
NOx Removed (Tons/Yr)	0	2,480	2,334	2,844	3,719	0	0	0	0	0
First Year Average Control Cost ($/Ton NOx Rem.)	0	312	660	822	1,812	0	0	0	0	0
Incremental Control Cost ($/Ton NOx Removed)	0	312	660	4,287	3,751	0	0	0	0	0
		2-1	3-1	4-2	5-3					
SO2 Removal Rate (%)	0.0%	0.0%	0.0%	0.0%	0.0%	80.1%	87.3%	91.5%	0.0%	0.0%
SO2 Removed (Tons/Yr)	0	0	0	0	0	12,061	7,530	7,895	0	0
First Year Average Control Cost ($/Ton SO2 Rem.)	0	0	0	0	0	918	1,929	1,705	0	0
Incremental Control Cost ($/Ton SO2 Removed)	Base	0	0	0	0	918	1,929	1,705	0	0
						6-1	7-1	8-1		
PM Removal Rate (%)	98.63%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	28.57%	73.21%
PM Removed (Tons/Yr)	0	0	0	0	0	0	0	0	117	299
First Year Average Control Cost ($/Ton PM Rem.)	0	0	0	0	0	0	0	0	1,721	11,493
Incremental Control Cost ($/Ton PM Removed)	Base	0	0	0	0	0	0	0	1,721	17,747
									9-1	10-9
PRESENT WORTH COST ($)	0	8,277,429	17,358,735	25,716,881	72,879,129	124,786,587	159,774,694	149,583,911	2,243,024	37,151,908

INPUT CALCULATIONS

Naughton Unit 1 — **Boiler Design:** Tangential-Fired PC

Parameter	Current Operation	NOx Control				SO2 Control			PM Control		Comments
		LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Dry FGD w/ESP & Higher S Coal	Dry FGD w/Fabric Filter	Wet FGD w/ESP	Flue Gas Conditioning	Fabric Filter	
Case	1	2	3	4	5	6	7	8	9	10	
NOx Emission Control System	None	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	None	None	None	None	None	
SO2 Emission Control System	None	None	None	None	None	Dry FGD w/ESP & Higher S Coal	Dry FGD w/Fabric Filter	Wet FGD w/ESP	None	None	
PM Emission Control System	ESP	ESP	ESP	ESP	ESP	ESP	ESP	ESP	Flue Gas Conditioning	Fabric Filter	
Unit Design and Coal Characteristics											
Type of Unit	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	
Net Power Output (kW)	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	
Net Plant Heat Rate (Btu/kW-Hr)	11,563	11,563	11,563	11,563	11,563	11,563	11,563	11,563	11,563	11,563	
Boiler Fuel	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	
Coal Heating Value (Btu/Lb)	9,800	9,800	9,800	9,800	9,800	9,875	9,800	9,800	9,800	9,800	
Coal Sulfur Content (wt.%)	0.58%	0.58%	0.58%	0.58%	0.58%	1.02%	0.58%	0.580%	0.58%	0.58%	
Coal Ash Content (wt.%)	5.00%	5.00%	5.00%	5.00%	5.00%	5.25%	5.00%	5.00%	5.00%	5.00%	
Boiler Heat Input, each (MMBtu/Hr)	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850	
Coal Flow Rate (Lb/Hr)	188,784	188,784	188,784	188,784	188,784	187,350	188,784	188,784	188,784	188,784	
(Ton/Yr)	744,185	744,185	744,185	744,185	744,185	738,533	744,185	744,185	744,185	744,185	
(MMBtu/Yr)	14,586,031	14,586,031	14,586,031	14,586,031	14,586,031	14,586,031	14,586,031	14,586,031	14,586,031	14,586,031	
Emissions											
Uncontrolled SO2 (Lb/Hr)	2,188	2,188	2,188	2,188	2,188	3,818	2,188	2,188	2,188	2,188	
(Lb/MMBtu)	1.18	1.18	1.18	1.18	1.18	2.06	1.18	1.18	1.18	1.18	
(Lb Moles/Hr)	34.15	34.15	34.15	34.15	34.15	59.60	34.15	34.15	34.15	34.15	
(Tons/Yr)	8,624	8,624	8,624	8,624	8,624	15,051	8,624	8,624	8,624	8,624	
SO2 Removal Rate (%)	0.0%	0.0%	0.0%	0.0%	0.0%	80.1%	87.3%	91.5%	0.0%	0.0%	
(Lb/Hr)	0	0	0	0	0	3,060	1,910	2,003	0	0	
(Ton/Yr)	0	0	0	0	0	12,061	7,530	7,895	0	0	
SO2 Emission Rate (Lb/Hr)	2,188	2,188	2,188	2,188	2,188	759	278	185	2,188	2,188	
(Lb/MMBtu)	1.18	1.18	1.18	1.18	1.18	0.41	0.15	0.10	1.18	1.18	
(Ton/Yr)	8,624	8,624	8,624	8,624	8,624	2,990	1,094	729	8,624	8,624	
Uncontrolled NOx (Lb/Hr)	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	
(Lb/MMBtu)	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	
(Lb Moles/Hr)	35.76	35.76	35.76	35.76	35.76	35.76	35.76	35.76	35.76	35.76	
(Tons/Yr)	4,230	4,230	4,230	4,230	4,230	4,230	4,230	4,230	4,230	4,230	
NOx Removal Rate (%)	0.0%	58.6%	55.2%	67.2%	87.9%	0.0%	0.0%	0%	0.0%	0%	
(Lb/Hr)	0	629	592	722	944	0	0	0	0	0	
(Lb Moles/Hr)	0.00	20.96	19.73	24.04	31.44	0.00	0.00	0.00	0.00	0.00	
(Ton/Yr)	0	2,480	2,334	2,844	3,719	0	0	0	0	0	
NOx Emission Rate (Lb/Hr)	1,073	444	481	352	130	1,073	1,073	1,073	1,073	1,073	
(Lb/MMBtu)	0.58	0.24	0.26	0.19	0.07	0.58	0.58	0.58	0.58	0.58	
(Ton/Yr)	4,230	1,750	1,896	1,386	511	4,230	4,230	4,230	4,230	4,230	
Uncontrolled Fly Ash (Lb/Hr)	7,551	104	104	104	104	104	104	104	104	104	
(Lb/MMBtu)	4.082	0.056	0.056	0.056	0.056	0.056	0.056	0.056	0.056	0.056	
(Lb Moles/Hr)	251.6	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	
(Tons/Yr)	29,767	408	408	408	408	408	408	408	408	408	
Fly Ash Removal Rate (%)	98.63%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	28.57%	73.21%	
(Lb/Hr)	7,448	0	0	0	0	0	0	0	30	76	
(Ton/Yr)	29,359	0	0	0	0	0	0	0	117	299	
Fly Ash Emission Rate (Lb/Hr)	104	104	104	104	104	104	104	104	74	28	
(Lb/MMBtu)	0.056	0.056	0.056	0.056	0.056	0.056	0.056	0.056	0.040	0.015	
(Ton/Yr)	408	408	408	408	408	408	408	408	292	109	

Parameter	Current Operation	NOx Control: LNB w/OFA	NOx Control: ROFA	NOx Control: LNB w/OFA & SNCR	NOx Control: LNB w/OFA & SCR	SO2 Control: Dry FGD w/ESP & Higher S Coal	SO2 Control: Dry FGD w/Fabric Filter	SO2 Control: Wet FGD w/ESP	PM Control: Flue Gas Conditioning	PM Control: Fabric Filter	Comments
Case	1	2	3	4	5	6	7	8	9	10	
General Plant Data											
Annual Operation (Hours/Year)	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	
Annual On-Site Power Plant Capacity Factor	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	
Economic Factors											
Interest Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	
Discount Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	
Plant Economic Life (Years)	20	20	20	20	20	20	20	20	20	20	
Installed Capital Costs											
NOx Emission Control System ($2006)	0	7,300,000	9,068,746	17,526,855	58,227,447	0	0	0	0	0	
SO2 Emission Control System ($2006)	0	0	0	0	0	64,297,623	108,995,970	91,696,610	0	0	
PM Emission Control System ($2006)	0	0	0	0	0	0	0	0	1,298,352	29,798,898	
Total Emission Control Systems ($2006)	0	7,300,000	9,068,746	17,526,855	58,227,447	64,297,623	108,995,970	91,696,610	1,298,352	29,798,898	
NOx Emission Control System ($/kW)	0	46	57	110	364	0	0	0	0	0	
SO2 Emission Control System ($/kW)	0	0	0	0	0	402	681	573	0	0	
PM Emission Control System ($/kW)	0	0	0	0	0	0	0	0	8	186	
Total Emission Control Systems ($/kW)	0	46	57	110	364	402	681	573	8	186	
Total Fixed Operating & Maintenance Costs											
Operating Labor ($)	0	0	0	0	0	506,128	506,128	809,804	0	0	
Maintenance Material ($)	0	32,000	48,000	83,000	132,000	587,643	632,660	963,589	0	45,016	
Maintenance Labor ($)	0	48,000	72,000	124,500	198,000	391,762	459,286	642,393	10,000	67,524	
Administrative Labor ($)	0	0	0	0	0	0	0	0	0	0	
Total Fixed O&M Cost ($)	0	80,000	120,000	207,500	330,000	1,485,533	1,598,074	2,415,786	10,000	112,540	
Annual Fixed O&M Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Water Cost											
Makeup Water Usage (Gpm)	0	0	0	0	0	120	120	160	0	0	
Unit Price ($/1000 Gallons)	1.22	1.22	1.22	0.00	1.22	1.22	1.22	1.22	1.22	1.22	
First Year Water Cost ($)	0	0	0	0	0	69,063	69,063	92,084	0	0	
Annual Water Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Reagent Cost	None	None	None	Urea	Anhydrous NH3	Lime	Lime	Lime	Elemental Sulfur	None	
Unit Cost ($/Ton)	0.00	0.00	0.00	370	400	91.25	91.25	91.25	370	0.00	
($/Lb)	0.000	0.000	0.000	0.185	0.200	0.046	0.046	0.046	0.185	0.000	
Molar Stoichiometry	0.00	0.00	0.00	0.45	1.00	1.40	1.15	1.05	0.00	0.00	
Reagent Purity (Wt.%)	100%	100%	100%	100%	100%	90%	90%	90%	100%	90%	
Reagent Usage (Lb/Hr)	0	0	0	274	179	5,199	2,447	2,045	33	0	
First Year Reagent Cost ($)	0	0	0	399,761	281,492	1,870,139	880,203	735,700	47,609	0	
Annual Reagent Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
SCR Catalyst / FF Bag Replacement Cost					SCR Catalyst	Bags	Bags	Bags		Bags	
Annual SCR Catalyst (m3) / No. FF Bags	0	0	0	0	67	0	865	0	0	865	
SCR Catalyst ($/m3) / Bag Cost ($/ea.)	3,000	3,000	3,000	3,000	3,000	104	104	104	3,000	104	
First Year SCR Catalyst / Bag Replace. Cost ($)	0	0	0	0	201,000	0	89,960	0	0	89,960	
Annual SCR Catalyst / Bag Cost Esc. Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
FGD Waste Disposal Cost											
FGD Solid Waste Disposal Rate, Dry (Lb/Hr)	0	0	0	0	0	9,158	4,919	5,716	0	0	
FGD Waste Disposal Unit Cost ($/Dry Ton)	24.33	24.33	24.33	24.33	24.33	24.33	24.33	24.33	24.33	24.33	
First Year FGD Waste Disposal Cost ($)	0	0	0	0	0	878,461	471,814	548,278	0	0	
Annual Waste Disposal Cost Esc. Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Auxiliary Power Cost											
Auxiliary Power Requirement (% of Plant Output)	0.00%	0.00%	0.89%	0.10%	0.61%	1.03%	1.66%	1.50%	0.03%	0.63%	
(MW)	0.00	0.00	1.42	0.16	0.98	1.64	2.66	2.40	0.05	1.01	
Unit Cost ($2006/MW-Hr)	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	
First Year Auxiliary Power Cost ($)	0	0	558,514	63,072	386,710	647,671	1,046,995	946,080	19,710	399,325	
Annual Power Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	

Input Tables

Table 1 - Cases

		Existing	NOx Control				SO2 Control			PM Control	
Index No.	Name of Unit | Case --->	1	2	3	4	5	6	7	8	9	10
1	Dave Johnston Unit 3	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Dry FGD w/ESP	Dry FGD w/Fabric Filter	Wet FGD w/ESP	N/A	Fabric Filter
2	Dave Johnston Unit 4	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	N/A	Dry FGD w/Fabric Filter	Wet FGD w/Fabric Filter	N/A	Fabric Filter
3	Jim Bridger Unit 1	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	N/A	N/A	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
4	Jim Bridger Unit 2	Current Operation	Exist. LNB w/OFA	ROFA	SNCR	SCR	N/A	N/A	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
5	Jim Bridger Unit 3	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	N/A	N/A	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
6	Jim Bridger Unit 4	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	N/A	N/A	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
7	Naughton Unit 1	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Dry FGD w/ESP & Higher S Coal	Dry FGD w/Fabric Filter	Wet FGD w/ESP	Flue Gas Conditioning	Fabric Filter
8	Naughton Unit 2	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Dry FGD w/ESP & Higher S Coal	Dry FGD w/Fabric Filter	Wet FGD w/ESP	Flue Gas Conditioning	Fabric Filter
9	Naughton Unit 3	Current Operation	Tune Exist. LNB w/OFA	ROFA	SNCR	SCR	N/A	Wet FGD w/Waste Liquor	Wet FGD w/Soda Ash	Enhancements to Existing ESP	Fabric Filter
10	Wyodak	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Upgraded Dry FGD	Dry FGD w/Fabric Filter	Wet FGD	N/A	Fabric Filter

Table 2 - Unit Design and Coal Characteristics

		Current Emission Control Systems			Unit Design			Coal Quality			
Index No.	Name of Unit	NOx	SO2	PM	Boiler Design	Net Power Output (kW)	Net Plant Heat Rate (Btu/kW-Hr)	Coal	Heating Value, HHV (Btu/Lb)	Sulfur Content (Wt.%)	Ash Content (Wt.%)
1	Dave Johnston Unit 3	None	None	ESP	3-Cell Burner, Opposed Wall-Fired PC	250,000	11,200	Dry Fork PRB	7,784	0.47%	5.01%
2	Dave Johnston Unit 4	Windbox Mods.	Lime Added to Venturi Scrubber	Venturi Scrubber	Tangential-Fired PC	360,000	11,390	Dry Fork PRB	7,784	0.47%	5.01%
3	Jim Bridger Unit 1	LNCFS-1 & Windbox Mods.	Wet FGD	ESP	Tangential-Fired PC	530,000	11,320	Bridger Mine Underground	9,660	0.58%	10.30%
4	Jim Bridger Unit 2	LNB - TFS 2000	Wet FGD	ESP	Tangential-Fired PC	530,000	11,320	Bridger Mine Underground	9,660	0.58%	10.30%
5	Jim Bridger Unit 3	LNCFS-1 & Windbox Mods.	Wet FGD	ESP	Tangential-Fired PC	530,000	11,320	Bridger Mine Underground	9,660	0.58%	10.30%
6	Jim Bridger Unit 4	LNCFS-1 & Windbox Mods.	Wet FGD	ESP	Tangential-Fired PC	530,000	11,320	Bridger Mine Underground	9,660	0.58%	10.30%
7	Naughton Unit 1	None	None	ESP	Tangential-Fired PC	160,000	11,563	Kemmerer Mine	9,800	0.58%	5.00%
8	Naughton Unit 2	None	None	ESP	Tangential-Fired PC	210,000	11,428	Kemmerer Mine	9,800	0.58%	5.00%
9	Naughton Unit 3	LNCFS II LNB	Wet FGD	ESP	Tangential-Fired PC	330,000	11,212	Kemmerer Mine	9,875	1.02%	5.25%
10	Wyodak	LNB	Dry FGD	ESP	Opposed Wall-Fired PC	365,000	12,877	Clovis Point Mine	8,050	0.65%	7.46%

Table 3 - Emissions

Index No.	Name of Unit	Current Emission Rates (Lb/MMBtu) Controlled SO2	Controlled NOx	Controlled PM	NOx Control Emission Rates (Lb/MMBtu) Case 2	Case 3	Case 4	Case 5	SO2 Control Emission Rates (Lb/MMBtu) Case 6	Case 7	Case 8	PM Emission Rates (Lb/MMBtu) Case 9	Case 10
1	Dave Johnston Unit 3	1.18	0.70	0.030	0.24	0.19	0.19	0.07	0.22	0.15	0.10	N/A	0.015
2	Dave Johnston Unit 4	0.50	0.40	0.061	0.15	0.15	0.12	0.07	N/A	0.15	0.10	N/A	0.015
3	Jim Bridger Unit 1	0.27	0.45	0.045	0.24	0.22	0.20	0.07	N/A	N/A	0.10	0.030	0.015
4	Jim Bridger Unit 2	0.27	0.24	0.074	0.24	0.22	0.20	0.07	N/A	N/A	0.10	0.030	0.015
5	Jim Bridger Unit 3	0.27	0.45	0.057	0.24	0.22	0.20	0.07	N/A	N/A	0.10	0.030	0.015
6	Jim Bridger Unit 4	0.17	0.45	0.030	0.24	0.22	0.20	0.07	N/A	N/A	0.10	0.030	0.015
7	Naughton Unit 1	1.18	0.58	0.056	0.24	0.26	0.19	0.07	0.41	0.15	0.10	0.040	0.015
8	Naughton Unit 2	1.18	0.54	0.064	0.24	0.26	0.19	0.07	0.41	0.15	0.10	0.040	0.015
9	Naughton Unit 3	0.50	0.45	0.094	0.35	0.28	0.28	0.07	N/A	0.21	0.10	0.040	0.015
10	Wyodak	0.50	0.31	0.030	0.23	0.20	0.18	0.07	0.32	0.16	0.10	N/A	0.015

Table 4 - Case 1 O&M Costs (Current Operation)

Index No.	Name of Unit	Annual Fixed O&M Costs Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Variable Operating Requirements Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ -	$ -	$ -	-	None	-	-
2	Dave Johnston Unit 4	$ -	$ -	$ -	$ -	-	None	-	-
3	Jim Bridger Unit 1	$ -	$ -	$ -	$ -	-	None	-	-
4	Jim Bridger Unit 2	$ -	$ -	$ -	$ -	-	None	-	-
5	Jim Bridger Unit 3	$ -	$ -	$ -	$ -	-	None	-	-
6	Jim Bridger Unit 4	$ -	$ -	$ -	$ -	-	None	-	-
7	Naughton Unit 1	$ -	$ -	$ -	$ -	-	None	-	-
8	Naughton Unit 2	$ -	$ -	$ -	$ -	-	None	-	-
9	Naughton Unit 3	$ -	$ -	$ -	$ -	-	None	-	-
10	Wyodak	$ -	$ -	$ -	$ -	-	None	-	-

Table 5 - Case 2 O&M Costs (LNB w/OFA)

Index No.	Name of Unit	Annual Fixed O&M Costs Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Variable Operating Requirements Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 40,000	$ 60,000	$ -	-	None	-	-
2	Dave Johnston Unit 4	$ -	$ 36,000	$ 54,000	$ -	-	None	-	-
3	Jim Bridger Unit 1	$ -	$ 28,000	$ 42,000	$ -	-	None	-	-
4	Jim Bridger Unit 2	$ -	$ -	$ -	$ -	-	None	-	-
5	Jim Bridger Unit 3	$ -	$ 28,000	$ 42,000	$ -	-	None	-	-
6	Jim Bridger Unit 4	$ -	$ 28,000	$ 42,000	$ -	-	None	-	-
7	Naughton Unit 1	$ -	$ 32,000	$ 48,000	$ -	-	None	-	-
8	Naughton Unit 2	$ -	$ 32,000	$ 48,000	$ -	-	None	-	-
9	Naughton Unit 3	$ -	$ -	$ -	$ -	-	None	-	-
10	Wyodak	$ -	$ 24,000	$ 36,000	$ -	-	None	-	-

Table 6 - Case 3 O&M Costs (Mobotec ROFA)

		Annual Fixed O&M Costs				Variable Operating Requirements			
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 60,000	$ 90,000	$ -	-	None	-	2.76
2	Dave Johnston Unit 4	$ -	$ 54,000	$ 81,000	$ -	-	None	-	4.33
3	Jim Bridger Unit 1	$ -	$ 42,000	$ 63,000	$ -	-	None	-	6.41
4	Jim Bridger Unit 2	$ -	$ 42,000	$ 63,000	$ -	-	None	-	6.41
5	Jim Bridger Unit 3	$ -	$ 42,000	$ 63,000	$ -	-	None	-	6.41
6	Jim Bridger Unit 4	$ -	$ 42,000	$ 63,000	$ -	-	None	-	6.41
7	Naughton Unit 1	$ -	$ 48,000	$ 72,000	$ -	-	None	-	1.42
8	Naughton Unit 2	$ -	$ 48,000	$ 72,000	$ -	-	None	-	2.61
9	Naughton Unit 3	$ -	$ 48,000	$ 72,000	$ -	-	None	-	4.47
10	Wyodak	$ -	$ 36,000	$ 54,000	$ -	-	None	-	5.22

Table 7 - Case 4 O&M Costs (LNB w/OFA & SNCR))

		Annual Fixed O&M Costs				Variable Operating Requirements			
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 98,000	$ 147,000	$ -	-	Urea	0.41	0.23
2	Dave Johnston Unit 4	$ -	$ 105,000	$ 157,500	$ -	-	Urea	0.45	0.33
3	Jim Bridger Unit 1	$ -	$ 123,000	$ 184,500	$ -	-	Urea	0.45	0.53
4	Jim Bridger Unit 2	$ -	$ 95,000	$ 142,500	$ -	-	Urea	0.45	0.53
5	Jim Bridger Unit 3	$ -	$ 122,000	$ 183,000	$ -	-	Urea	0.45	0.52
6	Jim Bridger Unit 4	$ -	$ 123,000	$ 184,500	$ -	-	Urea	0.45	0.53
7	Naughton Unit 1	$ -	$ 83,000	$ 124,500	$ -	-	Urea	0.45	0.16
8	Naughton Unit 2	$ -	$ 93,000	$ 139,500	$ -	-	Urea	0.51	0.22
9	Naughton Unit 3	$ -	$ 75,000	$ 112,500	$ -	-	Urea	0.45	0.33
10	Wyodak	$ -	$ 93,000	$ 139,500	-	-	Urea	0.45	0.34

Table 8 - Case 5 O&M Costs (LNB w/OFA & SCR))

		Annual Fixed O&M Costs				Variable Operating Requirements				
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual SCR Catalyst Replace. (m3)	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 155,000	$ 232,500	$ -	-	Anhydrous NH3	1.00	128	1.57
2	Dave Johnston Unit 4	$ -	$ 166,000	$ 249,000	$ -	-	Anhydrous NH3	1.00	123	2.29
3	Jim Bridger Unit 1	$ -	$ 190,000	$ 285,000	$ -	-	Anhydrous NH3	1.00	198	3.28
4	Jim Bridger Unit 2	$ -	$ 162,000	$ 243,000	$ -	-	Anhydrous NH3	1.00	198	3.25
5	Jim Bridger Unit 3	$ -	$ 190,000	$ 285,000	$ -	-	Anhydrous NH3	1.00	200	3.22
6	Jim Bridger Unit 4	$ -	$ 190,000	$ 285,000	$ -	-	Anhydrous NH3	1.00	214	3.36
7	Naughton Unit 1	$ -	$ 132,000	$ 198,000	$ -	-	Anhydrous NH3	1.00	67	0.98
8	Naughton Unit 2	$ -	$ 160,000	$ 240,000	$ -	-	Anhydrous NH3	1.00	101	1.34
9	Naughton Unit 3	$ -	$ 156,000	$ 234,000	$ -	-	Anhydrous NH3	1.00	167	1.99
10	Wyodak	$ -	$ 181,000	$ 271,500	$ -	-	Anhydrous NH3	1.00	160	2.42

Table 9 - Case 6 O&M Costs (Dry FGD)

		Annual Fixed O&M Costs				Variable Operating Requirements				
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ 506,128	$ 714,175	$ 476,928	$ -	173	Lime	1.15	-	2.49
2	Dave Johnston Unit 4	$ -	$ -	$ -	$ -	-	Lime	-	-	-
3	Jim Bridger Unit 1	$ -	$ -	$ -	$ -	-	Lime	-	-	-
4	Jim Bridger Unit 2	$ -	$ -	$ -	$ -	-	Lime	-	-	-
5	Jim Bridger Unit 3	$ -	$ -	$ -	$ -	-	Lime	-	-	-
6	Jim Bridger Unit 4	$ -	$ -	$ -	$ -	-	Lime	-	-	-
7	Naughton Unit 1	$ 506,128	$ 587,643	$ 391,762	$ -	120	Lime	1.40	-	1.64
8	Naughton Unit 2	$ 506,128	$ 860,174	$ 573,044	$ -	165	Lime	1.40	-	2.25
9	Naughton Unit 3	$ -	$ -	$ -	$ -	-	Lime	-	-	-
10	Wyodak	$ -	$ 21,900	$ 14,600	-	25	Lime	1.10	-	0.11

Table 10 - Case 7 O&M Costs (Dry FGD w/Fabric Filter)

		Annual Fixed O&M Costs				Variable Operating Requirements				
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ 506,128	$ 714,175	$ 476,928	$ -	173	Lime	1.15	1,457	3.88
2	Dave Johnston Unit 4	$ 506,128	$ 1,102,288	$ 734,858	$ -	248	Lime	1.10	1,798	4.54
3	Jim Bridger Unit 1	$ -	$ -	$ -	$ -	-	Lime	-	-	-
4	Jim Bridger Unit 2	$ -	$ -	$ -	$ -	-	Lime	-	-	-
5	Jim Bridger Unit 3	$ -	$ -	$ -	$ -	-	Lime	-	-	-
6	Jim Bridger Unit 4	$ -	$ -	$ -	$ -	-	Lime	-	-	-
7	Naughton Unit 1	$ 506,128	$ 632,660	$ 459,286	$ -	120	Lime	1.15	865	2.66
8	Naughton Unit 2	$ 506,128	$ 905,190	$ 640,568	$ -	165	Lime	1.15	1,193	3.63
9	Naughton Unit 3	$ -	$ 21,900	$ 14,600	$ -	66	Waste Liquor	1.02	-	0.33
10	Wyodak	$ -	$ 30,660	$ 20,440	-	30	Lime	1.10	-	0.15

Table 11 - Case 8 O&M Costs (Wet FGD)

		Annual Fixed O&M Costs				Variable Operating Requirements				
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ 809,804	$ 1,182,587	$ 788,391	$ -	230	Lime	1.02	-	3.45
2	Dave Johnston Unit 4	$ 809,804	$ 1,430,784	$ 953,856	$ -	330	Lime	1.02	1,798	6.29
3	Jim Bridger Unit 1	$ -	$ 25,550	$ 17,033	$ -	53	Soda Ash	1.02	-	0.53
4	Jim Bridger Unit 2	$ -	$ 25,550	$ 17,033	$ -	53	Soda Ash	1.02	-	0.53
5	Jim Bridger Unit 3	$ -	$ 25,550	$ 17,033	$ -	52	Soda Ash	1.02	-	0.52
6	Jim Bridger Unit 4	$ -	$ 25,550	$ 17,033	$ -	27	Soda Ash	1.02	-	0.53
7	Naughton Unit 1	$ 809,804	$ 963,589	$ 642,393	$ -	160	Lime	1.05	-	2.40
8	Naughton Unit 2	$ 809,804	$ 1,226,386	$ 817,591	$ -	220	Lime	1.05	-	3.30
9	Naughton Unit 3	$ -	$ 21,900	$ 14,600	$ -	66	Soda Ash	1.02	-	0.33
10	Wyodak	$ 303,677	$ 328,496	$ 218,998	$ -	82	Lime	1.02	-	1.75

Table 12 - Case 9 O&M Costs (Flue Gas Conditioning)

Index No.	Name of Unit	Annual Fixed O&M Costs: Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Variable Operating Requirements: Makeup Water Use (Gpm)	Reagent	Reagent Usage (Lb/Hr)	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ -	$ -	$ -	-	None	-	-	-
2	Dave Johnston Unit 4	$ -	$ -	$ -	$ -	-	None	-	-	-
3	Jim Bridger Unit 1	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	100	-	0.05
4	Jim Bridger Unit 2	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	100	-	0.05
5	Jim Bridger Unit 3	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	100	-	0.05
6	Jim Bridger Unit 4	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	100	-	0.05
7	Naughton Unit 1	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	33	-	0.05
8	Naughton Unit 2	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	43	-	0.05
9	Naughton Unit 3	$ -	$ -	$ -	$ -	-	None	-	-	-
10	Wyodak	$ -	$ -	$ -	-	-	None	-	-	-

Table 13 - Case 10 O&M Costs (Fabric Filter)

Index No.	Name of Unit	Annual Fixed O&M Costs: Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Variable Operating Requirements: Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 45,016	$ 67,524	$ -	-	None	-	1,457	1.38
2	Dave Johnston Unit 4	$ -	$ 68,133	$ 102,199	$ -	-	None	-	1,798	2.35
3	Jim Bridger Unit 1	$ -	$ 51,099	$ 76,649	$ -	-	None	-	2,885	3.39
4	Jim Bridger Unit 2	$ -	$ 51,099	$ 76,649	$ -	-	None	-	2,885	3.37
5	Jim Bridger Unit 3	$ -	$ 51,099	$ 76,649	$ -	-	None	-	2,827	3.33
6	Jim Bridger Unit 4	$ -	$ 51,099	$ 76,649	$ -	-	None	-	2,885	3.39
7	Naughton Unit 1	$ -	$ 45,016	$ 67,524	$ -	-	None	-	865	1.01
8	Naughton Unit 2	$ -	$ 45,016	$ 67,524	$ -	-	None	-	1,193	1.38
9	Naughton Unit 3	$ -	$ 48,666	$ 72,999	$ -	-	None	-	1,799	2.06
10	Wyodak	$ -	$ 48,666	$ 72,999	$ -	-	None	-	1,798	2.06

Table 14 - Major Materials Design and Supply Costs

Index No.	Name of Unit | Case --->	NOx Control: 2	3	4	5	SO2 Control: 6	7	8	PM Control: 9	10
1	Dave Johnston Unit 3	$ 5,449,830	$ 3,556,617	$ 5,773,000	$ 49,355,000	$ 56,379,000	$ 85,647,000	$ 88,913,000	$ -	$ 18,359,000
2	Dave Johnston Unit 4	$ 2,673,501	$ 4,343,192	$ 7,171,085	$ 66,200,000	$ -	$ 137,267,000	$ 178,174,384	$ -	$ 30,853,530
3	Jim Bridger Unit 1	$ 2,981,982	$ 6,056,955	$ 9,528,000	$ 80,923,000	$ -	$ -	$ 8,010,093	$ -	$ 29,814,000
4	Jim Bridger Unit 2	$ -	$ 6,056,955	$ 9,528,000	$ 80,923,000	$ -	$ -	$ 8,010,093	$ -	$ 29,814,000
5	Jim Bridger Unit 3	$ 2,981,982	$ 6,056,955	$ 9,419,000	$ 80,923,000	$ -	$ -	$ 8,010,093	$ -	$ 29,814,000
6	Jim Bridger Unit 4	$ 2,981,982	$ 6,056,955	$ 9,528,000	$ 93,009,000	$ -	$ -	$ 3,549,000	$ -	$ 29,814,000
7	Naughton Unit 1	$ 2,502,123	$ 2,675,792	$ 7,257,000	$ 37,292,000	$ 39,617,991	$ 67,159,581	$ 56,500,308	$ 800,000	$ 18,361,060
8	Naughton Unit 2	$ 2,570,674	$ 3,123,533	$ 8,784,000	$ 47,934,000	$ 54,775,108	$ 87,030,191	$ 77,695,625	$ 800,000	$ 21,503,389
9	Naughton Unit 3	$ -	$ 4,351,377	$ 11,203,578	$ 67,373,000	$ -	$ 2,772,643	$ 8,934,073	$ 8,194,701	$ 49,476,278
10	Wyodak	$ 3,187,636	$ 4,500,245	$ 7,234,860	$ 72,479,000	$ 16,487,985	$ 41,146,026	$ 58,619,840	$ -	$ 20,106,000

CAPITAL COST

Naughton Unit 1

Parameter	NOx Control								SO2 Control						PM Control			
	LNB w/OFA		ROFA		LNB w/OFA & SNCR		LNB w/OFA & SCR		Dry FGD w/ESP & Higher		Dry FGD w/Fabric Filter		Wet FGD w/ESP		Flue Gas Conditioning		Fabric Filter	
Case	2		3		4		5		6		7		8		9		10	
NOx Emission Control System	LNB w/OFA		ROFA		LNB w/OFA & SNCR		LNB w/OFA & SCR		None		None		None		None		None	
SO2 Emission Control System	None		None		None		None		Dry FGD w/ESP & Higher S Coal		Dry FGD w/Fabric Filter		Wet FGD w/ESP		None		None	
PM Emission Control System	ESP		ESP		ESP		ESP		ESP		ESP		ESP		Flue Gas Conditioning		Fabric Filter	
CAPITAL COST COMPONENT	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost
LNB w/OFA or ROFA		LNB w/OFA		ROFA		LNB w/OFA		LNB w/OFA										
Major Materials Design and Supply	Vendor	$2,502,123	Vendor	$2,675,792	Vendor	$2,502,123	Vendor	$2,502,123	Vendor	$0	Vendor	$0	Vendor	$0	Vendor	$0	Vendor	$0
Construction	85.3%	$2,135,156	85.3%	$2,283,354	85.3%	$2,135,156	85.3%	$2,135,156	85.3%	$0	85.3%	$0	85.3%	$0	85.3%	$0	85.3%	$0
Balance of Plant	51.7%	$1,293,401	51.7%	$1,383,174	51.7%	$1,293,401	51.7%	$1,293,401	51.7%	$0	51.7%	$0	51.7%	$0	51.7%	$0	51.7%	$0
Electrical (Allowance)	0.0%	$0	30.0%	$802,738	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0
Owner's Costs	13.2%	$331,490	13.2%	$354,498	13.2%	$331,490	13.2%	$331,490	13.2%	$0	13.2%	$0	13.2%	$0	13.2%	$0	13.2%	$0
Surcharge	16.4%	$410,986	16.4%	$439,512	16.4%	$410,986	16.4%	$410,986	16.4%	$0	16.4%	$0	16.4%	$0	16.4%	$0	16.4%	$0
AFUDC	12.2%	$305,721	12.2%	$326,941	12.2%	$305,721	12.2%	$305,721	12.2%	$0	12.2%	$0	12.2%	$0	12.2%	$0	12.2%	$0
Subtotal		$6,978,877		$8,266,008		$6,978,877		$6,978,877		$0		$0		$0		$0		$0
Contingency	12.8%	$321,124	30.0%	$802,738	12.8%	$321,124	12.8%	$321,124	12.8%	$0	12.8%	$0	12.8%	$0	12.8%	$0	12.8%	$0
Total Capital Cost for LNB w/OFA or ROFA		$7,300,000		$9,068,746		$7,300,000		$7,300,000		$0		$0		$0		$0		$0
SNCR or SCR						SNCR		SCR										
Major Materials Design and Supply	S&L Report	$0	S&L Report	$0	S&L Report	$7,257,000	S&L Report	$37,292,000	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$0
Contingency	20.0%	$0	20.0%	$0	20.0%	$1,451,400	10.0%	$3,729,200	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$0
Labor Premium	5.6%	$0	5.6%	$0	5.6%	$405,884	5.6%	$2,085,742	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$0
EPC Premium	0.0%	$0	0.0%	$0	0.0%	$0	8.4%	$3,150,055	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$0
Boiler Reinforcement (Allowance)	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0
Sales Tax	1.1%	$0	1.1%	$0	1.1%	$79,972	1.1%	$410,958	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$0
Escalation	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0
Contingency on Adders	2.8%	$0	2.8%	$0	2.8%	$203,704	0.0%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0
Surcharge and AFUDC	11.4%	$0	11.4%	$0	11.4%	$828,895	11.4%	$4,259,492	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$0
Total Capital Cost for SNCR or SCR		$0		$0		$10,226,855		$50,927,447		$0		$0		$0		$0		$0
Dry or Wet FGD, FGC or Fabric Filter										Dry FGD		Dry FGD w/FF		Wet FGD		FGC		Fabric Filter
Major Materials Design and Supply	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$39,617,991	S&L Report	$67,159,581	S&L Report	$56,500,308	S&L Report	$800,000	S&L Report	$18,361,060
Contingency	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$7,923,598	20.0%	$13,431,916	20.0%	$11,300,062	20.0%	$160,000	20.0%	$3,672,212
Labor Premium	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$2,215,834	5.6%	$3,756,235	5.6%	$3,160,062	5.6%	$44,744	5.6%	$1,026,934
EPC Premium	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$3,346,532	8.4%	$5,672,970	8.4%	$4,772,581	8.4%	$67,576	8.4%	$1,550,959
Boiler Reinforcement (Allowance)	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$1,114,850	2.8%	$1,889,871	2.8%	$1,589,919	2.8%	$22,512	2.8%	$516,680
Sales Tax	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$436,590	1.1%	$740,099	1.1%	$622,633	1.1%	$8,816	1.1%	$202,339
Escalation	10.1%	$0	10.1%	$0	10.1%	$0	10.1%	$0	10.1%	$4,004,983	10.1%	$6,789,162	10.1%	$5,711,616	10.1%	$80,872	10.1%	$1,856,120
Contingency on Adders	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$1,112,077	2.8%	$1,885,169	2.8%	$1,585,964	2.8%	$22,456	2.8%	$515,395
Surcharge and AFUDC	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$4,525,167	11.4%	$7,670,967	11.4%	$6,453,465	11.4%	$91,376	11.4%	$2,097,200
Total Capital Cost for Dry/Wet FGD, FGC or FF		$0		$0		$0		$0		$64,297,623		$108,995,970		$91,696,610		$1,298,352		$29,798,898

Naughton Unit 1 — LNB w/OFA

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton NOx Removed)
0	2013										
1	2014	80,000	-	-	-	-	-	-	694,433	774,433	312
2	2015	81,600	-	-	-	-	-	-	694,433	776,033	313
3	2016	83,232	-	-	-	-	-	-	694,433	777,665	314
4	2017	84,897	-	-	-	-	-	-	694,433	779,330	314
5	2018	86,595	-	-	-	-	-	-	694,433	781,028	315
6	2019	88,326	-	-	-	-	-	-	694,433	782,760	316
7	2020	90,093	-	-	-	-	-	-	694,433	784,526	316
8	2021	91,895	-	-	-	-	-	-	694,433	786,328	317
9	2022	93,733	-	-	-	-	-	-	694,433	788,166	318
10	2023	95,607	-	-	-	-	-	-	694,433	790,041	319
11	2024	97,520	-	-	-	-	-	-	694,433	791,953	319
12	2025	99,470	-	-	-	-	-	-	694,433	793,903	320
13	2026	101,459	-	-	-	-	-	-	694,433	795,893	321
14	2027	103,489	-	-	-	-	-	-	694,433	797,922	322
15	2028	105,558	-	-	-	-	-	-	694,433	799,991	323
16	2029	107,669	-	-	-	-	-	-	694,433	802,103	323
17	2030	109,823	-	-	-	-	-	-	694,433	804,256	324
18	2031	112,019	-	-	-	-	-	-	694,433	806,452	325
19	2032	114,260	-	-	-	-	-	-	694,433	808,693	326
20	2033	116,545	-	-	-	-	-	-	694,433	810,978	327
Present Worth		977,428	-	-	-	-	-	-	7,300,000	8,277,429	167
(% of PW)		11.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	88.2%	100.0%	

Naughton Unit 1 — ROFA

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton NOx Removed)
0	2013										
1	2014	120,000	-	-	-	-	558,514	558,514	862,690	1,541,204	660
2	2015	122,400	-	-	-	-	569,685	569,685	862,690	1,554,775	666
3	2016	124,848	-	-	-	-	581,078	581,078	862,690	1,568,616	672
4	2017	127,345	-	-	-	-	592,700	592,700	862,690	1,582,735	678
5	2018	129,892	-	-	-	-	604,554	604,554	862,690	1,597,136	684
6	2019	132,490	-	-	-	-	616,645	616,645	862,690	1,611,825	691
7	2020	135,139	-	-	-	-	628,978	628,978	862,690	1,626,807	697
8	2021	137,842	-	-	-	-	641,557	641,557	862,690	1,642,090	704
9	2022	140,599	-	-	-	-	654,389	654,389	862,690	1,657,678	710
10	2023	143,411	-	-	-	-	667,476	667,476	862,690	1,673,578	717
11	2024	146,279	-	-	-	-	680,826	680,826	862,690	1,689,795	724
12	2025	149,205	-	-	-	-	694,442	694,442	862,690	1,706,337	731
13	2026	152,189	-	-	-	-	708,331	708,331	862,690	1,723,210	738
14	2027	155,233	-	-	-	-	722,498	722,498	862,690	1,740,421	746
15	2028	158,337	-	-	-	-	736,948	736,948	862,690	1,757,975	753
16	2029	161,504	-	-	-	-	751,687	751,687	862,690	1,775,881	761
17	2030	164,734	-	-	-	-	766,721	766,721	862,690	1,794,145	769
18	2031	168,029	-	-	-	-	782,055	782,055	862,690	1,812,774	777
19	2032	171,390	-	-	-	-	797,696	797,696	862,690	1,831,776	785
20	2033	174,817	-	-	-	-	813,650	813,650	862,690	1,851,157	793
Present Worth		1,466,142	-	-	-	-	6,823,847	6,823,847	9,068,746	17,358,735	372
(% of PW)		8.4%	0.0%	0.0%	0.0%	0.0%	39.3%	39.3%	52.2%	100.0%	

Sierra Club/106
Fisher/70

Naughton Unit 1 — LNB w/OFA & SNCR

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton NOx Removed)
0	2013										
1	2014	207,500	-	399,761	-	-	63,072	462,833	1,667,292	2,337,624	822
2	2015	211,650	-	407,756	-	-	64,333	472,089	1,667,292	2,351,031	827
3	2016	215,883	-	415,911	-	-	65,620	481,531	1,667,292	2,364,706	831
4	2017	220,201	-	424,229	-	-	66,933	491,162	1,667,292	2,378,654	836
5	2018	224,605	-	432,714	-	-	68,271	500,985	1,667,292	2,392,881	841
6	2019	229,097	-	441,368	-	-	69,637	511,005	1,667,292	2,407,393	846
7	2020	233,679	-	450,195	-	-	71,029	521,225	1,667,292	2,422,195	852
8	2021	238,352	-	459,199	-	-	72,450	531,649	1,667,292	2,437,293	857
9	2022	243,119	-	468,383	-	-	73,899	542,282	1,667,292	2,452,693	862
10	2023	247,982	-	477,751	-	-	75,377	553,128	1,667,292	2,468,401	868
11	2024	252,941	-	487,306	-	-	76,884	564,190	1,667,292	2,484,423	873
12	2025	258,000	-	497,052	-	-	78,422	575,474	1,667,292	2,500,766	879
13	2026	263,160	-	506,993	-	-	79,991	586,984	1,667,292	2,517,435	885
14	2027	268,423	-	517,133	-	-	81,590	598,723	1,667,292	2,534,438	891
15	2028	273,792	-	527,476	-	-	83,222	610,698	1,667,292	2,551,781	897
16	2029	279,268	-	538,025	-	-	84,887	622,912	1,667,292	2,569,471	903
17	2030	284,853	-	548,786	-	-	86,584	635,370	1,667,292	2,587,515	910
18	2031	290,550	-	559,761	-	-	88,316	648,077	1,667,292	2,605,919	916
19	2032	296,361	-	570,957	-	-	90,082	661,039	1,667,292	2,624,692	923
20	2033	302,288	-	582,376	-	-	91,884	674,260	1,667,292	2,643,840	930
Present Worth		2,535,205	-	4,884,217	-	-	770,604	5,654,821	17,526,855	25,716,881	452
(% of PW)		9.9%	0.0%	19.0%	0.0%	0.0%	3.0%	22.0%	68.2%	100.0%	

Naughton Unit 1 — LNB w/OFA & SCR

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton NOx Removed)
0	2013										
1	2014	330,000	-	281,492	201,000	-	386,710	869,203	5,539,050	6,738,253	1,812
2	2015	336,600	-	287,122	205,020	-	394,444	886,587	5,539,050	6,762,237	1,818
3	2016	343,332	-	292,865	209,120	-	402,333	904,318	5,539,050	6,786,701	1,825
4	2017	350,199	-	298,722	213,303	-	410,380	922,405	5,539,050	6,811,654	1,831
5	2018	357,203	-	304,696	217,569	-	418,588	940,853	5,539,050	6,837,106	1,838
6	2019	364,347	-	310,790	221,920	-	426,959	959,670	5,539,050	6,863,067	1,845
7	2020	371,634	-	317,006	226,359	-	435,498	978,863	5,539,050	6,889,547	1,852
8	2021	379,066	-	323,346	230,886	-	444,208	998,441	5,539,050	6,916,557	1,860
9	2022	386,648	-	329,813	235,504	-	453,093	1,018,409	5,539,050	6,944,107	1,867
10	2023	394,381	-	336,409	240,214	-	462,154	1,038,778	5,539,050	6,972,208	1,875
11	2024	402,268	-	343,138	245,018	-	471,398	1,059,553	5,539,050	7,000,872	1,882
12	2025	410,314	-	350,000	249,918	-	480,826	1,080,744	5,539,050	7,030,108	1,890
13	2026	418,520	-	357,000	254,917	-	490,442	1,102,359	5,539,050	7,059,929	1,898
14	2027	426,890	-	364,140	260,015	-	500,251	1,124,406	5,539,050	7,090,347	1,906
15	2028	435,428	-	371,423	265,215	-	510,256	1,146,894	5,539,050	7,121,373	1,915
16	2029	444,137	-	378,852	270,520	-	520,461	1,169,832	5,539,050	7,153,019	1,923
17	2030	453,019	-	386,429	275,930	-	530,870	1,193,229	5,539,050	7,185,299	1,932
18	2031	462,080	-	394,157	281,449	-	541,488	1,217,093	5,539,050	7,218,223	1,941
19	2032	471,321	-	402,040	287,077	-	552,317	1,241,435	5,539,050	7,251,807	1,950
20	2033	480,748	-	410,081	292,819	-	563,364	1,266,264	5,539,050	7,286,062	1,959
Present Worth		4,031,892	-	3,439,233	2,455,789	-	4,724,768	10,619,790	58,227,447	72,879,129	980
(% of PW)		5.5%	0.0%	4.7%	3.4%	0.0%	6.5%	14.6%	79.9%	100.0%	

Sierra Club/106
Fisher/71

Naughton Unit 1 — Dry FGD w/ESP & Higher S Coal

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton SO2 Removed)
0	2013										
1	2014	1,485,533	69,063	1,870,139	-	878,461	647,671	3,465,334	6,116,493	11,067,360	918
2	2015	1,515,244	70,444	1,907,542	-	896,030	660,624	3,534,640	6,116,493	11,166,377	926
3	2016	1,545,549	71,853	1,945,693	-	913,950	673,836	3,605,333	6,116,493	11,267,375	934
4	2017	1,576,460	73,290	1,984,607	-	932,229	687,313	3,677,440	6,116,493	11,370,392	943
5	2018	1,607,989	74,756	2,024,299	-	950,874	701,059	3,750,989	6,116,493	11,475,470	951
6	2019	1,640,149	76,251	2,064,785	-	969,891	715,081	3,826,008	6,116,493	11,582,650	960
7	2020	1,672,952	77,776	2,106,081	-	989,289	729,382	3,902,528	6,116,493	11,691,973	969
8	2021	1,706,411	79,332	2,148,202	-	1,009,075	743,970	3,980,579	6,116,493	11,803,483	979
9	2022	1,740,539	80,918	2,191,166	-	1,029,257	758,849	4,060,191	6,116,493	11,917,222	988
10	2023	1,775,350	82,537	2,234,990	-	1,049,842	774,026	4,141,394	6,116,493	12,033,237	998
11	2024	1,810,857	84,187	2,279,690	-	1,070,838	789,507	4,224,222	6,116,493	12,151,572	1,008
12	2025	1,847,074	85,871	2,325,283	-	1,092,255	805,297	4,308,707	6,116,493	12,272,274	1,018
13	2026	1,884,015	87,589	2,371,789	-	1,114,100	821,403	4,394,881	6,116,493	12,395,389	1,028
14	2027	1,921,696	89,340	2,419,225	-	1,136,382	837,831	4,482,779	6,116,493	12,520,967	1,038
15	2028	1,960,130	91,127	2,467,609	-	1,159,110	854,588	4,572,434	6,116,493	12,649,057	1,049
16	2029	1,999,332	92,950	2,516,961	-	1,182,292	871,679	4,663,883	6,116,493	12,779,708	1,060
17	2030	2,039,319	94,809	2,567,301	-	1,205,938	889,113	4,757,160	6,116,493	12,912,972	1,071
18	2031	2,080,105	96,705	2,618,647	-	1,230,057	906,895	4,852,304	6,116,493	13,048,902	1,082
19	2032	2,121,707	98,639	2,671,020	-	1,254,658	925,033	4,949,350	6,116,493	13,187,550	1,093
20	2033	2,164,141	100,612	2,724,440	-	1,279,751	943,534	5,048,337	6,116,493	13,328,971	1,105
Present Worth		18,150,027	843,802	22,849,089	-	10,732,902	7,913,144	42,338,938	64,297,623	124,786,587	517
(% of PW)		14.5%	0.7%	18.3%	0.0%	8.6%	6.3%	33.9%	51.5%	100.0%	

Naughton Unit 1 — Dry FGD w/Fabric Filter

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton SO2 Removed)
0	2013										
1	2014	1,598,074	69,063	880,203	89,960	471,814	1,046,995	2,558,035	10,368,549	14,524,658	1,929
2	2015	1,630,035	70,444	897,807	91,759	481,250	1,067,935	2,609,196	10,368,549	14,607,780	1,940
3	2016	1,662,636	71,853	915,763	93,594	490,875	1,089,294	2,661,380	10,368,549	14,692,565	1,951
4	2017	1,695,888	73,290	934,078	95,466	500,693	1,111,080	2,714,607	10,368,549	14,779,045	1,963
5	2018	1,729,806	74,756	952,760	97,376	510,707	1,133,301	2,768,899	10,368,549	14,867,255	1,974
6	2019	1,764,402	76,251	971,815	99,323	520,921	1,155,967	2,824,277	10,368,549	14,957,229	1,986
7	2020	1,799,690	77,776	991,251	101,310	531,339	1,179,087	2,880,763	10,368,549	15,049,003	1,999
8	2021	1,835,684	79,332	1,011,076	103,336	541,966	1,202,668	2,938,378	10,368,549	15,142,612	2,011
9	2022	1,872,398	80,918	1,031,298	105,402	552,805	1,226,722	2,997,146	10,368,549	15,238,093	2,024
10	2023	1,909,846	82,537	1,051,924	107,511	563,861	1,251,256	3,057,089	10,368,549	15,335,484	2,037
11	2024	1,948,043	84,187	1,072,962	109,661	575,139	1,276,281	3,118,230	10,368,549	15,434,822	2,050
12	2025	1,987,004	85,871	1,094,421	111,854	586,641	1,301,807	3,180,595	10,368,549	15,536,148	2,063
13	2026	2,026,744	87,589	1,116,310	114,091	598,374	1,327,843	3,244,207	10,368,549	15,639,500	2,077
14	2027	2,067,279	89,340	1,138,636	116,373	610,342	1,354,400	3,309,091	10,368,549	15,744,919	2,091
15	2028	2,108,624	91,127	1,161,409	118,700	622,549	1,381,488	3,375,273	10,368,549	15,852,446	2,105
16	2029	2,150,797	92,950	1,184,637	121,074	635,000	1,409,118	3,442,778	10,368,549	15,962,124	2,120
17	2030	2,193,813	94,809	1,208,330	123,496	647,700	1,437,300	3,511,634	10,368,549	16,073,996	2,135
18	2031	2,237,689	96,705	1,232,496	125,966	660,654	1,466,046	3,581,866	10,368,549	16,188,105	2,150
19	2032	2,282,443	98,639	1,257,146	128,485	673,867	1,495,367	3,653,504	10,368,549	16,304,496	2,165
20	2033	2,328,091	100,612	1,282,289	131,055	687,344	1,525,274	3,726,574	10,368,549	16,423,215	2,181
Present Worth		19,525,029	843,802	10,754,186	1,099,118	5,764,555	12,792,034	31,253,695	108,995,970	159,774,694	1,061
(% of PW)		12.2%	0.5%	6.7%	0.7%	3.6%	8.0%	19.6%	68.2%	100.0%	

Naughton Unit 1 — Wet FGD w/ESP

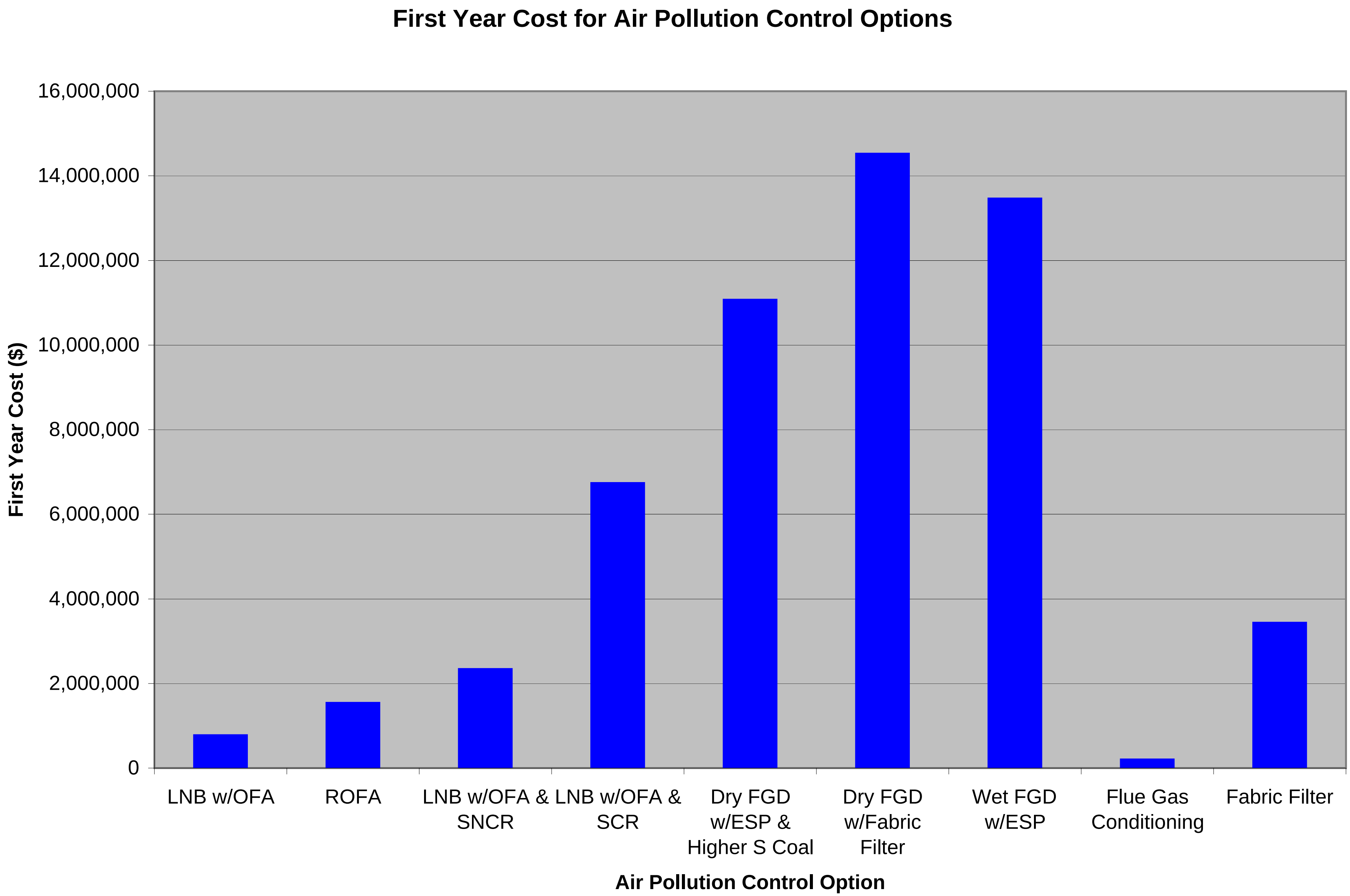
Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton SO2 Removed)
0	2013										
1	2014	2,415,786	92,084	735,700	-	548,278	946,080	2,322,141	8,722,899	13,460,826	1,705
2	2015	2,464,102	93,926	750,414	-	559,243	965,002	2,368,584	8,722,899	13,555,585	1,717
3	2016	2,513,384	95,804	765,422	-	570,428	984,302	2,415,956	8,722,899	13,652,238	1,729
4	2017	2,563,651	97,720	780,730	-	581,836	1,003,988	2,464,275	8,722,899	13,750,825	1,742
5	2018	2,614,924	99,675	796,345	-	593,473	1,024,067	2,513,560	8,722,899	13,851,384	1,755
6	2019	2,667,223	101,668	812,272	-	605,343	1,044,549	2,563,832	8,722,899	13,953,953	1,768
7	2020	2,720,567	103,702	828,517	-	617,450	1,065,440	2,615,108	8,722,899	14,058,575	1,781
8	2021	2,774,979	105,776	845,088	-	629,799	1,086,749	2,667,410	8,722,899	14,165,288	1,794
9	2022	2,830,478	107,891	861,989	-	642,394	1,108,484	2,720,759	8,722,899	14,274,136	1,808
10	2023	2,887,088	110,049	879,229	-	655,242	1,130,653	2,775,174	8,722,899	14,385,161	1,822
11	2024	2,944,830	112,250	896,814	-	668,347	1,153,266	2,830,677	8,722,899	14,498,406	1,836
12	2025	3,003,726	114,495	914,750	-	681,714	1,176,332	2,887,291	8,722,899	14,613,916	1,851
13	2026	3,063,801	116,785	933,045	-	695,348	1,199,858	2,945,037	8,722,899	14,731,736	1,866
14	2027	3,125,077	119,121	951,706	-	709,255	1,223,855	3,003,937	8,722,899	14,851,913	1,881
15	2028	3,187,578	121,503	970,740	-	723,441	1,248,332	3,064,016	8,722,899	14,974,493	1,897
16	2029	3,251,330	123,933	990,155	-	737,909	1,273,299	3,125,296	8,722,899	15,099,525	1,913
17	2030	3,316,356	126,412	1,009,958	-	752,668	1,298,765	3,187,802	8,722,899	15,227,058	1,929
18	2031	3,382,684	128,940	1,030,157	-	767,721	1,324,740	3,251,558	8,722,899	15,357,141	1,945
19	2032	3,450,337	131,519	1,050,760	-	783,075	1,351,235	3,316,590	8,722,899	15,489,826	1,962
20	2033	3,519,344	134,149	1,071,776	-	798,737	1,378,260	3,382,921	8,722,899	15,625,164	1,979
Present Worth		29,515,719	1,125,070	8,988,671	-	6,698,774	11,559,067	28,371,582	91,696,610	149,583,911	947
(% of PW)		19.7%	0.8%	6.0%	0.0%	4.5%	7.7%	19.0%	61.3%	100.0%	

Naughton Unit 1 — Flue Gas Conditioning

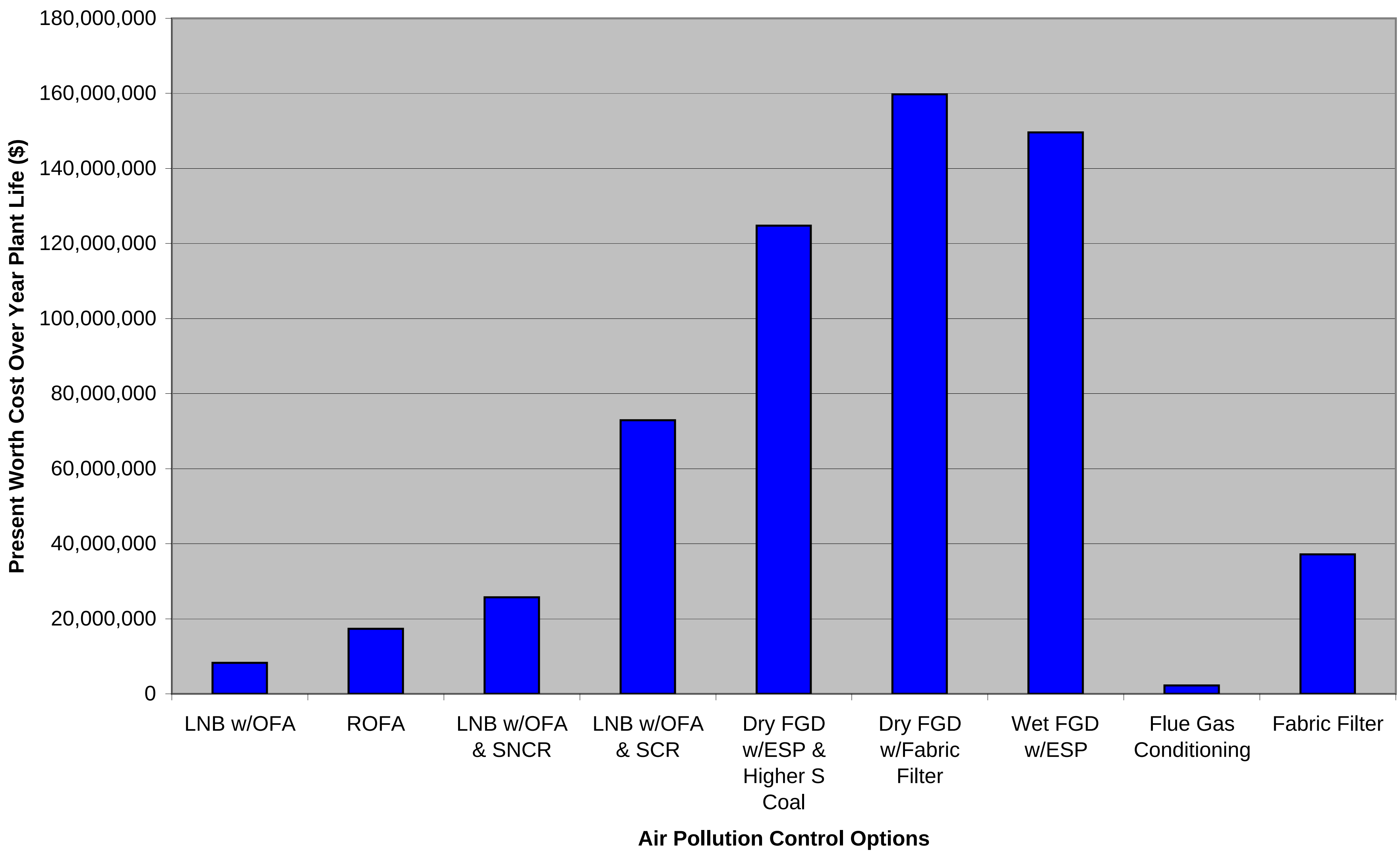
Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton PM Removed)
0	2013										
1	2014	10,000	-	47,609	-	-	19,710	67,319	123,509	200,828	1,721
2	2015	10,200	-	48,561	-	-	20,104	68,665	123,509	202,375	1,734
3	2016	10,404	-	49,532	-	-	20,506	70,039	123,509	203,952	1,748
4	2017	10,612	-	50,523	-	-	20,916	71,439	123,509	205,561	1,762
5	2018	10,824	-	51,533	-	-	21,335	72,868	123,509	207,202	1,776
6	2019	11,041	-	52,564	-	-	21,761	74,326	123,509	208,876	1,790
7	2020	11,262	-	53,615	-	-	22,197	75,812	123,509	210,583	1,805
8	2021	11,487	-	54,688	-	-	22,641	77,328	123,509	212,325	1,820
9	2022	11,717	-	55,781	-	-	23,093	78,875	123,509	214,101	1,835
10	2023	11,951	-	56,897	-	-	23,555	80,452	123,509	215,913	1,850
11	2024	12,190	-	58,035	-	-	24,026	82,061	123,509	217,761	1,866
12	2025	12,434	-	59,196	-	-	24,507	83,703	123,509	219,646	1,882
13	2026	12,682	-	60,380	-	-	24,997	85,377	123,509	221,569	1,899
14	2027	12,936	-	61,587	-	-	25,497	87,084	123,509	223,530	1,916
15	2028	13,195	-	62,819	-	-	26,007	88,826	123,509	225,530	1,933
16	2029	13,459	-	64,075	-	-	26,527	90,602	123,509	227,571	1,950
17	2030	13,728	-	65,357	-	-	27,058	92,414	123,509	229,652	1,968
18	2031	14,002	-	66,664	-	-	27,599	94,263	123,509	231,775	1,986
19	2032	14,282	-	67,997	-	-	28,151	96,148	123,509	233,940	2,005
20	2033	14,568	-	69,357	-	-	28,714	98,071	123,509	236,149	2,024
Present Worth		122,179	-	581,679	-	-	240,814	822,493	1,298,352	2,243,024	961
(% of PW)		5.4%	0.0%	25.9%	0.0%	0.0%	10.7%	36.7%	57.9%	100.0%	

Naughton Unit 1 — Fabric Filter

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton PM Removed)
0	2013										
1	2014	112,540	-	-	89,960	-	399,325	489,285	2,834,704	3,436,529	11,493
2	2015	114,791	-	-	91,759	-	407,311	499,070	2,834,704	3,448,566	11,533
3	2016	117,087	-	-	93,594	-	415,457	509,052	2,834,704	3,460,843	11,574
4	2017	119,429	-	-	95,466	-	423,766	519,233	2,834,704	3,473,366	11,616
5	2018	121,817	-	-	97,376	-	432,242	529,617	2,834,704	3,486,139	11,659
6	2019	124,254	-	-	99,323	-	440,887	540,210	2,834,704	3,499,168	11,702
7	2020	126,739	-	-	101,310	-	449,704	551,014	2,834,704	3,512,457	11,747
8	2021	129,274	-	-	103,336	-	458,698	562,034	2,834,704	3,526,012	11,792
9	2022	131,859	-	-	105,402	-	467,872	573,275	2,834,704	3,539,838	11,838
10	2023	134,496	-	-	107,511	-	477,230	584,740	2,834,704	3,553,941	11,886
11	2024	137,186	-	-	109,661	-	486,774	596,435	2,834,704	3,568,326	11,934
12	2025	139,930	-	-	111,854	-	496,510	608,364	2,834,704	3,582,998	11,983
13	2026	142,728	-	-	114,091	-	506,440	620,531	2,834,704	3,597,964	12,033
14	2027	145,583	-	-	116,373	-	516,569	632,942	2,834,704	3,613,229	12,084
15	2028	148,495	-	-	118,700	-	526,900	645,601	2,834,704	3,628,800	12,136
16	2029	151,465	-	-	121,074	-	537,438	658,513	2,834,704	3,644,682	12,189
17	2030	154,494	-	-	123,496	-	548,187	671,683	2,834,704	3,660,881	12,243
18	2031	157,584	-	-	125,966	-	559,151	685,117	2,834,704	3,677,405	12,298
19	2032	160,735	-	-	128,485	-	570,334	698,819	2,834,704	3,694,259	12,355
20	2033	163,950	-	-	131,055	-	581,741	712,795	2,834,704	3,711,450	12,412
Present Worth		1,375,002	-	-	1,099,118	-	4,878,889	5,978,007	29,798,898	37,151,908	6,212
(% of PW)		3.7%	0.0%	0.0%	3.0%	0.0%	13.1%	16.1%	80.2%	100.0%	


First Year Cost for Air Pollution Control Options
First Year Cost ($)
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
0
LNB w/OFA
ROFA
LNB w/OFA & SNCR
LNB w/OFA & SCR
Dry FGD w/ESP & Higher S Coal
Dry FGD w/Fabric Filter
Wet FGD w/ESP
Flue Gas Conditioning
Fabric Filter
Air Pollution Control Option

Present Worth Cost for Air Pollution Control Options



APPENDIX B

2006 Wyoming BART Protocol

BART Air Modeling Protocol

Individual Source Visibility Assessments for BART Control Analyses

September, 2006

State of Wyoming
Department of Environmental Quality
Air Quality Division
Cheyenne, WY 82002

Table of Contents

1.0 INTRODUCTION

The U.S. EPA has issued final amendments to the Regional Haze Regulations, along with Guidelines for Best Available Retrofit Technology (BART) Determinations.(1) The guidelines address the methodology for determining which facilities must apply BART (sources subject-to-BART) and the evaluation of control options.

The State of Wyoming used air quality modeling in accordance with the EPA Guidelines to determine the Wyoming sources which are subject-to-BART. This Protocol defines the specific methodology to be used by those sources for determining the improvement in visibility to be achieved by BART controls.

The methodology presented in this Protocol is consistent with EPA guidance and the Air Quality Division (AQD) determination of subject-to-BART sources. It is intended that all Wyoming sources that must conduct BART analyses will use this Protocol for their evaluation of control technology visibility improvement. Any deviations from the procedures described herein must be approved by the Division prior to implementation.

(1) 40 CFR Part 51: Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. 70 Federal Register, 39103-39172, July 6, 2005.

2.0 OVERVIEW

Wyoming AQD determined that eight facilities (sources) in the state are subject-to-BART. The sources are listed in Table 1. Division modeling indicated that each of these sources causes or contributes to visibility impairment in one or more Class I areas. Each source must conduct a BART analysis to define Best Available Retrofit Technology (BART) applicable to that source, and quantify the improvement in Class I visibility associated with BART controls. This Protocol sets out the procedures for quantifying visibility improvement. Other aspects of the full BART analysis are not addressed here.

There are many Class I areas within and surrounding Wyoming (See Figure 1). On the basis of distance from subject-to-BART sources, topography, meteorology, and prior modeling, the AQD has determined that only five Class I areas need be addressed in BART individual source analyses. These are Badlands and Wind Cave National Parks in South Dakota, Mt. Zirkel Wilderness Area in Colorado, and Bridger and Fitzpatrick Wilderness Areas in Wyoming. Sources in eastern Wyoming have been shown to have greatest visibility impacts at the two South Dakota Class I areas, and western Wyoming sources have maximum impacts at Bridger and Fitzpatrick Wilderness Areas, and Mt. Zirkel. Visibility improvement at these highest impact areas will provide the best measure of the effectiveness of BART controls.

Each facility should carry out modeling with the CALPUFF modeling system for the Class I areas specified in Table 2. The AQD will provide meteorological input for CALMET for the years 2001, 2002, and 2003. The model domain covered by the AQD meteorological data is centered in southwest Wyoming, and extends roughly from Twin Falls, ID in the west to the Missouri River in the east, and from Denver in the south to Helena, MT in the north. The domain is shown, along with Class I areas, in Figure 1.

Sources may wish to utilize a smaller domain for CALPUFF modeling. Smaller domains are acceptable if they provide adequate additional area beyond the specific source and Class I areas being addressed. Figure 1 includes a "southwest Wyoming" domain which represents the minimum acceptable area for sources impacting the Bridger and Fitzpatrick Wilderness Areas, and the Mt. Zirkel Wilderness Area, and a "northeast Wyoming" domain as a minimum area for Badlands and Wind Cave National Parks modeling.

The CALPUFF model should be used with each of the three years of meteorological data to calculate visibility impacts for a baseline (existing emissions) case, and for cases reflecting BART controls. The control scenarios are to include individual scenarios for proposed BART controls for each pollutant (SO_2, NO_x, and particulate matter), and a combined scenario representing application of all proposed BART controls. If desired, additional modeling may be performed for controls that are not selected as BART. This might be done, for example, to provide data useful in identifying the control technologies that represent BART. However, visibility modeling is required only for the proposed BART controls.

Table 1. Wyoming Sources Subject-to-BART

Basin Electric	Laramie River Power Plant	Boilers #1,2,3
FMC Corporation	Granger Soda Ash Plant	Boilers #1,2
FMC Corporation	Green River Sodium Plant	Three boilers
General Chemical Co.	Green River Soda Ash	Two boilers
PacifiCorp	Dave Johnson Power Plant	Boilers #3,4
PacifiCorp	Jim Bridger Power Plant	Boilers #1-4
PacifiCorp	Naughton Power Plant	Boilers #1,2,3
PacifiCorp	Wyodak Power Plant	Boiler

Results of visibility modeling will be presented as a comparison between baseline impacts and those calculated for the BART control scenarios. Quantitative measures of impact will be the 98th percentile deciview change (Δdv) relative to the 20% best days natural background, and the number of days with deciview change exceeding 0.5 (EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, 70 FR 39103). Results should be presented for each year.

Table 2. Source-Specific Class I Areas to be Addressed

Source	Class I Areas to be Evaluated
Basin Electric Laramie River	Wind Cave NP, Badlands NP
FMC Corporation Granger Soda Ash	Bridger WA, Fitzpatrick WA
FMC Corporation Sodium Products	Bridger WA, Fitzpatrick WA
General Chemical Green River Soda Ash	Bridger WA, Fitzpatrick WA
Pacificorp Dave Johnston	Wind Cave NP, Badlands NP
Pacificorp Jim Bridger	Bridger WA, Fitzpatrick WA, Mt. Zirkel WA
Pacificorp Naughton Plant	Bridger WA, Fitzpatrick WA
Pacificorp Wyodak	Wind Cave NP, Badlands NP

3.0 EMISSIONS DATA FOR MODELING

CALPUFF model input requires source (stack) – specific emission rates for each pollutant, and stack parameters (height, diameter, exit gas temperature, and exit gas velocity). Per EPA BART guidance, these parameters must be representative of maximum actual 24-hour average emitting conditions for baseline (existing) operation, and maximum proposed 24-hour average emissions for future (BART) operations.

3.1 Baseline Modeling

Sources are required to utilize representative baseline emission conditions if data are available; baseline emissions must be documented. Possible sources of emission data are stack tests, CEM data, fuel consumption data, etc. Remember that emissions should represent maximum 24-hour rates. EPA BART guidance states that you should "Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario)." Thus, baseline conditions should reference data from 2001 through 2003 (or 2004).

As a minimum, modeled emissions must include:

SO_2	sulfur dioxide
NO_x	oxides of nitrogen
$PM_{2.5}$	particles with diameter less than 2.5µm
$PM_{10-2.5}$	particles with diameters greater than 2.5µm but less than or equal to 10 µm

If the fraction of PM_{10} in the $PM_{2.5}$ (fine) and $PM_{10-2.5}$ (coarse) categories cannot be determined all particulate matter should be assumed to be $PM_{2.5}$.

In addition, direct emissions of sulfate (SO_4) should be included where possible. Sulfate can be emitted as sulfuric acid (H_2SO_4), sulfur trioxide (SO_3), or as sulfate compounds; emissions should be quantified as the equivalent mass of SO_4.

When test or engineering data are not available to specify SO_4 emissions or the relative fractions of fine and coarse particles, use can be made of speciation profiles available from Federal Land Managers at the website http://ww2.nature.nps.gov/air/permits/ect/index.cfm. Profiles are available for a number of source type and control technology combinations. The FLM speciation factors are acceptable if data are available for the appropriate source type.

Emissions of VOC (volatile organic compounds), condensable organics measured in stack tests, and elemental carbon components of PM_{10} do not need to be included for BART modeling. The only other pollutant noted in EPA BART guidance is ammonia (NH_3). Though ammonia is not believed to be a significant contributor to visibility impairment in most cases in Wyoming, it could be important for sources with significant ammonia emissions – for example from some NO_x control systems. Sources that are expected to emit ammonia (in pre-or post-control configurations) should include ammonia emissions in their model input.

If quantitative baseline emissions data are unavailable and sources believe that the maximum 24-hour emission rates estimated by the Division (presented in the Subject-to-BART final report) are representative of baseline conditions for their facility, they may be used for baseline modeling. However, emissions of sulfate and ammonia (if applicable) should be included based on the best available test information or speciation factors from current literature.

3.2 Post-Control Modeling

All pollutants described above should be included for each post-control scenario. Post-control emissions (maximum 24-hour average) will generally be the baseline emissions multiplied by a control factor appropriate to the BART control. However, some proposed controls may simply increase the efficiency of existing controls; others may result in an increase in emissions of one pollutant while controlling another. These factors must all be considered in defining emission rates for post-control modeling. Any changes in stack parameters resulting from control application must also be included.

The required visibility assessment will include the effect of each proposed BART control. For example, if a source proposes to add a scrubber for SO_2 control, low NO_x burners for NO_x control, and a baghouse for particulate control, four sets of visibility results should be developed:

- Use of SO_2 control alone
- Use of NO_x control alone
- Use of particulate control alone
- Use of proposed combination of all three controls

All pollutants should be modeled in each CALPUFF model run, but the modeled emissions should reflect only the specific controls or combination of controls addressed in that run.

Additional modeling could be necessary in situations where a facility is comprised of more than one subject-to-BART source, and different BART controls are applicable to different sources. Excessive modeling to address multiple control combinations is not necessary; however, visibility modeling should quantify the effect of BART controls on all affected sources for each pollutant, and of all facility BART controls combined.

4.0 METEOROLOGICAL DATA

Wyoming AQD will provide MM5 meteorological data fields for years 2001, 2002, and 2003 that can be utilized as input to CALMET. The MM5 output will have 12 kilometer resolution and cover the full domain shown in Figure 1.

Mesoscale meteorological data (MM5) were developed and evaluated as part of the AQD's southwest Wyoming NO_2 increment analysis. Three years of MM5 data at 36 km resolution were used to initialize 12 km MM5 simulations. The 12km MM5 modeling used identical physics options to the original 36 km runs. CALMM5 was then used as a preprocessor to produce CALMET – ready MM5 data input files. Quality assurance was performed by comparing the original MM5 output on the 36km national RPO grid to the 12 km MM5 output and observations.

The CALMET model (version 5.53a, level 040716) should be used to prepare meteorological input for CALPUFF. The user may select a domain smaller than the MM5 domain for CALMET and CALPUFF modeling if desired. Figure 1 shows minimum domain areas for modeling of western and eastern Wyoming BART sources. Four kilometer resolution should be specified for CALMET output.

CALMET processing should use the AQD MM5 data, and appropriate surface, upper air, and precipitation data. Figure 2 shows the locations of surface and upper air stations within the MM5 model domain. The MM5 data are used as the initial guess wind field; this wind field is then adjusted by CALMET for terrain and land use to generate a step 1 wind field, and refined using surface and upper air data to create the final step 2 wind field.

Surface, upper air, and precipitation data can be obtained from the National Climatic Data Center. Land use and terrain data are available from the U.S. Geological Survey. Data can be formatted for use in CALMET with standard conversion and processing programs available with the CALMET/CALPUFF software.

Table 3 provides a listing of applicable CALMET input variables for BART meteorological processing. The table includes inputs that are specific to Wyoming BART modeling. Inputs not shown in Table 3 are not relevant to the present application, are dependent on the specific model domain of the user, use model default values, or are obvious from the context.

Table 3. CALMET Control File Inputs

Variable	Description	Value
	Input Group 1	
IBYR	Year	2001
		2002
		2003
IBTZ	Base time zone	7
IRTYPE	Run type	1
LCALGRD	Compute data fields for CALGRID	T
	Input Group 2	
PMAP	Map projection	LCC
DGRIDKM	Grid spacing (km)	4
NZ	Number of layers	10
ZFACE	Cell face heights (m)	0
		20
		40
		100
		140
		320
		580
		1020
		1480
		2220
		3500
	Input Group 4	
NOOBS	No observation Mode	0
	Input Group 5	
IWFCOD	Model selection variable	1
IFRADJ	Froude number adjustment	1
IKINE	Kinematic effects	0
IOBR	Use O'Brien procedure	0
ISLOPE	Slope flow effects	1
IEXTRP	Extrapolate surface wind observations	-4
ICALM	Extrapolate calm surface winds	0
BIAS	Biases for weights of surface and upper air stations	All 0
RMIN2	Minimum distance for extrapolation	-1
IPROG	Use gridded prognostic model output	14
ISTEPPG	Time Step (hours)	1
LVARY	Use varying radius of influence	F

Table 3. CALMET Control File Inputs (continued)

Variable	Description	Value
RMAX 1	Maximum radius of influence (km)	30
RMAX 2	Maximum radius of influence (km)	50
RMIN	Minimum radius of influence (km)	0.1
TERRAD	Radius of influence for terrain (km)	15
R1	Relative weighting of first guess wind field and observations (km)	5
R2	Relative weighting aloft (km)	25
IDIOPT 1	Surface temperature	0
IDIOPT 2	Upper air lapse rate	0
ZUPT	Lapse rate depth (m)	200
IDIOPT 3	Average wind components	0
IUPWND	Upper air station	-1
ZUPWND (1) ZUPWND (2)	Bottom and top of layer for domain scale winds (m)	1, 1000 1, 1000
IDIOPT4	Surface wind components	0
IDIOPT5	Upper air wind components	0
	Input Group 6	
IAVEZI	Spatial averaging	1
MNMDAV	Max search radius	1
HAFANG	Half angle for averaging (deg)	30
ILEVZI	Layer of winds in averaging	1
ZIMAX	Maximum overland mixing height (m)	3500
ITPROG	3D temperature source	1
IRAD	Interpolation type	1
TRADKM	Radius of influence – temperature (km)	500
NUMTS	Maximum number of Stations	5
IAVET	Spatial averaging of temperatures	1
NFLAGP	Precipitation interpolation	2

5.0 CALPUFF MODEL APPLICATION

The CALPUFF model (version 5.711a, level 040716) will be used to calculate pollutant concentrations at receptors in each Class I area. Application of CALPUFF should, in general, follow the guidance presented in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 report (EPA – 454/R98-019) and the EPA Regional Haze Regulations and Guidelines for BART Determinations (70 FR 39103).

Appropriate CALPUFF control file inputs are in Table 4. Note should be taken of the basis for several of the recommended CALPUFF inputs.

- Building downwash effects need not be included. Because of the transport distances involved and the fact that most sources have tall stacks, building downwash is unlikely to have a significant effect on model-predicted concentrations

- Puff splitting is not required. The additional computation time necessary for puff splitting is not justified for purposes of BART analyses.

- Hourly ozone files should be used to define background ozone concentration. Data are available from the following sites within the model domain.
  Rocky Mountain NP, CO
  Craters of the Moon NP, ID
  AIRS – Highland UT
  Mountain Thunder, WY
  Yellowstone NP, WY
  Centennial, WY
  Pinedale, WY

  The background ozone concentration shown in Table 4 is used only when hourly data are missing.

- A constant background ammonia concentration of 2.0 ppb is specified. This value is based upon monitoring data from nearby states and IWAQM guidance. Experience suggests that 2.0 ppb is conservative in that it is unlikely to significantly limit nitrate formation in the model computations.

- MESOPUFF II chemical transformation rates should be used.

- The species to be modeled should be the seven identified in CALPUFF: SO_2, SO_4, NO_x, HNO_3, NO_3, $PM_{2.5}$, and $PM_{10-2.5}$. If ammonia (NH_3) is emitted it should be added to the species list. In most cases, all pollutants modeled will also be emitted, except for HNO_3 and NO_3.

Concentration calculations should be made for receptors covering the areas of the Class I areas being addressed. Receptors in each Class I area will be those designated by the Federal Land Managers and available from the National Park Service website.

Table 4. CALPUFF Control File Inputs

Variable	Description	Value
	Input Group 1	
METRUN	Control parameter for running all periods in met file	1
IBYR	Starting year	2001 2002 2003
XBTZ	Base time zone	7
NSPEC	Number of chemical species modeled	7 (or 8)
NSE	Number of species emitted	5 (or 6)
METFM	Meteorological data format	1
	Input Group 2	
MGAUSS	Vertical distribution in near field	1
MCTADJ	Terrain adjustment method	3
MCTSG	Subgrid scale complex terrain	0
MSLUG	Elongated puffs	0
MTRANS	Transitional plume rise	1
MTIP	Stack tip downwash	1
MSHEAR	Vertical wind shear	0
MSPLIT	Puff splitting allowed?	0
MCHEM	Chemical mechanism	1
MAQCHEM	Aqueous phase transformation	0
MWET	Wet removal	1
MDRY	Dry deposition	1
MDISP	Dispersion Coefficients	3
MROUGH	Adjust sigma for roughness	0
MPARTL	Partial plume penetration of inversions	1
MPDF	PDF for convective conditions	0
	Input Group 4	
PMAP	Map projection	LCC
DGRIDKM	Grid spacing	4

Table 4. CALPUFF Control File Inputs (continued)

ZFACE	Cell face heights (m)	0
		20
		40
		100
		140
		320
		580
		1020
		1480
		2220
		3500
	Input Group 6	
NHILL	Number of terrain features Input Group 7	0
Dry Gas Depo	Chemical parameters for dry gas deposition	Defaults
	Input Group 8	
Dry Part. Depo	Size parameters for dry particle deposition SO_4, NO_3, PM25 PM10	 Defaults 6.5, 1.0
	Input Group 11	
MOZ	Ozone Input option	1
BCK03	Background ozone – all months (ppb)	44.0
BCKNH3	Background ammonia – all months (ppb)	2.0
	Input Group 12	
XMAXZI	Maximum mixing height (m)	3500
XMINZI	Minimum mixing height (m)	50

6.0 POST PROCESSING

Visibility impacts are calculated from the CALPUFF concentration results using CALPOST. CALPOST version 5.51, level 030709 should be used; the output from CALPOST will provide the highest deciview impact on each day from all receptors within each Class I area modeled.

For some CALPUFF applications such as deposition calculations, the POSTUTIL program is used prior to CALPOST. POSTUTIL is also used to repartition total nitrate by accounting for ammonia limiting. The ammonia limiting calculation in POSTUTIL should not be applied for Wyoming BART modeling. If you believe that ammonia limiting is appropriate for a specific BART analysis, justification should be discussed with the Division prior to its used.

Visibility calculations by CALPOST for BART purposes use Method 6. This method requires input of monthly relative humidity factors, f(RH), for each Class I area. The EPA guidance document provides appropriate data for each area. Table 5 lists monthly f(RH) factors to use for the Wyoming, Colorado, and South Dakota areas to be addressed in BART modeling. The factors shown in Table 5 include averages for the adjacent Class I areas, and are within 0.2 units of the Guideline table values for the individual Class I areas.

Natural background conditions as a reference for determination of the delta-dv change due to a source should be representative of the 20% best natural visibility days. EPA BART guidance provides the 20% best days deciview values for each Class I area on an annual basis, but does not provide species concentration data for the 20% best background conditions. These concentrations are needed for input to CALPOST.

Annual species concentrations corresponding to the 20% best days were calculated for each Class I area to be addressed, by scaling back the annual average concentrations given in Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (Table 2-1). A separate scaling factor was derived for each Class I area such that, when multiplied by the Guidance table annual concentrations, the 20% best days deciview value for that area would be calculated. The scaled aerosol concentrations were averaged for the Bridger and Fitzpatrick WAs, and for Wind Cave and Badlands NPs, because of their geographical proximity and similar annual background visibility. The 20% best days aerosol concentrations to be used for each month for Wyoming BART evaluations are listed in Table 6.

Table 7 is a list of inputs for CALPOST. These inputs should be used for all BART visibility calculations. Output from CALPOST should be configured to provide a ranked list of the highest delta-deciview values in each Class I area. The 98^{th} percentile delta-deciview value and the number of values exceeding 0.5 can then be determined directly from the CALPOST output.

Table 5. Monthly f(RH) Factors for Class I Areas

Month	Wind Cave NP Badlands NP	Bridger WA Fitzpatrick WA	Mt. Zirkel WA
January	2.65	2.50	2.20
February	2.65	2.30	2.20
March	2.65	2.30	2.00
April	2.55	2.10	2.10
May	2.70	2.10	2.20
June	2.60	1.80	1.80
July	2.30	1.50	1.70
August	2.30	1.50	1.80
September	2.20	1.80	2.00
October	2.25	2.00	1.90
November	2.75	2.50	2.10
December	2.65	2.40	2.10

Table 6. Natural Background Concentrations of Aerosol Components for 20% Best Days for BART Analyses ($\mu g/m^3$)

Aerosol Component	Wind Cave NP Badlands NP	Fitzpatrick WA Bridger WA	Mt. Zirkel WA
Ammonium Sulfate	.047	.045	.046
Ammonium Nitrate	.040	.038	.038
Organic Carbon	.186	.178	.179
Elemental Carbon	.008	.008	.008
Soil	.198	.189	.190
Coarse Mass	1.191	1.136	1.141

Table 7. CALPOST Control File Inputs

Variable	Description	Value
	Input Group 1	
ASPEC	Species to Process	VISIB
ILAYER	Layer/deposition code	1
A,B	Scaling factors	0,0
LBACK	Add background concentrations?	F
BTZONE	Base time zone	7
LVSO4	Species to be included in extinction	T
LVNO3		T
LVOC		F
LVPMC		T
LVPMF		T
LVEC		F
LVBK	Include background?	T
SPECPMC	Species name for particulates	PM10
SPECPMF		PM25
EEPMC	Extinction efficiencies	0.6
EEPMF		1.0
EEPMCBK		0.6
EESO4		3.0
EENO3		3.0
EEOC		4.0
EESOIL		1.0
EEEC		10.0
MVISBK	Visibility calculation method	6
RHFAC	Monthly RH adjustment factors	Table 5
BKSO4	Background concentrations	Table 6
BKNO3		Table 6
BKPMC		Table 6
BK OC		Table 6
BKSOIL		Table 6
BKEC		Table 6
BEXTRAY	Extinction due to Rayleigh scattering	10.0

7.0 REPORTING

A report on the BART visibility analysis should be submitted that clearly compares impacts for post-control emissions to those for baseline emissions. Data for baseline and BART scenarios should include both the 98th percentile values and the number of days with delta-deciview values exceeding 0.5. Results should be given for each model year.

Table 8 is an example of a recommended format for presentation of model input and model results. The example is for baseline conditions; similar tables should be provided for each control scenario (SO_2, NO_x, and PM10) and for the combination of all BART controls. Your report tables need not follow the exact format shown in Table 8; but the same information should be provided in a concise and clear form. If additional scenarios were modeled or you wish to present supplemental information, they should be provided in an appendix or separate from the specified final results.

Table 8. Example Format for Presentation of Model Input and Results

Baseline Conditions Model Input Data

Source (Unit) Description And ID	SO_2 Emission Rate (lb/day)	NO_x Emission Rate (lb/day)	$PM_{2.5}$ Emission Rate (lb/day)	$PM_{10\text{-}2.5}$ Emission Rate (lb/day)	SO_4 Emission Rate (lb/day)	NH_3 Emission Rate (lb/day)	Location Easting UTM (m)	Location Northing UTM (m)	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Gas Temp (deg K)

Baseline Visibility Modeling Results

Name of Facility	Class I Area	2001		2002		2003	
		98^{th} Percentile Value (dv)	No. of days exceeding 0.5 dv	98^{th} Percentile Value (dv)	No. of days exceeding 0.5 dv	98^{th} Percentile Value (dv)	No. of days exceeding 0.5 dv

PUBLIC UTILITY COMMISSION OF OREGON

UE 246

SIERRA CLUB EXHIBIT 107

BART Analysis for Naughton Unit 2
2007

Final Report

BART Analysis for Naughton Unit 2

Prepared For:

PacifiCorp
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December 2007

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Final Report

BART Analysis for Naughton Unit 2

Submitted to

PacifiCorp

December 2007

CH2MHILL

Executive Summary

Background

In response to the Regional Haze Rule and Best Available Retrofit Technology (BART) regulations and guidelines, CH2M HILL was requested to perform a BART analysis for PacifiCorp's Naughton Unit 2 (hereafter referred to as Naughton 2). A BART analysis has been conducted for the following criteria pollutants: nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter less than 10 micrometers in aerodynamic diameter (PM_{10}). The Naughton Station consists of three units with a total generating capacity of 700 megawatts (MW). Presumptive BART limits do not directly apply to Naughton 2, based on the United States Environmental Protection Agency's (EPA) guidelines. Presumptive BART limits are a goal unless an alternative control level is justified based on careful consideration of the statutory factors. BART emission limits must be achieved within 5 years after the State Implementation Plan (SIP) is approved by the EPA, and a compliance date of 2014 was assumed for this analysis.

In completing the BART analysis, technology alternatives were investigated and potential reductions in NO_x, SO_2, and PM_{10} emissions rates were identified. The following technology alternatives were investigated, listed below by pollutant:

- NO_x emission controls:
  - Low-NO_x burners (LNBs) with over-fire air (OFA)
  - Rotating opposed fire air
  - LNBs with selective non-catalytic reduction system (SNCR)
  - LNBs with selective catalytic reduction (SCR) system
- SO_2 emission controls:
  - Dry flue gas desulfurization (FGD) system with existing electrostatic precipitator (ESP)
  - Dry FGD system with new fabric filter
  - Wet FGD system with existing ESP
- PM_{10} emission controls:
  - Sulfur trioxide (SO_3) injection flue gas conditioning (FGC) system on existing ESP
  - Polishing fabric filter
  - Replacement fabric filter

BART Engineering Analysis

The specific steps in a BART engineering analysis are identified in the *Code of Federal Regulations* (CFR) at 40 CFR 51, Appendix Y, Section IV. The evaluation must include:

- The identification of available, technically feasible, retrofit control options
- Consideration of any pollution control equipment in use at the source, which affects the availability of options and their impacts
- The costs of compliance with the control options
- The remaining useful life of the facility
- The energy and non-air quality environmental impacts of compliance
- The degree of visibility improvement that may reasonably be anticipated from the use of BART

The following steps are incorporated into the BART analysis:

- Step 1 – Identify All Available Retrofit Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
  - The identification of available, technically feasible, retrofit control options
  - Consideration of any pollution control equipment in use at the source (which affects the applicability of options and their impacts)
- Step 3 – Evaluate Effectiveness of Remaining Control Technologies
- Step 4 – Evaluate Impacts and Document Results
  - The costs of compliance with control options
  - The remaining useful life of the facility
  - The energy and non-air quality environmental impacts of compliance
- Step 5 – Evaluate Visibility Impacts
  - The degree of visibility improvement that may reasonably be anticipated from the use of BART

Separate analyses have been conducted for NO_x, SO_2, and PM_{10} emissions. All costs included in the BART analyses are in 2006 dollars; costs have not been escalated to the assumed 2014 BART implementation date.

Coal Characteristics

The main source of coal burned at Naughton 2 will be the low-sulfur and high-sulfur P&M Kemmerer Mines (P&M). These coals are ranked as sub-bituminous but are closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. These coals have higher nitrogen content than coals from the Powder River Basin (PRB), which represent the bulk of sub-bituminous coal use in the United States. This BART analysis has compared the higher nitrogen content and the different combustion characteristics of PRB coals to those coals used at Naughton 2, and has evaluated the effect of these qualities on NO_x formation and achievable emission rates.

Recommendations

CH2M HILL recommends installing LNBs with OFA, a dry FGD system, and operating the existing ESP with an SO_3 FGC system. This combination of control devices is identified as Scenario 1 throughout this report.

NO_x Emission Control

Naughton 2 burns coal from P&M. As documented in this analysis, the characteristics of P&M coals are aligned more closely with bituminous coals.

CH2M HILL recommends LNB with OFA as BART for Naughton 2, based on the projected significant reduction in NO_x emissions, reasonable control costs, and the advantages of no additional power requirements or non-air quality environmental impacts. Reductions of NO_x are expected to be similar to those realized at the Jim Bridger plant where LNBs with OFA have been installed on Unit 2. Selection of new LNB with OFA at Naughton 1 is projected to attain an emission rate at or below 0.26 pound per million British thermal units (MMBtu).

SO_2 Emission Control

CH2M HILL recommends a dry lime FGD system with the existing ESP as BART for Naughton 2, assuming use of coal containing no more than 1.02 percent sulfur by weight, based on the significant reduction in SO_2 emissions, reasonable control costs, and the advantages of minimal additional power requirements and minimal non-air quality environmental impacts. This technology is projected to attain an SO_2 limit of 0.41 pound per MMBtu.

PM_{10} Emission Control

CH2M HILL recommends the addition of FGC system to enhance the performance of the existing electrostatic precipitator (ESP) as BART for Naughton 2, based on the reduction in PM_{10} emissions, reasonable control costs, and the advantages of minimal additional power requirements and no non-air quality environmental impacts.

BART Modeling Analysis

CH2M HILL used the CALPUFF modeling system to assess the visibility impacts of emissions from Naughton 2 at Class I areas. The Class I areas potentially affected are located more than 50 kilometers, but less than 300 kilometers, from the Naughton Plant.

The Class I areas include the following wilderness areas (WAs):

- Bridger WA
- Fitzpatrick WA

Because Naughton 2 simultaneously will control NO_x, SO_2, and PM_{10} emissions, four post-control atmospheric dispersion modeling scenarios were developed to cover the range of effectiveness for combining the individual NO_x, SO_2, and PM_{10} control technologies under evaluation. These modeling scenarios, and the controls assumed, are as follows:

- **Scenario 1**: New LNB with OFA modifications, a dry FGD system, and an FGC system for enhanced ESP performance. As indicated previously, this scenario represents the preliminary BART recommendation of CH2M HILL.
- **Scenario 2**: New LNB with OFA modifications, a dry FGD system, and installation of a new fabric filter.
- **Scenario 3**: New LNB with OFA modifications and SCR, a dry FGD system, and installation of a new fabric filter.
- **Scenario 4**: New LNB with OFA modifications and SCR, installation of a new wet FGD system, installation of FGC for enhanced ESP performance, and construction of a new stack.

Visibility improvements for all emission control scenarios were analyzed, and the results were compared using a least-cost envelope, as outlined in the *New Source Review Workshop Manual*.[1]

Least-cost Envelope Analysis

EPA has adopted the Least-cost Envelope Analysis Methodology as an accepted methodology for selecting the most reasonable, cost-effective controls. Incremental cost-effectiveness comparisons focus on annualized cost and emission reduction differences between dominant alternatives. The dominant set of control alternatives is determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for total emissions reductions for all control alternatives identified in the BART analysis.

To evaluate the impacts of the modeled control scenarios on the three Class I areas, the total annualized cost, cost per deciview (dV) reduction, and cost per reduction in number of days above 0.5 dV were analyzed. This report provides a comparison of the average incremental costs between relevant scenarios for the three Class I areas; the total annualized cost versus number of days above 0.5 dV, and the total annualized cost versus 98th percentile delta-deciview (ΔdV) reduction.

Results of the Least-cost Envelope Analysis validate the selection of Scenario 1, based on incremental cost and visibility improvements. The other scenarios were eliminated for the following reasons:

- Scenario 2 (LNB with OFA, dry FGD, and fabric filter) is to the left of the curve formed by the dominant control alternative scenario, which indicates a scenario with lower improvement and/or higher costs.

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[1] EPA, 1990. *New Source Review Workshop Manual.* Draft. Environmental Protection Agency. October, 1990.

- Scenario 3 (LNB with OFA and SCR, dry FGD, and new fabric filter) has very high incremental costs, on the basis of both a cost per day of improvement and cost per dV reduction.
- While Scenario 4 (LNB with OFA and SCR, wet FGD and new stack, and ESP with SO_3 injection) provides some potential visibility advantage over Scenario 1, the projected improvement is less than 0.5 dV, and the projected costs are excessive.

Therefore, Scenario 1 represents BART for Naughton 2.

Just-Noticeable Differences in Atmospheric Haze

Studies have been conducted that demonstrate only dV differences of approximately 1.5 to 2.0 dV or more are perceptible by the human eye. Deciview changes of less than 1.5 cannot be distinguished by the average person. Therefore, the modeling analysis results indicate that only minimal, if any, observable visibility improvements at the Class I areas studied would be expected under any of the control scenarios. Thus, the results indicate that only minimal discernable visibility improvements would occur, although PacifiCorp would be spending many millions of dollars at this single unit, and over a billion dollars when considering its entire fleet of coal-fired power plants.

Contents

Tables

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Acronyms and Abbreviations

°C	Degrees Celsius
°F	Degrees Fahrenheit
f(RH)	Relative Humidity Factor
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CALDESK	Program to display data and results
CALMET	Meteorological data preprocessing program for CALPUFF
CALPOST	Post-processing program for calculating visibility impacts
CALPUFF	Gaussian puff dispersion model
CFR	*Code of Federal Regulations*
CO	Carbon Monoxide
COHPAC	Compact Hybrid Particulate Collector
dV	Deciview
ΔdV	Delta Deciview, Change in Deciview
ESP	Electrostatic Precipitator
EPA	United States Environmental Protection Agency
FGC	Flue Gas Conditioning
FGD	Flue Gas Desulfurization
kW	Kilowatt
kWh	Kilowatt-hour
LAER	Lowest Achievable Emission Rate
lb	Pound
LNB	Low-NO_x Burner
MMBtu	Million British Thermal Units
MM5	Mesoscale Meteorological Model, Version 5
MW	Megawatt
N_2	Molecular Nitrogen
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxide
$(NH_4)HSO_4$	Ammonium Bisulfate
$(NH_4)_2SO_4$	Ammonium Sulfate

NP	National Park
OFA	Over-fire Air
P&M	P&M Kemmerer Mine
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 Micrometers in Aerodynamic Diameter
PRB	Powder River Basin
ROFA	Rotating Opposed Fire Air
S&L	Sargent & Lundy
S&L Study	*Multi-Pollutant Control Report* dated October, 2002.
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
TRC	TRC Companies, Inc.
USGS	United States Geological Survey
WA	Wilderness Area
WDEQ	Wyoming Department of Environmental Quality
WDEQ-AQD	Wyoming Department of Environmental Quality – Air Quality Division

1.0 Introduction

Best Available Retrofit Technology (BART) guidelines were established as a result of United States Environmental Protection Agency (EPA) regulations intended to reduce the occurrence of regional haze in national parks (NPs) and other Class I protected air quality areas in the United States. These guidelines provide direction for states when determining which facilities must install additional controls, and the type of controls that must be used. Facilities eligible for BART installation were built between 1962 and 1977, and have the potential to emit more than 250 tons per year of visibility-impairing pollutants.

The Wyoming Department of Environmental Quality (WDEQ) BART regulations state that each source subject to BART must submit a BART application for a construction permit by December 15, 2006. PacifiCorp received an extension from the WDEQ to submit the BART report for Naughton Unit 2 (hereafter referred to as Naughton 2) by February 9, 2007. The BART Report that was submitted to WDEQ in February 2007 included a BART analysis, as well as a proposal and justification for BART at the source. This revised report—submitted in October 2007—incorporates editorial revisions and new model runs since the February 2007 version.

The State of Wyoming has identified those eligible, in-state facilities that are required to reduce emissions under BART and will set BART emissions limits for those facilities. This information will be included in the State of Wyoming State Implementation Plan (SIP), which the State has estimated will be submitted formally to the EPA by early 2008. EPA BART guidelines also state that the BART emission limits must be fully implemented within 5 years after EPA approval of the SIP.

Five elements related to BART address the issue of emissions for the identified facilities:

- Cost of the controls
- Energy and non-air quality environmental impacts of compliance
- Any existing pollution control technology in use at the source
- Remaining useful life of the source
- Degree of improvement in visibility that reasonably could be anticipated from the use of such technology

This report documents the BART analysis that CH2M HILL performed on Naughton 2 by for PacifiCorp. The analysis was performed for nitrogen oxides (NO_x), SO_2 (sulfur dioxide), and particulate matter less than 10 micrometers in aerodynamic diameter (PM_{10}) because these are the primary criteria pollutants that affect visibility.

Section 2 of this report provides a description of the present unit operation, including a discussion of coal sources and characteristics. The BART Engineering Analysis is provided in Section 3 by pollutant type. Section 4 provides the methodology and results of the BART Modeling Analysis, followed by recommendations in Section 5 and references are provided in Section 6. Appendices provide more detail on the economic analysis and the 2006 Wyoming BART Protocol.

2.0 Present Unit Operation

Naughton 2 is a nominal 210-megawatt (MW) unit located approximately 6 miles southwest of Kemmerer, Wyoming. The unit is equipped with a tangentially fired boiler manufactured by the former Combustion Engineering (now Alstom). The unit was constructed with a United Conveyor mechanical dust collector for particulate matter (PM) control, and a Lodge Cottrell electrostatic precipitator (ESP) was added in 1976. The unit presently uses low sulfur coal to control SO_x emissions below 1.2 pounds per million British thermal units (MMBtu) and good combustion practices for NO_x control. A Honeywell distributed control system was installed in 1998.

Naughton 2 began operation in 1968. Its current economic depreciation life is through 2032; however, this analysis is based on a 20-year life for BART control technologies. Assuming a BART implementation date of 2014, this will result in an approximate remaining useful life for Naughton 2 of 20 years from the installation date of any new or modified BART-related equipment. This report does not attempt to quantify any additional life extension costs needed to allow the unit at Naughton 2 to operate until 2034. Table 2-1 lists additional unit information and study assumptions for this analysis.

The main source of coal burned at Naughton 2 is the P&M Kemmerer Mine (P&M). This coal is ranked as sub-bituminous, but it is closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. P&M coal has higher nitrogen content than coals from the Powder River Basin (PRB), which represent the bulk of sub-bituminous coal use in the United States.

This BART analysis has considered the higher nitrogen content and different combustion characteristics of PRB coals, compared to those coals used Naughton 2 and the effect of these qualities on NO_x formation. Coal sources and characteristics are summarized in Table 2-2. The primary source of coal will be from P&M, and data on coal from this source were used in the modeling analysis.

TABLE 2-1
Present Unit Operation
Naughton 2

General Plant Data	
Site Elevation (feet above mean sea level)	6936
Stack Height (feet)	224
Stack Exit Internal Diameter (feet) / Exit Area (square feet)	16 / 201.1
Stack Exit Temperature (degrees Fahrenheit [°F])	280
Stack Exit Velocity (feet per second [feet per second])	78
Stack Flow (actual cubic feet per minute)	940,970
Latitude deg: (minutes:seconds)	41:45:27.36
Longitude deg: (minutes:seconds)	110:35:53.05
Annual Unit Capacity Factor (percentage [%])	90
Net Unit Output (megawatts)	210
Net Unit Heat Rate (British thermal unit [Btu] per kilowatt-hour)(100% load)	10,550 (as measured by fuel throughput)
Boiler Heat Input (million Btu [MMBtu] per hour)(100% load)	2,400 (as measured by continuous emissions monitoring)
Type of Boiler	Tangentially fired
Boiler Fuel	Coal
Coal Sources	P&M Kemmerer Mine
Coal Heating Value (Btu per pound)[a]	9,800
Coal Sulfur Content (% by weight)[a]	0.58
Coal Ash Content (% by weight)[a]	5.00
Coal Moisture Content (% by weight)[a]	21.00
Coal Nitrogen Content (% by weight)[a]	1.3
Current Nitrogen Oxide (NO_x) Controls	Good Combustion Practices
Pre-project NO_x Emission Rate (pounds per MMBtu)[b]	0.54
Current Sulfur Dioxide (SO_2) Controls	None
Pre-project SO_2 Emission Rate (pounds per MMBtu)	1.20
Current PM_{10}[c] Controls	Electrostatic Precipitator
Pre-project Particulate Matter Emission Rate (pounds per MMBtu)[d]	0.064

NOTES:

[a]Coal characteristics vary between coal sources
[b]Emission rates stated on annual average basis
[c]PM_{10} refers to particulate matter less than 10 micrometers in aerodynamic diameter
[d]Emission rate stated from test results

TABLE 2-2
Coal Sources and Characteristics
Naughton 2

Mines	Moisture (%)	Ash (%)	Volatile Matter (%)	Fixed Carbon (%)	British thermal unit per pound	Sulfur (%)	Ultimate Analysis (% dry basis)					
							Hydrogen	Carbon	Sulfur	Nitrogen	Oxygen	Ash
Low-Sulfur P&M Mine												
Average	20.90	4.49	33.46	41.17	9970	0.59	5.06	71.67	0.73	1.33	15.35	5.86
Standard Deviation *	0.97	1.11	0.57	1.18	303	0.05	0.19	1.43	0.06	0.16	0.97	1.04
High Sulfur P&M Mine												
Average	20.26	5.50	33.77	40.48	9965	1.29	5.02	70.87	1.68	1.22	14.57	6.64
Standard Deviation *	0.84	1.41	0.50	1.44	232	0.29	0.20	1.34	0.33	0.17	0.92	1.08

NOTES:
*Statistics are based on daily delivered samples except for ultimate analysis, which is based on weekly composites of daily samples

3.0 BART Engineering Analysis

This section presents the required BART engineering analysis.

3.1 Applicability

In compliance with regional haze requirements, the State of Wyoming must prepare and submit visibility SIPs to EPA for Class I areas. The state has estimated that formal submittal of the SIPs will occur by early 2008. The first phase of the regional haze program is the implementation of BART emission controls on all BART-eligible units, within 5 years after EPA approval of the SIP.

3.2 BART Process

The specific steps in a BART engineering analysis are identified in the *Code of Federal Regulations* (CFR) at 40 CFR 51 Appendix Y, Section IV. The evaluation must include:

- The identification of available, technically feasible, retrofit control options
- Consideration of any pollution control equipment in use at the source, which affects the availability of options and their impacts
- The costs of compliance with the control options
- The remaining useful life of the facility
- The energy and non-air quality environmental impacts of compliance
- The degree of visibility improvement that may reasonably be anticipated from the use of BART

The following steps are incorporated into the BART analysis:

- Step 1 – Identify All Available Retrofit Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
  - Identification of available, technically feasible, retrofit control options
  - Consideration of any pollution control equipment in use at the source, which affects the applicability of options and their impacts
- Step 3 – Evaluate Effectiveness of Remaining Control Technologies
- Step 4 – Evaluate Impacts and Document Results
  - Costs of compliance with the control options
  - Remaining useful life of the facility

  - Energy and non-air quality environmental impacts of compliance
- Step 5 – Evaluate Visibility Impacts
  - Degree of visibility improvement that reasonably could be anticipated from the use of BART

To minimize costs in the BART analysis, consideration was made of any pollution control equipment in use at the source, the costs of compliance associated with the control options, and the energy and non-air quality environmental impacts of compliance using these existing control devices. In some cases, enhancing the performance of the existing control equipment was considered. Other scenarios with new control equipment also were developed.

Separate cost analyses have been conducted for NO_x, SO_2, and PM_{10} emissions. All costs included in the BART analysis are in 2006 dollars (not escalated to the 2014 BART implementation date).

3.2.1 BART NO_x Analysis

Nitrogen oxide formation in coal-fired boilers is a complex process that is dependent on a number of variables, including operating conditions, equipment design, and coal characteristics.

Formation of NO_x

During coal combustion, NO_x is formed in three different ways. The dominant source of NO_x formation is the oxidation of fuel-bound nitrogen. During combustion, part of the fuel-bound nitrogen is released from the coal with the volatile matter, and part is retained in the solid portion (char). The nitrogen chemically bound in the coal is partially oxidized to nitrogen oxides (NO and nitrogen dioxide) and partially reduced to molecular nitrogen (N_2). A smaller part of NO_x formation is due to high temperature fixation of atmospheric nitrogen in the combustion air (thermal NO_x). A small amount of NO_x is called prompt NO_x, which results from an interaction of hydrocarbon radicals, nitrogen, and oxygen.

In a conventional pulverized coal burner, air is introduced with turbulence to promote good mixing of fuel and air and provide stable combustion. However, not all of the oxygen in the air is used for combustion. Some of the oxygen combines with the fuel nitrogen to form NO_x.

Coal characteristics directly and significantly affect NO_x emissions from coal combustion. Coal ranking is a means of classifying coal according to its degree of metamorphism in the natural series, from lignite to sub-bituminous to bituminous and on to anthracite. Lower rank coal, such as the sub-bituminous coal from the PRB, produces lower NO_x emissions than higher rank bituminous coal, due to its higher reactivity and lower nitrogen content. The fixed carbon to volatile matter ratio (fuel ratio), coal oxygen content, and rank are good relative indices of the reactivity of a coal. Lower rank coals release more organically bound nitrogen earlier in the combustion process than do higher rank bituminous coals. When used with low-NO_x burners (LNBs), sub-bituminous coal creates a longer time for the kinetics to promote more stable N_2, and hence results in lower NO_x emissions.

Coals from the PRB are classified as sub-bituminous C and demonstrate the high reactivity and low NO_x production characteristics previously described. Based on data from the Energy Information Administration, PRB coals currently represent 88 percent of the total production of sub-bituminous coal in the United States and 73 percent of all the western coal production (Energy Information Administration, 2006). Most references to western coal and sub-bituminous coal imply PRB origin and characteristics. Emissions standards differentiating between bituminous and sub-bituminous coals are presumed to use PRB coal as the basis for the sub-bituminous standards, due to its dominant market presence and unique characteristics.

A number of western coals are classified as sub-bituminous; however, these coals border on being ranked as bituminous and do not display many of the qualities of PRB coals including most of the low NO_x-forming characteristics. Coals from P&M fall into this category.

One distinguishing characteristic that classifies a sub-bituminous from a bituminous coal is whether it is agglomerating or non-agglomerating. Agglomerating, as applied to coal, has "the property of softening when it is heated to above about 400 degrees Celsius (°C) in a non-oxidizing atmosphere, and then appearing as a coherent mass after cooling to room temperature." Because the agglomerating property of coals is the result of particles transforming into a plastic or semi-liquid state when heated, it reflects a change in surface area of the particle. Thus, with the application of heat, agglomerating coals would tend to develop a non-porous surface, while the surface of non-agglomerating coals would become even more porous with combustion.

As shown in Figure 3-1, the increased porosity provides more particle surface area resulting in more favorable combustion conditions. This non-agglomerating property assists in making sub-bituminous coals more amenable to controlling NO_x by allowing less air to be introduced during the initial ignition portion of the combustion process. The coals from the P&M Mine just barely fall into the category of non-agglomerating coals. While each of these coals is considered non-agglomerating, they either do not exhibit properties of non-agglomerating coals or exhibit the properties to only a minor degree. The conditions during combustion of typical non-agglomerating coals that make it easier to control NO_x emissions do not exist for the coal used at Naughton 2.

FIGURE 3-1
Illustration of the Effect of Agglomeration on the Speed of Coal Combustion
Naughton 2

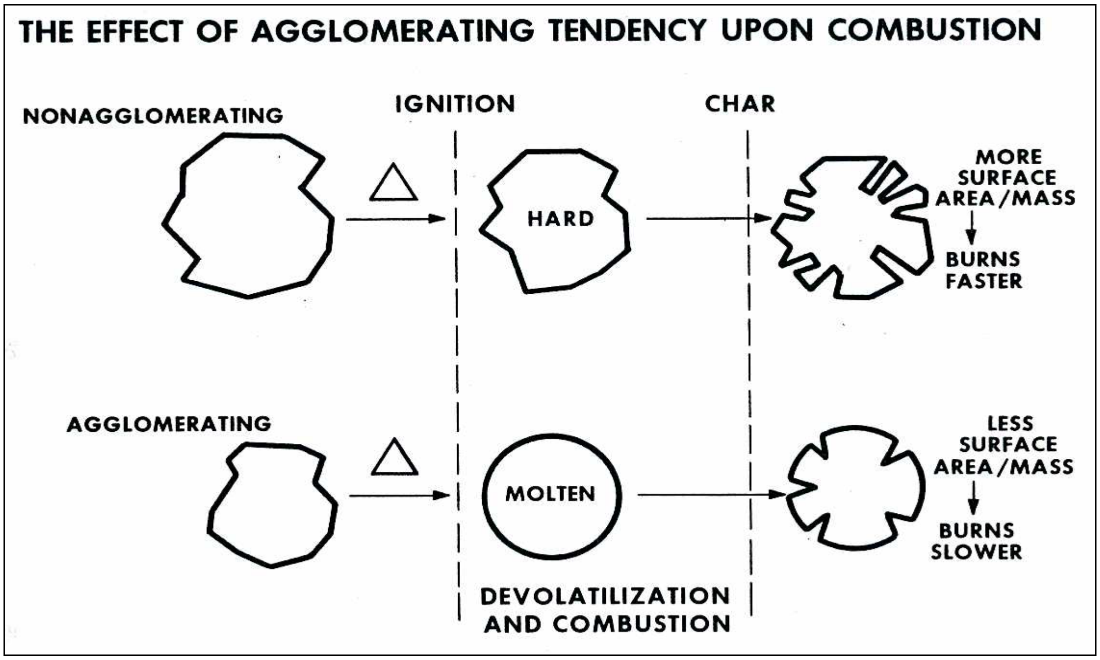


Table 3-1 shows key NO_x-forming characteristics of a typical PRB coal compared to low-sulfur and high-sulfur P&M coals, and to coals from Twentymile, which is a representative western bituminous coal.

TABLE 3-1
Coal Characteristics Comparison
Naughton 2

Parameter	Powder River Basin	P&M Low Sulfur	P&M High Sulfur	Twentymile
Nitrogen (% dry)	1.10	1.33	1.22	1.85
Oxygen (% dry)	16.2	15.35	14.5	7.19
Coal rank	Sub C	Sub B	Sub B	Bitum. high-volatility B

As shown in Table 3-1, although P&M coal is classified as sub-bituminous, the coal exhibits higher nitrogen content and lower oxygen content than PRB coal. The higher nitrogen content is an indication that more nitrogen is available to the combustion process and higher NO_x emissions are likely. Oxygen content can be correlated to the reactivity of the coal; more reactive coals generally contain higher levels of oxygen. More reactive coals tend to produce lower NO_x emissions. More reactive coals are also more conducive to reduction of NO_x

emissions, through use of combustion-control measures such as LNBs and over-fire air (OFA).

These characteristics indicate that higher NO_x formation is more likely with P&M coal than with PRB coal. The P&M coal contains quality characteristics that fall between a typical PRB coal and Twentymile coal. Twentymile coal is a clearly bituminous coal that produces higher NO_x as has been demonstrated at power plants burning this fuel.

Figures 3-2 and 3-3 illustrate the relationship of nitrogen and oxygen content to BART-presumptive NO_x limits for the coals listed in Table 3-1. Each chart identifies the presumptive BART limit associated with a typical bituminous and sub-bituminous coal, and demonstrates how the P&M coal falls between these two general coal classifications. Twentymile shows the achievement of the BART presumptive NO_x limit for a bituminous coal, and the PRB coal corresponds to the sub-bituminous BART presumptive NO_x limit. The "Present" data point represents coal from P&M that has been used at Naughton 2 and indicates the average NO_x emission rate of 0.57 pound per MMBtu achieved during 2005. The LNB with OFA data point indicates the projected NO_x emission rate of 0.24 after installation of new LNBs and OFA.

Figures 3-2 and 3-3 both demonstrate that for the Naughton 2 with the TFS2000 low NO_x emission system installed and burning P&M coal, the likely NO_x emission rate will be closer to the bituminous end (0.28) of the BART-presumptive NO_x limit range than to the sub-bituminous BART presumptive NO_x limit of 0.15 pound per MMBtu. Neither limit applies to Naughton 2.

All these factors are consistent with the observed sustainable emission rate of 0.24 pound per MMBtu for the control device that has been installed at another PacifiCorp Plant, Jim Bridger Unit 2.

Coal quality characteristics also affect the design and operation of the boiler and associated auxiliary equipment. Minor changes in quality sometimes can be accommodated through operational adjustments or changes to equipment. However, consistent variations in quality or assumptions of "average" quality for performance projections can be problematic, which is particularly troublesome when dealing with performance issues that are sensitive to coal quality and combustion conditions (for example, formation of NO_x). Significant variability can occur in the quality of coal from mines, such as P&M coal, that is burned at Naughton 2.

Several of the coal quality characteristics and their effects on NO_x formation have been previously discussed. Some additional considerations illustrate the complexity of achieving and maintaining low NO_x emissions with pulverized coal on a consistent shorter term basis, such as a 30-day rolling-average basis.

Good combustion is based on the "three Ts": time, temperature, and turbulence. These parameters, along with a "design" coal, are taken into consideration when designing a boiler and associated firing equipment, including fans, burners, and pulverizers. If a performance requirement, such as NO_x emission limits, is changed subsequently, conflicts with and between other performance issues can result.

FIGURE 3-2
Plot of Typical Nitrogen Content of Various Coals and Applicable Presumptive BART NO_x Limits
Naughton 2

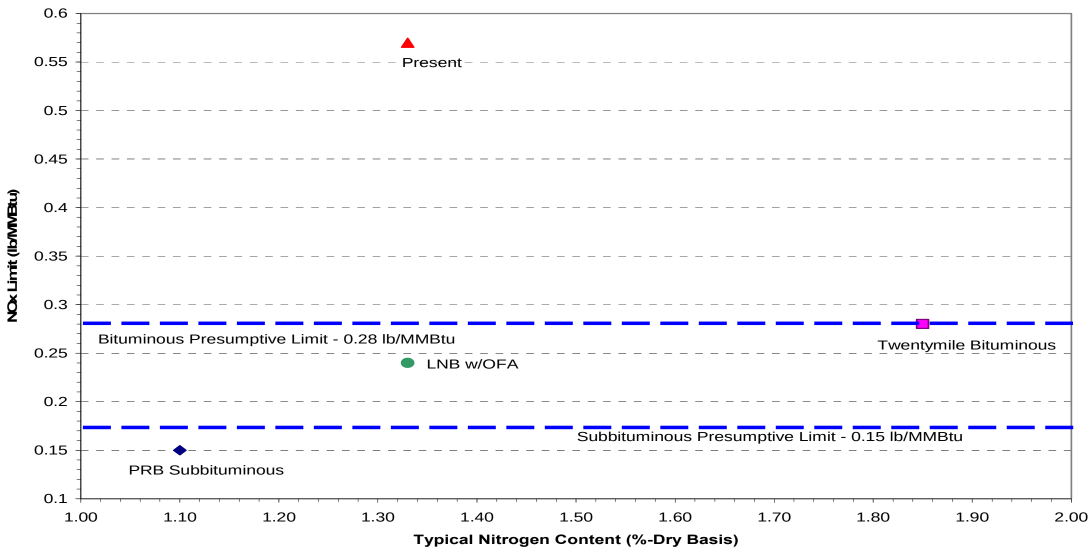
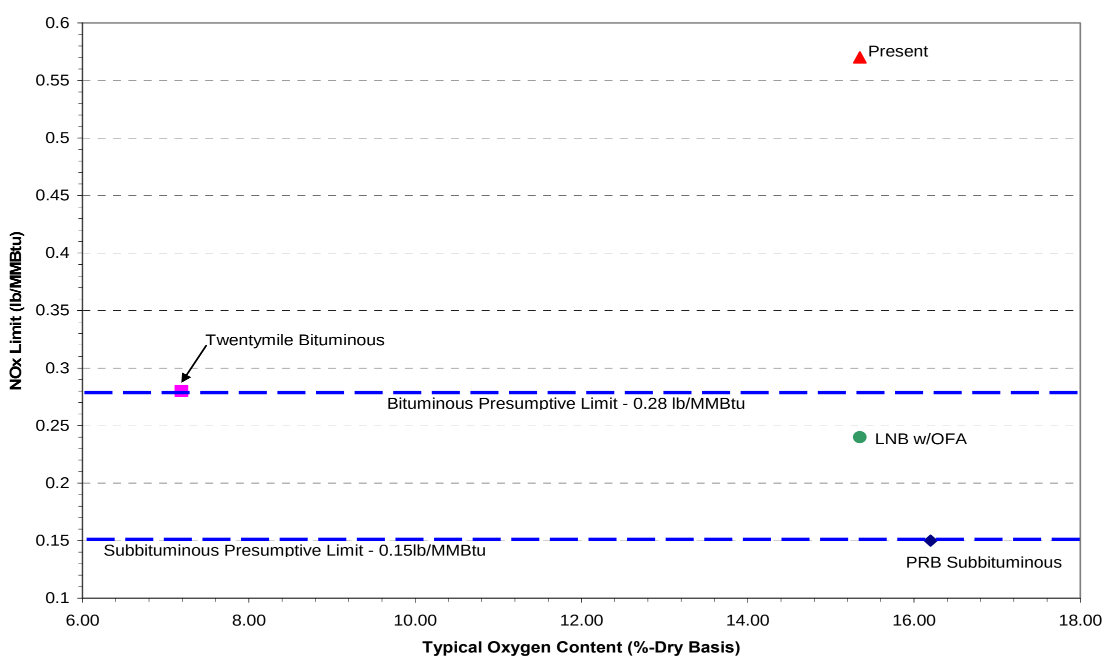


FIGURE 3-3
Plot of Typical Oxygen Content of Various Coals and Applicable Presumptive BART NO_x Limits
Naughton 2



Naughton 2 is located at an altitude of 6,936 feet above sea level. At this elevation, atmospheric pressure is lower (11.3 pounds per square inch) than pressure at sea level (14.7 pounds per square inch). This lower pressure means that less oxygen is available for combustion for each volume of air. To provide adequate oxygen to meet the requirements for efficient combustion, larger volumes of air are required. When adjusting air flows and distribution to reduce NO_x emissions using LNBs with OFA, original boiler design restrictions again limit the modifications that can be made and still achieve satisfactory combustion performance.

Another significant factor in controlling NO_x emissions is the fineness of the coal entering the burners. Fineness is influenced by the grindability index (Hardgrove) of the coal. Finer coal particles promote the release of volatile particles and assist char burnout due to more surface area that is exposed to air. Reduction of NO_x with high volatile coals is improved with greater fineness and with proper air staging. Coal fineness can deteriorate over time periods between pulverizer maintenance and service because of the wear to pulverizer grinding surfaces.

When all of the factors are taken into account (agglomeration versus non-agglomeration, nitrogen and oxygen content of the coals, and the grindability index), this analysis demonstrates that for the coal used at Naughton 2, the LNB technology (referred to in the presumptive BART analysis by EPA) will achieve NO_x reductions similar to the rates identified for tangentially fired boilers that burn bituminous coals. The current NO_x emission rate at Naughton 2 is 0.54 pound per MMBtu.

The BART analysis for NO_x emissions from Naughton 2 is further described in the following section.

Step 1: Identify All Available Retrofit Control Technologies

The first step of the BART process is to evaluate NO_x control technologies with practical potential for application to Naughton 2, including those control technologies identified as Best Available Control Technology (BACT) or lowest achievable emission rate (LAER) by permitting agencies across the United States. A broad range of information sources have been reviewed in an effort to identify potentially applicable emission control technologies. NO_x emissions from Naughton 2 currently are controlled through the use of good combustion practices and OFA.

The following potential NO_x control technology options were considered:

- New/modified LNBs with advanced OFA
- Mobotec rotating opposed-fire air (ROFA)
- Conventional selective non-catalytic reduction (SNCR) system
- Selective catalytic reduction (SCR) system

Step 2: Eliminate Technically Infeasible Options

For Naughton 2, technical feasibility primarily will be determined by physical constraints, and boiler configuration. Naughton 2 has an uncontrolled NO_x emission rate of 0.54 pound per MMBtu.

For this BART analysis, information pertaining to LNBs, OFA, SNCR, and SCR were based on the Sargent & Lundy (S&L) *Multi-Pollutant Control Report* (Sargent and Lundy, 2002). Hereafter, we refer to that document as the S&L Study. Sargent and Lundy (S&L) updated the cost estimates for SCR and SNCR in October 2006. PacifiCorp provided additional emissions data and costs developed by boiler vendors for LNBs and OFA. Also, CH2M HILL solicited a proposal from Mobotec for its ROFA technology.

With SNCR, an amine-based reagent such as ammonia or, more commonly, urea is injected into the furnace within a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100°F, where the temperature reduces NO_x to nitrogen and water. NO_x reductions of up to 40 to 60 percent have been achieved, although 15 to 30 percent is more realistic for most applications. SNCR typically is applied on smaller units. Adequate reagent distribution in the furnaces of large units can be problematic.

Table 3-2 provides a summary of the control technology options evaluated in this BART analysis, along with projected NO_x emission rates.

TABLE 3-2
NO_x Control Technology Projected Emission Rates
Naughton 2

Technology	Projected Emission Rate (Pound per million British thermal units)
Low-NO_x Burner (LNB) with Over-fire Air (OFA)	0.24
Rotating Opposed Fire Air (ROFA)	0.26
LNB with OFA and Selective Non-catalytic Reduction	0.19
LNB with OFA and Selective Catalytic Reduction	0.07

Step 3: Evaluate Effectiveness of Remaining Control Technologies

Preliminary vendor proposals, such as those used to support portions of this BART analysis, might be technically feasible and provide expected or guaranteed emission rates; however, the vendor proposals include inherent uncertainties. These proposals usually are prepared in a limited time frame, could be based on incomplete information, could contain overoptimistic conclusions, and are non-binding. Therefore, emission rate values obtained in such preliminary proposals must be qualified, contractual guarantees can be established only after more detailed analysis has been completed. The following subsections describe the control technologies and the control effectiveness evaluated in this BART analysis.

New LNBs with OFA System. The mechanism used to lower NO_x with LNBs is to stage the combustion process and provide a fuel-rich condition initially; this is so oxygen needed for combustion is not diverted to combine with nitrogen and form NO_x. Fuel-rich conditions favor the conversion of fuel nitrogen to N_2 instead of NO_x. Additional air (or OFA) is then introduced downstream in a lower temperature zone to burn out the char.

Low-NO_x burners and OFA are considered to be a capital cost, combustion technology retrofit. PacifiCorp provided CH2M HILL information that was based on the S&L Study and data from boiler vendors indicating that a new retrofit of LNBs and OFA at Naughton 2 would result in an expected NO_x emission rate of 0.24 pound per MMBtu. PacifiCorp has indicated that this rate corresponds to a vendor guarantee plus an added operating margin, not a vendor prediction. Vendors believe that this emission rate can be sustained as an average between overhauls, which would rate represent a significant reduction from the NO_x emission rate of 0.54 pound per MMBtu.

Rotating Opposed-Fire Air. Mobotec markets ROFA as an improved second generation OFA system, stating: "…the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles. Rotation is reported to prevent laminar flow, so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. The combustion air is also mixed more effectively."

A typical ROFA installation would have a booster fan(s) to supply the high-velocity air to the ROFA boxes. Mobotec would propose one 3,500-horsepower fan for Naughton 2.

Mobotec expects to achieve a NO_x emission rate of 0.24 pound per MMBtu using ROFA technology. An operating margin of 0.02 pound per MMBtu was added to the expected rate due to the limited ROFA experience that Mobotec has with western sub-bituminous coals. Under the Mobotec proposal, which was primarily based on ROFA equipment, the operation of existing burners was analyzed. While a typical installation does not require modification to the existing burner system, results of computational fluid dynamics modeling would determine the quantity and location of new ROFA ports. The Mobotec proposal included bent-tube assemblies for OFA port installation.

Mobotec does not provide installation services because it believes that the Owner can more cost-effectively contract for these services. However, Mobotec does provide one onsite construction supervisor during installation and startup.

Because of the expected marginal improvement in emission rate, the burden of significant ongoing parasitic costs, the operating difficulties, and the lack of vendor experience with sub-bituminous coals, ROFA was not considered in the post-control modeling scenarios.

Selective Non-catalytic Reduction. SNCR generally is used to achieve modest reductions of NO_x on smaller units. With SNCR, an amine-based reagent such as ammonia or, more commonly, urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where the temperature reduces NO_x to nitrogen and water. NO_x reductions of up to 60 percent have been achieved, although 20 to 40 percent is more realistic for most applications.

Reagent utilization, which is a measure of the efficiency with which the reagent reduces NO_x, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create problems downstream. The ammonia might render fly ash unsaleable, might react with sulfur to foul heat exchange surfaces, and/or might create a visible stack plume. Reagent utilization can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost.

Reductions from higher baseline concentrations (inlet NO_x) are lower in cost per ton but result in higher operating costs due to greater reagent consumption. To reduce reagent costs, S&L assumed that combustion modifications, including LNBs and advanced OFA, providing a NO_x emission rate of 0.24 pound per MMBtu, would be installed in conjunction with SNCR. At Naughton 2, a further reduction of 20 percent in NO_x emission rates results in a projected emission rate of 0.19 pound per MMBtu for SNCR.

Because of the expected marginal improvement in emission rate, the burden of significant ongoing parasitic costs, the operating difficulties, and the potential ammonia slip emission problems, SNCR was not considered in the post-control modeling scenarios.

Selective Catalytic Reduction System. SCR works on the same principle as SNCR, but it uses a catalyst to promote the reaction. Ammonia is injected into the flue-gas stream, where it reduces NO_x to nitrogen and water. Unlike the high temperatures required for SNCR, the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580°F to 750°F. Due to the catalyst, the SCR process is more efficient than SNCR. The most common type of SCR is the high-dust configuration, where the catalyst is located upstream of the air heater and downstream from the economizer. The high-dust configuration was assumed for Naughton 2. In a full-scale SCR, the flue ducts are routed to a separate large reactor containing the catalyst. With an in-duct SCR, the catalyst would be located in the existing gas duct, which could be expanded in the area of the catalyst to increase flue-gas residence time. Due to the higher removal rate, a full-scale SCR was used as the basis for analysis at Naughton 2.

S&L prepared the design conditions and cost estimates for SCR at Naughton 2. As with SNCR, reducing NO_x emission levels as much as possible through combustion modifications is generally more cost effective due to minimizing the catalyst surface area and ammonia requirements of the SCR. To reduce reagent costs, S&L assumed that combustion modifications, including LNBs and OFA that would provide a NO_x emission rate of 0.24 pound per MMBtu, would be installed in conjunction with the SCR. The S&L design basis results in a projected NO_x emission rate of 0.07 pound per MMBtu. Additional catalyst surface was included in the SCR design to accommodate the characteristics of the coal used at Naughton 2.

Level of Confidence for Vendor Post-control Emissions Estimates. To determine the level of NO_x emissions needed to consistently achieve compliance with an established goal, a review of typical NO_x emissions from coal-fired generating units was completed. During this review, NO_x emissions were noted to vary significantly around an average emissions level. Variations could result for many reasons including coal characteristics, unit load, and boiler operation. Impacts from boiler operation would include such conditions as excess air, boiler slagging, condition of burner equipment, and coal mill fineness.

The following steps are used for determining a level of confidence for the vendor expected value:

- Establish expected NO_x emissions value from vendor.

- Evaluate vendor's experience and historical basis for achieving expected values.
- Review and evaluate physical and operational characteristics and restrictions of the unit. The fewer variations existing in operations, coal supply, etc., the more predictable and less variant the NO_x emissions are.
- For the expected value of each technology, a corresponding potential exists for actual NO_x emissions to vary from the expected value. From the vendor information presented, along with anticipated unit operational data, an adjustment to the expected value can be made.

Step 4: Evaluate Impacts and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during this evaluation.

Energy Impacts. Installation of LNBs with OFA is not expected to significantly affect the boiler efficiency or power usage of the forced draft fan. Therefore, LNBs with OFA will not have energy impacts.

The Mobotec ROFA system requires installation and operation of one 3,500-horsepower ROFA fan.

SCR retrofit affects the existing flue-gas fan systems due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch increase. Total additional power requirements for SCR installation at Naughton 2 are estimated at approximately 1,340 kilowatts (kW) based on the S&L Study.

Environmental Impacts. Mobotec has predicted that the ROFA system could result in an increase in carbon monoxide (CO) emissions. Unburned carbon in the ash, commonly referred to as loss on ignition, would be the same or lower than previous levels. Installation of LNBs with OFA also could result in higher CO emissions and loss on ignition, which could result in higher unburned carbon in the ash.

Installation of an SCR system could affect the saleability and disposal of fly ash due to ammonia levels and potentially could create a visible stack plume, which might negate other improvements to visibility. Other environmental impacts involve the storage of ammonia, especially if anhydrous ammonia is used, and the transportation of the ammonia to the power plant site.

Economic Impacts. PacifiCorp furnished CH2M HILL the costs and schedules for the LNBs and OFA, SNCR, and SCR, all of which were developed using the S&L internal proprietary database and supplemented (as needed) by vendor-obtained price quotes. The relative accuracy of these cost estimates is stated by S&L to be plus or minus 20 percent. Cost for the ROFA system was obtained from Mobotec, to which construction and other costs were added to make a comparable estimate.

A comparison of the technologies on the basis of costs, design control efficiencies, and tons of NO_x removed is summarized in Table 3-3. The first year control costs are shown in Figure 3-4. The complete economic analysis is contained in Appendix A.

TABLE 3-3
NO_x Control Cost Comparison
Naughton 2

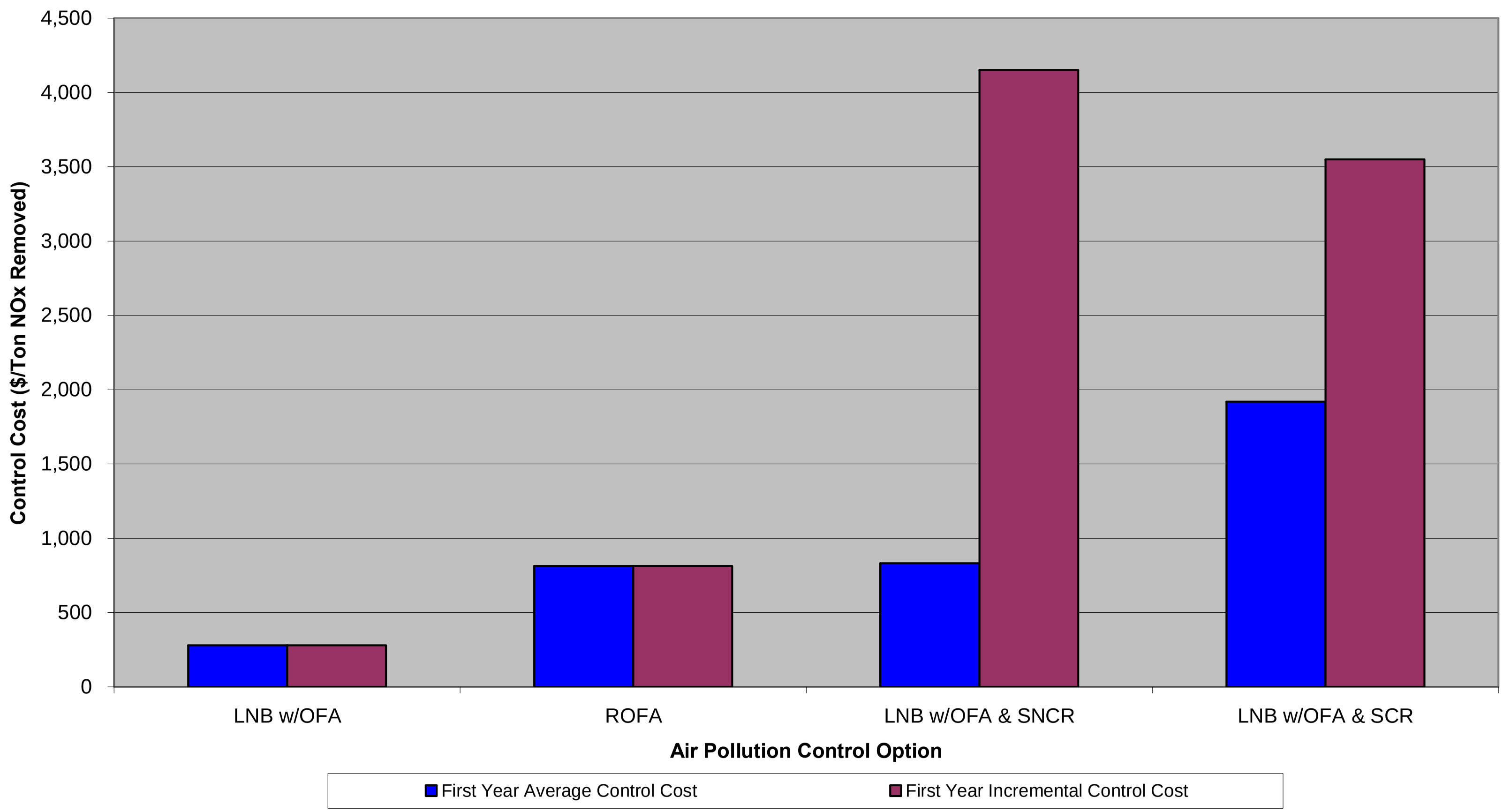
Factor	Low-NO_x Burner (LNB) with Over-fire Air (OFA)	Rotating Opposed Fire Air (ROFA)	LNB with OFA and Selective Non-catalytic Reduction	LNB with OFA and Selective Catalytic Reduction
Total Installed Capital Costs	$7.5 million	$10.6 million	$19.9 million	$73.0 million
Total First Year Fixed and Variable Operations and Maintenance (O&M) Costs	$0.1 million	$1.1 million	$0.9 million	$1.6 million
Total First Year Annualized Cost	$0.8 million	$2.2 million	$2.8 million	$8.5 million
Power Consumption (megawatts)	--	2.6	0.2	1.3
Annual Power Usage (1,000 megawatt hours per year)	--	20.6	1.7	10.6
Nitrogen Oxide (NO_x) Design Control Efficiency	55.6%	51.9%	64.8%	87.0%
Tons NO_x Removed per Year	2,838	2,649	3,311	4,446
First Year Average Control Cost ($ per ton of NO_x Removed)	280	814	833	1,920
Incremental Control Cost ($ per ton of NO_x Removed)	280	814	4,152	3,550

Preliminary BART Selection. CH2M HILL recommends selection of LNBs with OFA as BART for Naughton 2. This recommendation is based on the significant reduction in NO_x emissions, reasonable control cost, as well as the fact that LNBs with OFA do not create additional power requirements or environmental impacts. As previously discussed, the recommended technology and the achieved emission rate are deemed appropriate as BART for NO_x emissions from the coals combusted at Naughton 2.

Step 5: Evaluate Visibility Impacts

Please see Section 4, BART Modeling Analysis.

FIGURE 3-4
First Year Control Cost for NO_x Air Pollution Control Options
Naughton 2



3.2.2 BART SO_2 Analysis

Sulfur dioxide forms in the boiler during the combustion process and is primarily dependent on sulfur content in the coal. The BART analysis for SO_2 emissions at Naughton 2 is described in this section.

Step 1: Identify All Available Retrofit Control Technologies

A broad range of information sources were reviewed in an effort to identify potentially applicable emission control technologies for SO_2 at Naughton 2. This included control technologies identified as BACT or LAER by permitting agencies across the United States.

The following potential SO_2 control technology options were considered:

- Dry flue gas desulfurization (FGD) with existing ESP
- Dry FGD with new fabric filter
- Wet lime/limestone FGD with existing ESP and new stack

Step 2: Eliminate Technically Infeasible Options

Naughton 2 currently has an uncontrolled SO_2 emission rate of approximately 1.20 pound per MMBtu.

Dry FGD with Existing ESP. The lime spray dryer typically injects lime slurry in the top of the absorber vessel with a rapidly rotating atomizer wheel. The rapid speed of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas. The SO_2 in the flue gas reacts with the calcium in the lime slurry to form calcium sulfate in the form of particulate matter. At Naughton 2, this dry particulate matter would be captured downstream in the existing ESP along with the fly ash. A lime spray dryer system typically produces a dry waste product suitable for landfill disposal.

Dry FGD with the existing ESP is projected to achieve 85 percent SO_2 removal using the lower-sulfur coal. The resulting controlled SO_2 emission rate from Naughton 2 would be equal to 0.18 pound per MMBtu, based on an average coal sulfur content of 0.58 percent by weight.

Similarly, with coal having a higher sulfur content of 1.02 percent, the controlled SO_2 emission rate would be 0.41 pound per MMBtu. Hence, this option cannot meet a limit of 0.15 pound of SO_2 per MMBtu.

Lime Spray Drying FGD with New Fabric Filter. If the existing ESP is replaced with a fabric filter located downstream of the lime spray dryer, then an 87.5 percent SO_2 removal is projected when using the lower-sulfur coal, allowing the facility to meet a limit of 0.15 pound of SO_2 per MMBtu.

However, if higher-sulfur coal (with 1.02 percent sulfur) is used, the controlled SO_2 emission rate is projected to be 0.21 pound of SO_2 per MMBtu.

Wet Lime/Limestone FGD. Wet SO_2 scrubbers operate by flowing the flue gas upward through a large reactor vessel that has an alkaline reagent (typically, a lime or limestone slurry) flowing down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to distribute the reagent across the scrubber vessel. The calcium in the reagent reacts with the SO_2 in the flue gas to form calcium sulfite and/or calcium sulfate, which would be removed from the scrubber with the sludge, and disposed of.

Most wet FGD systems use forced oxidation to assure that only calcium sulfate sludge is produced. The wet lime/limestone forced oxidation process is used in most new wet FGD installations. Several variations of wet FGD technology are offered by various process developers. These variations include using a jet bubbling reactor as a combination SO_2 absorber and calcium sulfite oxidation vessel, and using magnesium-enhanced lime as the alkaline reagent.

Wet lime/limestone scrubbing is projected to achieve 90 to 95 percent SO_2 removal. At Naughton 2, this removal efficiency is projected to meet a limit of 0.15 pound of SO_2 per MMBtu if low- or high-sulfur coal is used with the existing ESP.

Step 3: Evaluate Effectiveness of Remaining Control Technologies

Table 3-4 contains a summary of the projected emission rates for the FGD technologies being evaluated for Naughton 2.

TABLE 3-4
SO_2 Control Technology Emission Rates
Naughton 2

Control Technology	**Projected SO_2 Emission Rate (pound per million British thermal units)**
Dry Flue Gas Desulfurization (FGD) with Existing Electrostatic Precipitator (ESP)	0.41
Dry FGD with Fabric Filter	0.15
Wet FGD with Existing ESP and New Stack	0.10

Step 4: Evaluate Impacts and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. A dry FGD system with the existing ESP has the advantage of requiring less electric power for its operation, compared to a wet FGD system. A dry FGD system at Naughton 2 using the existing ESP would require approximately 2.2 MW of power, compared to approximately 3.3 MW for a wet FGD system. Based on a 90 percent annual plant capacity factor, this difference would equate to an annual power savings of approximately 8.3 million kilowatt-hours (kWh) for a dry FGD rather than a wet FGD at Naughton 2.

Environmental Impacts. The dry FGD system has the following environmental advantages when compared to wet FGD technology:

- **Sulfuric Acid Mist.** Sulfur trioxide (SO_3) in the flue gas, which condenses to liquid sulfuric acid at temperatures below the acid dew point, is removed efficiently with a lime spray dryer system. Wet scrubbers capture less than 40 to 60 percent of SO_3 and might require the addition of a wet ESP or hydrated lime injection to remove the balance of SO_3, when medium- to high-sulfur coal is burned in a unit. Otherwise, the emission of sulfuric acid mist, if above a threshold value, could result in a visible plume after the vapor plume dissipates.
- **Plume Buoyancy**. Flue gas following a dry FGD system is not saturated with water (30°F to 50°F above dew point), which reduces or eliminates a visible moisture plume. Wet FGD scrubbers produce flue gas that is saturated with water, which would require a gas-gas heat exchanger to reheat the flue gas if it were to operate as a dry stack. Due to the high capital and operating costs associated with heating the flue gas, all recent wet FGD systems in the United States have used wet stack operation.
- **Liquid Waste Disposal**. No liquid waste results from use of a dry FGD system. However, wet FGD systems produce a wastewater blowdown stream that must be treated to limit chloride buildup in the absorber scrubbing loop. In some cases, a wastewater treatment plant must be installed to treat the liquid waste prior to disposal. The wastewater treatment plant would produce a small volume of solid waste that could contain toxic metals and might require special considerations for disposal.
- **Solid Waste Disposal.** The creation of a wet sludge from the wet FGD process creates a solid waste handling and disposal challenge. This sludge needs to be handled properly to prevent groundwater contamination. Wet FGD systems can produce saleable gypsum if a gypsum market is available, reducing the quantity of solid waste from the power plant that needs to be disposed of.
- **Makeup Water Requirements**. Dry FGD has the advantages over a wet scrubber of producing a dry waste material and requiring less makeup water in the absorber. Given that water is a valuable commodity in Wyoming, the reduced water consumption required for a dry FGD system is a major advantage for this technology.

Economic Impacts. A summary of the costs and amount of SO_2 removed for each technology is provided in Table 3-5, and a comparison of the first year control cost (cost per ton removed) is shown in Figure 3-5. A complete economic analysis is found in Appendix A.

Preliminary BART Selection. CH2M HILL recommends the combination of using a dry FGD system with the existing ESP, and using a coal with a sulfur content that does not exceed 1.02 percent by weight, as BART for Naughton 2. This recommendation is based on significant reduction in SO_2 emissions, reasonable control costs, as well as the advantages of minimal additional power requirements and environmental impacts with the use of a dry FGD system and existing ESP.

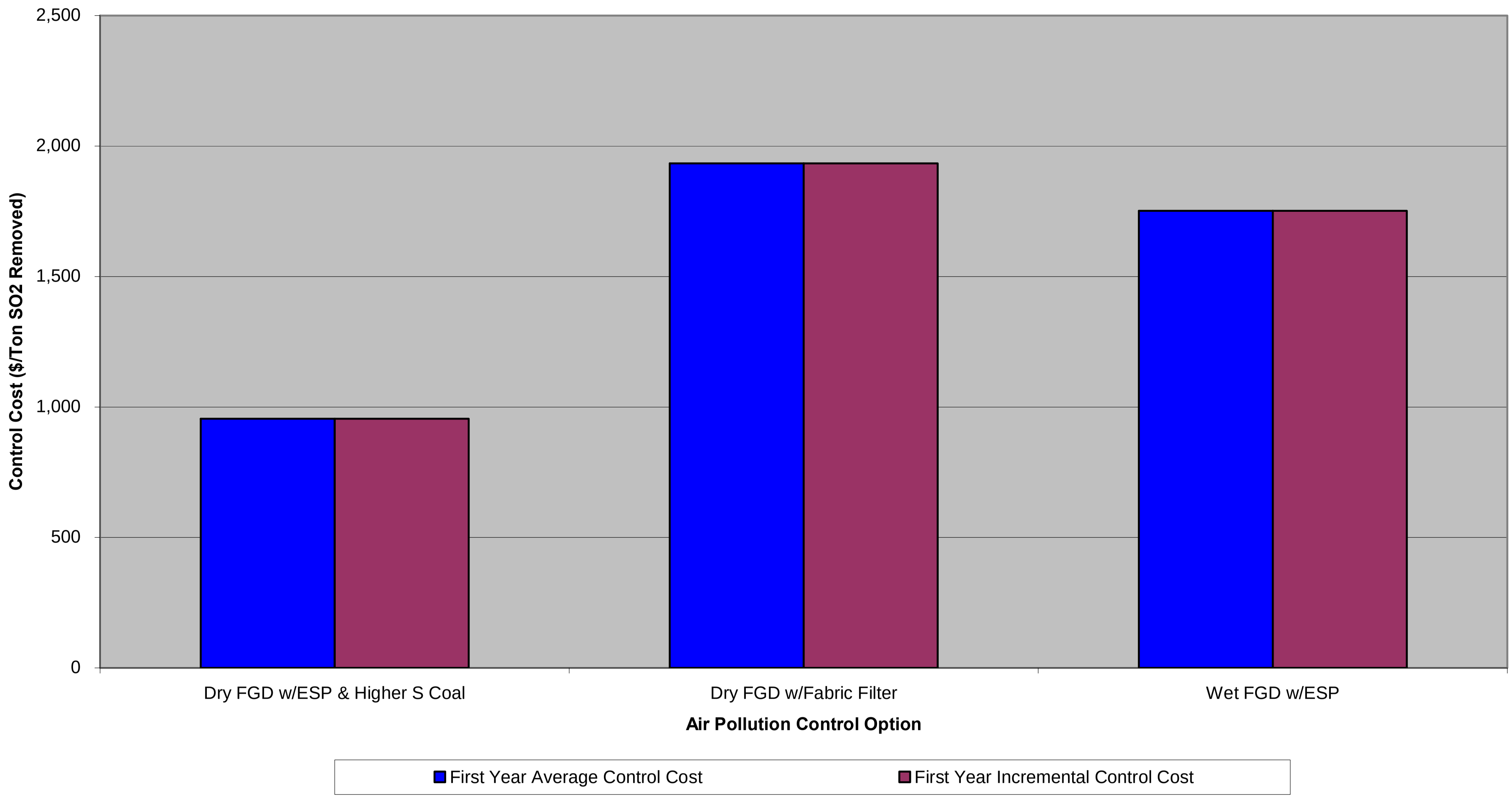
Step 5: Evaluate Visibility Impacts

Please see Section 4, BART Modeling Analysis.

TABLE 3-5
SO_2 Control Cost Comparison (Incremental to Existing FGD System)
Naughton 2

Factor	Dry Flue Gas Desulfurization (FGD) with Electrostatic Precipitator (ESP)	Dry FGD with Fabric Filter	Wet FGD
Total Installed Capital Costs	$88.9 million	$141.2	$126.1 million
Total First Year Fixed & Variable Operations & Maintenance Costs	$6.5 million	$5.5 million	$5.9 million
Total First Year Annualized Cost	$14.9 million	$18.9 million	$17.9 million
Power Consumption (megawatts)	2.2	3.6	3.3
Annual Power Usage (1,000 megawatt hours per year)	17.7	28.6	26.0
Sulfur Dioxide (SO_2) Design Control Efficiency	80.1%	87.3%	91.5%
Tons SO_2 Removed per Year	15,645	9,768	10,241
First Year Average Control Cost ($ per ton of SO_2 Removed)	955	1,934	1,752
Incremental Control Cost ($ per ton of SO_2 Removed)	955	1,934	1,752

FIGURE 3-5
First Year Control Cost for SO_2 Air Pollution Control Options
Naughton 2



3.2.3 BART PM_{10} Analysis

Naughton 2 currently is equipped with a mechanical dust collector and an ESP. ESPs remove PM from the flue gas stream by charging fly ash particles with a high direct-current voltage, then attracting these charged particles to grounded collection plates. A layer of collected particulate matter forms on the collecting plates and is removed by periodically rapping the plates. The collected ash particles drop into hoppers below the precipitator and are removed periodically by the fly ash-handling system. Historically, the ESP at Naughton 2 has controlled PM_{10} emissions to level of 0.064 pound per MMBtu.

The BART analysis for PM_{10} emissions from Naughton 2 is described in the following steps. For the modeling analysis in Section 4, PM_{10} was used as an indicator for PM, and PM_{10} includes $PM_{2.5}$ as a subset.

Step 1: Identify Available Retrofit Control Technologies

Three retrofit control technologies have been identified for additional PM control:

- Flue gas conditioning (FGC)
- Polishing fabric filter
- Replacement of fabric filter

Step 2: Eliminate Technically Infeasible Options

Flue Gas Conditioning. If the fly ash from coal has high resistivity, such as fly ash from sub-bituminous coal, the ash is not collected effectively in a small ESP because the elevated resistivity makes the particles less willing to accept an electrical charge. Adding FGC, which typically is accomplished by injection of SO_3, will lower the resistivity of the particles so that they will accept more charge, allowing the ESP to collect the ash more effectively. Adding FGC can account for large improvements in collection efficiency for small ESPs.

Polishing Fabric Filter. A polishing fabric filter could be added downstream of the existing ESP at Naughton 2. One such technology is licensed by the Electric Power Research Institute, and referred to as a Compact Hybrid Particulate Collector (COHPAC). The COHPAC collects the ash that the ESP does not collect, thus acting as a polishing device. The ESP needs to be kept in service for the COHPAC fabric filter to work.

The COHPAC fabric filter is about one-half to two-thirds the size of a full-sized fabric filter. The smaller size is due to the fact that the COHPAC has a higher air-to-cloth ratio (7 to 9:1), compared to the ratio of a full-sized pulse jet fabric filter (3.5 to 4:1).

Replacement Fabric Filter. Another available control technology is replacing the existing ESP with a new fabric filter. However, because of the environmental and cost benefits (that is, the fact that the same control efficiencies that would be achieved by a replacement fabric filter are achieved by installing a polishing fabric filter downstream of the existing ESP only at lower costs) installation of a full fabric filter was not considered in the analysis.

Step 3: Evaluate Effectiveness of Remaining Control Technologies

The existing ESP at Naughton 2 achieves a controlled PM emission rate of 0.064 pound per MMBtu. Adding FGC upstream of the existing ESP is projected to reduce PM emissions to approximately 0.040 pound per MMBtu. Adding a COHPAC fabric filter downstream of the existing ESP is projected to reduce PM emissions to approximately 0.015 pound per MMBtu. A new fabric filter is also projected to reduce PM emissions to approximately 0.015 pound per MMBtu.

A summary of the PM_{10} control technology emission rates is shown in Table 3-6.

TABLE 3-6
PM_{10} Control Technology Emission Rates
Naughton 2

Control Technology	Projected PM_{10} Emission Rate (pound per million British thermal units)
Flue Gas Conditioning	0.040
Polishing Fabric Filter	0.015
Replacement Fabric Filter	0.015

Step 4: Evaluate Impacts and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. Energy is required to overcome the additional pressure drop from the COHPAC fabric filter and associated ductwork. Therefore, a COHPAC retrofit would require an induced draft fan upgrade and upgrade of the auxiliary power supply system.

A COHPAC fabric filter at Naughton 2 would require approximately 1.4 MW of power, equating to an annual power usage of approximately 10.9 million kWh, based on a 90 percent annual plant capacity factor.

No negative environmental impacts would result from the addition of an FGC system.

Environmental Impacts. No negative environmental impacts result from the addition of a COHPAC polishing fabric filter or FGC system.

Economic Impacts. A summary of the costs and PM removed for COHPAC and flue gas conditionings are recorded in Table 3-7, and the first year of control costs for FGC and fabric filters are shown in Figure 3-6. The complete economic analysis is contained in Appendix A.

Preliminary BART Selection. CH2M HILL recommends adding flue gas conditioning to the existing ESP as BART for Naughton 2. This recommendation is based on the significant reduction in PM_{10} emissions, reasonable control costs, as well as the advantages of creating no additional power requirements or non-air quality environmental impacts.

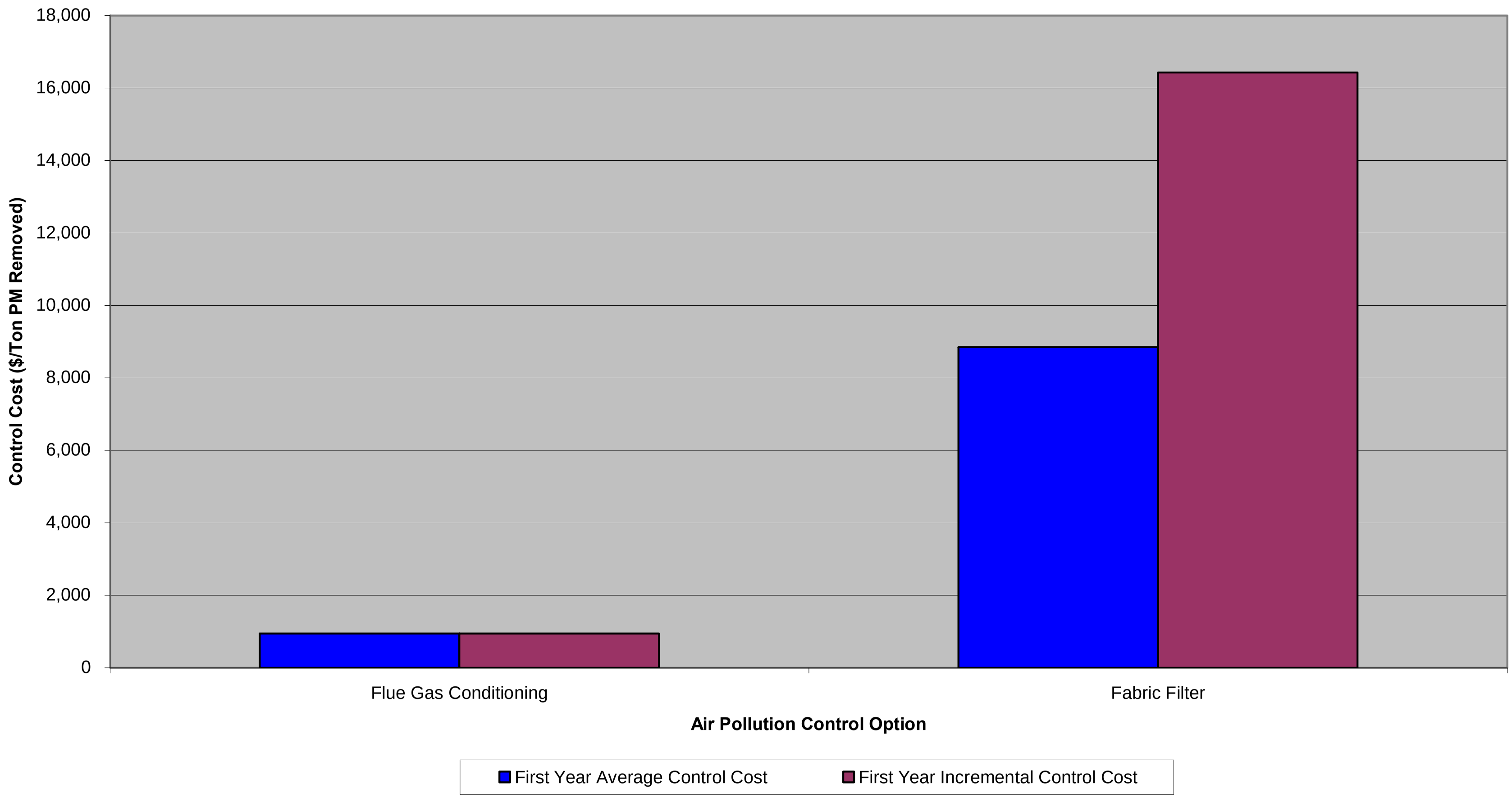
Step 5: Evaluate Visibility Impacts

Please see Section 4, BART Modeling Analysis.

TABLE 3-7
PM_{10} Control Cost Comparison
Naughton 2

Factor	Flue Gas Conditioning	Polishing Fabric Filter
Total Installed Capital Costs	$1.3 million	$34.9 million
Total First Year Fixed and Variable Operation and Maintenance Costs	$0.1 million	$0.8 million
Total First Year Annualized Cost	$0.2 million	$4.1 million
Power Consumption (megawatts)	0.1	1.4
Annual Power Usage (1,000 megawatt hours per year)	0.4	10.9
PM Design Control Efficiency	37.5%	76.6%
Tons Particulate Matter (PM) Removed per Year	227	464
First Year Average Control Cost ($ per ton of PM Removed)	949	8,848
Incremental Control Cost ($ per ton of PM Removed)	949	16,432

FIGURE 3-6
First Year Control Cost for PM Air Pollution Control Options
Naughton 2



4.0 BART Modeling Analysis

4.1 Model Selection

CH2M HILL used a Gaussian puff dispersion modeling system, CALPUFF, to assess the visibility impacts of emissions from Naughton 2 at Class I areas. The Class I areas potentially affected are located more than 50 but less than 300 kilometers from the Naughton 2 Plant. These wilderness areas (WA) include:

- Bridger WA
- Fitzpatrick WA

The CALPUFF modeling system includes the CALMET meteorological model with algorithms for chemical transformation and deposition, and a post-processor capable of calculating concentrations, visibility impacts, and deposition (CALPOST). The CALPUFF modeling system was applied in a full, refined mode. Version numbers of the various programs in the CALPUFF system that CH2M HILL used were as follows:

- CALMET Version 5.53a, Level 040716
- CALPUFF Version 5.711a, Level 040716
- CALPOST Version 5.51, Level 030709

4.2 CALMET Methodology

4.2.1 Dimensions of the Modeling Domain

CH2M HILL used the CALMET model to generate a three-dimensional wind field and other meteorological parameters suitable for use by the CALPUFF model. A modeling domain was established to encompass Naughton 2 and to include a 50-kilometer buffer around the Class I areas that were within 300 kilometers of the facility. Grid resolution was 4 kilometers. Figure 4-1 shows the extent of the modeling domain. Except when specifically instructed otherwise by the Wyoming Department of Environmental Quality – Air Quality Division (WDEQ-AQD), CH2M HILL followed the methodology spelled out in the BART Modeling Protocol, which is included in Appendix B of this report. WDEQ-AQD prepared this protocol.

CH2M HILL used the Lambert Conformal Conic map projection for the analysis due to the large extent of the domain. The latitude of the projection origin and the longitude of the central meridian were chosen at the approximate center of the domain. Standard parallels were drawn to represent one-sixth and five-sixths of the north-south extent of the domain to minimize distortion in the north-south direction.

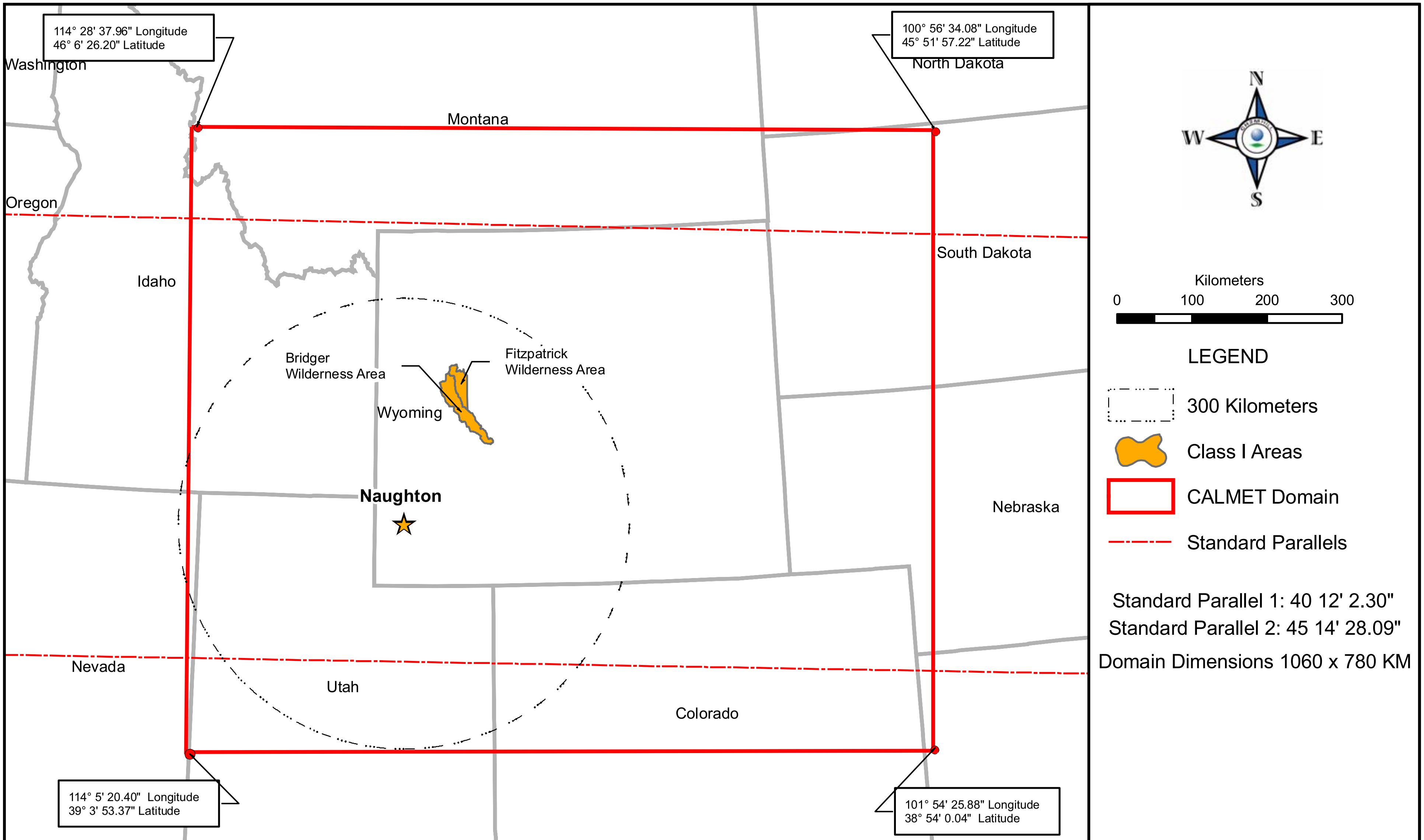


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Figure 4-1
Naughton Source-Specific
Class I Areas to be Addressed

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The default technical options listed in current example CALMET.inp file of TRC Companies, Inc. (TRC) were used for CALMET. Vertical resolution of the wind field included 10 layers, with vertical face heights as follows (in meters):

- 0, 20, 40, 100, 140, 320, 580, 1020, 1480, 2220, 3500

Other user-specified model options were set to values established by WDEQ-AQD, which appear in Table 3 of Appendix B. Table 4-1 lists the key user-specified options for this analysis.

TABLE 4-1
User-specified CALMET Options
Naughton 2

CALMET Input Parameter	Value
CALMET Input Group 2	
Map projection (PMAP)	Lambert Conformal
Grid spacing (DGRIDKM)	4
Number vertical layers (NZ)	10
Top of lowest layer (m)	20
Top of highest layer (m)	3500
CALMET Input Group 4	
Observation mode (NOOBS)	0
CALMET Input Group 5	
Prog. Wind data (IPROG)	14
(RMAX1)	30
(RMAX2)	50
Terrain influence (TERRAD)	15
(R1)	5
(R2)	25
CALMET Input Group 6	
Max mixing ht (ZIMAX)	3500

4.2.2 CALMET Input Data

CH2M HILL ran the CALMET model to produce 3 years of analysis: 2001, 2002, and 2003. WDEQ-AQD provided 12-kilometer-resolution Mesoscale Meteorological Model, Version 5 (MM5) meteorological data fields that covered the entire modeling domain for each year.

These three data sets were chosen because they are current and have been evaluated for quality. The MM5 data were used as input to CALMET as the “initial guess” wind field. CALMET adjusted the initial guess wind field for local terrain and land use effects to generate a Step 1 wind field, and further refined using local surface observations to create a final Step 2 wind field.

Surface data for 2001 through 2003 were obtained from the National Climatic Data Center. CH2M HILL processed the data from the Automated Surface Observing System network of the National Weather Service for all stations that are in the domain. The surface data were obtained in abbreviated DATSAV3 format. A conversion routine available from the TRC Web site was used to convert the DATSAV3 files to CD-144 format for input into the SMERGE preprocessor and CALMET.

Land use and terrain data were obtained from the United States Geological Survey (USGS). Land use data were obtained in Composite Theme Grid format from the USGS, and the Level I USGS land use categories were mapped into the 14 primary CALMET land use categories. Surface properties such as albedo, Bowen ratio, roughness length, and leaf area index were computed from the land use values. Terrain data were taken from USGS 1-degree Digital Elevation Model data, which primarily derive from USGS 1:250,000-scale topographic maps. Missing land use data were filled with values that were assumed appropriate for the missing area.

Precipitation data were ordered from the National Climatic Data Center. All available data in fixed-length, TD-3240 format were ordered for the modeling domain. The list of available stations that have collected complete data varies by year, but CH2M HILL processed all available stations/data within the domain for each year. Precipitation data were prepared with the PXTRACT/PMERGE processors in preparation for use within CALMET.

Upper-air data were prepared for the CALMET model with the READ62 preprocessor for the following stations:

- Denver, Colorado
- Salt Lake City, Utah
- Riverton, Wyoming
- Rapid City, South Dakota

Figure 4-2 shows the locations of surface and upper air stations within the MM5 modeling domain.

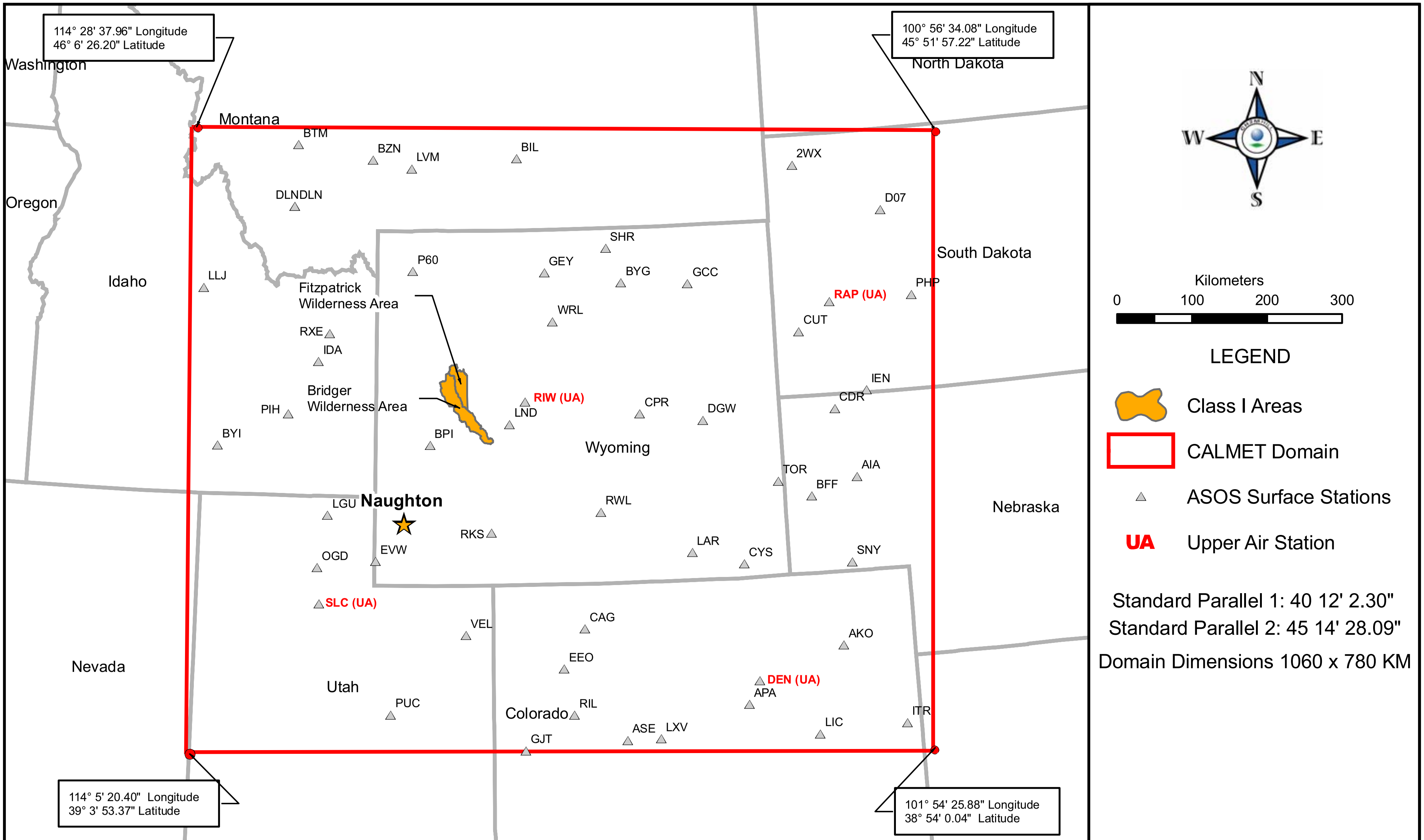

Figure 4-2
Surface and Upper Air Stations Used in the Naughton BART Analysis

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4.2.3 Validation of CALMET Wind Field

CH2M HILL used the CALDESK data display and analysis system (v2.97, Enviromodeling Ltd.) to view plots of wind vectors and other meteorological parameters to evaluate the CALMET wind fields. The CALDESK displays were compared to observed weather conditions, as depicted in surface and upper-air weather maps (National Oceanic and Atmospheric Administration, 2006).

4.3 CALPUFF Modeling Approach

For the BART control technology visibility improvement modeling, CH2M HILL followed WDEQ-AQD guidance (WDEQ-AQD, 2006).

CH2M HILL drove the CALPUFF model with the meteorological output from CALMET over the modeling domain described earlier. The CALPUFF model was used to predict visibility impacts for the precontrol (baseline) scenario for comparison to the predicted impacts for post-control scenarios for Naughton 2.

4.3.1 Background Ozone and Ammonia

CALPUFF used hourly values of background ozone concentrations for the calculation of SO_2 and NO_x transformation with the MESOPUFF II chemical transformation scheme. CH2M HILL obtained hourly ozone data from the following stations located within the modeling domain for 2001, 2002, and 2003:

- Rocky Mountain National Park, Colorado
- Craters of the Moon National Park, Idaho
- Highland, Utah
- Thunder Basin National Grasslands, Wyoming
- Yellowstone National Park, Wyoming
- Centennial, Wyoming
- Pinedale, Wyoming

For periods of missing hourly ozone data, the chemical transformation relied on a monthly default value of 44 parts per billion. Background ammonia was set to 2 parts per billion (WDEQ-AQD, 2006).

4.3.2 Stack Parameters

The stack parameters used for the baseline modeling reflect those that are in place under the current permit for Naughton 2. Post-control stack parameters reflect the anticipated changes associated with installation of the control technology alternatives that are being evaluated.

4.3.3 Emission Rates

Precontrol emission rates for Naughton 2 reflect the peak 24-hour-average emissions that could occur under the current permit of the source. The emission rates reflect actual emissions under normal operating conditions, as EPA described in the *Regional Haze*

Regulations and Guidelines for Best Available Retrofit Technology Determinations; Final Rule (40 CFR Part 51).

CH2M HILL used available continuous-emission monitoring data to determine peak 24-hour emission rates. Data reflected operations from the most recent 3- to 5-year period unless a more recent period was more representative. Allowable short-term (24 hours or less) emissions or short-term emission limits were used if continuous-emission monitoring data were not available.

Emissions were modeled for the following pollutants:

- SO_2
- NO_x
- Coarse particulate ($PM_{2.5}$<diameter<PM_{10})
- Fine particulate (diameter<$PM_{2.5}$)
- Sulfates

Post-control emission rates reflect the effects of the emissions control scenario under consideration. Modeled pollutants were the same as those listed for the precontrol scenario.

4.3.4 Post-control Scenarios

Four post-control modeling scenarios were developed to cover the range of effectiveness for the combination of the individual NO_x, SO_2, and PM control technologies being evaluated. The selection of each control device was made based on the engineering analyses performed in Section 3 for reasonable technologies that would meet or exceed the presumptive BART levels for each pollutant.

- **Scenario 1:** New LNBs with OFA modifications, a dry FGD system, and flue gas conditioning for enhanced ESP performance. As indicated previously, this scenario represents the preliminary BART recommendation of CH2M HILL.

- **Scenario 2**: New LNBs with OFA modifications, a dry FGD system, and new fabric filter.

- **Scenario 3:** New LNB with OFA modifications and SCR, dry FGD system, and new fabric filter.

- **Scenario 4**: New LNB with OFA modifications and SCR, wet FGD system, FGC for enhanced ESP performance, and a new stack.

Table 4-2 presents the stack parameters and emission rates used for the Naughton 2 analysis for baseline and post-control modeling. In accordance with the WDEQ BART modeling protocol, elemental carbon stack emissions and organic aerosol emissions were not modeled.

TABLE 4-2
BART Model Input Data
Naughton 2

	Baseline	Post-control Scenario 1	Post-control Scenario 2	Post-control Scenario 3	Post-control Scenario 4
Model Input Data	**Current Operations with ESP**	**LNB with OFA, Dry FGD, ESP**	**LNB with OFA, Dry FGD, New Fabric Filter**	**LNB with OFA and SCR, Dry FGD, Fabric Filter**	**LNB with OFA and SCR, Wet FGD, ESP (New Stack)**
Sulfur Dioxide (SO_2) Stack Emissions (pounds per hour [lb/hr])	2,868	984	359	359	239
Nitrogen Oxide (NO_x) Stack Emissions (lb/hr)	1,291	576	574	167	167
PM_{10} Stack Emissions (lb/hr)	154	96.0	36.0	36.0	96.0
Coarse Particulate ($PM_{2.5}$ <diameter< PM_{10}) Stack Emissions (lb/hr)[a]	65.8	41.3	20.4	20.4	41.1
Fine Particulate (diameter<$PM_{2.5}$) Stack Emissions (lb/hr)[b]	87.2	54.7	15.4	15.4	54.5
Sulfuric Acid (H_2SO_4) Stack Emissions (lb/hr)	44.2	2.16	2.16	3.12	37.9
H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr)	43.3	2.12	2.12	3.06	37.2
Ammonium Sulfate [$(NH_4)_2SO_4$] Stack Emissions (lb/hr)				0.55	2.76
$(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr)				0.40	2.01
$(NH_4)HSO_4$ Stack Emissions (lb/hr)				1.0	4.80
$(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)				0.80	4.01
Total Sulfate (SO_4) (lb/hr)	43.1	2.12	2.11	4.24	43.0
Stack Conditions					
Stack Height (meters)	68	68	68	68	152
Stack Exit Diameter (meters)	4.88	4.88	4.88	4.88	5.49
Stack Exit Temperature (Kelvin)	411	350	343	343	323
Stack Exit Velocity (meters per second)	27.8	20.21	24.3	24.3	18.5

Notes:
[a]Based on AP-42, Table 1.1-6, the coarse particulates are counted as a percentage of PM_{10}. This equates to 43 percent ESP and 57 percent baghouse. PM_{10} and $PM_{2.5}$ refer to particulate matter less than 10 and 2.5 micrometers, respectively, in aerodynamic diameter.
[b]Based on AP-42, Table 1.1-6, the fine particulates are counted as a percentage of PM_{10}. This equates to 57 percent ESP and 43 percent baghouse.
Total Sulfate (SO_4) (lb/hr) = H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr) + $(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr) + $(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)

4.3.5 Modeling Process

The CALPUFF modeling for the control technology options for Naughton 2 followed this sequence:

- Model precontrol (baseline) emissions
- Model preferred post-control scenario (if applicable)
- Determine degree of visibility improvement
- Model other control scenarios
- Determine degree of visibility improvement
- Factor visibility results into the BART five-step evaluation

4.3.6 Receptor Grids

Discrete receptors for the CALPUFF modeling were placed at uniform receptor spacing along the boundary and in the interior of each area of concern. Class I area receptors were taken from the National Park Service database for Class I area modeling receptors. The TRC COORDS program was used to convert all latitude and longitude coordinates to Lambert Conformal Conic coordinates, including receptors, meteorological stations, and source locations.

4.4 CALPOST

The CALPOST processor was used to determine 24-hour-average visibility results with output specified in deciview (dV) units. Calculations of light extinction were made for each pollutant modeled. The sum of all extinction values were used to calculate the delta-dV (ΔdV) change in deciview relative to natural background. Default extinction coefficients for each pollutant, as shown below, were used.

- Ammonium sulfate 3.0
- Ammonium nitrate 3.0
- PM coarse (PM_{10}) 0.6
- PM fine ($PM_{2.5}$) 1.0
- Organic carbon 4.0
- Elemental carbon 10.0

CALPOST visibility Method 6 was used to determine the visibility impacts. Monthly relative humidity factors [f(RH)] were used in the light-extinction calculations to account for the hygroscopic characteristics of nitrate and sulfate particles. Table 5 in the WDEQ BART Air Modeling Protocol (shown in Appendix B) lists the monthly f(RH) for the Class I areas. These values were used for the specific Class I area being modeled.

The natural background conditions as a reference for determining the ΔdV change represented the 20 percent best natural visibility days. The EPA BART guidance document provided dV values for the 10 percent best days for each Class I area but did not provide individual species concentration data for the 20 percent best background conditions. Species concentrations corresponding to the 20 percent best days were calculated for each Class I area by scaling back the annual average species concentrations in Table 2-1 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA, 2003).

A separate scaling factor was derived for each Class I area such that, when multiplied by the guidance table annual concentrations, the 20 percent best days dV value for that area would be calculated. This procedure was taken from *Protocol for BART-Related Visibility Improvement Modeling Analysis in North Dakota* (North Dakota Department of Health; 2005). However, the Wyoming BART Air Modeling Protocol provided natural background concentrations of aerosol components to use in the BART analysis (Appendix B). Table 4-3 lists the annual average species concentrations from the BART protocol.

TABLE 4-3
Average Natural Levels of Aerosol Components
Naughton 2

Aerosol Component	Average Natural Concentration Bridger and Fitzpatrick WA Class I Areas (micrograms per cubic meter)
Ammonium Sulfate	0.045
Ammonium Nitrate	0.038
Organic Carbon	0.178
Elemental Carbon	0.008
Soil	0.189
Coarse Mass	1.136

NOTE:
Source: WDEQ-AQD, 2006

4.5 Presentation of Modeling Results

This section presents the results of the CALPUFF visibility improvement modeling analysis for Naughton 2.

4.5.1 Visibility Changes for Baseline vs. Preferred Scenario

CH2M HILL modeled Naughton 2 for the baseline and four post-control scenarios. The post-control scenarios included emission rates for SO_2, NO_x, and PM_{10} that would be achieved if BART state-of-the-art technology were installed at Unit 2.

Baseline and post-control 98th percentile results were greater than 0.5-ΔdV for the Bridger WA and Fitzpatrick WA. The 98th percentile results for each Class I area are presented in Table 4-4.

TABLE 4-4
Costs and Visibility Modeling Results for Baseline vs. Post-control Scenarios at Class I Areas
Naughton 2

Scenario	Total First Year Annualized Cost	Class I Area	Modeling Results: Highest Delta-Deciview (ΔdV)	Modeling Results: 98th Percentile Delta-Deciview (ΔdV)	Modeling Results: No. of Days Above 0.5 dV	Cost per dV Reduction	Cost per Reduction in No. of Days Above 0.5 dV	Incremental Cost per dV Reduction	Incremental Cost per Reduction in No. of Days Above 0.5 dV
2001									
Baseline: current operation with electrostatic precipitator (ESP)		Bridger WA	5.420	2.127	61	--	--		
		Fitzpatrick WA	3.277	1.158	26	--	--		
Scenario 1: Low-NO_x burner (LNB) with over-fire air (OFA), dry flue gas desulfurization (FGD), ESP	$15,951,704	Bridger WA	2.635	0.838	28	$12,375,255	$483,385		
	$15,951,704	Fitzpatrick WA	1.515	0.462	6	$22,919,115	$797,585		
Scenario 2: LNB with OFA, dry FGD, fabric filter	$19,686,224	Bridger WA	2.078	0.642	14	$38,151,597	$1,640,519	$19,053,673	$266,751
	$19,686,224	Fitzpatrick WA	1.113	0.312	3	$23,269,768	$855,923	$24,896,800	$1,244,840
Scenario 3: LNB with OFA and selective catalytic reduction (SCR), dry FGD, fabric filter	$27,429,327	Bridger WA	0.949	0.284	2	$14,882,977	$464,904	$21,628,779	$645,259
	$27,429,327	Fitzpatrick WA	0.519	0.158	1	$27,429,327	$1,097,173	$50,279,890	$3,871,552
Scenario 4: LNB with OFA and SCR, wet FGD, ESP, new stack	$26,693,951	Bridger WA	1.627	0.482	7	$16,227,326	$494,332	NA	NA
	$26,693,951	Fitzpatrick WA	0.717	0.208	2	$28,098,896	$1,112,248	NA	NA
2002									
Baseline: current operation with ESP		Bridger WA	4.349	1.860	56	--	--		
		Fitzpatrick WA	3.900	1.099	24	--	--		
Scenario 1: LNB with OFA, dry FGD, ESP	$15,951,704	Bridger WA	1.728	0.926	18	$17,078,912	$419,782		
	$15,951,704	Fitzpatrick WA	1.667	0.413	5	$23,253,213	$839,563		
Scenario 2: LNB with OFA, dry FGD, fabric filter	$19,686,224	Bridger WA	1.389	0.745	11	$17,655,806	$437,472	$20,632,707	$533,503
	$19,686,224	Fitzpatrick WA	1.153	0.286	4	$24,214,298	$984,311	$29,405,669	$3,734,520
Scenario 3: LNB with OFA and SCR, dry FGD, fabric filter	$27,429,327	Bridger WA	0.618	0.321	3	$17,822,825	$517,534	$18,262,035	$967,888
	$27,429,327	Fitzpatrick WA	0.542	0.141	1	$28,631,865	$1,192,579	$53,400,710	$2,581,034
Scenario 4: LNB with OFA and SCR, wet FGD, ESP, new stack	$26,693,951	Bridger WA	1.076	0.354	4	$17,725,067	$513,345	NA	NA
	$26,693,951	Fitzpatrick WA	0.887	0.138	1	$27,777,264	$1,160,607	NA	NA

TABLE 4-4
Costs and Visibility Modeling Results for Baseline vs. Post-control Scenarios at Class I Areas
Naughton 2

			Modeling Results						
Scenario	**Total First Year Annualized Cost**	**Class I Area**	**Highest Delta-Deciview (ΔdV)**	**98th Percentile Delta-Deciview (ΔdV)**	**No. of Days Above 0.5 dV**	**Cost per dV Reduction**	**Cost per Reduction in No. of Days Above 0.5 dV**	**Incremental Cost per dV Reduction**	**Incremental Cost per Reduction in No. of Days Above 0.5 dV**
2003									
Baseline: current operation with ESP		Bridger WA	4.678	2.087	55	--	--		
		Fitzpatrick WA	2.466	1.110	22	--	--		
Scenario 1: LNB with OFA, dry FGD, ESP	$15,951,704	Bridger WA	2.136	0.882	19	$13,237,929	$443,103		
	$15,951,704	Fitzpatrick WA	1.296	0.448	6	$24,096,230	$996,982		
Scenario 2: LNB with OFA, dry FGD, fabric filter	$19,686,224	Bridger WA	1.735	0.614	12	$13,364,714	$457,819	$13,934,776	$533,503
	$19,686,224	Fitzpatrick WA	0.855	0.313	4	$24,700,407	$1,093,679	$27,663,111	$1,867,260
Scenario 3: LNB with OFA and SCR, dry FGD, fabric filter	$27,429,327	Bridger WA	0.791	0.291	3	$15,272,454	$527,487	$23,972,455	$860,345
	$27,429,327	Fitzpatrick WA	0.465	0.148	0	$28,512,814	$1,246,788	$46,927,897	$1,935,776
Scenario 4: LNB with OFA and SCR, wet FGD, ESP, new stack	$26,693,951	Bridger WA	1.102	0.526	8	$17,100,545	$567,956	NA	NA
	$26,693,951	Fitzpatrick WA	0.363	0.162	0	$28,158,176	$1,213,361	NA	NA
3-Year Averages									
Baseline: current operation with ESP		Bridger WA		2.025	57.3				
		Fitzpatrick WA		1.122	24.0				
Scenario 1: LNB with OFA, dry FGD, ESP	$15,951,704	Bridger WA		0.882	21.7	$13,960,068	$447,244		
	$15,951,704	Fitzpatrick WA		0.441	5.7	$23,412,481	$870,093		
Scenario 2: LNB with OFA, dry FGD, fabric filter	$19,686,224	Bridger WA		0.667	12.3	$14,500,042	$437,472	$17,369,860	$400,127
	$19,686,224	Fitzpatrick WA		0.304	3.7	$24,046,691	$968,175	$27,193,107	$1,867,260
Scenario 3: LNB with OFA and SCR, dry FGD, fabric filter	$27,429,327	Bridger WA		0.299	2.7	$15,891,846	$501,756	$21,021,999	$801,011
	$27,429,327	Fitzpatrick WA		0.149	0.7	$28,180,815	$1,175,543	$50,063,166	$2,581,034
Scenario 4: LNB with OFA and SCR, wet FGD, ESP, new stack	$26,693,951	Bridger WA		0.454	6.3	$16,995,300	$523,411	NA	NA
	$26,693,951	Fitzpatrick WA		0.169	1.0	$28,010,442	$1,160,607	NA	NA

NOTES:
Scenario 4 produces worse results than Scenario 3.
Sample Calculations: Cost per dV Reduction for Scenario 1 for 2001: = $15,951,704/ (2.306 - 0.908) = $11,410,375
Sample Calculations: Cost per Reduction in No. of Days Exceeding 0.5 dV for 2001: = $15,951,704 / (76 - 32) = $362,539

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5.0 Preliminary Assessment and Recommendations

As a result of the completed technical and economic evaluations, and in consideration of the modeling analysis completed for Naughton 2, the preliminary recommended BART controls for NO_x, SO_2, and PM are as follows:

- New LNBs and OFA system for NO_x control
- Lime spray dryer FGD for SO_2 control and a coal sulfur limit less than 1.02 weight percent
- Add FGC ahead of the existing ESP for PM control

The above recommendations were identified as Scenario 1 for the modeling analysis described in Section 4, except for the FGC. Visibility improvements for all emission control scenarios were analyzed, and the results are compared in Table 5-1 using a Least-Cost Envelope, as outlined in the *New Source Review Workshop Manual* (EPA, 1990), referred to hereafter as the NSR Manual.

5.1 Least-cost Envelope Analysis

An objective analysis of the results has been performed using the EPA Least-cost Envelope method. The methodology and results of the analysis are described in this section.

5.1.1 Analysis Methodology

On page B-41 of the NSR Manual, the EPA states (EPA, 1990): "Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between dominant alternatives. Dominant set of control alternatives are determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for a total emissions reductions for all control alternatives identified in the BACT analysis."

An analysis of incremental cost-effectiveness has been conducted. This analysis was performed in the following manner. First, the control option scenarios are ranked in ascending order of annualized total costs as shown in Tables 5-1 and 5-2. The incremental cost-effectiveness data, expressed per day and per dV reduction, represent a comparison of the different scenarios and are summarized in Tables 5-3 and 5-4 for each of the two Class I areas. The incremental cost-effectiveness is determined by the difference in total annual costs between two contiguous scenarios divided by the difference in emissions reduction.

Then, the most reasonable smooth curve of least-cost control option scenarios is plotted for each analysis. Figures 5-1 through 5-4 present the two analyses (cost per dV reduction and cost per reduction in number of days above 0.5 dV) for each of the two Class I areas affected by the operation of Naughton 2.

TABLE 5-1
Bridger WA Class I Agent Control Data
Naughton 2

Scenario	Controls	98th Percentile deciview (dV(Reduction	Exceedance Reduction (Days)	Total Annualized Cost (million$)	Cost per dV Reduction (million$/ dV Reduced)	Cost per Reduction in No. of Days Above 0.5 dV (million$/ Day Reduced)
Base	Current Operation with Electrostatic Precipitator (ESP)	0.00	0.0	$0.0	$0.0	$0.0
1	Low-NO_x Burner (LNB) with Over-fire Air (OFA), Dry Flue Gas Desulfurization (FGD), ESP	1.14	35.7	$16.0	$14.0	$0.4
2	LNB with OFA, Dry FGD, New Fabric Filter	1.36	45.0	$19.7	$14.5	$0.4
3	LNB with OFA and Selective Catalytic Reduction (SCR), Dry FGD, Fabric Filter	1.73	54.7	$27.4	$15.9	$0.5
4	LNB with OFA and SCR, Wet FGD, ESP, New Stack	1.57	51.0	$26.7	$17.0	$0.5

TABLE 5-2
Fitzpatrick WA Class I Area Control Data
Naughton 2

Scenario	Controls	98th Percentile dV Reduction	Exceedance Reduction (Days)	Total Annualized Cost (million$)	Cost per dV Reduction (million$/dV Reduced)	Cost per Reduction in No. of Days Exceeding 0.5 dV (million$/Day Reduced)
Base	Current Operation with ESP	0.00	0.0	$0.0	$0.0	$0.0
1	LNB with OFA, Dry FGD, ESP	0.68	18.3	$16.0	$23.4	$0.9
2	LNB with OFA, Dry FGD, New Fabric Filter	0.82	20.3	$19.7	$24.0	$1.0
3	LNB with OFA and SCR, Dry FGD, Fabric Filter	0.97	23.3	$27.4	$28.2	$1.2
4	LNB with OFA and SCR, Wet FGD, ESP, New Stack	0.95	23.0	$26.7	$28.0	$1.2

TABLE 5-3
Bridger WA Class I Agent Incremental Data
Naughton 2

Options Compared	Incremental Exceedance Reductions (Days)	Incremental dV Reductions (dV)	Incremental Cost Effectiveness (million$/Days)	Incremental Cost Effectiveness (million$/dV)
Baseline and Scenario 1	35.7	1.14	$0.45	$13.96
Scenario 1 and Scenario 2	9.3	0.22	$0.4	$17.4
Scenario 1 and Scenario 3	19.0	0.58	$0.6	$19.7
Scenario 1 and Scenario 4	15.3	0.43	$0.7	$25.1

NOTE:
Because Scenario 3 produces better results in visibility than Scenario 4, Scenario 4 was not analyzed further.

TABLE 5-4
Fitzpatrick WA Class I Area Incremental Data
Naughton 2

Options Compared	Incremental Exceedance Reductions (Days)	Incremental dV Reductions (dV)	Incremental Cost Effectiveness (million$/Days)	Incremental Cost Effectiveness (million$/dV)
Baseline and Scenario 1	18.3	0.68	$0.87	$23.41
Scenario 1 and Scenario 2	2.0	0.14	$1.9	$27.2
Scenario 1 and Scenario 3	5.0	0.29	$2.3	$39.3
Scenario 1 and Scenario 4	4.7	0.27	$2.3	$39.5

NOTE:
Because Scenario 3 produces better results in visibility than Scenario 4, Scenario 4 was not analyzed further.

FIGURE 5-1
Least-cost Envelope Bridger WA Class I Area Reduction Days Reduction
Naughton 2

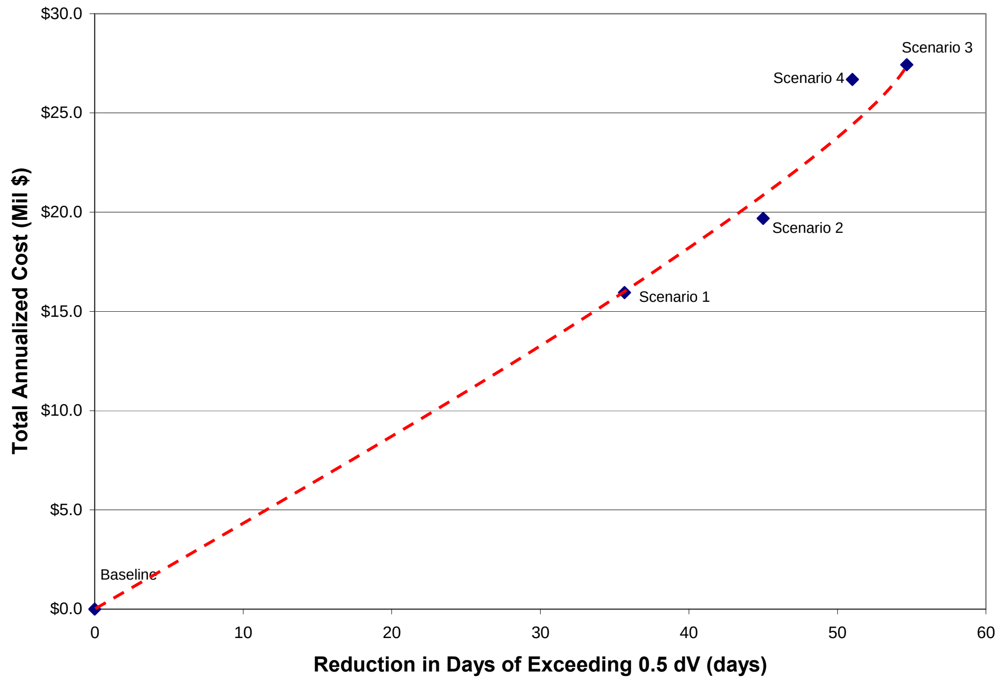


FIGURE 5-2
Least-cost Envelope Bridger WA Class I Area 98th Percentile dV Reduction
Naughton 2

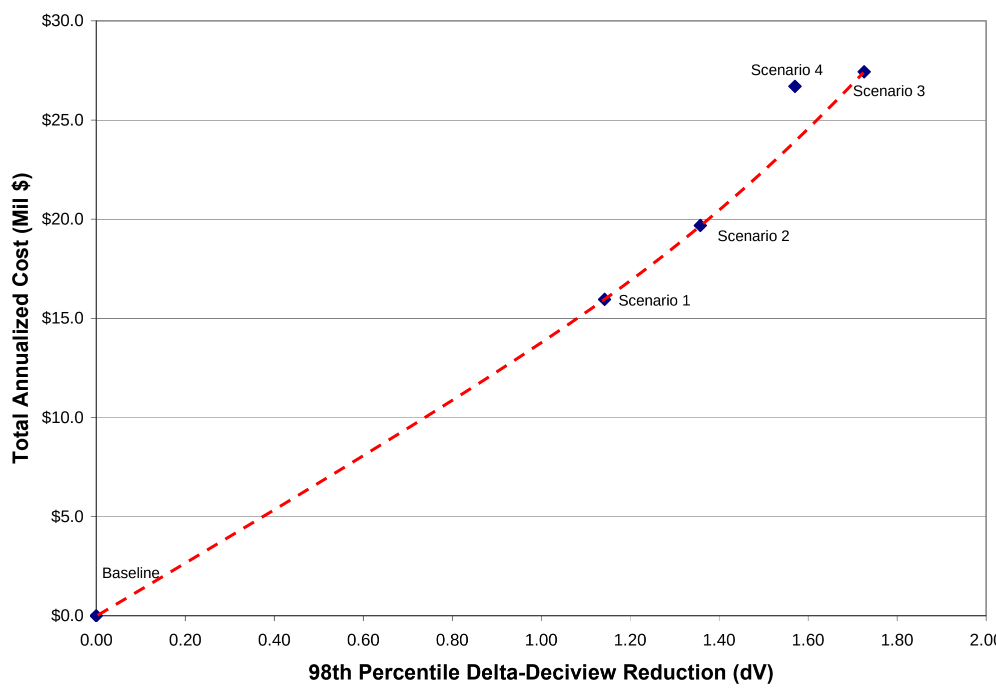


FIGURE 5-3
Least-cost Envelope Fitzpatrick WA Class I Area Days Reduction
Naughton 2

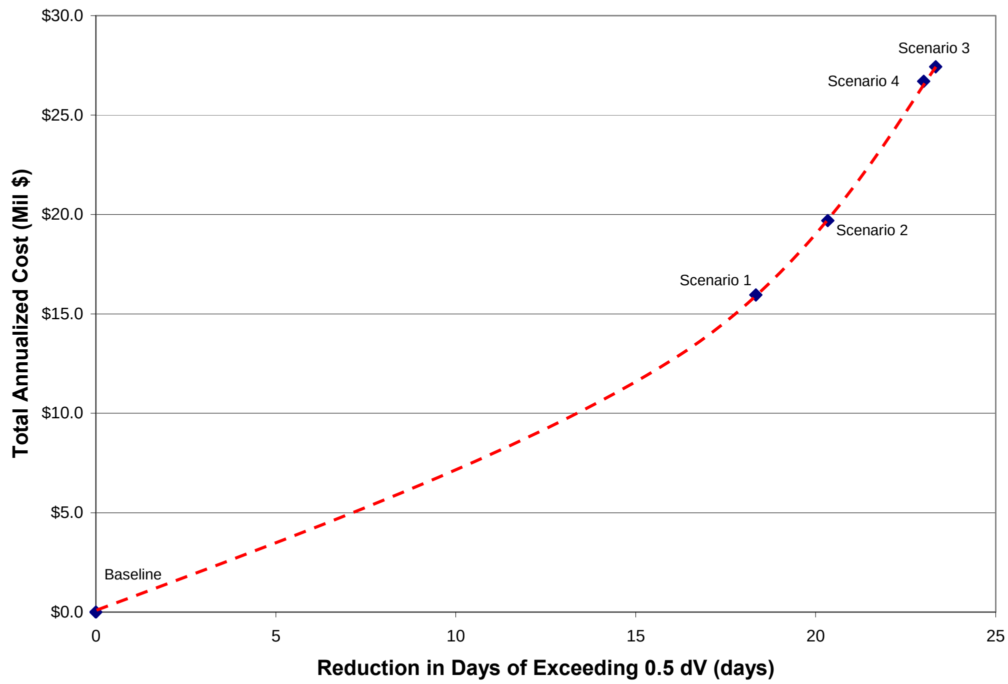
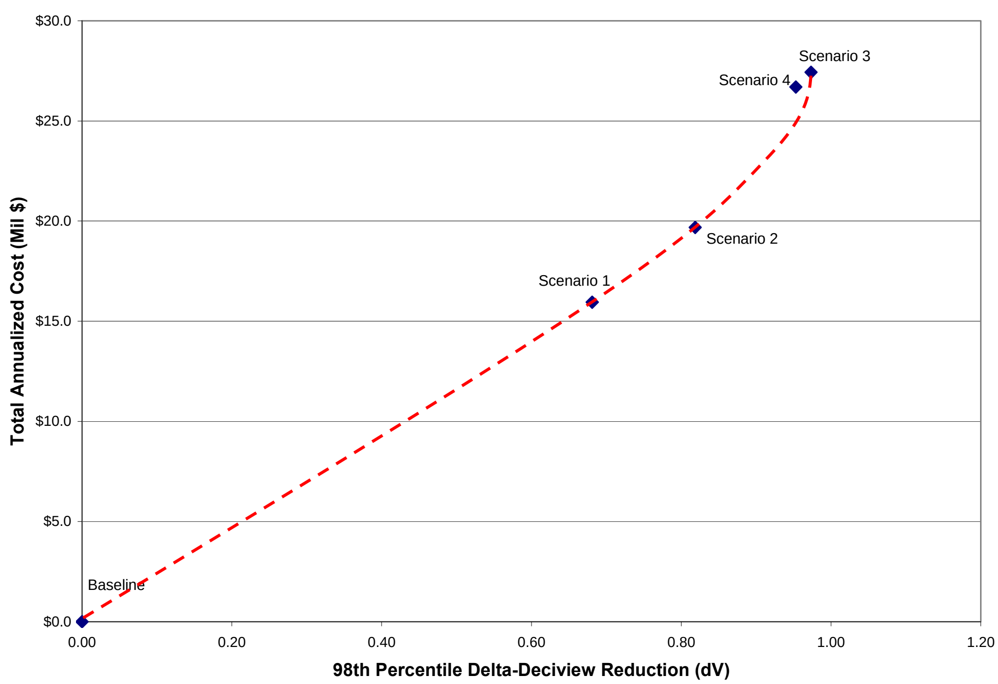


FIGURE 5-4
Least-cost Envelope Fitzpatrick WA Class I Area 98th Percentile dV Reduction
Naughton 2



5.1.2 Analysis of Results

Results of the least-cost analysis shown in Tables 5-1 to 5-4 and Figures 5-1 to 5-4 confirm the selection of Scenario 1, based on incremental cost and visibility improvements. The other scenarios were eliminated for the following reasons:

- Scenario 2 is to the left of the curve formed by the "dominant" control alternative scenarios, which indicates a scenario with lower improvement and/or higher costs.
- Scenario 3 has high incremental costs on the bases of a cost per day of improvement and a cost per dV reduction.
- While Scenario 4 provides some potential visibility advantage over Scenario 1, the projected improvement is less than 0.5 dV, and the cost increment is excessive. It is also to the left of the curves indicating a scenario with lower improvement or higher costs. Thus, the scenario was eliminated from consideration.

Analysis of the results for the Bridger Class I WA in Tables 5-1 and 5-3 and Figures 5-1 and 5-2 illustrates the conclusions stated above. The greatest reduction in 98^{th} percentile dV and number of days above 0.5 dV is between the Baseline and Scenario 1. For example, Table 5-3 shows that the incremental cost-effectiveness for Scenario 1 compared to the Baseline is $450,000 per day and $13.96 million per dV to improve visibility at the Bridger WA.

In addition, the incremental cost-effectiveness for Scenario 2 compared to Scenario 1 is $400,000 per day and $17.4 million per dV. The incremental cost-effectiveness for Scenario 3 compared to Scenario 1 is also excessive at $600,000 per day and $19.7 million per dV.

Using Table 5-4, a similar conclusion is reached for improving visibility at the Fitzpatrick WA. In fact, the incremental costs are higher for improving visibility in the Fitzpatrick WA than in the Bridger WA. Therefore, the EPA Least-cost Analysis indicates that Scenario 1 represents the proper BART control technology for Naughton 2 because the incremental cost-effectiveness would be excessive if either Scenario 2 or Scenario 3 were chosen compared to Scenario 1.

5.2 Recommendations

5.2.1 NO_x Emission Control

The characteristics of the P&M coals are more closely aligned with bituminous coals that produce higher NO_x emissions than typical sub-bituminous coals, such as PRB coals.

CH2M HILL recommends LNB with OFA as BART for Naughton 2, based on the projected significant reduction in NO_x emissions, reasonable control costs, and the advantages of no additional power requirements or non-air quality environmental impacts. NO_x reductions are expected to be similar to those realized at the Jim Bridger plant where these devices have been installed on Unit 2. This selection of new LNB with OFA at Naughton 2 is projected to attain an emission rate at or below 0.26 pound per MMBtu.

5.2.2 SO_2 Emission Control

CH2M HILL recommends installing a dry lime FGD system as BART for Naughton 2, assuming use of coal containing no more than 1.02 percent sulfur by weight. This recommendation is based on the significant reduction in SO_2 emissions, reasonable control costs, and the advantages of minimal additional power requirements and minimal non-air quality environmental impacts.

5.2.3 PM_{10} Emission Control

CH2M HILL recommends the addition of an FGC system to enhance the performance of the existing ESP as BART for Naughton 2. This recommendation is based on the reduction in PM_{10} emissions, reasonable control costs, and the advantages of minimal additional power requirements and no non-air quality environmental impacts.

5.3 Just-Noticeable Differences in Atmospheric Haze

Conclusions reached in the reference document *Just-Noticeable Differences in Atmospheric Haze* by Dr. Ronald Henry (2002), state that only dV differences of approximately 1.5 to 2.0 dV or more are perceivable by the human eye. Deciview changes of less than 1.5 cannot be distinguished by the average person. Therefore, the modeling analysis results indicate that only minimal, if any, visibility improvements at the Class I areas studied would be expected under any of the scenarios. Thus, the results indicate that, although many millions of dollars would be spent, only minimal visibility improvements might result.

Finally, none of the data were corrected for natural obscuration. During the period of 2001 through 2003, several mega-wildfires occurred and lasted for many days, and the fires could have had a significant impact on visibility in these Class I areas. If natural obscuration were to reduce the visibility impacts modeled for the Naughton 2 facility, the costs per dV reduction that are presented in this report would increase.

6.0 References

40 CFR Part 51. *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations; Final Rule.* July 6, 2005.

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APPENDIX A

Economic Analysis

PacifiCorp BART Analysis Scenarios

Select Unit:	8	Naughton Unit 2

Index No.	Name of Unit
1	Dave Johnston Unit 3
2	Dave Johnston Unit 4
3	Jim Bridger Unit 1
4	Jim Bridger Unit 2
5	Jim Bridger Unit 3
6	Jim Bridger Unit 4
7	Naughton Unit 1
8	Naughton Unit 2
9	Naughton Unit 3
10	Wyodak

Dave Johnston				Naughton					
DJ Unit 3		DJ Unit 4		NTN Unit 1		NTN Unit 2		NTN Unit 3	
Scenario	First Year Cost	Scenario	First Year Cost	Scenario	First Year Cost	Scenario	First Year Cost	Scenario	First Year Cost
Baseline - Current Operation with ESP		Baseline - Current Operation with Venturi Scrubber		Baseline - Current Operation with ESP		Baseline - Current Operation with ESP		Baseline - Current Operation with Wet FGD and ESP	
Scenario 1 - LNB with OFA, Dry FGD, Existing ESP	**N/A** N/A	Scenario 1 - LNB with OFA, Dry FGD, Fabric Filter	**N/A** N/A	Scenario 1 - LNB with OFA, Dry FGD, ESP and Higher Sulfur Coal	**N/A** N/A	Scenario 1 - LNB with OFA, Dry FGD, ESP	**$ 15,951,704** $ 15,951,704	Scenario 1 - LNB with OFA, Waste Liquor FGD, Enhance ESP	**N/A** N/A
Scenario 2 - LNB with OFA, Dry FGD, New Fabric Filter	**N/A** N/A	Scenario 2 - LNB with OFA, Wet FGD, New Fabric Filter	**N/A** N/A	Scenario 2 - LNB with OFA, Dry FGD, New Fabric Filter	**N/A** N/A	Scenario 2 - LNB with OFA, Dry FGD, New Fabric Filter	**$ 19,686,224** $ 19,686,224	Scenario 2 - LNB with OFA and SCR, Waste Liquor FGD, Enhance ESP	**N/A** N/A
Scenario 3 - LNB with OFA and SCR, Dry FGD, New Fabric Filter	**N/A** N/A	Scenario 3 - LNB with OFA and SCR, Dry FGD, New Fabric Filter	**N/A** N/A	Scenario 3 - LNB with OFA and SCR, Dry FGD, New Fabric Filter	**N/A** N/A	Scenario 3 - LNB with OFA and SCR, Dry FGD, New Fabric Filter	**$ 27,429,327** $ 27,429,327	Scenario 3 - LNB with OFA and SCR, Waste Liquor FGD, New Fabric Filter	**N/A** N/A
Scenario 4 - LNB with OFA and SCR, Wet FGD, Existing ESP, New Stack	**N/A** N/A	Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	**N/A** N/A	Scenario 4 - LNB with OFA and SCR, Wet FGD, ESP, New Stack	**N/A** N/A	Scenario 4 - LNB with OFA and SCR, Wet FGD, ESP, New Stack	**$ 26,693,951** $ 26,693,951	Scenario 4 - LNB with OFA and SCR, Soda Ash FGD, New Fabric Filter	**N/A** N/A

Jim Bridger								Wyodak	
JB Unit 1		JB Unit 2		JB Unit 3		JB Unit 4		Wyodak	
Scenario	First Year Cost	Scenario	First Year	Scenario	First Year Cost	Scenario	First Year Cost	Scenario	First Year Cost
Baseline - Current Operation with Wet FGD and ESP		Baseline - Current Operation with Wet FGD and ESP		Baseline - Current Operation with Wet FGD and ESP		Baseline - Current Operation with Wet FGD and ESP		Baseline - Current Operation with Dry FGD, ESP	
Scenario 1 - LNB with OFA, Wet FGD, ESP	**N/A** N/A N/A	Scenario 1 - LNB with OFA, Wet FGD, ESP	**N/A** N/A N/A	Scenario 1 - LNB with OFA, Wet FGD, ESP	**N/A** N/A N/A	Scenario 1 - LNB with OFA, Wet FGD, ESP	**N/A** N/A N/A	Scenario 1 - LNB with OFA, Dry FGD, ESP	**N/A** N/A
Scenario 2 - LNB with OFA, Wet FGD, New Fabric Filter	**N/A** N/A N/A	Scenario 2 - LNB with OFA, Wet FGD, New Fabric Filter	**N/A** N/A N/A	Scenario 2 - LNB with OFA, Wet FGD, New Fabric Filter	**N/A** N/A N/A	Scenario 2 - LNB with OFA, Wet FGD, Fabric Filter	**N/A** N/A N/A	Scenario 2 - LNB with OFA, Dry FGD, Fabric Filter	**N/A** N/A
Scenario 3 - LNB with OFA and SCR, Wet FGD, ESP	**N/A** N/A N/A	Scenario 3 - LNB with OFA and SCR, Wet FGD, ESP	**N/A** N/A N/A	Scenario 3 - LNB with OFA and SCR, Wet FGD, ESP	**N/A** N/A N/A	Scenario 3 - LNB with OFA and SCR, Wet FGD, ESP	**N/A** N/A N/A	Scenario 3 - LNB with OFA and SCR, Dry FGD, Fabric Filter	**N/A** N/A
Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	**N/A** N/A N/A	Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	**N/A** N/A N/A	Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	**N/A** N/A N/A	Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	**N/A** N/A N/A	Scenario 4 - LNB with OFA and SCR, Wet FGD, ESP	**N/A** N/A

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ECONOMIC ANALYSIS SUMMARY

Naughton Unit 2 **Boiler Design:** **Tangential-Fired PC**

Parameter	Current Operation	NOx Control				SO2 Control			PM Control	
		LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Dry FGD w/ESP & Higher S Coal	Dry FGD w/Fabric Filter	Wet FGD w/ESP	Flue Gas Conditioning	Fabric Filter
Case	1	2	3	4	5	6	7	8	9	10
NOx Emission Control System	None	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	None	None	None	None	None
SO2 Emission Control System	None	None	None	None	None	Dry FGD w/ESP & Higher S Coal	Dry FGD w/Fabric Filter	Wet FGD w/ESP	None	None
PM Emission Control System	ESP	ESP	ESP	ESP	ESP	ESP	ESP	ESP	Flue Gas Conditioning	Fabric Filter
TOTAL INSTALLED CAPITAL COST ($)	**0**	**7,500,001**	**10,586,222**	**19,878,765**	**72,960,588**	**88,896,713**	**141,244,778**	**126,095,338**	**1,298,352**	**34,898,710**
FIRST YEAR O&M COST ($)										
Operating Labor ($)	0	0	0	0	0	506,128	506,128	809,804	0	0
Maintenance Material ($)	0	32,000	48,000	93,000	160,000	860,174	905,190	1,226,386	0	45,016
Maintenance Labor ($)	0	48,000	72,000	139,500	240,000	573,044	640,568	817,591	10,000	67,524
Administrative Labor ($)	0	0	0	0	0	0	0	0	0	0
TOTAL FIXED O&M COST	**0**	**80,000**	**120,000**	**232,500**	**400,000**	**1,939,345**	**2,051,885**	**2,853,781**	**10,000**	**112,540**
Makeup Water Cost	0	0	0	0	0	94,962	94,962	126,616	0	0
Reagent Cost	0	0	0	547,170	365,145	2,425,901	1,141,778	954,332	62,194	0
SCR Catalyst / FF Bag Cost	0	0	0	0	303,000	0	124,072	0	0	124,072
Waste Disposal Cost	0	0	0	0	0	1,139,518	612,026	711,213	0	0
Electric Power Cost	0	0	1,028,842	86,724	527,834	886,556	1,431,734	1,300,860	19,710	545,179
TOTAL VARIABLE O&M COST	**0**	**0**	**1,028,842**	**633,894**	**1,195,979**	**4,546,936**	**3,404,572**	**3,093,020**	**81,904**	**669,251**
TOTAL FIRST YEAR O&M COST	**0**	**80,000**	**1,148,842**	**866,394**	**1,595,979**	**6,486,281**	**5,456,457**	**5,946,802**	**91,904**	**781,791**
FIRST YEAR DEBT SERVICE ($)	0	713,459	1,007,044	1,891,024	6,940,582	8,456,551	13,436,308	11,995,175	123,509	3,319,838
TOTAL FIRST YEAR COST ($)	**0**	**793,459**	**2,155,887**	**2,757,418**	**8,536,561**	**14,942,832**	**18,892,766**	**17,941,977**	**215,414**	**4,101,629**
Power Consumption (MW)	**0.0**	**0.0**	**2.6**	**0.2**	**1.3**	**2.2**	**3.6**	**3.3**	**0.1**	**1.4**
Annual Power Usage (Million kW-Hr/Yr)	**0.0**	**0.0**	**20.6**	**1.7**	**10.6**	**17.7**	**28.6**	**26.0**	**0.4**	**10.9**
CONTROL COST ($/Ton Removed)										
NOx Removal Rate (%)	**0.0%**	**55.6%**	**51.9%**	**64.8%**	**87.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
NOx Removed (Tons/Yr)	**0**	**2,838**	**2,649**	**3,311**	**4,446**	**0**	**0**	**0**	**0**	**0**
First Year Average Control Cost ($/Ton NOx Rem.)	**0**	**280**	**814**	**833**	**1,920**	**0**	**0**	**0**	**0**	**0**
Incremental Control Cost ($/Ton NOx Removed)	**0**	**280**	**814**	**4,152**	**3,550**	**0**	**0**	**0**	**0**	**0**
		2-1	3-1	4-2	5-3					
SO2 Removal Rate (%)	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**80.1%**	**87.3%**	**91.5%**	**0.0%**	**0.0%**
SO2 Removed (Tons/Yr)	**0**	**0**	**0**	**0**	**0**	**15,645**	**9,768**	**10,241**	**0**	**0**
First Year Average Control Cost ($/Ton SO2 Rem.)	**0**	**0**	**0**	**0**	**0**	**955**	**1,934**	**1,752**	**0**	**0**
Incremental Control Cost ($/Ton SO2 Removed)	**Base**	**0**	**0**	**0**	**0**	**955**	**1,934**	**1,752**	**0**	**0**
						6-1	7-1	8-1		
PM Removal Rate (%)	**98.43%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**37.50%**	**76.56%**
PM Removed (Tons/Yr)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**227**	**464**
First Year Average Control Cost ($/Ton PM Rem.)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**949**	**8,848**
Incremental Control Cost ($/Ton PM Removed)	**Base**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**949**	**16,432**
									9-1	10-9
PRESENT WORTH COST ($)	**0**	**8,477,429**	**24,622,608**	**30,464,242**	**92,460,027**	**168,145,144**	**207,910,972**	**198,752,487**	**2,421,226**	**44,450,517**

INPUT CALCULATIONS

Naughton Unit 2 — **Boiler Design:** Tangential-Fired PC

Parameter	Current Operation	NOx Control: LNB w/OFA	NOx Control: ROFA	NOx Control: LNB w/OFA & SNCR	NOx Control: LNB w/OFA & SCR	SO2 Control: Dry FGD w/ESP & Higher S Coal	SO2 Control: Dry FGD w/Fabric Filter	SO2 Control: Wet FGD w/ESP	PM Control: Flue Gas Conditioning	PM Control: Fabric Filter	Comments
Case	1	2	3	4	5	6	7	8	9	10	
NOx Emission Control System	None	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	None	None	None	None	None	
SO2 Emission Control System	None	None	None	None	None	Dry FGD w/ESP & Higher S Coal	Dry FGD w/Fabric Filter	Wet FGD w/ESP	None	None	
PM Emission Control System	ESP	ESP	ESP	ESP	ESP	ESP	ESP	ESP	Flue Gas Conditioning	Fabric Filter	
Unit Design and Coal Characteristics											
Type of Unit	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	
Net Power Output (kW)	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	210,000	
Net Plant Heat Rate (Btu/kW-Hr)	11,428	11,428	11,428	11,428	11,428	11,428	11,428	11,428	11,428	11,428	
Boiler Fuel	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	
Coal Heating Value (Btu/Lb)	9,800	9,800	9,800	9,800	9,800	9,875	9,800	9,800	9,800	9,800	
Coal Sulfur Content (wt.%)	0.58%	0.58%	0.58%	0.58%	0.58%	1.02%	0.58%	0.580%	0.58%	0.58%	
Coal Ash Content (wt.%)	5.00%	5.00%	5.00%	5.00%	5.00%	5.25%	5.00%	5.00%	5.00%	5.00%	
Boiler Heat Input, each (MMBtu/Hr)	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	
Coal Flow Rate (Lb/Hr)	244,886	244,886	244,886	244,886	244,886	243,026	244,886	244,886	244,886	244,886	
(Ton/Yr)	965,339	965,339	965,339	965,339	965,339	958,008	965,339	965,339	965,339	965,339	
(MMBtu/Yr)	18,920,654	18,920,654	18,920,654	18,920,654	18,920,654	18,920,654	18,920,654	18,920,654	18,920,654	18,920,654	
Emissions											
Uncontrolled SO2 (Lb/Hr)	2,838	2,838	2,838	2,838	2,838	4,953	2,838	2,838	2,838	2,838	
(Lb/MMBtu)	1.18	1.18	1.18	1.18	1.18	2.06	1.18	1.18	1.18	1.18	
(Lb Moles/Hr)	44.30	44.30	44.30	44.30	44.30	77.31	44.30	44.30	44.30	44.30	
(Tons/Yr)	11,187	11,187	11,187	11,187	11,187	19,524	11,187	11,187	11,187	11,187	
SO2 Removal Rate (%)	0.0%	0.0%	0.0%	0.0%	0.0%	80.1%	87.3%	91.5%	0.0%	0.0%	
(Lb/Hr)	0	0	0	0	0	3,969	2,478	2,598	0	0	
(Ton/Yr)	0	0	0	0	0	15,645	9,768	10,241	0	0	
SO2 Emission Rate (Lb/Hr)	2,838	2,838	2,838	2,838	2,838	984	360	240	2,838	2,838	
(Lb/MMBtu)	1.18	1.18	1.18	1.18	1.18	0.41	0.15	0.10	1.18	1.18	
(Ton/Yr)	11,187	11,187	11,187	11,187	11,187	3,879	1,419	946	11,187	11,187	
Uncontrolled NOx (Lb/Hr)	1,296	1,296	1,296	1,296	1,296	1,296	1,296	1,296	1,296	1,296	
(Lb/MMBtu)	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	
(Lb Moles/Hr)	43.18	43.18	43.18	43.18	43.18	43.18	43.18	43.18	43.18	43.18	
(Tons/Yr)	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	
NOx Removal Rate (%)	0.0%	55.6%	51.9%	64.8%	87.0%	0.0%	0.0%	0%	0.0%	0%	
(Lb/Hr)	0	720	672	840	1,128	0	0	0	0	0	
(Lb Moles/Hr)	0.00	23.99	22.39	27.99	37.59	0.00	0.00	0.00	0.00	0.00	
(Ton/Yr)	0	2,838	2,649	3,311	4,446	0	0	0	0	0	
NOx Emission Rate (Lb/Hr)	1,296	576	624	456	168	1,296	1,296	1,296	1,296	1,296	
(Lb/MMBtu)	0.54	0.24	0.26	0.19	0.07	0.54	0.54	0.54	0.54	0.54	
(Ton/Yr)	5,109	2,270	2,460	1,797	662	5,109	5,109	5,109	5,109	5,109	
Uncontrolled Fly Ash (Lb/Hr)	9,795	154	154	154	154	154	154	154	154	154	
(Lb/MMBtu)	4.082	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	
(Lb Moles/Hr)	326.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	
(Tons/Yr)	38,614	605	605	605	605	605	605	605	605	605	
Fly Ash Removal Rate (%)	98.43%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	37.50%	76.56%	
(Lb/Hr)	9,642	0	0	0	0	0	0	0	58	118	
(Ton/Yr)	38,008	0	0	0	0	0	0	0	227	464	
Fly Ash Emission Rate (Lb/Hr)	154	154	154	154	154	154	154	154	96	36	
(Lb/MMBtu)	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.040	0.015	
(Ton/Yr)	605	605	605	605	605	605	605	605	378	142	

Parameter	Current Operation	NOx Control				SO2 Control			PM Control		Comments
		LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Dry FGD w/ESP & Higher S Coal	Dry FGD w/Fabric Filter	Wet FGD w/ESP	Flue Gas Conditioning	Fabric Filter	
Case	1	2	3	4	5	6	7	8	9	10	
General Plant Data											
Annual Operation (Hours/Year)	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	
Annual On-Site Power Plant Capacity Factor	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	
Economic Factors											
Interest Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	
Discount Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	
Plant Economic Life (Years)	20	20	20	20	20	20	20	20	20	20	
Installed Capital Costs											
NOx Emission Control System ($2006)	0	7,500,001	10,586,222	19,878,765	72,960,588	0	0	0	0	0	
SO2 Emission Control System ($2006)	0	0	0	0	0	88,896,713	141,244,778	126,095,338	0	0	
PM Emission Control System ($2006)	0	0	0	0	0	0	0	0	1,298,352	34,898,710	
Total Emission Control Systems ($2006)	0	7,500,001	10,586,222	19,878,765	72,960,588	88,896,713	141,244,778	126,095,338	1,298,352	34,898,710	
NOx Emission Control System ($/kW)	0	36	50	95	347	0	0	0	0	0	
SO2 Emission Control System ($/kW)	0	0	0	0	0	423	673	600	0	0	
PM Emission Control System ($/kW)	0	0	0	0	0	0	0	0	6	166	
Total Emission Control Systems ($/kW)	0	36	50	95	347	423	673	600	6	166	
Total Fixed Operating & Maintenance Costs											
Operating Labor ($)	0	0	0	0	0	506,128	506,128	809,804	0	0	
Maintenance Material ($)	0	32,000	48,000	93,000	160,000	860,174	905,190	1,226,386	0	45,016	
Maintenance Labor ($)	0	48,000	72,000	139,500	240,000	573,044	640,568	817,591	10,000	67,524	
Administrative Labor ($)	0	0	0	0	0	0	0	0	0	0	
Total Fixed O&M Cost ($)	0	80,000	120,000	232,500	400,000	1,939,345	2,051,885	2,853,781	10,000	112,540	
Annual Fixed O&M Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Water Cost											
Makeup Water Usage (Gpm)	0	0	0	0	0	165	165	220	0	0	
Unit Price ($/1000 Gallons)	1.22	1.22	1.22	0.00	1.22	1.22	1.22	1.22	1.22	1.22	
First Year Water Cost ($)	0	0	0	0	0	94,962	94,962	126,616	0	0	
Annual Water Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Reagent Cost	None	None	None	Urea	Anhydrous NH3	Lime	Lime	Lime	Elemental Sulfur	None	
Unit Cost ($/Ton)	0.00	0.00	0.00	370	400	91.25	91.25	91.25	370	0.00	
($/Lb)	0.000	0.000	0.000	0.185	0.200	0.046	0.046	0.046	0.185	0.000	
Molar Stoichiometry	0.00	0.00	0.00	0.51	1.00	1.40	1.15	1.05	0.00	0.00	
Reagent Purity (Wt.%)	100%	100%	100%	100%	100%	90%	90%	90%	100%	90%	
Reagent Usage (Lb/Hr)	0	0	0	375	232	6,744	3,174	2,653	43	0	
First Year Reagent Cost ($)	0	0	0	547,170	365,145	2,425,901	1,141,778	954,332	62,194	0	
Annual Reagent Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
SCR Catalyst / FF Bag Replacement Cost					SCR Catalyst	Bags	Bags	Bags		Bags	
Annual SCR Catalyst (m3) / No. FF Bags	0	0	0	0	101	0	1,193	0	0	1,193	
SCR Catalyst ($/m3) / Bag Cost ($/ea.)	3,000	3,000	3,000	3,000	3,000	104	104	104	3,000	104	
First Year SCR Catalyst / Bag Replace. Cost ($)	0	0	0	0	303,000	0	124,072	0	0	124,072	
Annual SCR Catalyst / Bag Cost Esc. Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
FGD Waste Disposal Cost											
FGD Solid Waste Disposal Rate, Dry (Lb/Hr)	0	0	0	0	0	11,880	6,381	7,415	0	0	
FGD Waste Disposal Unit Cost ($/Dry Ton)	24.33	24.33	24.33	24.33	24.33	24.33	24.33	24.33	24.33	24.33	
First Year FGD Waste Disposal Cost ($)	0	0	0	0	0	1,139,518	612,026	711,213	0	0	
Annual Waste Disposal Cost Esc. Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Auxiliary Power Cost											
Auxiliary Power Requirement (% of Plant Output)	0.00%	0.00%	1.24%	0.10%	0.64%	1.07%	1.73%	1.57%	0.02%	0.66%	
(MW)	0.00	0.00	2.61	0.22	1.34	2.25	3.63	3.30	0.05	1.38	
Unit Cost ($2006/MW-Hr)	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	
First Year Auxiliary Power Cost ($)	0	0	1,028,842	86,724	527,834	886,556	1,431,734	1,300,860	19,710	545,179	
Annual Power Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	

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Input Tables

Table 1 - Cases

Index No.	Name of Unit | Case --->	Existing	NOx Control				SO2 Control			PM Control	
		1	2	3	4	5	6	7	8	9	10
1	Dave Johnston Unit 3	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Dry FGD w/ESP	Dry FGD w/Fabric Filter	Wet FGD w/ESP	N/A	Fabric Filter
2	Dave Johnston Unit 4	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	N/A	Dry FGD w/Fabric Filter	Wet FGD w/Fabric Filter	N/A	Fabric Filter
3	Jim Bridger Unit 1	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	N/A	N/A	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
4	Jim Bridger Unit 2	Current Operation	Exist. LNB w/OFA	ROFA	SNCR	SCR	N/A	N/A	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
5	Jim Bridger Unit 3	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	N/A	N/A	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
6	Jim Bridger Unit 4	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	N/A	N/A	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
7	Naughton Unit 1	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Dry FGD w/ESP & Higher S Coal	Dry FGD w/Fabric Filter	Wet FGD w/ESP	Flue Gas Conditioning	Fabric Filter
8	Naughton Unit 2	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Dry FGD w/ESP & Higher S Coal	Dry FGD w/Fabric Filter	Wet FGD w/ESP	Flue Gas Conditioning	Fabric Filter
9	Naughton Unit 3	Current Operation	Tune Exist. LNB w/OFA	ROFA	SNCR	SCR	N/A	Wet FGD w/Waste Liquor	Wet FGD w/Soda Ash	Enhancements to Existing ESP	Fabric Filter
10	Wyodak	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Upgraded Dry FGD	Dry FGD w/Fabric Filter	Wet FGD	N/A	Fabric Filter

Table 2 - Unit Design and Coal Characteristics

Index No.	Name of Unit	Current Emission Control Systems			Unit Design			Coal Quality			
		NOx	SO2	PM	Boiler Design	Net Power Output (kW)	Net Plant Heat Rate (Btu/kW-Hr)	Coal	Heating Value, HHV (Btu/Lb)	Sulfur Content (Wt.%)	Ash Content (Wt.%)
1	Dave Johnston Unit 3	None	None	ESP	3-Cell Burner, Opposed Wall-Fired PC	250,000	11,200	Dry Fork PRB	7,784	0.47%	5.01%
2	Dave Johnston Unit 4	Windbox Mods.	Lime Added to Venturi Scrubber	Venturi Scrubber	Tangential-Fired PC	360,000	11,390	Dry Fork PRB	7,784	0.47%	5.01%
3	Jim Bridger Unit 1	LNCFS-1 & Windbox Mods.	Wet FGD	ESP	Tangential-Fired PC	530,000	11,320	Bridger Mine Underground	9,660	0.58%	10.30%
4	Jim Bridger Unit 2	LNB - TFS 2000	Wet FGD	ESP	Tangential-Fired PC	530,000	11,320	Bridger Mine Underground	9,660	0.58%	10.30%
5	Jim Bridger Unit 3	LNCFS-1 & Windbox Mods.	Wet FGD	ESP	Tangential-Fired PC	530,000	11,320	Bridger Mine Underground	9,660	0.58%	10.30%
6	Jim Bridger Unit 4	LNCFS-1 & Windbox Mods.	Wet FGD	ESP	Tangential-Fired PC	530,000	11,320	Bridger Mine Underground	9,660	0.58%	10.30%
7	Naughton Unit 1	None	None	ESP	Tangential-Fired PC	160,000	11,563	Kemmerer Mine	9,800	0.58%	5.00%
8	Naughton Unit 2	None	None	ESP	Tangential-Fired PC	210,000	11,428	Kemmerer Mine	9,800	0.58%	5.00%
9	Naughton Unit 3	LNCFS II LNB	Wet FGD	ESP	Tangential-Fired PC	330,000	11,212	Kemmerer Mine	9,875	1.02%	5.25%
10	Wyodak	LNB	Dry FGD	ESP	Opposed Wall-Fired PC	365,000	12,877	Clovis Point Mine	8,050	0.65%	7.46%

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Table 3 - Emissions

Index No.	Name of Unit	Current Emission Rates (Lb/MMBtu) Controlled SO2	Controlled NOx	Controlled PM	NOx Control Emission Rates (Lb/MMBtu) Case 2	Case 3	Case 4	Case 5	SO2 Control Emission Rates (Lb/MMBtu) Case 6	Case 7	Case 8	PM Emission Rates (Lb/MMBtu) Case 9	Case 10
1	Dave Johnston Unit 3	1.18	0.70	0.030	0.24	0.19	0.19	0.07	0.22	0.15	0.10	N/A	0.015
2	Dave Johnston Unit 4	0.50	0.40	0.061	0.15	0.15	0.12	0.07	N/A	0.15	0.10	N/A	0.015
3	Jim Bridger Unit 1	0.27	0.45	0.045	0.24	0.22	0.20	0.07	N/A	N/A	0.10	0.030	0.015
4	Jim Bridger Unit 2	0.27	0.24	0.074	0.24	0.22	0.20	0.07	N/A	N/A	0.10	0.030	0.015
5	Jim Bridger Unit 3	0.27	0.45	0.057	0.24	0.22	0.20	0.07	N/A	N/A	0.10	0.030	0.015
6	Jim Bridger Unit 4	0.17	0.45	0.030	0.24	0.22	0.20	0.07	N/A	N/A	0.10	0.030	0.015
7	Naughton Unit 1	1.18	0.58	0.056	0.24	0.26	0.19	0.07	0.41	0.15	0.10	0.040	0.015
8	Naughton Unit 2	1.18	0.54	0.064	0.24	0.26	0.19	0.07	0.41	0.15	0.10	0.040	0.015
9	Naughton Unit 3	0.50	0.45	0.094	0.35	0.28	0.28	0.07	N/A	0.21	0.10	0.040	0.015
10	Wyodak	0.50	0.31	0.030	0.23	0.20	0.18	0.07	0.32	0.16	0.10	N/A	0.015

Table 4 - Case 1 O&M Costs (Current Operation)

Index No.	Name of Unit	Annual Fixed O&M Costs Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Variable Operating Requirements Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ -	$ -	$ -	-	None	-	-
2	Dave Johnston Unit 4	$ -	$ -	$ -	$ -	-	None	-	-
3	Jim Bridger Unit 1	$ -	$ -	$ -	$ -	-	None	-	-
4	Jim Bridger Unit 2	$ -	$ -	$ -	$ -	-	None	-	-
5	Jim Bridger Unit 3	$ -	$ -	$ -	$ -	-	None	-	-
6	Jim Bridger Unit 4	$ -	$ -	$ -	$ -	-	None	-	-
7	Naughton Unit 1	$ -	$ -	$ -	$ -	-	None	-	-
8	Naughton Unit 2	$ -	$ -	$ -	$ -	-	None	-	-
9	Naughton Unit 3	$ -	$ -	$ -	$ -	-	None	-	-
10	Wyodak	$ -	$ -	$ -	$ -	-	None	-	-

Table 5 - Case 2 O&M Costs (LNB w/OFA)

Index No.	Name of Unit	Annual Fixed O&M Costs Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Variable Operating Requirements Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 40,000	$ 60,000	$ -	-	None	-	-
2	Dave Johnston Unit 4	$ -	$ 36,000	$ 54,000	$ -	-	None	-	-
3	Jim Bridger Unit 1	$ -	$ 28,000	$ 42,000	$ -	-	None	-	-
4	Jim Bridger Unit 2	$ -	$ -	$ -	$ -	-	None	-	-
5	Jim Bridger Unit 3	$ -	$ 28,000	$ 42,000	$ -	-	None	-	-
6	Jim Bridger Unit 4	$ -	$ 28,000	$ 42,000	$ -	-	None	-	-
7	Naughton Unit 1	$ -	$ 32,000	$ 48,000	$ -	-	None	-	-
8	Naughton Unit 2	$ -	$ 32,000	$ 48,000	$ -	-	None	-	-
9	Naughton Unit 3	$ -	$ -	$ -	$ -	-	None	-	-
10	Wyodak	$ -	$ 24,000	$ 36,000	$ -	-	None	-	-

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Table 6 - Case 3 O&M Costs (Mobotec ROFA)

		Annual Fixed O&M Costs				Variable Operating Requirements			
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 60,000	$ 90,000	$ -	-	None	-	2.76
2	Dave Johnston Unit 4	$ -	$ 54,000	$ 81,000	$ -	-	None	-	4.33
3	Jim Bridger Unit 1	$ -	$ 42,000	$ 63,000	$ -	-	None	-	6.41
4	Jim Bridger Unit 2	$ -	$ 42,000	$ 63,000	$ -	-	None	-	6.41
5	Jim Bridger Unit 3	$ -	$ 42,000	$ 63,000	$ -	-	None	-	6.41
6	Jim Bridger Unit 4	$ -	$ 42,000	$ 63,000	$ -	-	None	-	6.41
7	Naughton Unit 1	$ -	$ 48,000	$ 72,000	$ -	-	None	-	1.42
8	Naughton Unit 2	$ -	$ 48,000	$ 72,000	$ -	-	None	-	2.61
9	Naughton Unit 3	$ -	$ 48,000	$ 72,000	$ -	-	None	-	4.47
10	Wyodak	$ -	$ 36,000	$ 54,000	$ -	-	None	-	5.22

Table 7 - Case 4 O&M Costs (LNB w/OFA & SNCR))

		Annual Fixed O&M Costs				Variable Operating Requirements			
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 98,000	$ 147,000	$ -	-	Urea	0.41	0.23
2	Dave Johnston Unit 4	$ -	$ 105,000	$ 157,500	$ -	-	Urea	0.45	0.33
3	Jim Bridger Unit 1	$ -	$ 123,000	$ 184,500	$ -	-	Urea	0.45	0.53
4	Jim Bridger Unit 2	$ -	$ 95,000	$ 142,500	$ -	-	Urea	0.45	0.53
5	Jim Bridger Unit 3	$ -	$ 122,000	$ 183,000	$ -	-	Urea	0.45	0.52
6	Jim Bridger Unit 4	$ -	$ 123,000	$ 184,500	$ -	-	Urea	0.45	0.53
7	Naughton Unit 1	$ -	$ 83,000	$ 124,500	$ -	-	Urea	0.45	0.16
8	Naughton Unit 2	$ -	$ 93,000	$ 139,500	$ -	-	Urea	0.51	0.22
9	Naughton Unit 3	$ -	$ 75,000	$ 112,500	$ -	-	Urea	0.45	0.33
10	Wyodak	$ -	$ 93,000	$ 139,500	-	-	Urea	0.45	0.34

Table 8 - Case 5 O&M Costs (LNB w/OFA & SCR))

		Annual Fixed O&M Costs				Variable Operating Requirements				
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual SCR Catalyst Replace. (m3)	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 155,000	$ 232,500	$ -	-	Anhydrous NH3	1.00	128	1.57
2	Dave Johnston Unit 4	$ -	$ 166,000	$ 249,000	$ -	-	Anhydrous NH3	1.00	123	2.29
3	Jim Bridger Unit 1	$ -	$ 190,000	$ 285,000	$ -	-	Anhydrous NH3	1.00	198	3.28
4	Jim Bridger Unit 2	$ -	$ 162,000	$ 243,000	$ -	-	Anhydrous NH3	1.00	198	3.25
5	Jim Bridger Unit 3	$ -	$ 190,000	$ 285,000	$ -	-	Anhydrous NH3	1.00	200	3.22
6	Jim Bridger Unit 4	$ -	$ 190,000	$ 285,000	$ -	-	Anhydrous NH3	1.00	214	3.36
7	Naughton Unit 1	$ -	$ 132,000	$ 198,000	$ -	-	Anhydrous NH3	1.00	67	0.98
8	Naughton Unit 2	$ -	$ 160,000	$ 240,000	$ -	-	Anhydrous NH3	1.00	101	1.34
9	Naughton Unit 3	$ -	$ 156,000	$ 234,000	$ -	-	Anhydrous NH3	1.00	167	1.99
10	Wyodak	$ -	$ 181,000	$ 271,500	$ -	-	Anhydrous NH3	1.00	160	2.42

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Table 9 - Case 6 O&M Costs (Dry FGD)

Index No.	Name of Unit	Annual Fixed O&M Costs: Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Variable Operating Requirements: Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ 506,128	$ 714,175	$ 476,928	$ -	173	Lime	1.15	-	2.49
2	Dave Johnston Unit 4	$ -	$ -	$ -	$ -	-	Lime	-	-	-
3	Jim Bridger Unit 1	$ -	$ -	$ -	$ -	-	Lime	-	-	-
4	Jim Bridger Unit 2	$ -	$ -	$ -	$ -	-	Lime	-	-	-
5	Jim Bridger Unit 3	$ -	$ -	$ -	$ -	-	Lime	-	-	-
6	Jim Bridger Unit 4	$ -	$ -	$ -	$ -	-	Lime	-	-	-
7	Naughton Unit 1	$ 506,128	$ 587,643	$ 391,762	$ -	120	Lime	1.40	-	1.64
8	Naughton Unit 2	$ 506,128	$ 860,174	$ 573,044	$ -	165	Lime	1.40	-	2.25
9	Naughton Unit 3	$ -	$ -	$ -	$ -	-	Lime	-	-	-
10	Wyodak	$ -	$ 21,900	$ 14,600	-	25	Lime	1.10	-	0.11

Table 10 - Case 7 O&M Costs (Dry FGD w/Fabric Filter)

Index No.	Name of Unit	Annual Fixed O&M Costs: Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Variable Operating Requirements: Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ 506,128	$ 714,175	$ 476,928	$ -	173	Lime	1.15	1,457	3.88
2	Dave Johnston Unit 4	$ 506,128	$ 1,102,288	$ 734,858	$ -	248	Lime	1.10	1,798	4.54
3	Jim Bridger Unit 1	$ -	$ -	$ -	$ -	-	Lime	-	-	-
4	Jim Bridger Unit 2	$ -	$ -	$ -	$ -	-	Lime	-	-	-
5	Jim Bridger Unit 3	$ -	$ -	$ -	$ -	-	Lime	-	-	-
6	Jim Bridger Unit 4	$ -	$ -	$ -	$ -	-	Lime	-	-	-
7	Naughton Unit 1	$ 506,128	$ 632,660	$ 459,286	$ -	120	Lime	1.15	865	2.66
8	Naughton Unit 2	$ 506,128	$ 905,190	$ 640,568	$ -	165	Lime	1.15	1,193	3.63
9	Naughton Unit 3	$ -	$ 21,900	$ 14,600	$ -	66	Waste Liquor	1.02	-	0.33
10	Wyodak	$ -	$ 30,660	$ 20,440	-	30	Lime	1.10	-	0.15

Table 11 - Case 8 O&M Costs (Wet FGD)

Index No.	Name of Unit	Annual Fixed O&M Costs: Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Variable Operating Requirements: Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ 809,804	$ 1,182,587	$ 788,391	$ -	230	Lime	1.02	-	3.45
2	Dave Johnston Unit 4	$ 809,804	$ 1,430,784	$ 953,856	$ -	330	Lime	1.02	1,798	6.29
3	Jim Bridger Unit 1	$ -	$ 25,550	$ 17,033	$ -	53	Soda Ash	1.02	-	0.53
4	Jim Bridger Unit 2	$ -	$ 25,550	$ 17,033	$ -	53	Soda Ash	1.02	-	0.53
5	Jim Bridger Unit 3	$ -	$ 25,550	$ 17,033	$ -	52	Soda Ash	1.02	-	0.52
6	Jim Bridger Unit 4	$ -	$ 25,550	$ 17,033	$ -	27	Soda Ash	1.02	-	0.53
7	Naughton Unit 1	$ 809,804	$ 963,589	$ 642,393	$ -	160	Lime	1.05	-	2.40
8	Naughton Unit 2	$ 809,804	$ 1,226,386	$ 817,591	$ -	220	Lime	1.05	-	3.30
9	Naughton Unit 3	$ -	$ 21,900	$ 14,600	$ -	66	Soda Ash	1.02	-	0.33
10	Wyodak	$ 303,677	$ 328,496	$ 218,998	$ -	82	Lime	1.02	-	1.75

Table 12 - Case 9 O&M Costs (Flue Gas Conditioning)

Index No.	Name of Unit	Annual Fixed O&M Costs: Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Variable Operating Requirements: Makeup Water Use (Gpm)	Reagent	Reagent Usage (Lb/Hr)	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ -	$ -	$ -	-	None	-	-	-
2	Dave Johnston Unit 4	$ -	$ -	$ -	$ -	-	None	-	-	-
3	Jim Bridger Unit 1	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	100	-	0.05
4	Jim Bridger Unit 2	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	100	-	0.05
5	Jim Bridger Unit 3	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	100	-	0.05
6	Jim Bridger Unit 4	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	100	-	0.05
7	Naughton Unit 1	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	33	-	0.05
8	Naughton Unit 2	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	43	-	0.05
9	Naughton Unit 3	$ -	$ -	$ -	$ -	-	None	-	-	-
10	Wyodak	$ -	$ -	$ -	-	-	None	-	-	-

Table 13 - Case 10 O&M Costs (Fabric Filter)

Index No.	Name of Unit	Annual Fixed O&M Costs: Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Variable Operating Requirements: Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 45,016	$ 67,524	$ -	-	None	-	1,457	1.38
2	Dave Johnston Unit 4	$ -	$ 68,133	$ 102,199	$ -	-	None	-	1,798	2.35
3	Jim Bridger Unit 1	$ -	$ 51,099	$ 76,649	$ -	-	None	-	2,885	3.39
4	Jim Bridger Unit 2	$ -	$ 51,099	$ 76,649	$ -	-	None	-	2,885	3.37
5	Jim Bridger Unit 3	$ -	$ 51,099	$ 76,649	$ -	-	None	-	2,827	3.33
6	Jim Bridger Unit 4	$ -	$ 51,099	$ 76,649	$ -	-	None	-	2,885	3.39
7	Naughton Unit 1	$ -	$ 45,016	$ 67,524	$ -	-	None	-	865	1.01
8	Naughton Unit 2	$ -	$ 45,016	$ 67,524	$ -	-	None	-	1,193	1.38
9	Naughton Unit 3	$ -	$ 48,666	$ 72,999	$ -	-	None	-	1,799	2.06
10	Wyodak	$ -	$ 48,666	$ 72,999	$ -	-	None	-	1,798	2.06

Table 14 - Major Materials Design and Supply Costs

Index No.	Name of Unit | Case --->	NOx Control: 2	3	4	5	SO2 Control: 6	7	8	PM Control: 9	10
1	Dave Johnston Unit 3	$ 5,449,830	$ 3,556,617	$ 5,773,000	$ 49,355,000	$ 56,379,000	$ 85,647,000	$ 88,913,000	$ -	$ 18,359,000
2	Dave Johnston Unit 4	$ 2,673,501	$ 4,343,192	$ 7,171,085	$ 66,200,000	$ -	$ 137,267,000	$ 178,174,384	$ -	$ 30,853,530
3	Jim Bridger Unit 1	$ 2,981,982	$ 6,056,955	$ 9,528,000	$ 80,923,000	$ -	$ -	$ 8,010,093	$ -	$ 29,814,000
4	Jim Bridger Unit 2	$ -	$ 6,056,955	$ 9,528,000	$ 80,923,000	$ -	$ -	$ 8,010,093	$ -	$ 29,814,000
5	Jim Bridger Unit 3	$ 2,981,982	$ 6,056,955	$ 9,419,000	$ 80,923,000	$ -	$ -	$ 8,010,093	$ -	$ 29,814,000
6	Jim Bridger Unit 4	$ 2,981,982	$ 6,056,955	$ 9,528,000	$ 93,009,000	$ -	$ -	$ 3,549,000	$ -	$ 29,814,000
7	Naughton Unit 1	$ 2,502,123	$ 2,675,792	$ 7,257,000	$ 37,292,000	$ 39,617,991	$ 67,159,581	$ 56,500,308	$ 800,000	$ 18,361,060
8	Naughton Unit 2	$ 2,570,674	$ 3,123,533	$ 8,784,000	$ 47,934,000	$ 54,775,108	$ 87,030,191	$ 77,695,625	$ 800,000	$ 21,503,389
9	Naughton Unit 3	$ -	$ 4,351,377	$ 11,203,578	$ 67,373,000	$ -	$ 2,772,643	$ 8,934,073	$ 8,194,701	$ 49,476,278
10	Wyodak	$ 3,187,636	$ 4,500,245	$ 7,234,860	$ 72,479,000	$ 16,487,985	$ 41,146,026	$ 58,619,840	$ -	$ 20,106,000

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CAPITAL COST

Naughton Unit 2

Parameter	NOx Control								SO2 Control						PM Control			
	LNB w/OFA		ROFA		LNB w/OFA & SNCR		LNB w/OFA & SCR		Dry FGD w/ESP & Higher		Dry FGD w/Fabric Filter		Wet FGD w/ESP		Flue Gas Conditioning		Fabric Filter	
Case	2		3		4		5		6		7		8		9		10	
NOx Emission Control System	LNB w/OFA		ROFA		LNB w/OFA & SNCR		LNB w/OFA & SCR		None		None		None		None		None	
SO2 Emission Control System	None		None		None		None		Dry FGD w/ESP & Higher S Coal		Dry FGD w/Fabric Filter		Wet FGD w/ESP		None		None	
PM Emission Control System	ESP		ESP		ESP		ESP		ESP		ESP		ESP		Flue Gas Conditioning		Fabric Filter	
CAPITAL COST COMPONENT	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost
LNB w/OFA or ROFA		LNB w/OFA		ROFA		LNB w/OFA		LNB w/OFA										
Major Materials Design and Supply	Vendor	$2,570,674	Vendor	$3,123,533	Vendor	$2,570,674	Vendor	$2,570,674	Vendor	$0	Vendor	$0	Vendor	$0	Vendor	$0	Vendor	$0
Construction	85.3%	$2,193,653	85.3%	$2,665,428	85.3%	$2,193,653	85.3%	$2,193,653	85.3%	$0	85.3%	$0	85.3%	$0	85.3%	$0	85.3%	$0
Balance of Plant	51.7%	$1,328,837	51.7%	$1,614,621	51.7%	$1,328,837	51.7%	$1,328,837	51.7%	$0	51.7%	$0	51.7%	$0	51.7%	$0	51.7%	$0
Electrical (Allowance)	0.0%	$0	30.0%	$937,060	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0
Owner's Costs	13.2%	$340,572	13.2%	$413,816	13.2%	$340,572	13.2%	$340,572	13.2%	$0	13.2%	$0	13.2%	$0	13.2%	$0	13.2%	$0
Surcharge	16.4%	$422,246	16.4%	$513,056	16.4%	$422,246	16.4%	$422,246	16.4%	$0	16.4%	$0	16.4%	$0	16.4%	$0	16.4%	$0
AFUDC	12.2%	$314,097	12.2%	$381,648	12.2%	$314,097	12.2%	$314,097	12.2%	$0	12.2%	$0	12.2%	$0	12.2%	$0	12.2%	$0
Subtotal		$7,170,079		$9,649,162		$7,170,079		$7,170,079		$0		$0		$0		$0		$0
Contingency	12.8%	$329,922	30.0%	$937,060	12.8%	$329,922	12.8%	$329,922	12.8%	$0	12.8%	$0	12.8%	$0	12.8%	$0	12.8%	$0
Total Capital Cost for LNB w/OFA or ROFA		$7,500,001		$10,586,222		$7,500,001		$7,500,001		$0		$0		$0		$0		$0
SNCR or SCR						SNCR		SCR										
Major Materials Design and Supply	S&L Report	$0	S&L Report	$0	S&L Report	$8,784,000	S&L Report	$47,934,000	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$0
Contingency	20.0%	$0	20.0%	$0	20.0%	$1,756,800	10.0%	$4,793,400	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$0
Labor Premium	5.6%	$0	5.6%	$0	5.6%	$491,289	5.6%	$2,680,949	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$0
EPC Premium	0.0%	$0	0.0%	$0	0.0%	$0	8.4%	$4,048,985	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$0
Boiler Reinforcement (Allowance)	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0
Sales Tax	1.1%	$0	1.1%	$0	1.1%	$96,800	1.1%	$528,233	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$0
Escalation	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0
Contingency on Adders	2.8%	$0	2.8%	$0	2.8%	$246,567	0.0%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0
Surcharge and AFUDC	11.4%	$0	11.4%	$0	11.4%	$1,003,308	11.4%	$5,475,021	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$0
Total Capital Cost for SNCR or SCR		$0		$0		$12,378,764		$65,460,588		$0		$0		$0		$0		$0
Dry or Wet FGD, FGC or Fabric Filter										Dry FGD		Dry FGD w/FF		Wet FGD		FGC		Fabric Filter
Major Materials Design and Supply	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$54,775,108	S&L Report	$87,030,191	S&L Report	$77,695,625	S&L Report	$800,000	S&L Report	$21,503,389
Contingency	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$10,955,022	20.0%	$17,406,038	20.0%	$15,539,125	20.0%	$160,000	20.0%	$4,300,678
Labor Premium	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$3,063,572	5.6%	$4,867,599	5.6%	$4,345,516	5.6%	$44,744	5.6%	$1,202,685
EPC Premium	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$4,626,853	8.4%	$7,351,440	8.4%	$6,562,949	8.4%	$67,576	8.4%	$1,816,391
Boiler Reinforcement (Allowance)	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$1,541,372	2.8%	$2,449,030	2.8%	$2,186,355	2.8%	$22,512	2.8%	$605,105
Sales Tax	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$603,622	1.1%	$959,073	1.1%	$856,206	1.1%	$8,816	1.1%	$236,967
Escalation	10.1%	$0	10.1%	$0	10.1%	$0	10.1%	$0	10.1%	$5,537,216	10.1%	$8,797,882	10.1%	$7,854,251	10.1%	$80,872	10.1%	$2,173,778
Contingency on Adders	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$1,537,537	2.8%	$2,442,937	2.8%	$2,180,916	2.8%	$22,456	2.8%	$603,600
Surcharge and AFUDC	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$6,256,413	11.4%	$9,940,588	11.4%	$8,874,394	11.4%	$91,376	11.4%	$2,456,117
Total Capital Cost for Dry/Wet FGD, FGC or FF		$0		$0		$0		$0		$88,896,713		$141,244,778		$126,095,338		$1,298,352		$34,898,710

Sierra Club/107
Fisher/69

Naughton Unit 2 — LNB w/OFA

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton NOx Removed)
0	2013										
1	2014	80,000	-	-	-	-	-	-	713,459	793,459	280
2	2015	81,600	-	-	-	-	-	-	713,459	795,059	280
3	2016	83,232	-	-	-	-	-	-	713,459	796,691	281
4	2017	84,897	-	-	-	-	-	-	713,459	798,355	281
5	2018	86,595	-	-	-	-	-	-	713,459	800,053	282
6	2019	88,326	-	-	-	-	-	-	713,459	801,785	283
7	2020	90,093	-	-	-	-	-	-	713,459	803,552	283
8	2021	91,895	-	-	-	-	-	-	713,459	805,354	284
9	2022	93,733	-	-	-	-	-	-	713,459	807,191	284
10	2023	95,607	-	-	-	-	-	-	713,459	809,066	285
11	2024	97,520	-	-	-	-	-	-	713,459	810,978	286
12	2025	99,470	-	-	-	-	-	-	713,459	812,929	286
13	2026	101,459	-	-	-	-	-	-	713,459	814,918	287
14	2027	103,489	-	-	-	-	-	-	713,459	816,947	288
15	2028	105,558	-	-	-	-	-	-	713,459	819,017	289
16	2029	107,669	-	-	-	-	-	-	713,459	821,128	289
17	2030	109,823	-	-	-	-	-	-	713,459	823,282	290
18	2031	112,019	-	-	-	-	-	-	713,459	825,478	291
19	2032	114,260	-	-	-	-	-	-	713,459	827,718	292
20	2033	116,545	-	-	-	-	-	-	713,459	830,004	292
Present Worth		977,428	-	-	-	-	-	-	7,500,001	8,477,429	149
(% of PW)		11.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	88.5%	100.0%	

Naughton Unit 2 — ROFA

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton NOx Removed)
0	2013										
1	2014	120,000	-	-	-	-	1,028,842	1,028,842	1,007,044	2,155,887	814
2	2015	122,400	-	-	-	-	1,049,419	1,049,419	1,007,044	2,178,863	823
3	2016	124,848	-	-	-	-	1,070,408	1,070,408	1,007,044	2,202,300	831
4	2017	127,345	-	-	-	-	1,091,816	1,091,816	1,007,044	2,226,205	840
5	2018	129,892	-	-	-	-	1,113,652	1,113,652	1,007,044	2,250,588	850
6	2019	132,490	-	-	-	-	1,135,925	1,135,925	1,007,044	2,275,459	859
7	2020	135,139	-	-	-	-	1,158,644	1,158,644	1,007,044	2,300,827	869
8	2021	137,842	-	-	-	-	1,181,816	1,181,816	1,007,044	2,326,703	878
9	2022	140,599	-	-	-	-	1,205,453	1,205,453	1,007,044	2,353,096	888
10	2023	143,411	-	-	-	-	1,229,562	1,229,562	1,007,044	2,380,017	898
11	2024	146,279	-	-	-	-	1,254,153	1,254,153	1,007,044	2,407,477	909
12	2025	149,205	-	-	-	-	1,279,236	1,279,236	1,007,044	2,435,485	919
13	2026	152,189	-	-	-	-	1,304,821	1,304,821	1,007,044	2,464,054	930
14	2027	155,233	-	-	-	-	1,330,917	1,330,917	1,007,044	2,493,194	941
15	2028	158,337	-	-	-	-	1,357,536	1,357,536	1,007,044	2,522,917	952
16	2029	161,504	-	-	-	-	1,384,686	1,384,686	1,007,044	2,553,235	964
17	2030	164,734	-	-	-	-	1,412,380	1,412,380	1,007,044	2,584,158	976
18	2031	168,029	-	-	-	-	1,440,628	1,440,628	1,007,044	2,615,701	987
19	2032	171,390	-	-	-	-	1,469,440	1,469,440	1,007,044	2,647,874	1,000
20	2033	174,817	-	-	-	-	1,498,829	1,498,829	1,007,044	2,680,691	1,012
Present Worth		1,466,142	-	-	-	-	12,570,244	12,570,244	10,586,222	24,622,608	465
(% of PW)		6.0%	0.0%	0.0%	0.0%	0.0%	51.1%	51.1%	43.0%	100.0%	

Naughton Unit 2 — LNB w/OFA & SNCR

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton NOx Removed)
0	2013										
1	2014	232,500	-	547,170	-	-	86,724	633,894	1,891,024	2,757,418	833
2	2015	237,150	-	558,114	-	-	88,458	646,572	1,891,024	2,774,746	838
3	2016	241,893	-	569,276	-	-	90,228	659,504	1,891,024	2,792,420	843
4	2017	246,731	-	580,661	-	-	92,032	672,694	1,891,024	2,810,448	849
5	2018	251,665	-	592,275	-	-	93,873	686,147	1,891,024	2,828,837	854
6	2019	256,699	-	604,120	-	-	95,750	699,870	1,891,024	2,847,593	860
7	2020	261,833	-	616,203	-	-	97,665	713,868	1,891,024	2,866,724	866
8	2021	267,069	-	628,527	-	-	99,619	728,145	1,891,024	2,886,238	872
9	2022	272,411	-	641,097	-	-	101,611	742,708	1,891,024	2,906,143	878
10	2023	277,859	-	653,919	-	-	103,643	757,562	1,891,024	2,926,445	884
11	2024	283,416	-	666,997	-	-	105,716	772,714	1,891,024	2,947,153	890
12	2025	289,085	-	680,337	-	-	107,830	788,168	1,891,024	2,968,276	896
13	2026	294,866	-	693,944	-	-	109,987	803,931	1,891,024	2,989,821	903
14	2027	300,764	-	707,823	-	-	112,187	820,010	1,891,024	3,011,797	910
15	2028	306,779	-	721,979	-	-	114,430	836,410	1,891,024	3,034,212	916
16	2029	312,914	-	736,419	-	-	116,719	853,138	1,891,024	3,057,076	923
17	2030	319,173	-	751,147	-	-	119,053	870,201	1,891,024	3,080,397	930
18	2031	325,556	-	766,170	-	-	121,435	887,605	1,891,024	3,104,185	938
19	2032	332,067	-	781,494	-	-	123,863	905,357	1,891,024	3,128,448	945
20	2033	338,709	-	797,124	-	-	126,340	923,464	1,891,024	3,153,196	952
Present Worth		2,840,651	-	6,685,245	-	-	1,059,581	7,744,827	19,878,765	30,464,242	460
(% of PW)		9.3%	0.0%	21.9%	0.0%	0.0%	3.5%	25.4%	65.3%	100.0%	

Naughton Unit 2 — LNB w/OFA & SCR

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton NOx Removed)
0	2013										
1	2014	400,000	-	365,145	303,000	-	527,834	1,195,979	6,940,582	8,536,561	1,920
2	2015	408,000	-	372,448	309,060	-	538,390	1,219,899	6,940,582	8,568,481	1,927
3	2016	416,160	-	379,897	315,241	-	549,158	1,244,297	6,940,582	8,601,039	1,934
4	2017	424,483	-	387,495	321,546	-	560,141	1,269,183	6,940,582	8,634,248	1,942
5	2018	432,973	-	395,245	327,977	-	571,344	1,294,566	6,940,582	8,668,121	1,949
6	2019	441,632	-	403,150	334,536	-	582,771	1,320,458	6,940,582	8,702,672	1,957
7	2020	450,465	-	411,213	341,227	-	594,427	1,346,867	6,940,582	8,737,914	1,965
8	2021	459,474	-	419,437	348,052	-	606,315	1,373,804	6,940,582	8,773,860	1,973
9	2022	468,664	-	427,826	355,013	-	618,441	1,401,280	6,940,582	8,810,526	1,982
10	2023	478,037	-	436,382	362,113	-	630,810	1,429,306	6,940,582	8,847,925	1,990
11	2024	487,598	-	445,110	369,355	-	643,426	1,457,892	6,940,582	8,886,072	1,999
12	2025	497,350	-	454,012	376,742	-	656,295	1,487,050	6,940,582	8,924,981	2,007
13	2026	507,297	-	463,093	384,277	-	669,421	1,516,791	6,940,582	8,964,669	2,016
14	2027	517,443	-	472,354	391,963	-	682,809	1,547,126	6,940,582	9,005,151	2,025
15	2028	527,792	-	481,801	399,802	-	696,465	1,578,069	6,940,582	9,046,442	2,035
16	2029	538,347	-	491,437	407,798	-	710,395	1,609,630	6,940,582	9,088,560	2,044
17	2030	549,114	-	501,266	415,954	-	724,603	1,641,823	6,940,582	9,131,519	2,054
18	2031	560,097	-	511,292	424,273	-	739,095	1,674,659	6,940,582	9,175,338	2,064
19	2032	571,298	-	521,517	432,759	-	753,877	1,708,153	6,940,582	9,220,033	2,074
20	2033	582,724	-	531,948	441,414	-	768,954	1,742,316	6,940,582	9,265,622	2,084
Present Worth		4,887,141	-	4,461,292	3,702,010	-	6,448,996	14,612,297	72,960,588	92,460,027	1,040
(% of PW)		5.3%	0.0%	4.8%	4.0%	0.0%	7.0%	15.8%	78.9%	100.0%	

Sierra Club/107
Fisher/70

Naughton Unit 2 — Dry FGD w/ESP & Higher S Coal

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton SO2 Removed)
0	2013										
1	2014	1,939,345	94,962	2,425,901	-	1,139,518	886,556	4,546,936	8,456,551	14,942,832	955
2	2015	1,978,132	96,861	2,474,419	-	1,162,309	904,287	4,637,875	8,456,551	15,072,558	963
3	2016	2,017,694	98,798	2,523,907	-	1,185,555	922,373	4,730,633	8,456,551	15,204,878	972
4	2017	2,058,048	100,774	2,574,385	-	1,209,266	940,820	4,825,245	8,456,551	15,339,844	980
5	2018	2,099,209	102,790	2,625,873	-	1,233,451	959,637	4,921,750	8,456,551	15,477,510	989
6	2019	2,141,193	104,845	2,678,390	-	1,258,120	978,829	5,020,185	8,456,551	15,617,929	998
7	2020	2,184,017	106,942	2,731,958	-	1,283,283	998,406	5,120,589	8,456,551	15,761,157	1,007
8	2021	2,227,697	109,081	2,786,597	-	1,308,948	1,018,374	5,223,001	8,456,551	15,907,249	1,017
9	2022	2,272,251	111,263	2,842,329	-	1,335,127	1,038,741	5,327,461	8,456,551	16,056,263	1,026
10	2023	2,317,696	113,488	2,899,176	-	1,361,830	1,059,516	5,434,010	8,456,551	16,208,257	1,036
11	2024	2,364,050	115,758	2,957,159	-	1,389,066	1,080,707	5,542,690	8,456,551	16,363,291	1,046
12	2025	2,411,331	118,073	3,016,303	-	1,416,848	1,102,321	5,653,544	8,456,551	16,521,426	1,056
13	2026	2,459,558	120,434	3,076,629	-	1,445,185	1,124,367	5,766,615	8,456,551	16,682,724	1,066
14	2027	2,508,749	122,843	3,138,161	-	1,474,088	1,146,854	5,881,947	8,456,551	16,847,247	1,077
15	2028	2,558,924	125,300	3,200,924	-	1,503,570	1,169,792	5,999,586	8,456,551	17,015,061	1,088
16	2029	2,610,103	127,806	3,264,943	-	1,533,641	1,193,187	6,119,578	8,456,551	17,186,231	1,099
17	2030	2,662,305	130,362	3,330,242	-	1,564,314	1,217,051	6,241,969	8,456,551	17,360,825	1,110
18	2031	2,715,551	132,969	3,396,847	-	1,595,601	1,241,392	6,366,809	8,456,551	17,538,910	1,121
19	2032	2,769,862	135,629	3,464,783	-	1,627,513	1,266,220	6,494,145	8,456,551	17,720,557	1,133
20	2033	2,825,259	138,341	3,534,079	-	1,660,063	1,291,544	6,624,028	8,456,551	17,905,838	1,144
Present Worth		23,694,629	1,160,228	29,639,298	-	13,922,466	10,831,809	55,553,801	88,896,713	168,145,144	537
(% of PW)		14.1%	0.7%	17.6%	0.0%	8.3%	6.4%	33.0%	52.9%	100.0%	

Naughton Unit 2 — Dry FGD w/Fabric Filter

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton SO2 Removed)
0	2013										
1	2014	2,051,885	94,962	1,141,778	124,072	612,026	1,431,734	3,404,572	13,436,308	18,892,766	1,934
2	2015	2,092,923	96,861	1,164,614	126,553	624,267	1,460,369	3,472,664	13,436,308	19,001,895	1,945
3	2016	2,134,781	98,798	1,187,906	129,085	636,752	1,489,576	3,542,117	13,436,308	19,113,206	1,957
4	2017	2,177,477	100,774	1,211,664	131,666	649,487	1,519,368	3,612,959	13,436,308	19,226,744	1,968
5	2018	2,221,026	102,790	1,235,897	134,300	662,477	1,549,755	3,685,218	13,436,308	19,342,553	1,980
6	2019	2,265,447	104,845	1,260,615	136,986	675,726	1,580,750	3,758,923	13,436,308	19,460,678	1,992
7	2020	2,310,756	106,942	1,285,827	139,725	689,241	1,612,365	3,834,101	13,436,308	19,581,165	2,005
8	2021	2,356,971	109,081	1,311,544	142,520	703,026	1,644,613	3,910,783	13,436,308	19,704,063	2,017
9	2022	2,404,110	111,263	1,337,775	145,370	717,086	1,677,505	3,988,999	13,436,308	19,829,418	2,030
10	2023	2,452,193	113,488	1,364,530	148,278	731,428	1,711,055	4,068,779	13,436,308	19,957,280	2,043
11	2024	2,501,237	115,758	1,391,821	151,243	746,056	1,745,276	4,150,154	13,436,308	20,087,699	2,057
12	2025	2,551,261	118,073	1,419,657	154,268	760,977	1,780,182	4,233,158	13,436,308	20,220,727	2,070
13	2026	2,602,286	120,434	1,448,051	157,353	776,197	1,815,785	4,317,821	13,436,308	20,356,415	2,084
14	2027	2,654,332	122,843	1,477,012	160,500	791,721	1,852,101	4,404,177	13,436,308	20,494,818	2,098
15	2028	2,707,419	125,300	1,506,552	163,710	807,555	1,889,143	4,492,261	13,436,308	20,635,988	2,113
16	2029	2,761,567	127,806	1,536,683	166,985	823,706	1,926,926	4,582,106	13,436,308	20,779,981	2,127
17	2030	2,816,799	130,362	1,567,416	170,324	840,181	1,965,465	4,673,748	13,436,308	20,926,855	2,142
18	2031	2,873,135	132,969	1,598,765	173,731	856,984	2,004,774	4,767,223	13,436,308	21,076,666	2,158
19	2032	2,930,597	135,629	1,630,740	177,205	874,124	2,044,869	4,862,567	13,436,308	21,229,473	2,173
20	2033	2,989,209	138,341	1,663,355	180,749	891,606	2,085,767	4,959,819	13,436,308	21,385,336	2,189
Present Worth		25,069,631	1,160,228	13,950,076	1,515,893	7,477,644	17,492,721	41,596,563	141,244,778	207,910,972	1,064
(% of PW)		12.1%	0.6%	6.7%	0.7%	3.6%	8.4%	20.0%	67.9%	100.0%	

Sierra Club/107
Fisher/71

Sierra Club/107
Fisher/72

Naughton Unit 2 — Wet FGD w/ESP

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton SO2 Removed)
0	2013										
1	2014	2,853,781	126,616	954,332	-	711,213	1,300,860	3,093,020	11,995,175	17,941,977	1,752
2	2015	2,910,857	129,148	973,419	-	725,437	1,326,877	3,154,881	11,995,175	18,060,913	1,764
3	2016	2,969,074	131,731	992,887	-	739,946	1,353,415	3,217,979	11,995,175	18,182,227	1,775
4	2017	3,028,455	134,365	1,012,745	-	754,745	1,380,483	3,282,338	11,995,175	18,305,968	1,788
5	2018	3,089,024	137,053	1,033,000	-	769,839	1,408,093	3,347,985	11,995,175	18,432,184	1,800
6	2019	3,150,805	139,794	1,053,660	-	785,236	1,436,255	3,414,945	11,995,175	18,560,924	1,812
7	2020	3,213,821	142,590	1,074,733	-	800,941	1,464,980	3,483,243	11,995,175	18,692,239	1,825
8	2021	3,278,097	145,442	1,096,228	-	816,960	1,494,279	3,552,908	11,995,175	18,826,181	1,838
9	2022	3,343,659	148,350	1,118,152	-	833,299	1,524,165	3,623,966	11,995,175	18,962,801	1,852
10	2023	3,410,533	151,317	1,140,515	-	849,965	1,554,648	3,696,446	11,995,175	19,102,153	1,865
11	2024	3,478,743	154,344	1,163,326	-	866,964	1,585,741	3,770,375	11,995,175	19,244,293	1,879
12	2025	3,548,318	157,431	1,186,592	-	884,303	1,617,456	3,845,782	11,995,175	19,389,275	1,893
13	2026	3,619,284	160,579	1,210,324	-	901,990	1,649,805	3,922,698	11,995,175	19,537,157	1,908
14	2027	3,691,670	163,791	1,234,531	-	920,029	1,682,801	4,001,152	11,995,175	19,687,997	1,923
15	2028	3,765,503	167,067	1,259,221	-	938,430	1,716,457	4,081,175	11,995,175	19,841,853	1,938
16	2029	3,840,814	170,408	1,284,406	-	957,199	1,750,786	4,162,798	11,995,175	19,998,787	1,953
17	2030	3,917,630	173,816	1,310,094	-	976,343	1,785,802	4,246,054	11,995,175	20,158,859	1,968
18	2031	3,995,982	177,292	1,336,296	-	995,869	1,821,518	4,330,975	11,995,175	20,322,133	1,984
19	2032	4,075,902	180,838	1,363,021	-	1,015,787	1,857,948	4,417,595	11,995,175	20,488,672	2,001
20	2033	4,157,420	184,455	1,390,282	-	1,036,102	1,895,107	4,505,947	11,995,175	20,658,542	2,017
Present Worth		34,867,078	1,546,971	11,659,892	-	8,689,491	15,893,717	37,790,071	126,095,338	198,752,487	970
(% of PW)		17.5%	0.8%	5.9%	0.0%	4.4%	8.0%	19.0%	63.4%	100.0%	

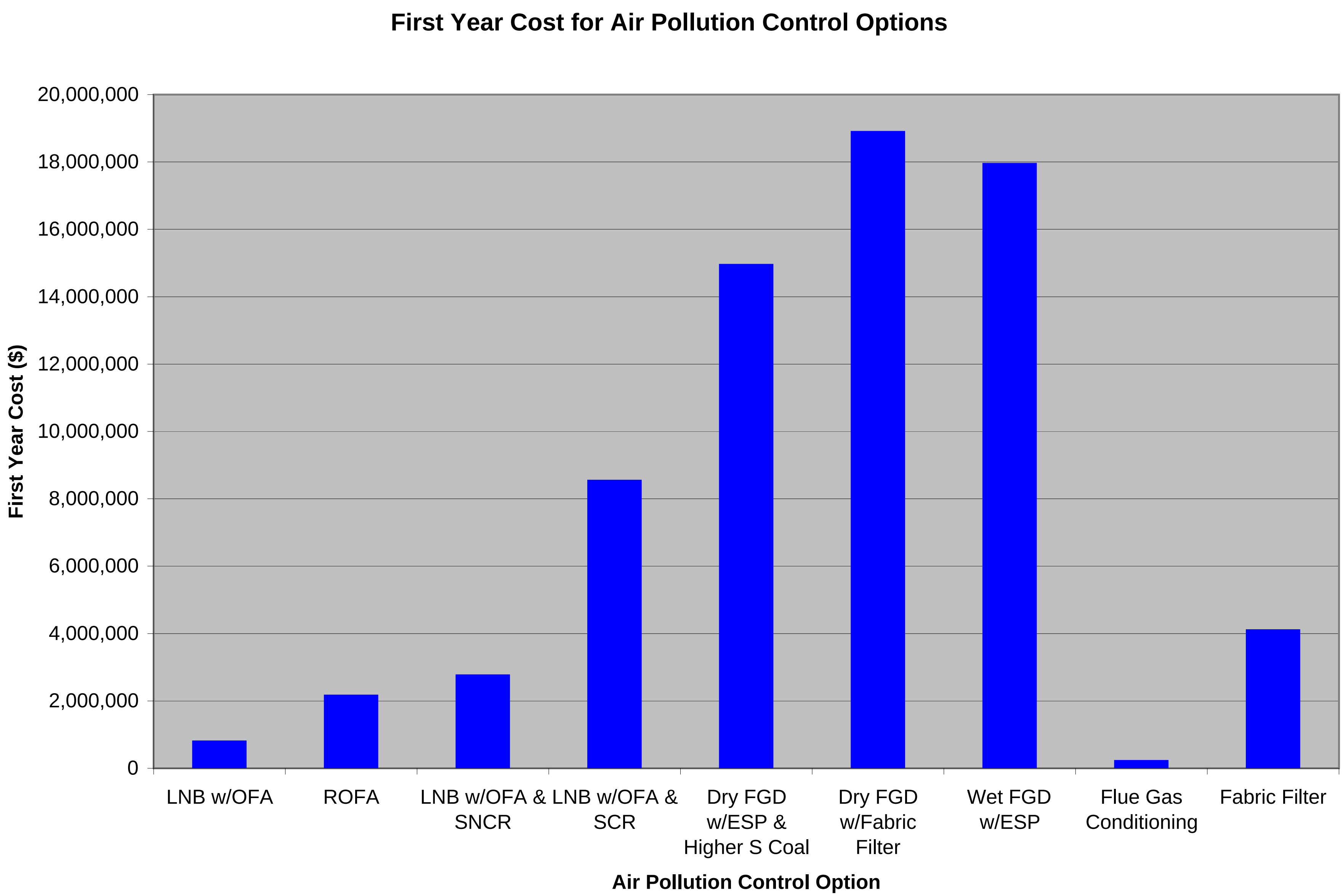
Naughton Unit 2 — Flue Gas Conditioning

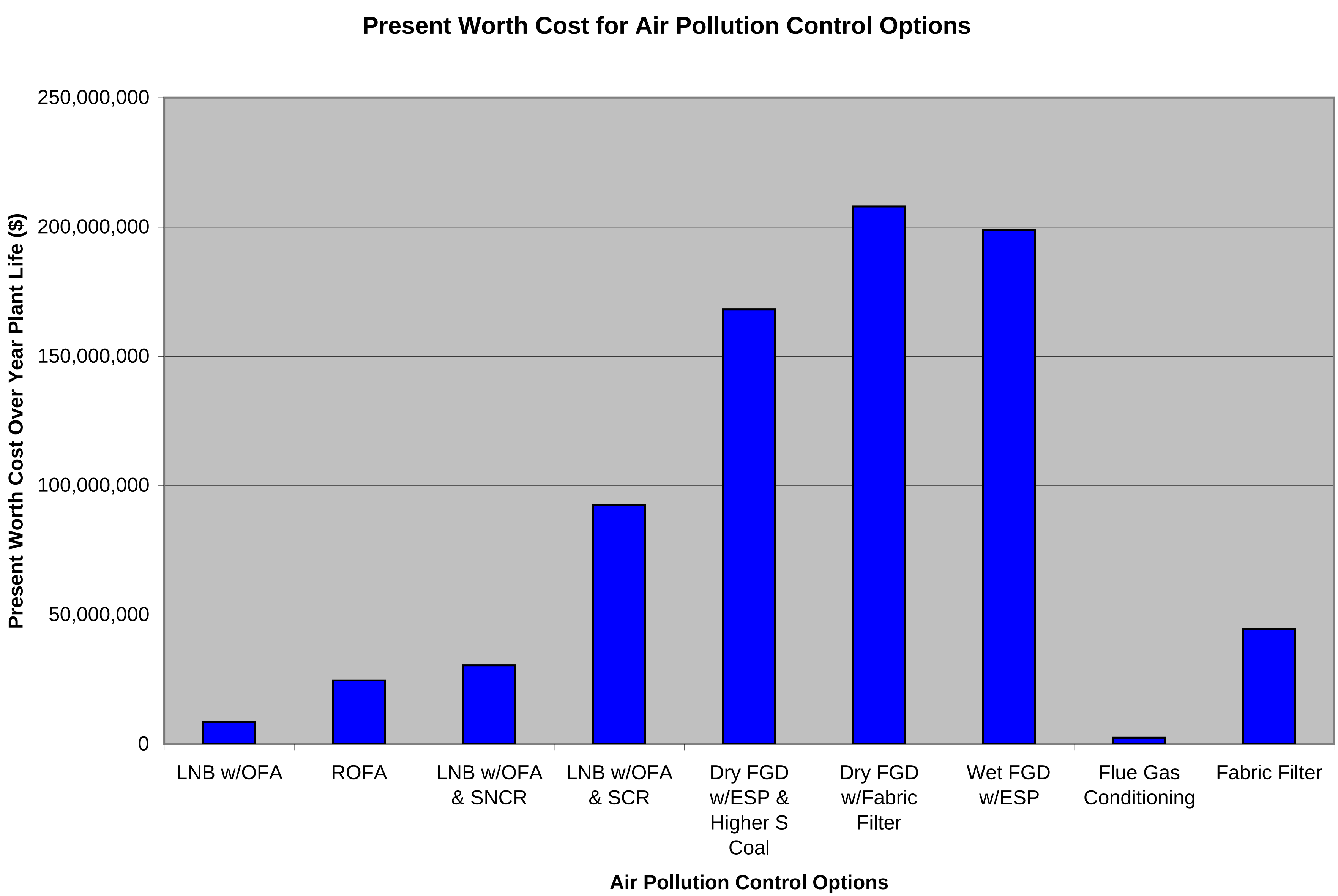
Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton PM Removed)
0	2013										
1	2014	10,000	-	62,194	-	-	19,710	81,904	123,509	215,414	949
2	2015	10,200	-	63,438	-	-	20,104	83,542	123,509	217,252	957
3	2016	10,404	-	64,707	-	-	20,506	85,213	123,509	219,127	965
4	2017	10,612	-	66,001	-	-	20,916	86,918	123,509	221,039	974
5	2018	10,824	-	67,321	-	-	21,335	88,656	123,509	222,990	982
6	2019	11,041	-	68,668	-	-	21,761	90,429	123,509	224,979	991
7	2020	11,262	-	70,041	-	-	22,197	92,238	123,509	227,009	1,000
8	2021	11,487	-	71,442	-	-	22,641	94,082	123,509	229,079	1,009
9	2022	11,717	-	72,871	-	-	23,093	95,964	123,509	231,190	1,018
10	2023	11,951	-	74,328	-	-	23,555	97,883	123,509	233,344	1,028
11	2024	12,190	-	75,815	-	-	24,026	99,841	123,509	235,540	1,037
12	2025	12,434	-	77,331	-	-	24,507	101,838	123,509	237,781	1,047
13	2026	12,682	-	78,877	-	-	24,997	103,875	123,509	240,066	1,057
14	2027	12,936	-	80,455	-	-	25,497	105,952	123,509	242,397	1,068
15	2028	13,195	-	82,064	-	-	26,007	108,071	123,509	244,775	1,078
16	2029	13,459	-	83,705	-	-	26,527	110,232	123,509	247,201	1,089
17	2030	13,728	-	85,380	-	-	27,058	112,437	123,509	249,674	1,100
18	2031	14,002	-	87,087	-	-	27,599	114,686	123,509	252,198	1,111
19	2032	14,282	-	88,829	-	-	28,151	116,980	123,509	254,771	1,122
20	2033	14,568	-	90,605	-	-	28,714	119,319	123,509	257,397	1,134
Present Worth		122,179	-	759,881	-	-	240,814	1,000,695	1,298,352	2,421,226	533
(% of PW)		5.0%	0.0%	31.4%	0.0%	0.0%	9.9%	41.3%	53.6%	100.0%	

Sierra Club/107
Fisher/73

Naughton Unit 2 — Fabric Filter

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton PM Removed)
0	2013										
1	2014	112,540	-	-	124,072	-	545,179	669,251	3,319,838	4,101,629	8,848
2	2015	114,791	-	-	126,553	-	556,082	682,636	3,319,838	4,117,265	8,882
3	2016	117,087	-	-	129,085	-	567,204	696,288	3,319,838	4,133,214	8,916
4	2017	119,429	-	-	131,666	-	578,548	710,214	3,319,838	4,149,481	8,951
5	2018	121,817	-	-	134,300	-	590,119	724,418	3,319,838	4,166,074	8,987
6	2019	124,254	-	-	136,986	-	601,921	738,907	3,319,838	4,182,999	9,024
7	2020	126,739	-	-	139,725	-	613,960	753,685	3,319,838	4,200,262	9,061
8	2021	129,274	-	-	142,520	-	626,239	768,759	3,319,838	4,217,870	9,099
9	2022	131,859	-	-	145,370	-	638,764	784,134	3,319,838	4,235,831	9,138
10	2023	134,496	-	-	148,278	-	651,539	799,816	3,319,838	4,254,151	9,177
11	2024	137,186	-	-	151,243	-	664,570	815,813	3,319,838	4,272,837	9,218
12	2025	139,930	-	-	154,268	-	677,861	832,129	3,319,838	4,291,897	9,259
13	2026	142,728	-	-	157,353	-	691,418	848,772	3,319,838	4,311,338	9,301
14	2027	145,583	-	-	160,500	-	705,247	865,747	3,319,838	4,331,168	9,343
15	2028	148,495	-	-	163,710	-	719,352	883,062	3,319,838	4,351,395	9,387
16	2029	151,465	-	-	166,985	-	733,739	900,723	3,319,838	4,372,026	9,431
17	2030	154,494	-	-	170,324	-	748,413	918,738	3,319,838	4,393,070	9,477
18	2031	157,584	-	-	173,731	-	763,382	937,112	3,319,838	4,414,534	9,523
19	2032	160,735	-	-	177,205	-	778,649	955,855	3,319,838	4,436,428	9,570
20	2033	163,950	-	-	180,749	-	794,222	974,972	3,319,838	4,458,760	9,619
Present Worth		1,375,002	-	-	1,515,893	-	6,660,912	8,176,806	34,898,710	44,450,517	4,795
(% of PW)		3.1%	0.0%	0.0%	3.4%	0.0%	15.0%	18.4%	78.5%	100.0%	


First Year Cost for Air Pollution Control Options
First Year Cost ($)
20,000,000
18,000,000
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
0
LNB w/OFA
ROFA
LNB w/OFA & SNCR
LNB w/OFA & SCR
Dry FGD w/ESP & Higher S Coal
Dry FGD w/Fabric Filter
Wet FGD w/ESP
Flue Gas Conditioning
Fabric Filter
Air Pollution Control Option


Present Worth Cost for Air Pollution Control Options
Present Worth Cost Over Year Plant Life ($)
250,000,000
200,000,000
150,000,000
100,000,000
50,000,000
0
LNB w/OFA
ROFA
LNB w/OFA & SNCR
LNB w/OFA & SCR
Dry FGD w/ESP & Higher S Coal
Dry FGD w/Fabric Filter
Wet FGD w/ESP
Flue Gas Conditioning
Fabric Filter
Air Pollution Control Options

APPENDIX B

2006 Wyoming BART Protocol

BART Air Modeling Protocol

Individual Source Visibility Assessments for BART Control Analyses

September, 2006

State of Wyoming
Department of Environmental Quality
Air Quality Division
Cheyenne, WY 82002

Table of Contents

1.0 INTRODUCTION

The U.S. EPA has issued final amendments to the Regional Haze Regulations, along with Guidelines for Best Available Retrofit Technology (BART) Determinations.[1] The guidelines address the methodology for determining which facilities must apply BART (sources subject-to-BART) and the evaluation of control options.

The State of Wyoming used air quality modeling in accordance with the EPA Guidelines to determine the Wyoming sources which are subject-to-BART. This Protocol defines the specific methodology to be used by those sources for determining the improvement in visibility to be achieved by BART controls.

The methodology presented in this Protocol is consistent with EPA guidance and the Air Quality Division (AQD) determination of subject-to-BART sources. It is intended that all Wyoming sources that must conduct BART analyses will use this Protocol for their evaluation of control technology visibility improvement. Any deviations from the procedures described herein must be approved by the Division prior to implementation.

[1] 40 CFR Part 51: Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. 70 Federal Register, 39103-39172, July 6, 2005.

2.0 OVERVIEW

Wyoming AQD determined that eight facilities (sources) in the state are subject-to-BART. The sources are listed in Table 1. Division modeling indicated that each of these sources causes or contributes to visibility impairment in one or more Class I areas. Each source must conduct a BART analysis to define Best Available Retrofit Technology (BART) applicable to that source, and quantify the improvement in Class I visibility associated with BART controls. This Protocol sets out the procedures for quantifying visibility improvement. Other aspects of the full BART analysis are not addressed here.

There are many Class I areas within and surrounding Wyoming (See Figure 1). On the basis of distance from subject-to-BART sources, topography, meteorology, and prior modeling, the AQD has determined that only five Class I areas need be addressed in BART individual source analyses. These are Badlands and Wind Cave National Parks in South Dakota, Mt. Zirkel Wilderness Area in Colorado, and Bridger and Fitzpatrick Wilderness Areas in Wyoming. Sources in eastern Wyoming have been shown to have greatest visibility impacts at the two South Dakota Class I areas, and western Wyoming sources have maximum impacts at Bridger and Fitzpatrick Wilderness Areas, and Mt. Zirkel. Visibility improvement at these highest impact areas will provide the best measure of the effectiveness of BART controls.

Each facility should carry out modeling with the CALPUFF modeling system for the Class I areas specified in Table 2. The AQD will provide meteorological input for CALMET for the years 2001, 2002, and 2003. The model domain covered by the AQD meteorological data is centered in southwest Wyoming, and extends roughly from Twin Falls, ID in the west to the Missouri River in the east, and from Denver in the south to Helena, MT in the north. The domain is shown, along with Class I areas, in Figure 1.

Sources may wish to utilize a smaller domain for CALPUFF modeling. Smaller domains are acceptable if they provide adequate additional area beyond the specific source and Class I areas being addressed. Figure 1 includes a "southwest Wyoming" domain which represents the minimum acceptable area for sources impacting the Bridger and Fitzpatrick Wilderness Areas, and the Mt. Zirkel Wilderness Area, and a "northeast Wyoming" domain as a minimum area for Badlands and Wind Cave National Parks modeling.

The CALPUFF model should be used with each of the three years of meteorological data to calculate visibility impacts for a baseline (existing emissions) case, and for cases reflecting BART controls. The control scenarios are to include individual scenarios for proposed BART controls for each pollutant (SO_2, NO_x, and particulate matter), and a combined scenario representing application of all proposed BART controls. If desired, additional modeling may be performed for controls that are not selected as BART. This might be done, for example, to provide data useful in identifying the control technologies that represent BART. However, visibility modeling is required only for the proposed BART controls.

Table 1. Wyoming Sources Subject-to-BART

Basin Electric	Laramie River Power Plant	Boilers #1,2,3
FMC Corporation	Granger Soda Ash Plant	Boilers #1,2
FMC Corporation	Green River Sodium Plant	Three boilers
General Chemical Co.	Green River Soda Ash	Two boilers
PacifiCorp	Dave Johnson Power Plant	Boilers #3,4
PacifiCorp	Jim Bridger Power Plant	Boilers #1-4
PacifiCorp	Naughton Power Plant	Boilers #1,2,3
PacifiCorp	Wyodak Power Plant	Boiler

Results of visibility modeling will be presented as a comparison between baseline impacts and those calculated for the BART control scenarios. Quantitative measures of impact will be the 98th percentile deciview change (Δdv) relative to the 20% best days natural background, and the number of days with deciview change exceeding 0.5 (EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, 70 FR 39103). Results should be presented for each year.

Table 2. Source-Specific Class I Areas to be Addressed

Source	Class I Areas to be Evaluated
Basin Electric Laramie River	Wind Cave NP, Badlands NP
FMC Corporation Granger Soda Ash	Bridger WA, Fitzpatrick WA
FMC Corporation Sodium Products	Bridger WA, Fitzpatrick WA
General Chemical Green River Soda Ash	Bridger WA, Fitzpatrick WA
Pacificorp Dave Johnston	Wind Cave NP, Badlands NP
Pacificorp Jim Bridger	Bridger WA, Fitzpatrick WA, Mt. Zirkel WA
Pacificorp Naughton Plant	Bridger WA, Fitzpatrick WA
Pacificorp Wyodak	Wind Cave NP, Badlands NP

3.0 EMISSIONS DATA FOR MODELING

CALPUFF model input requires source (stack) – specific emission rates for each pollutant, and stack parameters (height, diameter, exit gas temperature, and exit gas velocity). Per EPA BART guidance, these parameters must be representative of maximum actual 24-hour average emitting conditions for baseline (existing) operation, and maximum proposed 24-hour average emissions for future (BART) operations.

3.1 Baseline Modeling

Sources are required to utilize representative baseline emission conditions if data are available; baseline emissions must be documented. Possible sources of emission data are stack tests, CEM data, fuel consumption data, etc. Remember that emissions should represent maximum 24-hour rates. EPA BART guidance states that you should "Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario)." Thus, baseline conditions should reference data from 2001 through 2003 (or 2004).

As a minimum, modeled emissions must include:

SO_2	sulfur dioxide
NO_x	oxides of nitrogen
$PM_{2.5}$	particles with diameter less than 2.5μm
$PM_{10-2.5}$	particles with diameters greater than 2.5μm but less than or equal to 10 μm

If the fraction of PM_{10} in the $PM_{2.5}$ (fine) and $PM_{10-2.5}$ (coarse) categories cannot be determined all particulate matter should be assumed to be $PM_{2.5}$.

In addition, direct emissions of sulfate (SO_4) should be included where possible. Sulfate can be emitted as sulfuric acid (H_2SO_4), sulfur trioxide (SO_3), or as sulfate compounds; emissions should be quantified as the equivalent mass of SO_4.

When test or engineering data are not available to specify SO_4 emissions or the relative fractions of fine and coarse particles, use can be made of speciation profiles available from Federal Land Managers at the website http://ww2.nature.nps.gov/air/permits/ect/index.cfm. Profiles are available for a number of source type and control technology combinations. The FLM speciation factors are acceptable if data are available for the appropriate source type.

Emissions of VOC (volatile organic compounds), condensable organics measured in stack tests, and elemental carbon components of PM_{10} do not need to be included for BART modeling. The only other pollutant noted in EPA BART guidance is ammonia (NH_3). Though ammonia is not believed to be a significant contributor to visibility impairment in most cases in Wyoming, it could be important for sources with significant ammonia emissions – for example from some NO_x control systems. Sources that are expected to emit ammonia (in pre-or post-control configurations) should include ammonia emissions in their model input.

If quantitative baseline emissions data are unavailable and sources believe that the maximum 24-hour emission rates estimated by the Division (presented in the Subject-to-BART final report) are representative of baseline conditions for their facility, they may be used for baseline modeling. However, emissions of sulfate and ammonia (if applicable) should be included based on the best available test information or speciation factors from current literature.

3.2 Post-Control Modeling

All pollutants described above should be included for each post-control scenario. Post-control emissions (maximum 24-hour average) will generally be the baseline emissions multiplied by a control factor appropriate to the BART control. However, some proposed controls may simply increase the efficiency of existing controls; others may result in an increase in emissions of one pollutant while controlling another. These factors must all be considered in defining emission rates for post-control modeling. Any changes in stack parameters resulting from control application must also be included.

The required visibility assessment will include the effect of each proposed BART control. For example, if a source proposes to add a scrubber for SO_2 control, low NO_x burners for NO_x control, and a baghouse for particulate control, four sets of visibility results should be developed:

- Use of SO_2 control alone
- Use of NO_x control alone
- Use of particulate control alone
- Use of proposed combination of all three controls

All pollutants should be modeled in each CALPUFF model run, but the modeled emissions should reflect only the specific controls or combination of controls addressed in that run.

Additional modeling could be necessary in situations where a facility is comprised of more than one subject-to-BART source, and different BART controls are applicable to different sources. Excessive modeling to address multiple control combinations is not necessary; however, visibility modeling should quantify the effect of BART controls on all affected sources for each pollutant, and of all facility BART controls combined.

4.0 METEOROLOGICAL DATA

Wyoming AQD will provide MM5 meteorological data fields for years 2001, 2002, and 2003 that can be utilized as input to CALMET. The MM5 output will have 12 kilometer resolution and cover the full domain shown in Figure 1.

Mesoscale meteorological data (MM5) were developed and evaluated as part of the AQD's southwest Wyoming NO_2 increment analysis. Three years of MM5 data at 36 km resolution were used to initialize 12 km MM5 simulations. The 12km MM5 modeling used identical physics options to the original 36 km runs. CALMM5 was then used as a preprocessor to produce CALMET – ready MM5 data input files. Quality assurance was performed by comparing the original MM5 output on the 36km national RPO grid to the 12 km MM5 output and observations.

The CALMET model (version 5.53a, level 040716) should be used to prepare meteorological input for CALPUFF. The user may select a domain smaller than the MM5 domain for CALMET and CALPUFF modeling if desired. Figure 1 shows minimum domain areas for modeling of western and eastern Wyoming BART sources. Four kilometer resolution should be specified for CALMET output.

CALMET processing should use the AQD MM5 data, and appropriate surface, upper air, and precipitation data. Figure 2 shows the locations of surface and upper air stations within the MM5 model domain. The MM5 data are used as the initial guess wind field; this wind field is then adjusted by CALMET for terrain and land use to generate a step 1 wind field, and refined using surface and upper air data to create the final step 2 wind field.

Surface, upper air, and precipitation data can be obtained from the National Climatic Data Center. Land use and terrain data are available from the U.S. Geological Survey. Data can be formatted for use in CALMET with standard conversion and processing programs available with the CALMET/CALPUFF software.

Table 3 provides a listing of applicable CALMET input variables for BART meteorological processing. The table includes inputs that are specific to Wyoming BART modeling. Inputs not shown in Table 3 are not relevant to the present application, are dependent on the specific model domain of the user, use model default values, or are obvious from the context.

Table 3. CALMET Control File Inputs

Variable	Description	Value
	Input Group 1	
IBYR	Year	2001
		2002
		2003
IBTZ	Base time zone	7
IRTYPE	Run type	1
LCALGRD	Compute data fields for CALGRID	T
	Input Group 2	
PMAP	Map projection	LCC
DGRIDKM	Grid spacing (km)	4
NZ	Number of layers	10
ZFACE	Cell face heights (m)	0
		20
		40
		100
		140
		320
		580
		1020
		1480
		2220
		3500
	Input Group 4	
NOOBS	No observation Mode	0
	Input Group 5	
IWFCOD	Model selection variable	1
IFRADJ	Froude number adjustment	1
IKINE	Kinematic effects	0
IOBR	Use O'Brien procedure	0
ISLOPE	Slope flow effects	1
IEXTRP	Extrapolate surface wind observations	-4
ICALM	Extrapolate calm surface winds	0
BIAS	Biases for weights of surface and upper air stations	All 0
RMIN2	Minimum distance for extrapolation	-1
IPROG	Use gridded prognostic model output	14
ISTEPPG	Time Step (hours)	1
LVARY	Use varying radius of influence	F

Table 3. CALMET Control File Inputs (continued)

Variable	Description	Value
RMAX 1	Maximum radius of influence (km)	30
RMAX 2	Maximum radius of influence (km)	50
RMIN	Minimum radius of influence (km)	0.1
TERRAD	Radius of influence for terrain (km)	15
R1	Relative weighting of first guess wind field and observations (km)	5
R2	Relative weighting aloft (km)	25
IDIOPT 1	Surface temperature	0
IDIOPT 2	Upper air lapse rate	0
ZUPT	Lapse rate depth (m)	200
IDIOPT 3	Average wind components	0
IUPWND	Upper air station	-1
ZUPWND (1) ZUPWND (2)	Bottom and top of layer for domain scale winds (m)	1, 1000 1, 1000
IDIOPT4	Surface wind components	0
IDIOPT5	Upper air wind components	0
	Input Group 6	
IAVEZI	Spatial averaging	1
MNMDAV	Max search radius	1
HAFANG	Half angle for averaging (deg)	30
ILEVZI	Layer of winds in averaging	1
ZIMAX	Maximum overland mixing height (m)	3500
ITPROG	3D temperature source	1
IRAD	Interpolation type	1
TRADKM	Radius of influence – temperature (km)	500
NUMTS	Maximum number of Stations	5
IAVET	Spatial averaging of temperatures	1
NFLAGP	Precipitation interpolation	2

5.0 CALPUFF MODEL APPLICATION

The CALPUFF model (version 5.711a, level 040716) will be used to calculate pollutant concentrations at receptors in each Class I area. Application of CALPUFF should, in general, follow the guidance presented in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 report (EPA – 454/R98-019) and the EPA Regional Haze Regulations and Guidelines for BART Determinations (70 FR 39103).

Appropriate CALPUFF control file inputs are in Table 4. Note should be taken of the basis for several of the recommended CALPUFF inputs.

- Building downwash effects need not be included. Because of the transport distances involved and the fact that most sources have tall stacks, building downwash is unlikely to have a significant effect on model-predicted concentrations

- Puff splitting is not required. The additional computation time necessary for puff splitting is not justified for purposes of BART analyses.

- Hourly ozone files should be used to define background ozone concentration. Data are available from the following sites within the model domain.
  Rocky Mountain NP, CO
  Craters of the Moon NP, ID
  AIRS – Highland UT
  Mountain Thunder, WY
  Yellowstone NP, WY
  Centennial, WY
  Pinedale, WY

  The background ozone concentration shown in Table 4 is used only when hourly data are missing.

- A constant background ammonia concentration of 2.0 ppb is specified. This value is based upon monitoring data from nearby states and IWAQM guidance. Experience suggests that 2.0 ppb is conservative in that it is unlikely to significantly limit nitrate formation in the model computations.

- MESOPUFF II chemical transformation rates should be used.

- The species to be modeled should be the seven identified in CALPUFF: SO_2, SO_4, NO_x, HNO_3, NO_3, $PM_{2.5}$, and $PM_{10-2.5}$. If ammonia (NH_3) is emitted it should be added to the species list. In most cases, all pollutants modeled will also be emitted, except for HNO_3 and NO_3.

Concentration calculations should be made for receptors covering the areas of the Class I areas being addressed. Receptors in each Class I area will be those designated by the Federal Land Managers and available from the National Park Service website.

Table 4. CALPUFF Control File Inputs

Variable	Description	Value
	Input Group 1	
METRUN	Control parameter for running all periods in met file	1
IBYR	Starting year	2001 2002 2003
XBTZ	Base time zone	7
NSPEC	Number of chemical species modeled	7 (or 8)
NSE	Number of species emitted	5 (or 6)
METFM	Meteorological data format	1
	Input Group 2	
MGAUSS	Vertical distribution in near field	1
MCTADJ	Terrain adjustment method	3
MCTSG	Subgrid scale complex terrain	0
MSLUG	Elongated puffs	0
MTRANS	Transitional plume rise	1
MTIP	Stack tip downwash	1
MSHEAR	Vertical wind shear	0
MSPLIT	Puff splitting allowed?	0
MCHEM	Chemical mechanism	1
MAQCHEM	Aqueous phase transformation	0
MWET	Wet removal	1
MDRY	Dry deposition	1
MDISP	Dispersion Coefficients	3
MROUGH	Adjust sigma for roughness	0
MPARTL	Partial plume penetration of inversions	1
MPDF	PDF for convective conditions	0
	Input Group 4	
PMAP	Map projection	LCC
DGRIDKM	Grid spacing	4

Table 4. CALPUFF Control File Inputs (continued)

ZFACE	Cell face heights (m)	0
		20
		40
		100
		140
		320
		580
		1020
		1480
		2220
		3500
	Input Group 6	
NHILL	Number of terrain features Input Group 7	0
Dry Gas Depo	Chemical parameters for dry gas deposition	Defaults
	Input Group 8	
Dry Part. Depo	Size parameters for dry particle deposition SO_4, NO_3, PM25 PM10	 Defaults 6.5, 1.0
	Input Group 11	
MOZ	Ozone Input option	1
BCK03	Background ozone – all months (ppb)	44.0
BCKNH3	Background ammonia – all months (ppb)	2.0
	Input Group 12	
XMAXZI	Maximum mixing height (m)	3500
XMINZI	Minimum mixing height (m)	50

6.0 POST PROCESSING

Visibility impacts are calculated from the CALPUFF concentration results using CALPOST. CALPOST version 5.51, level 030709 should be used; the output from CALPOST will provide the highest deciview impact on each day from all receptors within each Class I area modeled.

For some CALPUFF applications such as deposition calculations, the POSTUTIL program is used prior to CALPOST. POSTUTIL is also used to repartition total nitrate by accounting for ammonia limiting. The ammonia limiting calculation in POSTUTIL should not be applied for Wyoming BART modeling. If you believe that ammonia limiting is appropriate for a specific BART analysis, justification should be discussed with the Division prior to its used.

Visibility calculations by CALPOST for BART purposes use Method 6. This method requires input of monthly relative humidity factors, f(RH), for each Class I area. The EPA guidance document provides appropriate data for each area. Table 5 lists monthly f(RH) factors to use for the Wyoming, Colorado, and South Dakota areas to be addressed in BART modeling. The factors shown in Table 5 include averages for the adjacent Class I areas, and are within 0.2 units of the Guideline table values for the individual Class I areas.

Natural background conditions as a reference for determination of the delta-dv change due to a source should be representative of the 20% best natural visibility days. EPA BART guidance provides the 20% best days deciview values for each Class I area on an annual basis, but does not provide species concentration data for the 20% best background conditions. These concentrations are needed for input to CALPOST.

Annual species concentrations corresponding to the 20% best days were calculated for each Class I area to be addressed, by scaling back the annual average concentrations given in Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (Table 2-1). A separate scaling factor was derived for each Class I area such that, when multiplied by the Guidance table annual concentrations, the 20% best days deciview value for that area would be calculated. The scaled aerosol concentrations were averaged for the Bridger and Fitzpatrick WAs, and for Wind Cave and Badlands NPs, because of their geographical proximity and similar annual background visibility. The 20% best days aerosol concentrations to be used for each month for Wyoming BART evaluations are listed in Table 6.

Table 7 is a list of inputs for CALPOST. These inputs should be used for all BART visibility calculations. Output from CALPOST should be configured to provide a ranked list of the highest delta-deciview values in each Class I area. The 98th percentile delta-deciview value and the number of values exceeding 0.5 can then be determined directly from the CALPOST output.

Table 5. Monthly f(RH) Factors for Class I Areas

Month	Wind Cave NP Badlands NP	Bridger WA Fitzpatrick WA	Mt. Zirkel WA
January	2.65	2.50	2.20
February	2.65	2.30	2.20
March	2.65	2.30	2.00
April	2.55	2.10	2.10
May	2.70	2.10	2.20
June	2.60	1.80	1.80
July	2.30	1.50	1.70
August	2.30	1.50	1.80
September	2.20	1.80	2.00
October	2.25	2.00	1.90
November	2.75	2.50	2.10
December	2.65	2.40	2.10

Table 6. Natural Background Concentrations of Aerosol Components for 20% Best Days for BART Analyses ($\mu g/m^3$)

Aerosol Component	Wind Cave NP Badlands NP	Fitzpatrick WA Bridger WA	Mt. Zirkel WA
Ammonium Sulfate	.047	.045	.046
Ammonium Nitrate	.040	.038	.038
Organic Carbon	.186	.178	.179
Elemental Carbon	.008	.008	.008
Soil	.198	.189	.190
Coarse Mass	1.191	1.136	1.141

Table 7. CALPOST Control File Inputs

Variable	Description	Value
	Input Group 1	
ASPEC	Species to Process	VISIB
ILAYER	Layer/deposition code	1
A,B	Scaling factors	0,0
LBACK	Add background concentrations?	F
BTZONE	Base time zone	7
LVSO4	Species to be included in extinction	T
LVNO3		T
LVOC		F
LVPMC		T
LVPMF		T
LVEC		F
LVBK	Include background?	T
SPECPMC	Species name for particulates	PM10
SPECPMF		PM25
EEPMC	Extinction efficiencies	0.6
EEPMF		1.0
EEPMCBK		0.6
EESO4		3.0
EENO3		3.0
EEOC		4.0
EESOIL		1.0
EEEC		10.0
MVISBK	Visibility calculation method	6
RHFAC	Monthly RH adjustment factors	Table 5
BKSO4	Background concentrations	Table 6
BKNO3		Table 6
BKPMC		Table 6
BK OC		Table 6
BKSOIL		Table 6
BKEC		Table 6
BEXTRAY	Extinction due to Rayleigh scattering	10.0

7.0 REPORTING

A report on the BART visibility analysis should be submitted that clearly compares impacts for post-control emissions to those for baseline emissions. Data for baseline and BART scenarios should include both the 98th percentile values and the number of days with delta-deciview values exceeding 0.5. Results should be given for each model year.

Table 8 is an example of a recommended format for presentation of model input and model results. The example is for baseline conditions; similar tables should be provided for each control scenario (SO_2, NO_x, and PM10) and for the combination of all BART controls. Your report tables need not follow the exact format shown in Table 8; but the same information should be provided in a concise and clear form. If additional scenarios were modeled or you wish to present supplemental information, they should be provided in an appendix or separate from the specified final results.

Table 8. Example Format for Presentation of Model Input and Results

Baseline Conditions Model Input Data

Source (Unit) Description And ID	SO_2 Emission Rate (lb/day)	NO_x Emission Rate (lb/day)	$PM_{2.5}$ Emission Rate (lb/day)	$PM_{10-2.5}$ Emission Rate (lb/day)	SO_4 Emission Rate (lb/day)	NH_3 Emission Rate (lb/day)	Location Easting UTM (m)	Location Northing UTM (m)	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Gas Temp (deg K)

Baseline Visibility Modeling Results

Name of Facility	Class I Area	2001		2002		2003	
		98th Percentile Value (dv)	No. of days exceeding 0.5 dv	98th Percentile Value (dv)	No. of days exceeding 0.5 dv	98th Percentile Value (dv)	No. of days exceeding 0.5 dv

PUBLIC UTILITY COMMISSION OF OREGON

UE 246

SIERRA CLUB EXHIBIT 108

Addendum to Naughton Unit 1 BART Report

TECHNICAL MEMORANDUM CH2MHILL

Addendum to Naughton Unit 1 BART Report

PREPARED FOR: Wyoming Division of Air Quality

PREPARED BY: CH2M HILL

COPIES: Bill Lawson/PacifiCorp

DATE: March 26, 2008

Introduction

In compliance with the Regional Haze Rule (40 Code of Federal Regulations [CFR] 51), the Wyoming Division of Air Quality (WDAQ) required PacifiCorp Energy to conduct a detailed Best Available Retrofit Technology (BART) review to analyze the effects to visibility in nearby Class I areas from plant emissions, both for baseline and for reasonable control technology scenarios. PacifiCorp submitted these evaluations to WDAQ in January 2007. A revised report was submitted in October 2007.

On January 3, 2008, PacifiCorp Energy personnel met with WDAQ staff to discuss the status of the BART reviews. At that time, the state requested that additional modeling scenarios for several of the PacifiCorp facilities be performed to aid in their BART review. This memorandum presents the economics analysis for two scenarios modeled, referred to as Scenario A and Scenario B and described as follows:

- Scenario A: PacifiCorp committed controls at permitted rates—low nitrogen oxide (NO_x) burners (LNBs) with over-fire air (OFA), wet flue gas desulfurization (FGD), ESP (electrostatic precipitator) with flue gas conditioning
- Scenario B: PacifiCorp committed controls and selective catalytic reduction (SCR) at permitted rates

The CALPUFF modeling system (v. 5.711a) was used for this analysis. All technical options and model triggers used in CALMET, CALPUFF, and CALPOST are consistent with those used for the previous BART analyses and described in the BART report submitted in October 2007.

Stack Parameters, Emissions Information, and Capital Cost

Table 1 summarizes the control equipment for Scenarios A and B as well as the current equipment installed at the plant. The overall capital cost of installing these options is also shown.

TABLE 1
Control Scenario Summary
Naughton Unit 1

	Equipment Type			Capital Cost
	NO_x	SO_2	PM_{10}	Million dollars
Baseline	Good combustion practice	Low sulfur coal	ESP	—
Scenario A	LNB with OFA	Wet FGD	ESP with gas conditioning	$100.8
Scenario B	LNB with OFA and SCR	Wet FGD	ESP with gas conditioning	$185.8

Emissions were modeled for the following pollutants:

- Sulfur dioxide (SO_2)
- NO_x
- Coarse particulate ($PM_{2.5}$<diameter<PM_{10})
- Fine particulate (diameter<$PM_{2.5}$)
- Sulfates

Table 2 shows stack parameters and emission rates that were used for the Naughton Unit 1 BART modeling and analysis.

TABLE 2
Calpuff Model Inputs
Naughton Unit 1

	BART Comparison[d]		
Model Input Data	Baseline	Scenario A [e]	Scenario B [f]
Hourly Heat Input (mmBtu/hour)	1,850	1,850	1,850
Sulfur Dioxide (SO_2) Stack Emissions (lb/hr)	2,220	278	278
Nitrogen Oxide (NO_x) Stack Emissions (lb/hr)	1,073	481	130
PM_{10} Stack Emissions (lb/hr)	104	77.7	77.7
Coarse Particulate ($PM_{2.5}$ <diameter< PM_{10}) Stack Emissions (lb/hr)[a]	44.5	33.4	33.4
Fine Particulate (diameter<$PM_{2.5}$) Stack Emissions (lb/hr)[b]	59.1	44.3	44.3
Sulfuric Acid (H_2SO_4) Stack Emissions (lb/hr)	34	17.0	29.3
Ammonium Sulfate [$(NH_4)_2SO_4$] Stack Emissions (lb/hr)	—	—	2.1
$(NH_4)HSO_4$ Stack Emissions (lb/hr)	—	—	3.7
H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr)	33.3	16.7	28.7
$(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr)	—	—	1.5
$(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)	—	—	3.1

TABLE 2
Calpuff Model Inputs
Naughton Unit 1

	BART Comparison[d]		
Model Input Data	**Baseline**	**Scenario A [e]**	**Scenario B [f]**
Total Sulfate (SO_4) (lb/hr)[c]	33.3	16.7	33.3
Stack Conditions			
Stack Height (meters)	61	145	145
Stack Exit Diameter (meters)	4.27	4.88	4.88
Stack Exit Temperature (Kelvin)	411	323	323
Stack Exit Velocity (meters per second)	28.1	18.1	18.1

NOTES:
[a] Based on AP-42, Table 1.1-6, the coarse particulates are counted as a percentage of PM_{10}. This equates to 43% ESP and 57% Baghouse. PM_{10} and $PM_{2.5}$ refer to particulate matter less than 10 and 2.5 micrometers, respectively, in aerodynamic diameter.
[b] Based on AP-42, Table 1.1-6, the fine particulates are counted as a percentage of PM_{10}. This equates to 57% ESP and 43% Baghouse.
[c] Total Sulfate (SO_4) (lb/hr) = H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr) + $(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr) + $(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)
[d] SO_2, NO_x, and PM rates are expressed in terms of permitted emission rates. Actual emissions will be less than the permitted rates.
[e] PacifiCorp Committed Controls @ permitted rates: LNB with OFA, Wet FGD, ESP with gas conditioning
[f] PacifiCorp Committed Controls and SCR @ permitted rates

Economic Analysis

In completing this additional analysis to supplement the previous BART study, technology alternatives were investigated and potential reductions in NO_x, SO_2, and PM_{10} emissions rates were identified.

A comparison of Scenarios A and B on the basis of costs, design control efficiencies, and tons of pollutant removed is summarized in Tables 3 through 5. Capital costs were provided by PacifiCorp. The complete economic analyses for these two scenarios are provided as Attachment 1.

TABLE 3
Scenario A Control Cost
Naughton Unit 1

	NO_x Control	SO_2 Control	PM_{10} Control	Scenario A
	LNB with OFA	Wet FGD	ESP with Gas Conditioning	Control Cost
Total Installed Capital Costs (million dollars)	$9.60	$89.40	$1.80	$100.80
Annualized First-Year Capital Costs	$0.91	$8.50	$0.17	$9.59
First Year Fixed & Variable O&M Costs (million dollars)	$0.08	$4.56	$0.08	$4.72
Total First Year Annualized Costs (million dollars) [a]	$0.99	$13.07	$0.25	$14.31
Power Consumption (MW)	—	2.4	0.05	2.45
Annual Power Usage (Million kWh/Yr)	—	18.92	0.39	19.32
Permitted Emission Rate (lb/mmBtu)	0.26	0.15	0.04	—
Additional Tons of Pollutant Removed per Year over Baseline	2,334	7,657	102	10,093
First Year Average Control Cost ($/Ton of Pollutant Removed)	426	1,707	2,440	1,418

NOTE:
[a] First year annualized costs include power consumption costs.

TABLE 4
Scenario B Control Cost
Naughton Unit 1

	NO_x Control	SO_2 Control	PM_{10} Control	Scenario B
	LNB with OFA & SCR	**Wet FGD**	**ESP with Gas Conditioning**	**Control Cost**
Total Installed Capital Costs (million dollars)	$94.60	$89.40	$1.80	$185.80
Annualized First-Year Capital Costs	$9.00	$8.50	$0.17	$17.68
First Year Fixed & Variable O&M Costs (million dollars)	$1.23	$4.68	$0.08	$5.87
Total First Year Annualized Costs (million dollars) [a]	$10.23	$13.07	$0.25	$23.55
Power Consumption (MW)	0.98	2.40	0.05	3.43
Annual Power Usage (Million kWh/Yr)	7.73	18.92	0.39	27.04
Permitted Emission Rate (lb/mmBtu)	0.07	0.15	0.04	—
Additional Tons of Pollutant Removed per Year over Baseline	3,719	7,657	102	11,479
First Year Average Control Cost ($/Ton of Pollutant Removed)	2,751	1,707	2,440	2,051

NOTE:
[a] First year annualized costs include power consumption costs.

TABLE 5
Incremental Control Costs, Scenario B compared to Scenario A
Naughton Unit 1

	NO_x Control	SO_2 Control	PM_{10} Control	Total
Incremental Installed Capital Costs (million dollars)	$85.00	0	0	$85.00
Incremental Annualized First-Year Capital Costs	$8.09	0	0	$8.09
Incremental First Year Fixed & Variable O&M Costs (million dollars)	$1.15	0	0	$1.15
Incremental First Year Annualized Costs (million dollars) [a]	$9.24	0	0	$9.24
Incremental Power Consumption (MW)	0.98	0	0	0.98
Incremental Annual Power Usage (Million kWh/Yr)	7.73	0	0	7.73
Incremental Improvement in Emission Rate (lb/mmBtu)	0.19	0	0	—
Incremental Tons of Pollutant Removed	1,386	0	0	1,386
Incremental First Year Average Control Cost ($/Ton of Pollutant Removed)	6,667	0	0	6,667

NOTE:
[a] Incremental first year annualized costs include power consumption costs.

Modeling Results and Least-Cost Envelope Analysis

CH2M HILL modeled Naughton Unit 1 for two post-control scenarios. The results determine the change in deciview based on each alternative at the Class I areas specific to the project. The Class I areas potentially affected are Bridger Wilderness and Fitzpatrick Wilderness for this unit.

Modeled Scenarios

Current operations (baseline) and two alternative control scenarios were modeled to cover the range of effectiveness for the combination of the individual NO_x, SO_2, and PM control technologies being evaluated. The modeled scenarios include the following:

- Baseline: Current operations with good combustion practice, low sulfur coal, and ESP
- Scenario A: LNB with OFA, Wet FGD, and ESP with gas conditioning
- Scenario B: Scenario A with SCR

Summary of Visibility Analysis

Tables 6 and 7 present a summary of the modeling period (2001–2003) results for each scenario and Class I area.

TABLE 6
Costs and Visibility Modeling Results as Applicable to Bridger Wilderness
Naughton Unit 1

Scenario	Controls	Total First Year Annualized Cost	Highest ΔdV	98th Percentile ΔdV	Maximum Annual Number of Days Above 0.5 dV
Baseline	Current Operations with FGD and ESP	—	4.649	1.797	48
Scenario A	Scenario A: PacifiCorp Committed Controls	$14,310,601	2.650	0.771	18
Scenario B	Scenario B: PacifiCorp Committed Controls and SCR	$23,548,376	1.512	0.446	5

TABLE 7
Costs and Visibility Modeling Results as Applicable to Fitzpatrick Wilderness
Naughton Unit 1

Scenario	Controls	Total First Year Annualized Cost	Highest ΔdV	98th Percentile ΔdV	Maximum Annual Number of Days Above 0.5 dV
Baseline	Current Operations with FGD and ESP	—	3.190	0.939	23
Scenario A	Scenario A: PacifiCorp Committed Controls	$14,310,601	1.334	0.305	4
Scenario B	Scenario B: PacifiCorp Committed Controls and SCR	$23,548,376	0.747	0.181	1

Results

Tables 8 and 9 present a summary of the costs and modeling results for each scenario and Class I area.

TABLE 8
Incremental Costs and Incremental Visibility Improvements Relative to Bridger Wilderness
Naughton Unit 1

Scenario Comparison	Controls	Incremental Annualized Cost (Million$)	Reduction in 98th Percentile maximum dV	Reduction in Number of Days Above 0.5 dV	Cost per dV Reduction (Million$/dV Reduced)	Cost per Day to Achieve a Reduction in the Days above 0.5 dV (Million$/Day)
Scenario A Compared to Baseline	Scenario A: PacifiCorp Committed Controls	$14.31	1.026	30	$13.95	$0.48
Scenario B Compared to Baseline	Scenario B: PacifiCorp Committed Controls and SCR	$23.55	1.351	43	$17.43	$0.55
Scenario B Compared To Scenario A	Addition of SCR	$9.24	0.325	13	$28.42	$0.71

TABLE 9
Incremental Costs and Incremental Visibility Improvements Relative to Fitzpatrick Wilderness
Naughton Unit 1

Scenario Comparison	Controls	Incremental Annualized Cost (Million$)	Reduction in 98th Percentile maximum dV	Reduction in Number of Days Above 0.5 dV	Cost per dV Reduction (Million$/dV Reduced)	Cost per Day to Achieve a Reduction in the Days above 0.5 dV (Million$/Day)
Scenario A Compared to Baseline	Scenario A: PacifiCorp Committed Controls	$14.31	0.634	19	$22.57	$0.75
Scenario B Compared to Baseline	Scenario B: PacifiCorp Committed Controls and SCR	$23.55	0.758	22	$31.07	$1.07
Scenario B Compared To Scenario A	Addition of SCR	$9.24	0.124	3	$74.50	$3.08

Least-Cost Envelope Analysis

The least-cost envelope graphs for Bridger Wilderness are shown in Figures 1 and 2 and for Fitzpatrick Wilderness are shown in Figures 3 and 4.

FIGURE 1

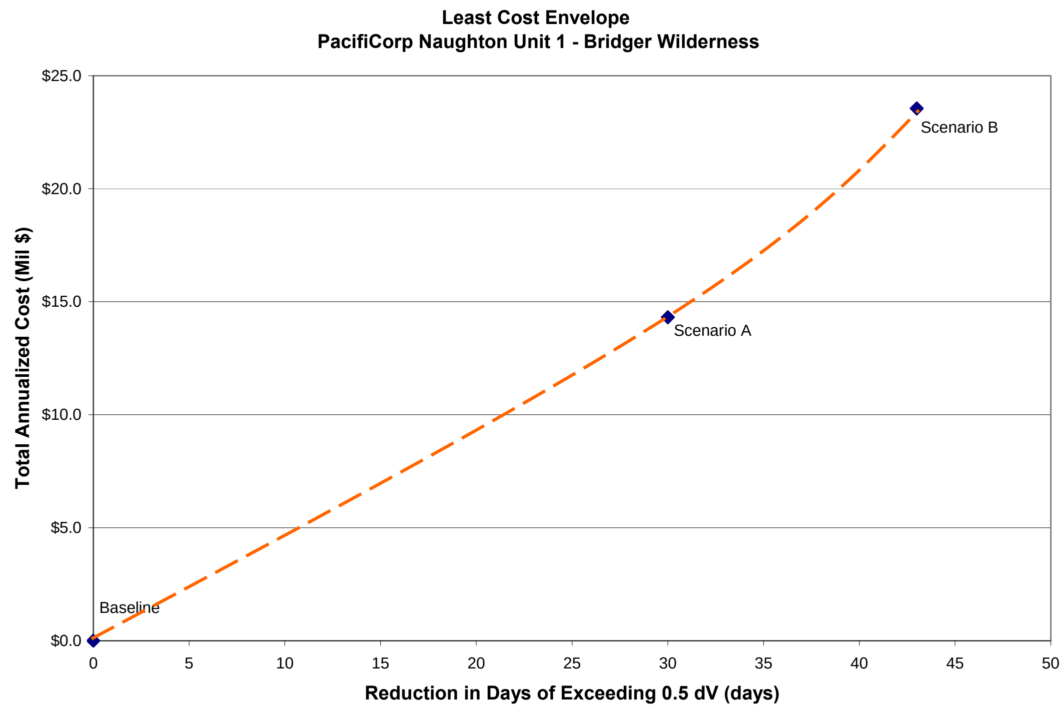


FIGURE 2

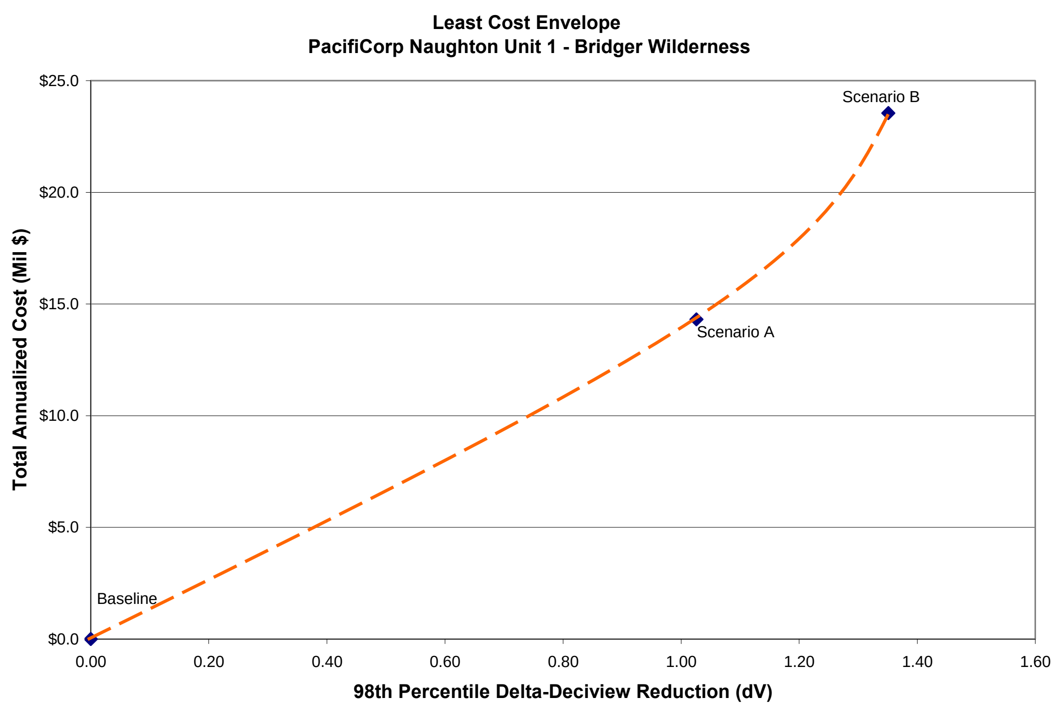


FIGURE 3

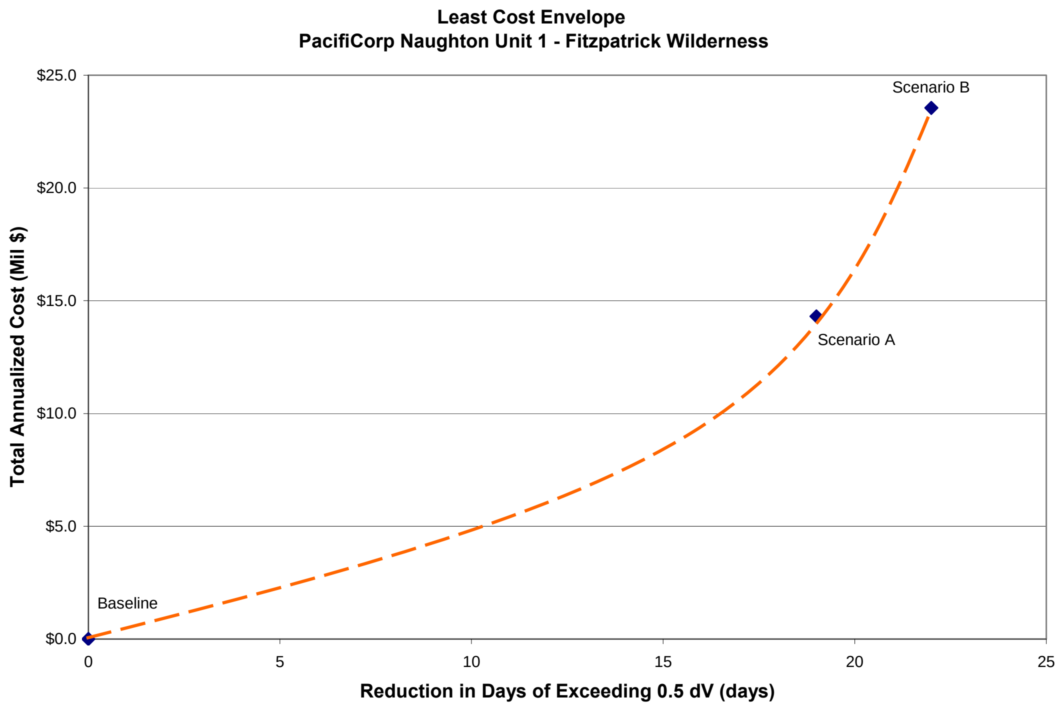
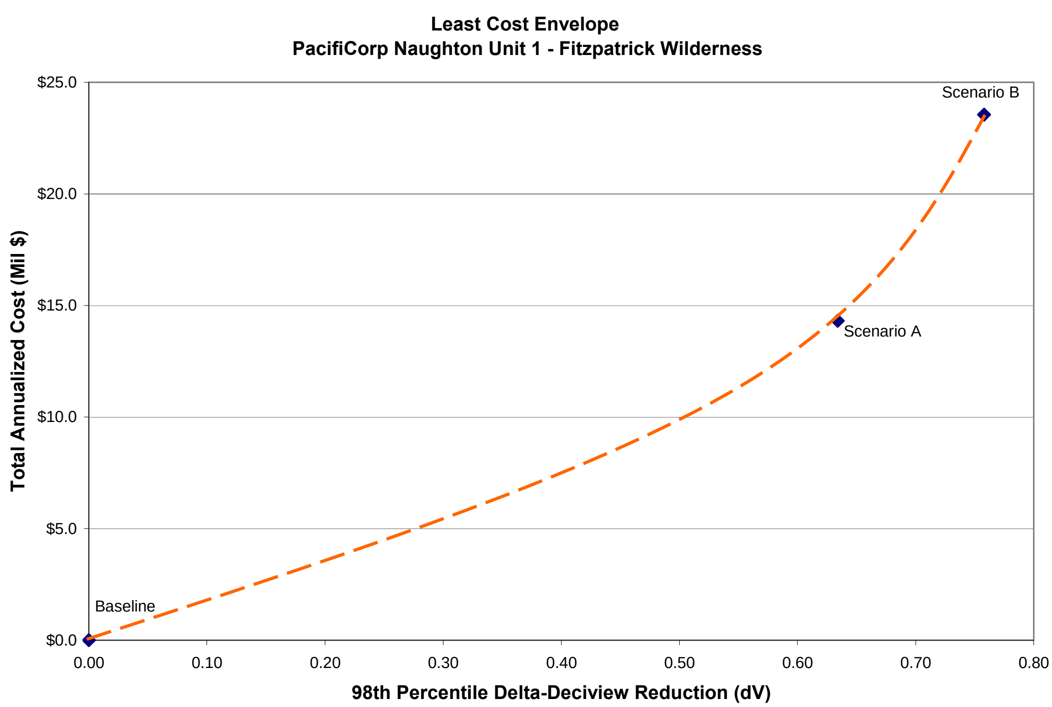


FIGURE 4



ATTACHMENT 1

Complete Economic Analyses for Scenarios A and B

ECONOMIC ANALYSIS SUMMARY - FIRST YEAR COSTS

Naughton 1

Boiler Design: Opposed Wall-Fired PC

TYPE OF EMISSIONS CONTROLS		NO_x Control				SO_2 Control			PM Control	Scenario A	Scenario B
Technology Label	**BASE**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**h**	**A+F**	**D+F**
	Current Operation	Low NO_x Burners with Overfire Air	Rotating Overfire Air	Low NO_x Burners with Overfire Air and Non-Selective Catalytic Reduction	Low NO_x Burners with Overfire Air and Selective Catalytic Reduction	Dry FGD	Dry FGD & Fabric Filter	Wet FGD	ESP W/ Gas Conditioning	LNB w/OFA, Wet Flue Gas Desulfurization and ESP w/gas conditioning	LNB w/OFA, SCR. Wet Flue Gas Desulfurization and ESP w/gas conditioning
ECONOMIC FACTORS											
Interest Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
Discount Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
Plant Economic Life (Years)	20	20	20	20	20	20	20	20	20	20	20
CAPITAL INVESTMENT											
Total Installed Capital Costs ($)	$0	$9,600,000	$9,068,746	$17,526,855	$94,600,000	$64,297,623	$108,995,970	$89,400,000	$1,800,000	$100,800,000	$185,800,000
FIRST YEAR DEBT SERVICE ($/Yr)	**$0**	**$913,227**	**$862,690**	**$1,667,292**	**$8,999,092**	**$6,116,493**	**$10,368,549**	**$8,504,427**	**$171,230**	**$9,588,885**	**$17,674,750**
FIRST YEAR FIXED O&M Costs ($/Yr)											
Operating Labor ($/Yr)	$0	$0	$0	$0	$0	$506,128	$506,128	$809,804	$0	$809,804	$809,804
Maintenance Material ($/Yr)	$0	$32,000	$48,000	$83,000	$132,000	$587,643	$632,660	$963,589	$0	$995,589	$1,095,589
Maintenance Labor ($/Yr)	$0	$48,000	$72,000	$124,500	$198,000	$391,762	$459,286	$642,393	$10,000	$700,393	$850,393
Administrative Labor ($/Yr)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FIRST YEAR FIXED O&M COST	**$0**	**$80,000**	**$120,000**	**$207,500**	**$330,000**	**$1,485,533**	**$1,598,074**	**$2,415,786**	**$10,000**	**$2,505,786**	**$2,755,786**
FIRST YEAR VARIABLE O&M Costs ($/Yr)											
Makeup Water Costs ($/Yr)	$0	$0	$0	$0	$0	$69,063	$69,063	$92,084	$0	$92,084	$92,084
Reagent Costs ($/Yr)	$0	$0	$0	$34,461	$314,596	$715,851	$781,547	$642,227	$48,132	$690,359	$1,004,955
SCR Catalyst / FF Bag Costs ($/Yr)	$0	$0	$0	$0	$201,000	$0	$89,960	$0	$0	$0	$201,000
Waste Disposal Costs ($/Yr)	$0	$0	$0	$0	$0	$309,360	$418,879	$467,697	$0	$467,697	$467,697
Electric Power Costs ($/Yr)	$0	$0	$559,764	$63,072	$386,316	$646,488	$1,048,572	$946,080	$19,710	$965,790	$1,352,106
TOTAL FIRST YEAR VARIABLE O&M Costs ($/Yr)	**$0**	**$0**	**$559,764**	**$97,533**	**$901,912**	**$1,740,762**	**$2,408,021**	**$2,148,088**	**$67,842**	**$2,215,930**	**$3,117,842**
SUMMARY OF FIRST YEAR COSTS ($/Yr)											
First Year Debt Service ($/Yr)	$0	$913,227	$862,690	$1,667,292	$8,999,092	$6,116,493	$10,368,549	$8,504,427	$171,230	$9,588,885	$17,674,750
First Year Fixed O&M Costs ($/Yr)	$0	$80,000	$120,000	$207,500	$330,000	$1,485,533	$1,598,074	$2,415,786	$10,000	$2,505,786	$2,755,786
First Year Variable O&M Costs ($/Yr)	$0	$0	$559,764	$97,533	$901,912	$1,740,762	$2,408,021	$2,148,088	$67,842	$2,215,930	$3,117,842
Total First Year Costs ($/Yr)	**$0**	**$993,227**	**$1,542,454**	**$1,972,324**	**$10,231,004**	**$9,342,788**	**$14,374,644**	**$13,068,302**	**$249,072**	**$14,310,601**	**$23,548,377**
CONTROL COST COMPARISONS											
NO_x Technology Comparison											
Additional NO_x Removed From Base Case (Tons/Yr)	0	2,334	2,334	2,698	3,719						
First Year Average Control Cost ($/Ton NO_x Removed)	$0	$426	$661	$731	$2,751						
Technology Case Comparison		A-BASE	B-A	C-A	D-A						
Incremental NO_x Removed (Tons/Yr)	0	2,334	0	365	1,386						
Incremental Control Cost ($/Ton NO_x Removed)	$0	$426	#DIV/0!	$2,685	$6,667						
SO_2 Technology Comparison	-1.5%					65.3%	87.3%	87.3%			
Additional SO_2 Removed From Base Case (Tons/Yr)	0					5,761	7,657	7,657			
First Year Average Control Cost ($/Ton SO_2 Removed)	$0					$1,622	$1,877	$1,707			
Technology Case Comparison						E-BASE	F-E	G-F			
Incremental SO_2 Removed (Tons/Yr)	0					5,761	1,896	0			
Incremental Control Cost ($/Ton SO_2 Removed)	$0					$1,622	$2,654	#DIV/0!			
PM Technology Comparison	0.0%										
Additional PM Removed From Base Case (Tons/Yr)	0								102		
First Year Average Control Cost ($/Ton PM Removed)	$0								$2,440		
Technology Case Comparison									h-base		
Incremental PM Removed (Tons/Yr)	0								102		
Incremental Control Cost ($/Ton PM Removed)	$0								$2,440		
SCENARIO A AND B COMPARISONS											
Additional NO_x, SO_2, & PM Removed From Base Case (Tons/Yr)	**0**									**10,093**	**11,47[illegible]**
First Year Average Control Cost Compared to Base Case ($/Ton Removed)	**$0**									**$1,418**	**$2,051**
Incremental Tons Removed - Scenario B vs Scenario A (Tons/Yr)	**0**										**1,386**
Incremental Control Costs - Scenario B vs Scenario A ($/Ton Removed)	**$0**										**$6,667**

Sierra Club/108
Fisher/1

INPUT CALCULATIONS

Naughton 1 — **Boiler Design:** **Tangentail-Fired PC**

PARAMETER	Current Operation	NO_x Control Technologies				SO_2 Control Technologies			PM Control Technologies	Scenario A	Scenario B
Control Technologies											
NO_x Emission Control System	None	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR					LNB w/OFA	LNB w/OFA & SCR
SO_2 Emission Control System	None					Dry FGD	Dry FGD	Wet FGD	N/A	Wet FGD	Wet FGD
PM Emission Control System	ESP					ESP	Fabric Filter	ESP	ESP W/ Gas Conditioning	ESP w/ Gas Conditioning	ESP w/ Gas Conditioning
General Plant Design and Operating Data											
Type of Unit	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC
Annual Power Plant Capacity Factor	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Annual Operation (Hours/Year)	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884
Net Power Output (kW)	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000
Net Plant Heat Rate (Btu/kW-Hr)	11,563	11,563	11,563	11,563	11,563	11,563	11,563	11,563	11,563	11,563	11,563
Boiler Heat Input, Measured by Fuel Input (MMBtu/Hr)	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850
Annual Heat Input, Measured by Fuel Input (MMBtu/Year)	14,586,031	14,586,031	14,586,031	14,586,031	14,586,031	14,586,031	14,586,031	14,586,031	14,586,031	14,586,031	14,586,031
Boiler Heat Input, Measured by CEM (MMBtu/Hr)	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850
Annual Heat Input, Measured by CEM (MMBtu/Year)	14,585,400	14,585,400	14,585,400	14,585,400	14,585,400	14,585,400	14,585,400	14,585,400	14,585,400	14,585,400	14,585,400
Plant Fuel Source											
Boiler Fuel Source	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine	Kemmerer Mine
Coal Heating Value (Btu/Lb)	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800	9,800
Coal Sulfur Content (wt.%)	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.580%	0.580%	0.58%	0.58%
Coal Ash Content (wt.%)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Coal Flow Rate (Lb/Hr)	188,784	188,784	188,784	188,784	188,784	188,784	188,784	188,784	188,784	188,784	188,784
Coal Consumed (Ton/Yr)	744,185	744,185	744,185	744,185	744,185	744,185	744,185	744,185	744,185	744,185	744,185
Nitrogen Oxide Emissions											
NO_x Emission Rate (Lb/MMBtu)	0.58	0.26	0.26	0.21	0.07					0.26	0.07
NO_x Emission Rate (Lb/Hr)	1,073	481	481	389	130					481	130
NO_x Emission Rate (Lb Moles/Hr)	35.75	16.03	16.03	12.95	4.32					16.03	4.32
NO_x Emission Rate (Ton/Yr)	4,230	1,896	1,896	1,531	510					1,896	510
Add'l NO_x Removed from Current Operations (Lb/Hr)	0	592	592	685	944					592	944
Add'l NO_x Removed from Current Operations (Ton/Yr)	0	2,334	2,334	2,698	3,719					2,334	3,719
Sulfur Dioxide Emissions											
Uncontrolled SO_2 (Lb/MMBtu)	1.18					1.18	1.18	1.18		1.18	1.18
Uncontrolled SO_2 (Lb/Hr)	2,188					2,188	2,188	2,188		2,188	2,188
Uncontrolled SO_2 (Lb Moles/Hr)	34.15					34.15	34.15	34.15		34.15	34.15
Uncontrolled SO_2 (Tons/Yr)	8,624					8,624	8,624	8,624		8,624	8,624
Controlled SO_2 Emission Rate (Lb/MMBtu)	1.20					0.41	0.15	0.15		0.15	0.15
SO_2 Removal Efficiency (%)	-1.5%					65.3%	87.3%	87.3%		87.3%	87.3%
Controlled SO_2 Emissions (Lb/Hr)	2,220					759	278	278		278	278
Controlled SO_2 Emissions (Ton/Yr)	8,751					2,990	1,094	1,094		1,094	1,094
SO_2 Removed (Lb/Hr)	-32					1,429	1,910	1,910		1,910	1,910
SO_2 Removed (Ton/Yr)	-128					5,634	7,530	7,530		7,530	7,530
Add'l SO_2 Removed from Current Operations (Lb/Hr)	0					1,462	1,943	1,943		1,943	1,943
Add'l SO_2 Removed from Current Operations (Ton/Yr)	0					5,761	7,657	7,657		7,657	7,657
Particulate Matter Emissions											
Uncontrolled Fly Ash (Lb/Hr)	7,551					7,551	7,551	7,551	7,551	7,551	7,551
Uncontrolled Fly Ash (Lb/MMBtu)	4.082					4.082	4.082	4.082	4.082	4.082	4.082
Uncontrolled Fly Ash (Tons/Yr)	29,767					29,767	29,767	29,767	29,767	29,767	29,767
Controlled Fly Ash Emission Rate (Lb/MMBtu)	0.056					0.056	0.015	0.056	0.042	0.042	0.042
Controlled Fly Ash Removal Efficiency (%)	98.6%					98.6%	99.6%	98.6%	99.0%	99.0%	99.0%
Controlled Fly Ash Emissions (Lb/Hr)	104					104	28	104	78	78	78
Controlled Fly Ash Emissions (Ton/Yr)	408					408	109	408	306	306	306
Fly Ash Removed (Lb/Hr)	7,448					7,448	7,524	7,448	7,474	7,474	7,474
Fly Ash Removed (Ton/Yr)	29,359					29,359	29,658	29,359	29,461	29,461	29,461
Add'l Ash Removed from Current Operation (Lb/Hr)	0					0	76	0	26	26	26
Add'l Ash Removed from Current Operation (Ton/Yr)	0					0	299	0	102	102	102
Economic Factors											
Interest Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
Discount Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
Plant Economic Life (Years)	20	20	20	20	20	20	20	20	20	20	20

INPUT CALCULATIONS

Naughton 1 | **Boiler Design:** Tangentail-Fired PC

PARAMETER	Current Operation	NO_x Control Technologies				SO_2 Control Technologies			PM Control Technologies	Scenario A	Scenario B
Control Technologies											
NO_x Emission Control System	None	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR					LNB w/OFA	LNB w/OFA & SCR
SO_2 Emission Control System	None					Dry FGD	Dry FGD	Wet FGD	N/A	Wet FGD	Wet FGD
PM Emission Control System	ESP					ESP	Fabric Filter	ESP	ESP W/ Gas Conditioning	ESP w/ Gas Conditioning	ESP w/ Gas Conditioning
Installed Capital Costs											
NO_x Emission Control System ($2006)		$9,600,000	$9,068,746	$17,526,855	$94,600,000					$9,600,000	$94,600,000
SO_2 Emission Control System ($2006)						$64,297,623	$108,995,970	$89,400,000	$0	$89,400,000	$89,400,000
PM Emission Control System ($2006)						$0	$0	$0	$1,800,000	$1,800,000	$1,800,000
Total Emission Control System Capital Costs ($2006)		$9,600,000	$9,068,746	$17,526,855	$94,600,000	$64,297,623	$108,995,970	$89,400,000	$1,800,000	$100,800,000	$185,800,000
NO_x Emission Control System ($/kW)		$60	$57	$110	$591					$60	$591
SO_2 Emission Control System ($/kW)						$402	$681	$559	$11	$559	$559
PM Emission Control System ($/kW)										$11	$11
Total Emission Control Capital Costs ($/kW)		$60	$57	$110	$591	$402	$681	$559	$11	$630	$1,161
Fixed Operating & Maintenance Costs											
Operating Labor ($)		$0	$0	$0	$0	$506,128	$506,128	$809,804	$0	$809,804	$809,804
Maintenance Material ($)		$32,000	$48,000	$83,000	$132,000	$587,643	$632,660	$963,589	$0	$995,589	$1,095,589
Maintenance Labor ($)		$48,000	$72,000	$124,500	$198,000	$391,762	$459,286	$642,393	$10,000	$700,393	$850,393
Administrative Labor ($)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total 1st Fixed Year O&M Cost ($)		$80,000	$120,000	$207,500	$330,000	$1,485,533	$1,598,074	$2,415,786	$10,000	$2,505,786	$2,755,786
Annual Fixed O&M Cost Escalation Rate (%)		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Fixed O&M Cost ($/Yr)		$94,840	$142,260	$245,992	$391,216	$1,761,104	$1,894,521	$2,863,921	$11,855	$2,970,617	$3,266,992
Variable Operating & Maintenance Costs											
Water Cost											
Makeup Water Usage (gpm)		0	0	0	0	120	120	160	0	160	160
Unit Price ($/1000 gallons)		$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22
First Year Water Cost ($)		$0	$0	$0	$0	$69,063	$69,063	$92,084	$0	$92,084	$92,084
Annual Water Cost Escalation Rate (%)		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Water Costs ($/Yr)		$0	$0	$0	$0	$81,874	$81,874	$109,166	$0	$109,166	$109,166
Reagent Cost											
Type of Reagent		None	None	Urea	Anhydrous NH3	Lime	Lime	Lime	Elemental Sulfur	Lime & Elemental Sulfur	Lime & Anhydrous NH_3 & Elemental Sulfur
Unit Cost ($/Ton)		$0.00		$370.00	$400.00	$91.25	$91.25	$91.25	$370.00		
Unit Cost ($/Lb)		$0.000		$0.185	$0.200	$0.046	$0.046	$0.046	$0.185		
Molar Stoichiometry		0.00		0.45	1.00	1.40	1.15	1.05	0.00		
Reagent Purity (Wt.%)		100%		100%	100%	90%	90%	100%	100%		
Reagent Usage (Lb/Hr)				24	200	1,990	2,173	1,785	33		
First Year Reagent Cost ($)		$0		$34,461	$314,596	$715,851	$781,547	$642,227	$48,132	$690,359	$1,004,955
Annual Reagent Cost Escalation Rate (%)		2.00%		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Reagent Costs ($/Yr)				$40,853	$372,954	$848,644	$926,526	$761,363	$57,060	$818,423	$1,191,377
SCR Catalyst / Fabric Filter Bag Replacement Cost											
Material Replaced					SCR Catalyst		Bags			0	& SCR Catalyst
Annual SCR Catalyst (m3) / No. FF Bags					67		865				
SCR Catalyst ($/m3) / Bag Cost ($/ea.)					$3,000		$104				
First Year SCR Catalyst / Bag Replacement Cost ($)					$201,000		$89,960			$0	$201,000
Annual SCR Catalyst / Bag Cost Escalation Rate (%)					2.00%		2.00%			0%	2.00%
Levelized Catalyst/Fabric Fitler Bag Costs ($/Yr)					$238,286		$106,648			$0	$238,286
FGD Waste Disposal Cost											
FGD Solid Waste Disposal Rate, Dry (Lb/Hr)						3,226	4,367	4,876		4,876	4,876
FGD Waste Disposal Unit Cost ($/Dry Ton)						$24.33	$24.33	$24.33		$24.33	$24.33
First Year FGD Waste Disposal Cost ($)						$309,360	$418,879	$467,697		$467,697	$467,697
Annual Waste Disposal Cost Esc. Rate (%)						2.00%	2.00%	2.00%		2.00%	2.00%
Levelized Waste Disposal Costs ($/Yr)						$366,747	$496,582	$554,456		$554,456	$554,456
Auxiliary Power Cost											
Auxiliary Power Requirement (MW)		0.00	1.42	0.16	0.98	1.64	2.66	2.40	0.05	2.45	3.43
Auxiliary Power Requirement (% of Plant Output)		0.00%	0.89%	0.10%	0.61%	1.03%	1.66%	1.50%	0.03%	1.53%	2.14%
Auxilliary Power Useage (MWh)		0	11,195	1,261	7,726	12,930	20,971	18,922	394	19,316	27,042
Unit Cost ($2006/MW-Hr)		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
First Year Auxiliary Power Cost ($)		$0	$559,764	$63,072	$386,316	$646,488	$1,048,572	$946,080	$19,710	$965,790	$1,352,106
Annual Power Cost Escalation Rate (%)		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Auxilliary Power Costs ($/Yr)		$0	$663,602	$74,772	$457,979	$766,413	$1,243,085	$1,121,581	$23,366	$1,144,947	$1,602,926

PUBLIC UTILITY COMMISSION OF OREGON

UE 246

SIERRA CLUB EXHIBIT 109

CONFIDENTIAL

APR#: 10003745

Naughton Unit 1 FGD

2009

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PUBLIC UTILITY COMMISSION OF OREGON

UE 246

SIERRA CLUB EXHIBIT 110

CONFIDENTIAL
APR#: 10003746
Naughton Unit 2 FGD
2009

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PUBLIC UTILITY COMMISSION OF OREGON

UE 246

SIERRA CLUB EXHIBIT 111

Wyoming DEQ Air Quality Division
BART Analysis for Naughton
AP-6042

DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

BART Application Analysis
AP-6042

May 28, 2009

NAME OF FIRM:	PacifiCorp
NAME OF FACILITY:	Naughton Power Plant
FACILITY LOCATION:	Sections 32 and 33, T21N, R116W UTM Zone: 12 Easting: 533,450 m, Northing: 4,622,700 m Lincoln County, Wyoming
TYPE OF OPERATION:	Coal-Fired Electric Generating Plant
RESPONSIBLE OFFICIAL:	Angie Skinner, Plant Managing Director
MAILING ADDRESS:	P.O. Box 191 Kemmerer, WY 83101
TELEPHONE NUMBER:	(307) 828-4211
REVIEWERS:	Cole Anderson, Air Quality Engineer James (Josh) Nall, Air Quality Modeler

PURPOSE OF APPLICATION:

Sections 169A and 169B of the 1990 Clean Air Act Amendments require states to improve visibility at Class I areas. On July 1, 1999, EPA first published the Regional Haze Rule, which provided specific details regarding the overall program requirements to improve visibility. The goal of the regional haze program is to achieve natural conditions by 2064.

Section 308 of the Regional Haze Rule (40 CFR part 51) includes discussion on control strategies for improving visibility impairment. One of these strategies is the requirement under 40 CFR 51.308(e) for certain stationary sources to install Best Available Retrofit Technology (BART) to reduce emissions of three (3) visibility impairing pollutants, nitrogen oxides (NO_x), particulate matter (PM), and sulfur dioxide (SO_2). EPA published Appendix Y to part 51 - *Guidelines for BART Determinations Under the Regional Haze Rule* in the July 6, 2005 Federal Register to provide guidance to regulatory authorities for making BART determinations. Chapter 6, Section 9, Best Available Retrofit Technology was adopted into the Wyoming Air Quality Standards and Regulations (WAQSR) and became effective on December 5, 2006. The Wyoming Department of Environmental Quality, Air Quality Division (Division) will determine BART for NO_x and PM_{10} for each source subject to BART and include each determination in the §308 Wyoming Regional Haze State Implementation Plan (SIP).

Section 309 of the Regional Haze Rule (40 CFR part 51), *Requirements related to the Grand Canyon Visibility Transport Commission*, provides states that are included within the Transport Region addressed by the Grand Canyon Visibility Transport Commission (i.e., Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming) an alternative to the requirements established in 40 CFR 51.308. This alternative control strategy for improving visibility contains special provisions for addressing SO_2 emissions, which include a market trading program and a provision for a series of SO_2 milestones. Wyoming submitted a §309 Regional Haze SIP to EPA on December 29, 2003. As of the date of this analysis, EPA has not taken action on the SIP. National litigation issues related to the Regional Haze Rule, including BART, required states to submit revisions. On November 21, 2008, the State of Wyoming submitted revisions to the 2003 §309 Regional Haze SIP submittal. Sources that are subject to BART are required to address SO_2 emissions as part of the BART analysis even though the control strategy has been identified in the Wyoming §309 Regional Haze SIP.

On February 12, 2007, in accordance with the requirements of WAQSR Chapter 6 Section 9(e)(i), PacifiCorp submitted three (3) BART applications, one for each existing coal-fired boiler at the Naughton Power Plant. A map showing the location of PacifiCorp's Naughton Power Plant is attached as Appendix A.

October 16, 2007, PacifiCorp submitted updated applications for each of the three (3) Naughton units subject to BART. Additional modeling performed after the February 12, 2007 submittal and revised visibility control effectiveness calculations were included.

December 5, 2007, PacifiCorp submitted revised applications incorporating changes to the post-processing of the visibility model runs for each of the three (3) Naughton units.

March 31, 2008, PacifiCorp submitted addendums to each of the BART applications for Naughton Units 1-3. Revised cost estimates and updated visibility modeling for two (2) NO_x control scenarios were included in the addendums.

February 2, 2009, PacifiCorp submitted additional information addressing presumptive BART emission rates for the three (3) coal-fired boilers at the Naughton Power Plant. The information addresses the type of coal fired in the three boilers and its impact on NO_x emissions.

BART ELIGIBILITY DETERMINATION:

In August of 2005 the Wyoming Air Quality Division began an internal review of sources that could be subject to BART. This initial effort followed the methods prescribed in 40 CFR part 51, Appendix Y: *Guidelines for BART Determinations Under the Regional Haze Rule* to identify sources and facilities. The rule requires that States identify and list BART-eligible sources, which are sources that fall within the 26 source categories, have emission units which were in existence on August 7, 1977 but not in operation before August 7, 1962 and have the potential to emit more than 250 tons per year (tpy) of any visibility impairing pollutant when emissions are aggregated from all eligible emission units at a stationary source. Fifty-one (51) sources at fourteen (14) facilities were identified that could be subject to BART in Wyoming.

The next step for the Division was to identify BART-eligible sources that may emit any air pollutant which may reasonably be anticipated to cause or contribute to impairment of Class I area visibility. Three pollutants are identified by 40 CFR part 51, Appendix Y as visibility impairing pollutants. They are sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM). Particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) was used as an indicator of PM. In order to determine visibility impairment of each source, a screening analysis was performed using CALPUFF. Sources that emitted over 40 tons of SO_2 or NO_x or 15 tons of PM_{10} were included in the screening analysis. Using three years of meteorological data, the screening analysis calculated visibility impacts from sources at nearby Class I areas. Sources whose modeled 98th percentile 24-hour impact or 8th highest modeled impact, by year, was equal to or greater than 0.5 deciviews (dv) above natural background conditions (Δdv) were determined to be subject to BART. For additional information on the Division's screening analysis see the Visibility Improvement Determination: Screening Modeling section of this analysis. The three existing coal-fired boilers at PacifiCorp's Naughton Power Plant were determined to be subject to BART. PacifiCorp was notified in a letter dated June 14, 2006 of the Division's finding.

DESCRIPTION OF BART ELIGIBLE SOURCES:

PacifiCorp's Naughton Power Plant is comprised of three (3) pulverized coal-fired units with a total net generating capacity of 700 megawatts (MW). Naughton Unit 1 generates a nominal 160 MW and commenced operation in 1963. The boiler on Unit 1 is tangential fired and was manufactured by Combustion Engineering (now ALSTOM). The unit uses good combustion practices (GCP) to control NO_x emissions. It was originally constructed with a Research Cottrell mechanical dust collector to control particulate matter emissions, and in 1974 a Lodge Cottrell electrostatic precipitator (ESP) was added to further reduce particulate emissions. SO_2 emissions are controlled using low sulfur coal to maintain emissions below 1.2 lb per million British thermal units (MMBtu). Naughton Unit 2 generates a nominal 210 MW and commenced operation in 1968. The boiler on Unit 2 is also tangential fired and was manufactured by ALSTOM. The unit uses GCP to control NO_x emissions. It was originally constructed with a United Conveyor mechanical dust collector to control particulate matter emissions and in 1976 a Lodge Cottrell ESP was added to further reduce particulate emissions. SO_2 emissions are controlled using low sulfur coal to maintain emissions below 1.2 lb/MMBtu. Naughton Unit 3 generates a nominal 330 MW and commenced operation in 1971. The boiler on Unit 3 is tangential fired and was manufactured by ALSTOM. The unit was retrofitted with ALSTOM LCCFS II low NO_x burners (LNB) in 1999. Particulate emissions are controlled using a Buell weighted wire ESP and flue gas conditioning (FGC). SO_2 emissions are controlled using low sulfur coal and a UOP LLC two-tower sodium based wet flue gas desulfurization (WFGD) system that was installed in 1997.

PacifiCorp Naughton Plant
AP-6042 BART Application Analysis
Page 4

Table 1: Naughton Units 1-3 Pre-2005 Emission Limits [a]

Source	Firing Rate (MMBtu/hour)	Existing Controls	NO_x (lb/MMBtu)	SO_2 (lb/MMBtu)	PM/PM_{10} (lb/MMBtu) [c][d]
Unit 1	1,850	GCP, ESP	0.75 (3-hour block) 0.58 (annual) [b]	1.2 (2-hour block)	0.24
Unit 2	2,400	GCP, ESP	0.75 (3-hour block) 0.54 (annual) [b]	1.2 (2-hour block)	0.23
Unit 3	3,700	LNB, ESP, FGC, WFGD	0.75 (3-hour block) 0.49 (annual) [b]	0.5 (2-hour block)	0.21

[a] Emissions taken from Operating Permit 31-121.
[b] Limit established through the 40 CFR part 76 (Acid Rain Program).
[c] Based on the equation: $0.8963/I^{0.1743}$ lb/MMBtu of heat input where I=boiler heat input in MMBtu/hr.
[d] Averaging period is 1 hour as determined by the appropriate test method.

PacifiCorp recently received an Air Quality permit to modify the three Naughton units. Units 1 and 2 will be equipped with new state-of-the-art low NO_x systems with advanced overfire air (OFA) and flue gas conditioning systems to help improve the particulate removal efficiency of the existing ESPs on each of the units. New wet flue gas desulfurization systems will be installed on Naughton Units 1 and 2. The existing ESP on Naughton Unit 3 will be replaced with a new full-scale fabric filter (FF) at which time the existing FGC system will be removed. Table 2 lists the new emission limits for the Naughton units. They become effective after the corresponding controls are installed and the applicable initial performance tests are completed.

Table 2: Naughton Units 1-3 Proposed Emission Limits [a]

Source	Permitted Controls	NO_x	SO_2	PM/PM_{10}
Unit 1	New LNB with advanced OFA, FGC, ESP, WFGD	0.75 lb/MMBtu (3-hr rolling) 0.26 lb/MMBtu (12-month rolling) 481 lb/hr (12-month rolling)	0.15 lb/MMBtu (12-month rolling) 1.2 lb/MMBtu (2-hr rolling) 833 lb/hr (3-hr block)	0.042 lb/MMBtu [b] 78 lb/hr [b] 340 tpy [b]
Unit 2	New LNB with advanced OFA, FGC, ESP, WFGD	0.75 lb/MMBtu (3-hr rolling) 0.26 lb/MMBtu (12-month rolling) 624 lb/hr (12-month rolling)	0.15 lb/MMBtu (12-month rolling) 1.2 lb/MMBtu (2-hr rolling) 1,080 lb/hr (3-hr block)	0.054 lb/MMBtu [b] 130 lb/hr [b] 568 tpy [b]
Unit 3	Existing LNB with OFA, FF, WFGD	0.75 lb/MMBtu (3-hr rolling) 0.45 lb/MMBtu (12-month rolling) 1,665 lb/hr (12-month rolling)	0.5 lb/MMBtu (2-hour rolling) 1,850 lb/hr (3-hr block)	0.015 lb/MMBtu (24-hour block) 56 lb/hr (24-hour block) 243 tpy

[a] Emissions limits taken from recent New Source Review construction permit for Naughton Units 1-3.
[b] Averaging period is 1 hour as determined by 40 CFR 60.46 and EPA Reference Test Methods 1-4 and 5.

A construction schedule for installing new LNB with advanced OFA, FGC, and WFGD on Naughton Units 1 and 2, and a full-scale FF on Unit 3 was submitted in the permit application. The installation of FGC on Units 1 and 2 was originally proposed to occur in 2008, however since the authorization to install the controls is dependent on the issuance of the pending Air Quality permit, installation will be delayed until permit issuance. A construction summary is provided in Table 3.

Table 3: Upgrades to Naughton Units 1-3

Source	NO_x Control Equipment, Installation year	SO_2 Control Equipment, Installation year	PM/PM_{10} Control Equipment, Installation year
Unit 1	New LNB with OFA, 2012	WFGD, 2012	FGC, 2009 [a]
Unit 2	New LNB with OFA, 2011	WFGD, 2011	FGC, 2009 [a]
Unit 3	LNB with OFA, Existing	WFGD, Existing	FF, 2014

[a] PacifiCorp originally proposed installing FGC on Units 1 and 2 in 2008, however the installation date has been moved to the date of permit issuance.

CHAPTER 6, SECTION 9 – BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

A BART determination is an emission limit based on the application of a continuous emission reduction technology for each visibility impairing pollutant emitted by a source. It is "…established, on a case-by-case basis, taking into consideration (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any pollution equipment in use or in existence at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."[1] A BART analysis is a comprehensive evaluation of potential retrofit technologies with respect to the five criteria above. At the conclusion of the BART analysis, a technology and corresponding emission limit is chosen for each pollutant for each unit subject to BART.

Visibility control options presented in the application for each source were reviewed using the methodology prescribed in 40 CFR 51 Appendix Y, as required in WAQSR Chapter 6 Section 9(c)(i). This methodology is comprised of five basic steps:

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

[1] 40 CFR Part 51 Appendix Y: Guidelines for BART Determinations under the Regional Haze Rule (70 Federal Register 39163).
[2] Footnote 12 of 40 CFR 51 Appendix Y defines the intended use of 'all' by stating "…you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies."

The Division acknowledges that BART is intended to identify retrofit technology for existing sources and is not the same as a top down analysis required for new sources under the Prevention of Significant Deterioration (PSD) rules known as Best Available Control Technology (BACT). Although BART is not the same as BACT, it is possible that BART may be equivalent to BACT on a case-by-case basis. The Division applied all five steps to each visibility impairing pollutant emitted from each coal-fired boiler (Units 1-3) at the Naughton Power Plant thereby conducting a comprehensive BART analysis for NO_x, SO_2 and PM/PM_{10}.

PRESUMPTIVE LIMITS FOR SO_2 AND NO_X FROM UTILITY BOILERS

EPA conducted detailed analyses of available retrofit technology to control NO_x and SO_2 emissions from coal-fired power plants. These analyses considered unit size, fuel type, cost effectiveness, and existing controls to determine reasonable control levels based on the application of an emissions reduction technology.

EPA's presumptive BART SO_2 limits analysis considered coal-fired units with existing SO_2 controls and units without existing control. Four key elements of the analysis were: "…(1) identification of all potentially BART-eligible EGUs [electric generating units], and (2) technical analyses and industry research to determine applicable and appropriate SO_2 control options, (3) economic analysis to determine cost effectiveness for each potentially BART-eligible EGU, and (4) evaluation of historical emissions and forecast emission reduction for each potentially BART-eligible EGU."[3] 491 BART-eligible coal-fired units were identified and included in the presumptive BART analysis for SO_2. Based on removal efficiencies of 90% for spray dry lime dry flue gas desulfurization systems and 95% for limestone forced oxidation wet flue gas desulfurization systems, EPA calculated projected SO_2 emission reductions and cost effectiveness for each unit. Based on the results of this analysis, EPA concluded that the majority of identified BART-eligible units greater than 200 MW without existing SO_2 control can meet the presumptive limits at a cost of \$400 to \$2,000 per ton of SO_2 removed.

A presumptive BART NO_x limits analysis was performed using the same 491 BART-eligible coal-fired units identified in the SO_2 presumptive BART analysis. EPA considered the same four key elements and established presumptive NO_x limits for EGUs based coal type and boiler configuration. For all boiler types, except cyclone, presumptive limits were based on combustion control technology (e.g., low NO_x burners and overfire air). Presumptive NO_x limits for cyclone boilers are based on the installation of SCR, a post combustion add-on control. EPA acknowledged that approximately 25% of the reviewed units could not meet the proposed limits based on current combustion control technology, but that nearly all the units could meet the presumptive limits using advanced combustion control technology, such as rotating opposed fire air. National average cost effectiveness values for presumptive NO_x limits ranged from \$281 to \$1,296 per ton removed.

Based on the results of the analyses for presumptive NO_x and SO_2 limits, EPA established presumptive limits for EGUs greater than 200 MW operating without NO_x post combustion controls or existing SO_2 controls located at facilities with a generating capacity greater than 750 MW. 40 CFR part 51 Appendix Y states that the presumptive SO_2 level for an uncontrolled unit is either 95% control or 0.15 lb/MMBtu. Presumptive NO_x levels for uncontrolled units are listed in Table 1 of Appendix Y and classified by the boiler burner configuration (unit type) and coal type. NO_x emission values range from 0.62 lb/MMBtu down to 0.15 lb/MMBtu. While Appendix Y establishes presumptive SO_2 limits and says that states

[3] 40 CFR Part 51 Appendix Y: Guidelines for BART Determinations under the Regional Haze Rule (70 Federal Register 39133).

should require presumptive NO_x, it also clearly gives states discretion to "…determine that an alternative [BART] control level is justified based on a careful consideration of the statutory factors."[4] The Division's following BART analysis for NO_x, SO_2, and PM/PM_{10} takes into account each of the five statutory factors.

PacifiCorp's Naughton Power Plant consists of three units with a total generating capacity of 700 MW. Naughton Unit 1, generating nominal 160 MW, Unit 2, generating a nominal 210 MW, and Unit 3, generating a nominal 330 MW, are tangentially fired pulverized coal boilers. SO_2 emissions from Units 1 and 2 are controlled by burning low sulfur coal without the use of add-on controls. Unit 3 SO_2 emissions are control using an existing UOP LLC two-tower sodium based WFGD system that was installed in 1997. NO_x emissions from Units 1 and 2 are not controlled using either NO_x combustion controls (LNB) or add-on controls. ALSTOM LCCFS II LNB were installed on Unit 3 in 1999. Presumptive SO_2 limits of 95% reduction or 0.15 lb/MMBtu and presumptive NO_x limits based on unit type and coal type, do not apply to the three Naughton units because the total generating capacity of the facility is below 750 MW. However, the Division required additional analysis of potential retrofit controls for NO_x, SO_2, and PM/PM_{10}, taking into consideration all five statutory factors, before making a BART determination.

NO_x emissions from coal combustion are affected by the chemical and physical properties of the feed coal. Heat content, carbon content, fuel-bound nitrogen and oxygen, volatile matter content, volatility, and agglomeration of the feed coal significantly affect the design and operation of combustion controls such as LNB and OFA systems. This is evidenced by EPA's decision to classify presumptive NO_x emission levels based on specific controls as applied to different boiler types firing various types of coal. In EPA's analysis for establishing presumptive NO_x limits, three primary coal types were identified: bituminous, sub-bituminous, and lignite. These coal classifications were based on EPA's Mercury Information Collection Request (ICR) for the Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort, OMB Control Number 2060-0396. In responding to the ICR PacifiCorp reported that Naughton Units 1-3 burned sub-bituminous coal. Subsequent to the ICR PacifiCorp further evaluated the coal classification using ASTM method *D 388 - 05 Standard Classification of Coals by Rank*, an industrial standard for classifying coal. After reviewing method D 388 coal classifications, PacifiCorp noted that high volatile C bituminous coal and sub-bituminous A coals have similar heating values, but different agglomeration characteristics. Table 3 from ASTM method *D 388 - 05 Standard Classification of Coals by Rank* is shown as Figure 1.

[4] Ibid. (70 Federal Register 39171).

Figure 1

Table 3
Classification of Coals by Rank[a] (ASTM D 388)

Class	Group	Fixed Carbon Limits, % (Dry, Mineral-Matter-Free Basis): Equal or Greater Than	Fixed Carbon Limits, %: Less Than	Volatile Matter Limits, % (Dry, Mineral-Matter-Free Basis): Greater Than	Volatile Matter Limits, %: Equal or Less Than	Calorific Value Limits, Btu/lb (Moist,[b] Mineral-Matter-Free Basis): Equal or Greater Than	Calorific Value Limits, Btu/lb: Less Than	Agglomerating Character
I. Anthracitic	1. Meta-anthracite	98	—	—	2	—	—	Nonagglomerating
	2. Anthracite	92	98	2	8	—	—	
	3. Semianthracite[c]	86	92	8	14	—	—	
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	—	—	Commonly agglomerating[e]
	2. Medium volatile bituminous coal	69	78	22	31	—	—	
	3. High volatile A bituminous coal	—	69	31	—	14,000[d]	—	
	4. High volatile B bituminous coal	—	—	—	—	13,000[d]	14,000	
	5. High volatile C bituminous coal	—	—	—	—	11,500	13,000	
						10,500[e]	11,500	Agglomerating
III. Subbituminous	1. Subbituminous A coal	—	—	—	—	10,500	11,500	Nonagglomerating
	2. Subbituminous B coal	—	—	—	—	9,500	10,500	
	3. Subbituminous C coal	—	—	—	—	8,300	9,500	
IV. Lignitic	1. Lignite A	—	—	—	—	6,300	8,300	
	2. Lignite B	—	—	—	—	—	6,300	

[a]This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high volatile bituminous and subbituminous ranks. All of these coals either contain less than 48% dry, mineral-matter-free Btu/lb.

[b]Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c]If agglomerating, classify in low volatile group of the bituminous class.

[d]Coals having 69% or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

[e]It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high volatile C bituminous group.

PacifiCorp contracted with CH2M Hill and ALSTOM, a boiler manufacturer, to further research the impact of coal characteristics on NO_x emissions. Laboratory tests, including tests using a bench-scale drop tube furnace run by ALSTOM, showed the influence of both fuel type and stoichiometry on NO_x emissions. Additional testing examined the impact of coal volatility on NO_x emissions. Based on the results of the research, PacifiCorp concluded that "[t]he coals used at Bridger and Naughton tend to be higher rank than typical PRB coals. As such, they will have less fuel nitrogen released during the devolatilization phase of combustion, and thus will produce have [*sic*] somewhat higher NO_x than will true PRB coals when fired under low-NO_x staged conditions."

PacifiCorp also examined how fuel-bound NO_x evolves from solid coal char after the volatile component of the coal is combusted. After reviewing laboratory test data on NO_x conversion from fuel-bound nitrogen during volatilization and during char combustion, PacifiCorp concluded: "Typically, lower rank (more reactive) fuels have more fuel NO_x associated with the volatiles than the char, so low-rank coals overall have the lowest NO_x potential. The performance of the Bridger and Naughton coals tends to fall between the PRB coals and eastern bituminous coals shown [Figure 3, CH2M Hill's *Technical Memorandum: Coal Quality and Nitrogen Oxide Formation* submitted by PacifiCorp on February 2, 2009]. This would support the conclusion that the Bridger and Naughton coals have a NO_x reduction potential below eastern bituminous coals, but not as low as true PRB coals."

Coal characteristics affect the design and efficiency of pollution control equipment, as well as boiler design. Based on the information presented by PacifiCorp, it is likely that the Naughton units will not be able to meet presumptive NO_x levels of 0.15 lb/MMBtu for tangential boilers firing sub-bituminous coal. Air Quality Permit MD-1552 authorized the installation of new ALSTOM TFS 2000™ LNB with separated OFA systems on all four units at PacifiCorp's Jim Bridger Power Plant. Units 2-4 are currently equipped with this combustion control system. Recent monitoring data supplied by the continuous emissions monitoring systems on the three units indicate that a NO_x emission rate of 0.15 lb/MMBtu is not achievable on a continuous basis. Fuel characteristics of the coal burned at the Naughton Power Plant are similar to the coal fed to the Jim Bridger units, which are also tangentially-fired boilers. In the absence of site-specific operational data, it is reasonable to anticipate NO_x reductions from the application of new state-of-the-art LNB on the Naughton units will be comparable to the Jim Bridger units.

Naughton was included in EPA's presumptive limits analyses for NO_x and SO_2. As a result of the final publication of 40 CFR part 51, Appendix Y establishing BART presumptive limits for facilities with a generating capacity greater than 750 MW, Naughton is not subject to presumptive limits. The Division required additional analysis of potential retrofit controls for NO_x, which included add-on controls in addition to combustion control, taking into consideration all five statutory factors, before making a BART determination. And while PacifiCorp addressed applicability of presumptive NO_x limits for the Naughton units in their BART applications, the effectiveness of the proposed combustion control for removing NO_x was evaluated in this analysis under Step 2: Eliminate technically infeasible options, Step 3: Evaluate control effectiveness of remaining control technologies, and Step 4: Evaluate impacts and document the results of the BART process.

NO_x: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

PacifiCorp identified four control technologies to control NO_x emissions: (1) low NO_x burners with advanced OFA, (2) rotating opposed fire air (ROFA), (3) selective non-catalytic reduction (SNCR), and (4) selective catalytic reduction (SCR). LNB with advanced OFA and ROFA are two combustion control technologies that reduce NO_x emissions by controlling the combustion process within the boiler. These two technologies have been demonstrated to effectively control NO_x emissions by reducing the amount of oxygen directly accessible to the fuel during combustion creating a fuel-rich environment and by enhancing control of air-fuel mixing throughout the boiler's combustion zone. SNCR and SCR are add-on controls that provide a chemical conversion mechanism for NO_x to form molecular nitrogen (N_2) in the flue gas after combustion occurs. These four technologies are proven emissions controls commonly used on coal-fired electric generating units.

1. Low NO_x Burners with Advanced Overfire Air – LNB technologies can rely on a combination of fuel staging and combustion air control to suppress the formation of thermal NO_x. Fuel staging occurs in the very beginning of combustion, where the pulverized coal is injected through the burner into the furnace. Careful control of the fuel-air mixture leaving the burner can limit the amount of oxygen available to the fuel during combustion creating a fuel rich zone that reduces the nitrogen to molecular nitrogen (N_2) rather than using oxygen in the combustion air to oxidize the nitrogen to NO_x. The addition of advanced overfire air provides additional NO_x control by injecting air into the lower temperature combustion zone when NO_x is less likely to form. This allows complete combustion of the fuel while reducing both thermal and chemical NO_x formation.

2. Rotating Opposed Fire Air – ROFA can be used with LNB technology to control the combustion process inside the boiler. Similar to the advanced overfire air technology discussed above, ROFA manipulates the flow of combustion air to enhance fuel-mixing and air-flow characteristics within the boiler. By inducing rotation of the combustion air within the boiler, ROFA can reduce the number of high temperature combustion zones in the boiler and increase the effective heat absorption. Both of which effectively reduce the formation of NO_x caused by fuel combustion within the boiler.

3. Selective Non-Catalytic Reduction – SNCR is similar to SCR in that it involves the injection of a reducing agent such as ammonia or urea into the flue gas stream. The reduction chemistry, however, takes place without the aid of a catalyst. SNCR systems rely on appropriate injection temperatures, proper mixing of the reagent and flue gas, and prolonged retention time in place of the catalyst. SNCR operates at higher temperatures than SCR. The effective temperature range for SNCR is 1,600 to 2,100°F. SNCR systems are very sensitive to temperature changes and typically have lower NO_x emissions reduction (up to fifty or sixty percent) and may emit ammonia out of the exhaust stack when too much ammonia is added to the system.

4. Selective Catalytic Reduction – SCR is a post combustion control technique in which vaporized ammonia or urea is injected into the flue gas upstream of a catalyst. NO_x entrained in the flue gas is reduced to molecular nitrogen (N_2) and water. The use of a catalyst facilitates the reaction at an exhaust temperature range of 300 to 1,100°F, depending on the application and type of catalyst used. When catalyst temperatures are not in the optimal range for the reduction reaction or when too much ammonia is injected into the process, unreacted ammonia can be released to the atmosphere through the stack. This release is commonly referred to as ammonia slip. A well controlled SCR system typically emits less ammonia than a comparable SNCR control system.

In addition to applying these control technologies separately, they can be combined to increase overall NO_x reduction. PacifiCorp evaluated the application of LNB with advanced OFA in combination with both SNCR and SCR add-on controls.

NO_x: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

None of the four control technologies proposed to control NO_x emissions were deemed technically infeasible by PacifiCorp.

NO_x: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

The Division considers the control effectiveness of a proposed control technology to be equivalent to the BART-determined permit limit. The limit is based on continuous compliance when the control equipment is well maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. In order to demonstrate continuous compliance with the permit limit it is important to consider that even well maintained and operated equipment will have some emissions variability. Complex emission control equipment, such as LNB with advanced OFA, generally have inherent variability that must be considered when establishing the limit. Otherwise, the source will be out of compliance even though the equipment is operated and maintained as well as possible.

PacifiCorp contracted with Sargent and Lundy (S&L) to conduct a study of applicable NO_x control technologies for the Naughton units and to collect data from boiler vendors. Based on results from the study, PacifiCorp indicates that new LNB with advanced OFA on Naughton Units 1 and 2 would result in a NO_x emission rate as low as 0.24 lb/MMBtu. On pages 3-9 of the December 2007 submittals for Naughton Units 1 and 2 PacifiCorp states: "PacifiCorp has indicated that this rate [0.24 lb/MMBtu] corresponds to a vendor guarantee plus an added operating margin, not a vendor prediction, and they believe that this emission rate can be sustained as an average between overhauls." However, due to unforeseen operational issues associated with retrofitting the boilers, including site specific challenges, PacifiCorp proposes an additional NO_x increase of 0.02 lb/MMBtu to total 0.26 lb/MMBtu. Naughton Unit 3 is equipped with LNB and has demonstrated compliance with a 0.40 lb/MMBtu NO_x emission rate. PacifiCorp reviewed the option of tuning the existing LNB to further reduce NO_x emissions and indicates that lowering emissions to 0.35 lb/MMBtu is possible. In the March 26, 2008 Addendum for Unit 3, PacifiCorp proposed a permitted rate of 0.37 lb/MMBtu to account for unforeseen operational issues and site specific challenges.

PacifiCorp worked with Mobotec to conduct an analysis of retrofitting the existing boilers at the Naughton Power Plant with Mobotec's ROFA. Mobotec analyzed the operation of existing burners and OFA ports. Typically the existing burner system does not require modification and the existing OFA ports are not used by a new ROFA system. Instead, computational fluid modeling is performed to determine the location of the new ROFA ports. Mobotec concluded that a NO_x emission rate of 0.24 lb/MMBtu was achievable on Units 1 and 2 using ROFA technology. Unit 3 may achieve 0.26 lb/MMBtu. PacifiCorp added an additional operating margin to each anticipated emission rate of 0.02 lb/MMBtu to account for site specific issues, including the type of coal burned in the boilers, for total proposed emission rates of 0.26 lb/MMBtu for Units 1 and 2, and 0.28 lb/MMBtu for Unit 3.

S&L evaluated emission reductions associated with installing SNCR in addition to retrofitting the boilers with LNB with advanced OFA. Based on installing LNB with OFA capable of achieving a NO_x emission rate of 0.26 lb/MMBtu on Units 1 and 2, S&L concluded that SNCR can reduce emissions by 20% resulting in a projected emission rate of 0.21 lb/MMBtu. Installing SNCR on Unit 3 can reduce the anticipated rate of 0.37 lb/MMBtu by 20% resulting in a NO_x emission rate of 0.30 lb/MMBtu. PacifiCorp noted in the analysis that the economics of SNCR are greatly impacted by reagent utilization. When SNCR is used to achieve high levels of NO_x reduction, lower reagent utilization can result in significantly higher operating cost.

S&L prepared the design conditions and cost estimates for installing SCR in each of the Naughton units. A high-dust SCR configuration, where the catalyst is located downstream from the boiler economizer before the air heater and any particulate control equipment, was used in the analysis. The flue gas ducts would be routed to a separate large reactor containing the catalyst to increase the removal rate. Additional catalyst would be added to accommodate the coal feedstock. Based on the S&L design, which included installing both new LNB with advanced OFA and SCR, PacifiCorp concluded the Naughton units could achieve a NO_x emission rate of 0.07 lb/MMBtu.

Table 4: NO_x Emission Rates Per Boiler

Control Technology	Unit 1 Resulting NO_x Emission Rate (lb/MMBtu)	Unit 2 Resulting NO_x Emission Rate (lb/MMBtu)	Unit 3 Resulting NO_x Emission Rate (lb/MMBtu)
Existing Burners	0.58 [a]	0.54 [a]	0.45 [b]
Tune Existing LNB	--	--	0.37
New LNB with advanced OFA	0.26	0.26	--
Existing Burners with ROFA	0.26	0.26	0.28
New LNB with advanced OFA and SNCR	0.21	0.21	0.30
New LNB with advanced OFA and SCR	0.07	0.07	0.07

[a] Annual averaged NO_x emissions listed in Operating Permit 31-121.
[b] Annual averaged NO_x emission listed in Operating Permit 3-2-121.

NO_x: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impacts associated with installing each of the proposed control technologies. Installing new LNB with advanced OFA on Naughton Units 1 and 2 and tuning the existing LNB on Unit 3 will not significantly impact the boiler efficiency or forced draft fan power usage, two common potential areas for adverse energy impact often affected by changes in boiler combustion.

Installing the Mobotec ROFA system has a significant energy impact on Naughton. One (1) 1,900 horsepower (hp) ROFA fan on Unit 1, one (1) 3,500 hp ROFA fan on Unit 2, and one (1) 6,000 hp ROFA fan on Unit 3 are required to induct a sufficient volume of air into each boiler to cause rotation of the combustion air throughout the boiler. The annual energy impact from operating the proposed ROFA fans is 11,200 Mega Watt-hour (MW-hr), 20,600 MW-hr, and 35,300 MW-hr for Units 1, 2, and 3, respectively.

PacifiCorp determined the SNCR system would require between 200 kilo Watt (kW) and 300 kW of additional power to operate pretreatment and injection equipment, pumps, compressors, and control systems. In addition to energy costs associated with the reagent handling and injection, installation of the SCR catalyst will require additional power from the existing flue gas fan systems to overcome the pressure drop across the catalyst. Based on the S&L study, PacifiCorp estimated the additional power requirements for SCR installation on each unit at the Naughton Power Plant ranged from approximately 1.0 MW to 2.0 MW.

PacifiCorp evaluated the environmental impacts from the proposed NO_x control technologies. Installing LNB with advanced OFA may increase carbon monoxide (CO) emissions and unburned carbon in the ash, commonly referred to as loss on ignition (LOI). Mobotec has predicted CO emissions and LOI would be the same or lower than prior levels for the ROFA system. The installation of SNCR and SCR could impact the saleability and disposal of fly ash due to higher ammonia levels, and could potentially create a visible stack plume sometimes referred to as a blue plume, if the ammonia injection rate is not well controlled. Other environmental impacts involve the storage of ammonia, especially if anhydrous ammonia is used, and transportation of the ammonia to the power plant site.

PacifiCorp anticipates operating Naughton Units 1-3 indefinitely and did not include life extension costs in the economic analysis. A standard control life of 20 years was used to calculate the capital recovery factor. The annual cost to control was determined using a capital recovery factor based on a 7.1% interest rate. PacifiCorp labor and service costs were used to calculate the annual operating and maintenance costs. Annual power costs, including a cost escalation factor, associated with the operation of pollution controls were included.

Several different metrics can be considered when evaluating the cost-benefit relationships of different emission control technologies. In 40 CFR part 51 Appendix Y two metrics are specifically mentioned: cost effectiveness and incremental cost effectiveness. Through the application of BACT, the Division has extensive experience using cost effectiveness (i.e., dollars per ton of pollutant removed) to evaluate different control technologies. Incremental cost effectiveness is also used extensively by the Division when comparing emission controls under the BACT process. While the BART and the BACT processes are not necessarily equivalent, control determinations from either process are based on cost effectiveness and incremental cost effectiveness and are indicative of the economic costs to control emissions. In addition to providing cost effectiveness and incremental cost effectiveness results, PacifiCorp provided cost information in terms of cost of applying emission controls and the level of visibility improvement achieved (i.e., dollars per deciviews). While this metric can illustrate the control cost and visibility improvement differences between control options, it is not commonly used to assess the overall effectiveness of pollution control equipment. When performing the presumptive BART limits analyses for NO_x and SO_2, EPA addressed cost effectiveness and incremental cost effectiveness separate from visibility improvement. EPA did not use the dollars per deciview metric to compare control options. Visibility improvements from the application of the analyzed control measures used to establish presumptive levels were addressed in a separate visibility analysis. As discussed in the comprehensive visibility analysis presented later in this analysis as Step 5: Evaluate visibility impacts, the Division evaluated the amount of anticipated visibility improvement gained by the application of additional emission control technology. The Division considered capital cost, annual cost, cost effectiveness, and incremental cost effectiveness in the evaluation of each proposed NO_x emission control. Economic and environmental costs for additional NO_x controls on Naughton Units 1-3 are summarized in the following tables.

Table 5: Naughton Unit 1 Economic Costs

Cost	Existing Burners	New LNB with advanced OFA	Existing Burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
Control Equipment Capital Cost	$0	$9,600,000	$9,068,746	$17,526,855	$94,600,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$913,248	$862,710	$1,667,330	$8,999,298
Annual O&M Costs	$0	$80,000	$679,764	$305,033	$1,231,912
Annual Cost of Control	$0	$993,248	$1,542,474	$1,972,363	$10,231,210

Table 6: Naughton Unit 1 Environmental Costs

	Existing Burners	New LNB with advanced OFA	Existing Burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
NO_x Emission Rate (lb/MMBtu)	0.58	0.26	0.26	0.21	0.07
Annual NO_x Emission (tpy) [(a)]	4,230	1,896	1,896	1,531	510
Annual NO_x Reduction (tpy)	N/A	2,334	2,334	2,699	3,720
Annual Cost of Control	$0	$993,248	$1,542,474	$1,972,363	$10,231,210
Cost per ton of Reduction	N/A	$426	$661	$731	$2,750
Incremental Cost per ton of Reduction	N/A	$426	$661 [(b)]	$1,178	$8,089

[(a)] Annual emissions based on individual heat input rate of 1,850 MMBtu/hr for 7,884 hours of operation per year.
[(b)] Incremental cost cannot be calculated as the reduced tons of NO_x are anticipated to be the same as installing new LNB with advanced OFA.

Table 7: Naughton Unit 2 Economic Costs

Cost	Existing Burners	New LNB with advanced OFA	Existing Burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
Control Equipment Capital Cost	$0	$9,100,000	$10,586,222	$19,878,765	$115,900,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$865,683	$1,007,067	$1,891,067	$11,025,567
Annual O&M Costs	$0	$80,000	$1,148,862	$369,890	$1,639,352
Annual Cost of Control	$0	$945,683	$2,155,929	$2,260,957	$12,664,919

Table 8: Naughton Unit 2 Environmental Costs

	Existing Burners	New LNB with advanced OFA	Existing Burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
NO_x Emission Rate (lb/MMBtu)	0.54	0.26	0.26	0.21	0.07
Annual NO_x Emission (tpy) [(a)]	5,109	2,460	2,460	1,987	662
Annual NO_x Reduction (tpy)	N/A	2,649	2,649	3,122	4,447
Annual Cost of Control	$0	$945,683	$2,155,929	$2,260,957	$12,664,919
Cost per ton of Reduction	N/A	$357	$814	$724	$2,848
Incremental Cost per ton of Reduction	N/A	$357	$814 [(b)]	$222	$7,852

[(a)] Annual emissions based on individual heat input rate of 2,400 MMBtu/hr for 7,884 hours of operation per year.
[(b)] Incremental cost cannot be calculated as the reduced tons of NO_x are anticipated to be the same as installing new LNB with advanced OFA.

Table 9: Naughton Unit 3 Economic Costs

Cost	Existing LNB	Tuning Existing LNB	Existing LNB and SNCR	Existing LNB with ROFA	Existing LNB and SCR
Control Equipment Capital Cost	$0	$1,000,000	$15,788,530	$14,747,608	$136,800,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$95,130	$1,501,963	$1,402,940	$13,013,784
Annual O&M Costs	$0	$0	$414,076	$1,882,074	$2,668,918
Annual Cost of Control	$0	$95,130	$1,916,039	$3,285,014	$15,682,702

Table 10: Naughton Unit 3 Environmental Costs

	Existing LNB	Tuning Existing LNB	Existing LNB and SNCR	Existing LNB with ROFA	Existing LNB and SCR
NO_x Emission Rate (lb/MMBtu)	0.45	0.37	0.30	0.28	0.07
Annual NO_x Emission (tpy) [(a)]	6,563	5,397	4,376	4,084	1,021
Annual NO_x Reduction (tpy)[)]	N/A	1,167	2,188	2,480	5,542
Annual Cost of Control	$0	$95,130	$1,916,039	$3,285,014	$15,682,702
Cost per ton of Reduction	N/A	$82	$876	$1,325	$2,830
Incremental Cost per ton of Reduction	N/A	$1,783	$4,688	$4,049	$1,783

[(a)] Annual emissions based on individual heat input rate of 3,700 MMBtu/hr for 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of the four proposed BART technologies for NO_x are all reasonable. PacifiCorp modeled the range of anticipated visibility improvement from the company-proposed BART controls for Units 1 and 2 by modeling LNB with advanced OFA and LNB with advanced OFA and SCR. PacifiCorp modeled the range of anticipated visibility improvement from the company-proposed BART controls for Unit 3 by modeling tuning the existing LNB and OFA and tuning the existing LNB and OFA and installing SCR. While the installation of SNCR and ROFA were not individually evaluated in Step 5: Evaluate visibility impact, the anticipated degree of visibility improvement from applying either control lies within the modeled range of visibility impacts.

The final step in the NO_x BART determination process for Naughton Units 1-3, Step 5: Evaluate visibility impacts, is addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants. The visibility analysis follows Steps 1-4 for SO_2 emissions in this application analysis. Tables 28-30, on pages 37-39, list the modeled control scenarios and associated emission rates.

PM_{10}: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Naughton Units 1 and 2 are currently equipped with mechanical dust collectors and electrostatic precipitators to control PM emissions from the boilers to 0.056 lb/MMBtu and 0.064 lb/MMBtu, respectively. Unit 3 is equipped with an ESP using FGC to control PM emission to 0.094 lb/MMBtu. As discussed below in more detail, ESPs control PM/PM_{10} from the flue gas stream by creating a strong electro-magnetic field in which fly ash particles gain electric charge. Three PM control technologies were analyzed for application on the three Naughton units: fabric filters or baghouses, ESPs, and flue gas conditioning.

1. Fabric filters (FF) – FF are woven pieces of material that collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99%. The layer of dust trapped on the surface of the fabric, commonly referred to as dust cake, is primarily responsible for such high efficiency. Joined pores within the cake act as barriers to trap particulate matter too large to flow through the pores as it travels through the cake. Limitations are imposed by the temperature and corrosivity of the gas and by adhesive properties of the particles. Most of the energy used to operate the system results from pressure drop across the bags and associated hardware and ducting.

2. Electrostatic precipitators – ESPs use electrical forces (charge) to move particulate matter out the gas stream onto collection plates. The particles are given an electrical charge by directing the gas stream through a corona, or region of gaseous ion flow. The charged particles are acted upon by an induced electrical field from high voltage electrodes in the gas flow that forces them to the walls or collection plates. Once the particles couple with the collection plates, they must be removed without re-entraining them into the gas stream. In dry ESP applications, this is usually accomplished by physically knocking them loose from the plates and into a hopper for disposal. Wet ESPs use water to wash the particles from the collector plates into a sump. The efficiency of an ESP is primarily determined by the resistivity of the particle, which is dependent on chemical composition, and also by the ability to clean the collector plates without reintroducing the particles back into the flue gas stream.

3. Flue Gas Conditioning (FGC) – Injecting a conditioning medium, typically SO_3, into the flue gas can lower the resistivity of the fly ash, improving the particles' ability to gain an electric charge. If the material is injected upstream of an ESP the flue gas particles more readily accept charge from the corona and are drawn to the collection plates. Adding FGC can account for large improvements in PM collection efficiency for existing ESPs that are constrained by space and flue gas residence time.

PM_{10}: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

PacifiCorp did not eliminate any of the three control technologies listed above as technically infeasible. PacifiCorp analyzed the impact of installing FGC using the existing ESPs and installing a polishing fabric filter downstream of the existing ESPs on Naughton Units 1 and 2. PacifiCorp analyzed the impact of installing a full-scale fabric filter on Unit 3.

PM_{10}: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

The Division considers the control effectiveness of a proposed control technology to be equivalent to the BART-determined permit limit. The limit is based on continuous compliance when the control equipment is well maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. In order to demonstrate continuous compliance with the permit limit it is important to consider that even well maintained and operated equipment will have some emissions variability. Complex emission control equipment, such as hot-side electrostatic precipitators, generally have inherent variability that must be considered when establishing the limit. Otherwise, the source will be out of compliance even though the equipment is operated and maintained as well as possible.

Naughton Units 1 and 2 have existing ESPs and rather than evaluate costs of replacing them, PacifiCorp evaluated additional controls to improve the PM_{10} removal efficiency. An ESP is an effective PM control device, as the existing units are already capable of controlling PM_{10} emissions to 0.056 lb/MMBtu, 0.064 lb/MMBtu, and 0.094 lb/MMBtu for Units 1, 2, and 3, respectively. The technology continually improves and is commonly proposed for consideration in BACT analyses to control particulate emissions from new PC boilers. Rather than demolishing the existing ESP and constructing an entirely new PM control device, PacifiCorp recognized the cost benefit of keeping the existing ESP and augmenting the control. Installing FGC on Units 1 and 2 can improve the PM removal efficiencies on the existing ESPs down to 0.040 lb/MMBtu. In addition to maintaining the existing ESPs, a polishing fabric filter can be installed downstream of the existing ESPs. PacifiCorp proposed the use of Compact Hybrid Particulate Collector (COHPAC) licensed by Electric Power Research Institute (EPRI). The COHPAC unit is smaller than a full-scale fabric filter and has a higher air-to-cloth ratio (7 to 9:1), compared to a full-size pulse jet fabric filter (3.5 to 4:1). COHPAC is effective at controlling particulates not captured by the primary PM control device, but is not designed to treat high PM concentrations in the entire flue gas stream immediately downstream of the boiler. The existing ESP must remain in service for the COHPAC fabric filter to effectively reduce PM/PM_{10} emissions. PacifiCorp estimates the application of the COHPAC unit in addition to using FGC with the existing ESPs can reduce emissions an additional 63% resulting in a PM emission rate of 0.015 lb/MMBtu. Demolishing the existing ESPs and installing a new full-scale fabric filter on Units 1 and 2 is anticipated to control emissions down to the same PM emission level, 0.015 lb/MMBtu, as installing a polishing fabric filter downstream of the existing ESP.

Naughton Unit 3 is currently equipped with an ESP and FGC system. PacifiCorp analyzed the impact of upgrading the existing FGC and resulting impact of installing a new full-scale fabric filter. PacifiCorp's proposed emission rates for each technology as applied to Naughton Units 1-3 are shown in Table 11.

Table 11: PM_{10} Emission Rates Per Boiler

Control Technology	Resulting PM_{10} Emission Rate (lb/MMBtu)
Existing ESP	0.056, 0.064, 0.094 [a]
Existing ESP with FGC	0.040
Existing ESP and New Polishing Fabric Filter [b]	0.015
Full-scale Fabric Filter [c]	0.015

[a] Current achievable PM_{10} emissions from Unit 1, 2, and 3, respectively.
[b] Applied to Naughton Units 1 and 2.
[c] Applied to Naughton Unit 3.

PM_{10}: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impact of installing COHPAC on Units 1 and 2. The pressure drop created by the fabric filter and associated ductwork requires additional energy from the existing draft fan, which will have to be upgraded. PacifiCorp calculated the additional energy costs based on a 90 percent annual plant capacity factor. The installation of a COHPAC fabric filter would require approximately 1.0 MW of power, equating to an annual power usage of approximately 8,000 MW-hr for Unit 1 and 1.4 MW of power, equal to an annual power usage of approximately 10,900 MW-hr for Unit 2. Installing a full-scale fabric filter on Unit 3 would require approximately 2.1 MW of power, equating to an annual power usage of approximately 16,240 MW-hr.

Installing FGC on Units 1 and 2 will require a minimal amount of additional power, about 100 kW which equates to an annual power consumption of 400 kW-hr. Upgrading the existing ESP on Unit 3 is not anticipated to require additional power.

PacifiCorp evaluated the environmental impacts associated with the proposed installation of FGC and COHPAC on Units 1and 2, and did not anticipate negative environmental impacts from the addition of either of these PM control technologies. Upgrading the existing FGC and installing a new full-scale fabric filter on Unit 3 are not anticipated to have significant negative environmental impacts.

PacifiCorp anticipates operating Naughton Units 1-3 indefinitely and did not include life extension costs in the economic analysis. A standard control life of 20 years was used to calculate the capital recovery factor. The annual cost to control was determined using a capital recovery factor based on a 7.1% interest rate. PacifiCorp labor and service costs were used to calculate the annual operating and maintenance costs. Annual power costs, including a cost escalation factor, associated with the operation of pollution controls were included.

Several different metrics can be considered when evaluating the cost-benefit relationships of different emission control technologies. In 40 CFR part 51 Appendix Y two metrics are specifically mentioned: cost effectiveness and incremental cost effectiveness. Through the application of BACT, the Division has extensive experience using cost effectiveness (i.e., dollars per ton of pollutant removed) to evaluate different control technologies. Incremental cost effectiveness is also used extensively by the Division when comparing emission controls under the BACT process. While the BART and the BACT processes are not necessarily equivalent, control determinations from either process are based on cost effectiveness and incremental cost effectiveness and are indicative of the economic costs to control emissions. In addition to providing cost effectiveness and incremental cost effectiveness results, PacifiCorp provided cost information in terms of cost of applying emission controls and the level of visibility improvement achieved (i.e., dollars per deciviews). While this metric can illustrate the control cost and visibility improvement differences between control options, it is not commonly used to assess the overall effectiveness of pollution control equipment. When performing the presumptive BART limits analyses for NO_x and SO_2, EPA addressed cost effectiveness and incremental cost effectiveness separate from visibility improvement. The dollars per deciview metric was not used to compare control options. Visibility improvements from the application of the analyzed control measures used to establish presumptive levels were addressed in a separate visibility analysis. As discussed in the comprehensive visibility analysis presented later in this analysis as Step 5: Evaluate visibility impacts, the Division evaluated the amount of visibility improvement gained in relation to each proposed emission control technology. The Division considered capital cost, annual cost, cost effectiveness, and incremental cost effectiveness in the evaluation of each proposed PM emission control. Economic and environmental costs for additional PM control on Naughton Units 1-3 are summarized in the following tables

Table 12: Naughton Unit 1 Economic Costs

Cost	Existing ESP	Existing ESP With Flue Gas Conditioning	Existing ESP With New Polishing Fabric Filter
Control Equipment Capital Cost	$0	$1,298,352	$29,798,898
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	$123,512	$2,834,769
Annual O&M Costs	$0	$77,319	$601,825
Annual Cost of Control	$0	$200,831	$3,436,594

Table 13: Naughton Unit 1 Environmental Costs

	Existing ESP	Existing ESP With Flue Gas Conditioning	Existing ESP With New Polishing Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.056	0.040	0.015
Annual PM_{10} Emission (tpy) [(a)]	408	292	109
Annual PM_{10} Reduction (tpy)	N/A	117	299
Annual Cost of Control	$0	$200,831	$3,436,594
Cost per ton of Reduction	N/A	$1,721	$11,494
Incremental Cost per ton of Reduction	N/A	$1,721	$17,748

[(a)] Annual emissions based on unit heat input rate of 1,850 MMBtu/hr and 7,884 hours of operation per year.

Table 14: Naughton Unit 2 Economic Costs

Cost	Existing ESP	Existing ESP With Flue Gas Conditioning	Existing ESP With New Polishing Fabric Filter
Control Equipment Capital Cost	$0	$1,298,352	$34,898,710
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	$123,512	$3,319,914
Annual O&M Costs	$0	$91,904	$781,791
Annual Cost of Control	$0	$215,416	$4,101,705

Table 15: Naughton Unit 2 Environmental Costs

	Existing ESP	Existing ESP With Flue Gas Conditioning	Existing ESP With New Polishing Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.064	0.040	0.015
Annual PM_{10} Emission (tpy) [(a)]	605	378	142
Annual PM_{10} Reduction (tpy)	N/A	227	464
Annual Cost of Control	$0	$215,416	$4,101,705
Cost per ton of Reduction	N/A	$949	$8,848
Incremental Cost per ton of Reduction	N/A	$949	$16,431

[(a)] Annual emissions based on unit heat input rate of 2,400 MMBtu/hr and 7,884 hours of operation per year.

Table 16: Naughton Unit 3 Economic Costs

Cost	Existing ESP	Existing ESP With Flue Gas Conditioning	New Full-scale Fabric Filter
Control Equipment Capital Cost	$0	$13,299,508	$121,000,000
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	$1,265,182	$11,510,730
Annual O&M Costs	$0	$0	$1,120,813
Annual Cost of Control	$0	$1,265,182	$12,631,543

Table 17: Naughton Unit 3 Environmental Costs

	Existing ESP	Existing ESP With Flue Gas Conditioning	New Full-scale Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.094	0.040	0.015
Annual PM_{10} Emission (tpy) [a]	1,371	583	219
Annual PM_{10} Reduction (tpy)	N/A	788	1,152
Annual Cost of Control	$0	$1,265,182	$12,631,543
Cost per ton of Reduction	N/A	$1,606	$10,963
Incremental Cost per ton of Reduction	N/A	$1,606	$31,172

[a] Annual emissions based on unit heat input rate of 3,700 MMBtu/hr and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of applying a new polishing fabric filter to Units 1 and 2 are not reasonable. The cost effectiveness and incremental cost effectiveness of applying a new full-scale fabric filter to Unit 3 are also not reasonable. However, the control was included in the final step in the PM/PM_{10} BART determination process for Naughton Units 1-3, Step 5: Evaluate visibility impacts, which is addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants and associated control options. The visibility analysis follows Steps 1-4 for SO_2 emissions in this application analysis. Tables 28-30, on pages 37-39, list the modeled control scenarios and associated emission rates.

SO_2: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

PacifiCorp reviewed a broad range of informative sources, including EPA's RACT/BACT/LAER clearinghouse, in an effort to identify applicable SO_2 emission control technologies for Naughton Units 1-3. Based on the results of this review, PacifiCorp proposed wet flue gas desulfurization (WFGD) and dry flue gas desulfurization (DFGD) as potential retrofit technologies to reduced SO_2 emissions.

1. Wet FGD – SO_2 is removed through absorption by mass transfer as soluble SO_2 in the exhaust gas mixture is dissolved in an alkaline water solvent that has low volatility under process conditions. SO_2 diffuses from the gas into the scrubber water when the liquid contains less than the equilibrium concentration of the gaseous SO_2. The rate of SO_2 mass transfer between the two phases is largely dependent on the surface area exposed and the time of contact. A properly designed wet scrubber or gas absorber will provide sufficient contact between the gas and the liquid solvent to allow diffusion of SO_2. Once the SO_2 enters the alkaline water phase, it will form a weak acid and react with the alkaline component dissolved in the scrubber water to form a sulfate (SO_4) or sulfite (SO_3). The acid/alkali chemical reaction prevents the SO_2 from diffusing back into the flue gas stream. When the alkaline scrubber water is saturated with sulfur compounds, it can be converted to a wet gypsum by-product that may be sold. SO_2 removal efficiencies for wet scrubbers can be as high as 99%.

2. Dry FGD – Dry scrubbers are similar to sorbent injection systems in that both systems introduce media directly into the flue gas stream, however the addition of the dry scrubber vessel provides greater contact area for adsorption and enhances chemical reactivity. A spray dryer dry scrubber sprays an atomized alkaline slurry into the flue gas upstream of particulate control system, often a fabric filter. Water in the slurry evaporates, hydrolizing the SO_2 into a weak acid, which reacts with the alkali to form a sulfate or sulfite. The resulting dry product is captured in the particulate control and physically moved from the exhaust gas into a storage bin. The dry by-product may be dissolved back into the lime slurry or dried and sold as a gypsum by-product. Spray dryer dry scrubbers typically require lower capital cost than a wet scrubber. They also require less flue gas after-treatment. When exhaust gas leaves the wet scrubber, it is at or near saturation. A wet scrubber can lower exhaust gas temperatures down into a temperature range of 110 to 140°F, which may lead to corrosive condensation in the exhaust stack. A spray dryer dry scrubber does not enhance stack corrosion like a wet scrubber because it will not saturate the exhaust gas or significantly lower the gas temperature. Removal efficiencies for spray dryer dry scrubbers can range from 70% to 95%.

SO_2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

PacifiCorp did not eliminate either of the two control technologies listed above as technically infeasible. PacifiCorp analyzed the impact of installing dry FGD using the existing ESP, installing dry FGD using a polishing fabric filter, and installing wet FGD using the existing ESP on Units 1 and 2. Upgrading the existing wet waste sodium liquor FGD system with the existing ESP and upgrading the existing wet FGD including switching to a soda ash reagent with the existing ESP were two SO_2 control options analyzed by PacifiCorp for Unit 3.

SO_2: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

The Division considers the control effectiveness of a proposed control technology to be equivalent to the BART-determined permit limit. The limit is based on continuous compliance when the control equipment is well maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. In order to demonstrate continuous compliance with the permit limit it is important to consider that even well maintained and operated equipment will have some emissions variability. Complex emission control equipment, such as wet FGD, generally have inherent variability that must be considered when establishing the limit. Otherwise, the source will be out of compliance even though the equipment is operated and maintained as well as possible.

Naughton Units 1 and 2 currently achieve emission rates of 1.20 lb/MMBtu. Both low sulfur coal, 0.58% sulfur by weight, and high sulfur coal, 1.02% by weight, are used to fuel the boilers in the Naughton units. Installing a new dry FGD system and utilizing the existing ESP on Naughton Units 1 and 2 may reduce uncontrolled SO_2 emissions from each unit by 85%. Resulting SO_2 emission rates for Units 1 and 2 would be 0.18 lb/MMBtu, based on an average coal sulfur content of 0.58% by weight, and 0.41 lb/MMBtu, based on an average coal sulfur content of 1.02% by weight. Replacing the existing ESP with a new full-scale fabric filter will increase the SO_2 removal efficiency to 87.5%. SO_2 emission rates for Units 1 and 2 from the new fabric filter would be 0.15 lb/MMBtu, based on an average coal sulfur content of 0.58% by weight, and 0.21 lb/MMBtu, based on an average coal sulfur content of 1.02% by weight.

As mentioned earlier in this analysis, BART presumptive SO_2 levels do not apply to Naughton. However, PacifiCorp used the presumptive SO_2 levels for uncontrolled units, 95% emissions reduction or 0.15 lb/MMBtu, as a reference for comparison. PacifiCorp does not anticipate achieving presumptive SO_2 emission levels using dry FGD. The application of wet FGD on Units 1 and 2 is anticipated to lower SO_2 emissions to 0.10 lb/MMBtu, based on an average coal sulfur content of 0.58% by weight, and 0.15 lb/MMBtu, based on an average coal sulfur content of 1.02% by weight, which meet presumptive SO_2 levels.

The existing wet FGD system on Naughton Unit 3 reduces emissions by 83% to achieve a SO_2 emissions rate of 0.50 lb/MMBtu when burning high sulfur coal, 1.02% by weight. Wet FGD is a state-of-the-art SO_2 emissions control technology and continually improves over time. PacifiCorp evaluated potential changes to the existing wet FGD systems to improve the SO_2 removal efficiencies. Improving inlet gas distribution, adding a second tray to improve gas/liquid contact, and upgrading the reagent and waste solids systems are projected to reduce emissions by 90% to achieve an emission rate of approximately 0.21 lb/MMBtu. Switching to a refined soda ash reagent in the upgraded wet FGD system is anticipated to reduce uncontrolled emissions by 95%, resulting in a SO_2 emission rate of 0.10 lb/MMBtu. PacifiCorp's proposed emission rates for each SO_2 emission reduction technology applied to Naughton Units 1-3 are shown in Table 18.

Table 18: SO_2 Emission Rates Per Boiler [a]

Control Technology	Unit 1 SO_2 Emission Rate (lb/MMBtu)	Unit 2 SO_2 Emission Rate (lb/MMBtu)	Unit 3 SO_2 Emission Rate (lb/MMBtu)
Existing Uncontrolled	1.2	1.2	--
Existing Wet FGD	--	--	0.50
New Dry FGD with Existing ESP	0.41	0.41	--
New Dry FGD with Polishing Fabric Filter	0.21	0.21	--
New Wet FGD with Existing ESP	0.15	0.15	--
Upgraded Wet FGD with Waste Liquor	--	--	0.21
Upgraded Wet FGD with Soda Ash Reagent	--	--	0.10

[a] SO_2 emissions based on an average coal sulfur content of 1.02% by weight.

SO_2: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impacts of installing both dry FGD and wet FGD systems on Units 1 and 2. PacifiCorp noted that dry FGD systems using the existing ESP require the least amount of power. A dry FGD system using the existing ESP installed on Naughton Units 1 and 2 would require approximately 1.6 MW and 2.2 MW of power, respectively. Wet FGD would require approximately 2.4 MW and 3.3 MW of power for Units 1 and 2, respectively. Based on an annual operating factor of 90%, the cost savings of using dry FGD on Units 1 and 2 would equate to approximately 5,900 MW-hr and 8,300 MW-hr, respectively.

PacifiCorp estimates that upgrading the existing wet sodium FGD system on Naughton Unit 3 would require approximately 330 kW of additional power. Using a 90% annual operating factor, the annual power cost is 2,602 MW-hr.

There are no anticipated environmental impacts from upgrading the existing wet sodium FGD system on Naughton Unit 3 except for an incremental addition to scrubber waste disposal and makeup water requirement. Recycling the waste liquor into the scrubber would save on disposal of these materials and conserve resources.

PacifiCorp compared the environmental impacts of dry FGD versus wet FGD technology. PacifiCorp concluded that dry FGD has five significant environmental advantages over wet FGD. These advantages are taken directly from PacifiCorp's environmental analyses for SO_2 controls on Naughton Units 1 and 2 and listed below.

- Sulfuric Acid Mist Sulfur trioxide (SO_3) in the flue gas, which condenses to liquid sulfuric acid at temperatures below the acid dew point, is removed efficiently with a lime spray dryer system. Wet scrubbers capture less than 40 to 60 percent of SO_3 and may require the addition of a wet electrostatic precipitator (ESP) or hydrated lime injection when medium to high sulfur coal is burned in a unit to remove the balance of SO_3. Otherwise, the emission of sulfuric acid mist, if above a threshold value, may result in a visible plume after the vapor plume dissipates.

- Plume Buoyancy Flue gas following a dry FGD system is not saturated with water (gas temperature 30°F to 50°F above dew point), which reduces or eliminates a visible moisture plume. Wet FGD scrubbers produce flue gas saturated with water, which would require a gas-gas heat exchanger to reheat the flue gas if it were to operate as a dry stack. Because of the high capital and operating costs associated with heating the flue gas, all recent wet FGD systems in the United States have used wet stack operation.

- Liquid Waste Disposal There is no liquid waste from a dry FGD system. However, wet FGD systems produce a wastewater blowdown stream that must be treated to limit chloride buildup in the absorber scrubbing loop. In some cases, a wastewater treatment plant must be installed to treat the liquid waste prior to disposal. The wastewater treatment plant would produce a small volume of solid waste, which may be contaminated with toxic metals (including mercury), requiring proper disposal.

- Solid Waste Disposal The creation of a wet sludge from the wet FGD process creates a solid waste handling and disposal challenge. This sludge must be handled properly to prevent groundwater contamination. Wet FGD systems can produce saleable gypsum if a gypsum market is available, reducing the quantity of solid waste from the power plant to be disposed.

- Makeup Water Requirements Dry FGD has advantages over a wet scrubber, producing a dry waste material and requiring less makeup water in the absorber. Given that water is a valuable commodity in Wyoming, the reduced water consumption required for dry FGD is major advantage for this technology.

PacifiCorp anticipates operating Naughton Units 1-3 indefinitely and did not include life extension costs in the economic analysis. A standard control life of 20 years was used to calculate the capital recovery factor. The annual cost to control was determined using a capital recovery factor based on a 7.1% interest rate. PacifiCorp labor and service costs were used to calculate the annual operating and maintenance costs. Annual power costs, including a cost escalation factor, associated with the operation of pollution controls were included.

Several different metrics can be considered when evaluating the cost-benefit relationships of different emission control technologies. In 40 CFR part 51 Appendix Y two metrics are specifically mentioned: cost effectiveness and incremental cost effectiveness. Through the application of BACT, the Division has extensive experience using cost effectiveness (i.e., dollars per ton of pollutant removed) to evaluate different control technologies. Incremental cost effectiveness is also used extensively by the Division when comparing emission controls under the BACT process. While the BART and the BACT processes are not necessarily equivalent, control determinations from either process are based on cost effectiveness and incremental cost effectiveness and are indicative of the economic costs to control emissions. In addition to providing cost effectiveness and incremental cost effectiveness results, PacifiCorp provided cost information in terms of cost of applying emission controls and the level of visibility improvement achieved (i.e., dollars per deciviews). While this metric can illustrate the control cost and visibility improvement differences between control options, it is not commonly used to assess the overall effectiveness of pollution control equipment. When performing the presumptive BART limits analyses for NO_x and SO_2, EPA addressed cost effectiveness and incremental cost effectiveness separate from visibility improvement. The dollars per deciview metric was not used to compare control options. Visibility improvements from the application of the analyzed control measures used to establish presumptive levels were addressed in a separate visibility analysis. The Division considered capital cost, annual cost, cost effectiveness, and incremental cost effectiveness in the evaluation of each proposed SO_2 emission control. Economic and environmental costs for additional controls on Naughton Units 1-3 are summarized in the following tables.

Table 19: Naughton Unit 1 Economic Costs

Cost	Existing	Dry FGD with Existing ESP	Dry FGD with Polishing Fabric Filter	Wet FGD with Existing ESP
Control Equipment Capital Cost	$0	$64,297,623	$108,995,970	$89,400,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$6,116,633	$10,368,787	$8,504,622
Annual O&M Costs	$0	$3,226,295	$4,006,095	$4,563,874
Annual Cost of Control	$0	$9,342,928	$14,374,882	$13,068,496

Table 20: Naughton Unit 1 Environmental Costs

	Existing	Dry FGD with Existing ESP	Dry FGD with Polishing Fabric Filter	Wet FGD with Existing ESP
SO_2 Emission Rate (lb/MMBtu)	1.20	0.41	0.15	0.15
Annual SO_2 Emission (tpy) [a]	8,7516	2,990	1,094	1,094
Annual SO_2 Reduction (tpy)	N/A	5,761	7,657	7,657
Annual Cost of Control	$0	$9,342,928	$14,374,882	$13,068,496
Cost per ton of Reduction	N/A	$1,622	$1,877	$1,707
Incremental Cost per ton of Reduction	N/A	$1,622	$2,654	$1,965 [b]

[a] Annual emissions based on an average coal sulfur content of 1.02%, a heat input rate of 1,850 MMBtu/hr, and 7,884 hours of operation per year.

[b] Incremental cost from installing dry FGD with a polishing fabric filter cannot be calculated since the reduced tons of SO_2 are anticipated to be the same. Therefore, the incremental cost from installing dry FGD with the existing ESP was calculated.

Table 21: Naughton Unit 2 Economic Costs

Cost	Existing	Dry FGD with Existing ESP	Dry FGD with Polishing Fabric Filter	Wet FGD with Existing ESP
Control Equipment Capital Cost	$0	$88,896,713	$141,244,778	$117,400,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$8,456,744	$13,436,616	$11,168,262
Annual O&M Costs	$0	$4,251,261	$5,259,175	$5,721,158
Annual Cost of Control	$0	$12,708,005	$18,695,791	$16,889,420

Table 22: Naughton Unit 2 Environmental Costs

	Existing	Dry FGD with Existing ESP	Dry FGD with Polishing Fabric Filter	Wet FGD with Existing ESP
SO_2 Emission Rate (lb/MMBtu)	1.20	0.41	0.15	0.15
Annual SO_2 Emission (tpy) [(a)]	11,353	3,879	1,419	1,419
Annual SO_2 Reduction (tpy)	N/A	7,474	9,934	9,934
Annual Cost of Control	$0	$12,708,005	$18,695,791	$16,889,420
Cost per ton of Reduction	N/A	$1,700	$1,882	$1,700
Incremental Cost per ton of Reduction	N/A	$1,700	$2,434	$1,700 [(b)]

[(a)] Annual emissions based on an average coal sulfur content of 1.02%, a heat input rate of 2,400 MMBtu/hr, and 7,884 hours of operation per year.
[(b)] Incremental cost from installing dry FGD with a polishing fabric filter cannot be calculated since the reduced tons of SO_2 are anticipated to be the same. Therefore, the incremental cost from installing dry FGD with the existing ESP was calculated.

Table 23: Naughton Unit 3 Economic Costs

Cost	Existing Wet FGD	Upgraded Wet FGD with Waste Liquor	Upgraded Wet FGD with Soda Ash Reagent
Control Equipment Capital Cost	$0	$6,000,000	$27,798,972
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	$570,780	$2,644,516
Annual O&M Costs	$0	$615,513	$1,656,269
Annual Cost of Control	$0	$1,186,293	$4,300,785

Table 24: Naughton Unit 3 Environmental Costs

	Existing Wet FGD	Upgrade Wet FGD Using Waste Liquor	Upgrading Wet FGD Using Soda Ash Reagent
SO_2 Emission Rate (lb/MMBtu)	0.50	0.21	0.15
Annual SO_2 Emission (tpy) [(a)]	7,293	3,063	2,188
Annual SO_2 Reduction (tpy)	N/A	4,230	5,105
Annual Cost of Control	$0	$1,186,293	$4,300,785
Cost per ton of Reduction	N/A	$280	$842
Incremental Cost per ton of Reduction	N/A	$280	$3,559

[(a)] Annual emissions based on an average coal sulfur content of 1.02%, a heat input rate of 3,700 MMBtu/hr, and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of the proposed wet FGD and dry FGD controls for Units 1 – 3 are reasonable. The final step in the SO_2 BART determination process for Naughton Units 1-3, Step 5: Evaluate visibility impacts, is addressed in a comprehensive visibility analysis presented in the next section of this BART application analysis. The Division evaluated the amount of visibility improvement gained from the application of additional NO_x, PM/PM_{10}, and SO_2 emission control technology in relation to all three visibility impairing pollutants. Tables 28-30, on pages 37-39, list the modeled control scenarios and associated emission rates.

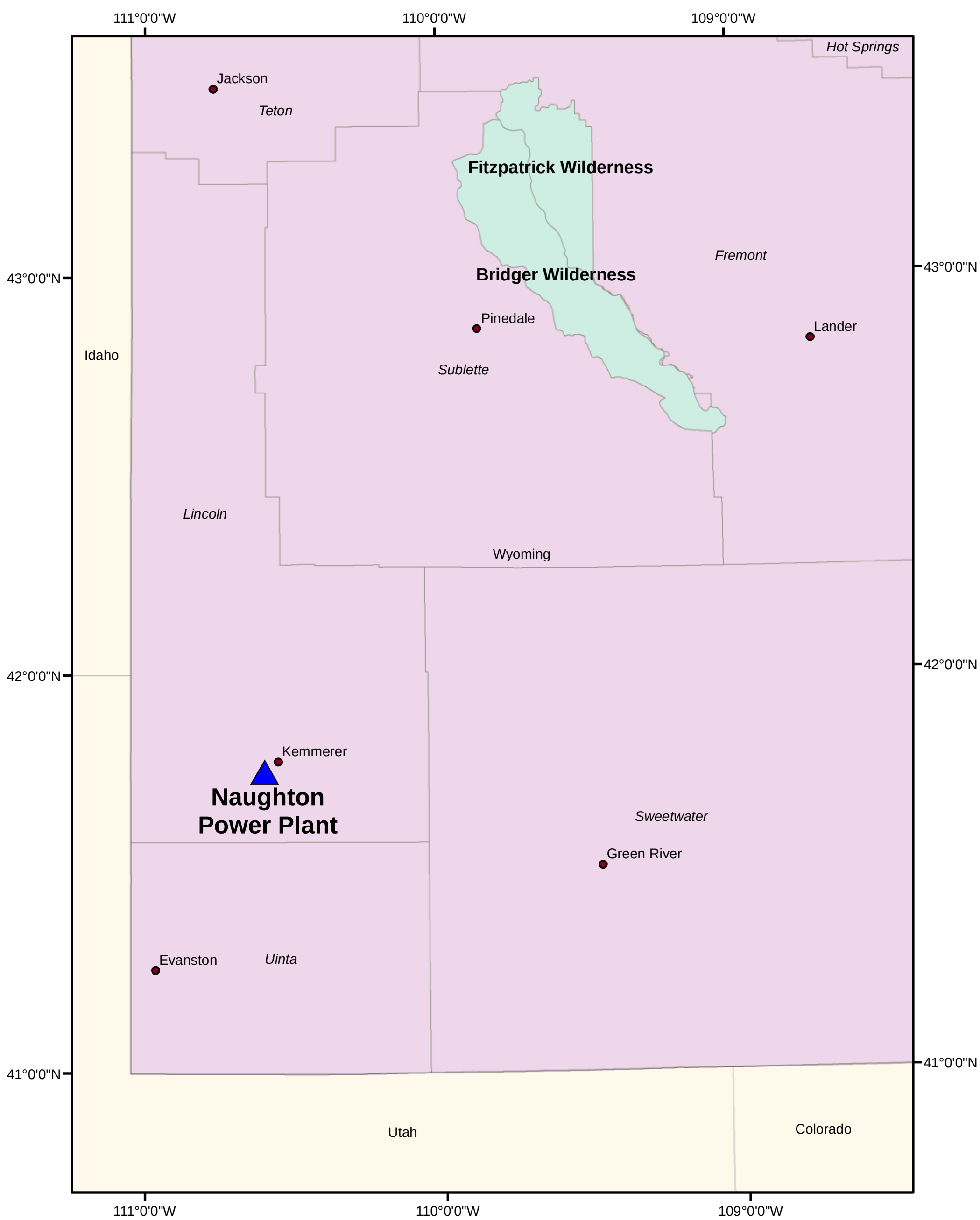
VISIBILITY IMPROVEMENT DETERMINATION:

The fifth of five steps in a BART determination analysis, as required by 40 CFR part 51 Appendix Y, is the determination of the degree of Class I area visibility improvement that would result from installation of the various options for control technology. This factor was evaluated for the PacifiCorp Naughton facility by using an EPA-approved dispersion modeling system (CALPUFF) to predict the change in Class I area visibility. The Division had previously determined that the facility was subject to BART based on the results of initial screening modeling that was conducted using current (baseline) emissions from the facility. The screening modeling, as well as more refined modeling conducted by the applicant, is described in detail below.

Bridger Wilderness Area (WA) and Fitzpatrick WA in Wyoming are the closest Class I areas to the PacifiCorp Naughton facility, as shown in Figure 2 below. Bridger WA is located approximately 140 kilometers (km) northeast of the facility and Fitzpatrick WA is located approximately 165 km northeast of the facility.

Only those Class I areas most likely to be impacted by the Naughton Power Plant sources were modeled, as determined by source/Class I area locations, distances to each Class I area, and professional judgment considering meteorological and terrain factors. It can be reasonably assumed that areas at greater distances and in directions of less frequent plume transport will experience lower impacts than those predicted for the modeled areas.

Figure 2
Naughton Power Plant and Class I Areas



SCREENING MODELING

To determine if the PacifiCorp Naughton facility would be subject to BART, the Division conducted CALPUFF modeling using three years of meteorological data. These data, from 1995-1996 and 2001, consisted of surface and upper-air observations and gridded output from the Mesoscale Model (MM5). Resolution of the MM5 data was 36-km for all three of the modeled years. Potential emissions for current operation from the three coal-fired boilers at the Naughton plant were input to the model.

Results of the modeling showed that the 98th percentile value for the change in visibility (in units of delta deciview [Δdv]) was above 0.5 Δdv for Bridger WA and Fitzpatrick WA for all three years of meteorology. As defined in EPA's final BART rule, a predicted 98th percentile impact equal to or greater than 0.5 Δdv from a given source indicates that the source contributes to visibility impairment, and therefore is subject to BART. The results of the screening modeling are shown in the table below.

Table 25: Results of the Class I Area Screening Modeling

Class I Area	Maximum Modeled Value (Δdv)	98th Percentile Value (Δdv)
1995		
Bridger WA	5.984	3.119
Fitzpatrick WA	3.305	1.632
1996		
Bridger WA	6.185	4.364
Fitzpatrick WA	5.253	2.378
2001		
Bridger WA	7.331	4.277
Fitzpatrick WA	4.789	2.428

Δdv = delta deciview
WA = wilderness area

REFINED MODELING

Because of the results of the Division's screening modeling, PacifiCorp was required to conduct a refined BART analysis that included CALPUFF visibility modeling for the facility. The modeling approach followed the requirements described in the Division's BART modeling protocol, *BART Air Modeling Protocol - Individual Source Visibility Assessments for BART Control Analyses* (WDEQ-AQD, September 2006).

CALPUFF System

Predicted visibility impacts from the PacifiCorp Naughton sources were determined with the EPA CALPUFF modeling system, which is the EPA-preferred modeling system for long-range transport. As described in the EPA Guideline on Air Quality Models (Appendix W of 40 CFR part 51), long-range transport is defined as modeling with source-receptor distances greater than 50 km. Because all modeled areas are located more than 50 km from the facility, the CALPUFF system was appropriate for use.

The CALPUFF modeling system consists of a meteorological data pre-processor (CALMET), an air dispersion model (CALPUFF), and post-processor programs (POSTUTIL, CALSUM, CALPOST). The CALPUFF model was developed as a non-steady-state air quality modeling system for assessing the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal.

CALMET is a diagnostic wind model that develops hourly wind and temperature fields in a three-dimensional, gridded modeling domain. Meteorological inputs to CALMET can include surface and upper-air observations from multiple meteorological monitoring stations. Additionally, the CALMET model can utilize gridded analysis fields from various mesoscale models such as MM5 to better represent regional wind flows and complex terrain circulations. Associated two-dimensional fields such as mixing height, land use, and surface roughness are included in the input to CALMET. The CALMET model allows the user to “weight” various terrain influence parameters in the vertical and horizontal directions by defining the radius of influence for surface and upper-air stations.

CALPUFF is a multi-layer, Lagrangian puff dispersion model. CALPUFF can be driven by the three-dimensional wind fields developed by the CALMET model (refined mode), or by data from a single surface and upper-air station in a format consistent with the meteorological files used to drive steady-state dispersion models. All far-field modeling assessments described here were completed using the CALPUFF model in a refined mode.

CALSUM is a post-processing program that can operate on multiple CALPUFF output files to combine the results for further post-processing. POSTUTIL is a post-processing program that processes CALPUFF concentrations and wet/dry flux files. The POSTUTIL model operates on one or more output data files from CALPUFF to sum, scale, and/or compute species derived from those that are modeled, and outputs selected species to a file for further post-processing. CALPOST is a post-processing program that can read the CALPUFF (or POSTUTIL or CALSUM) output files and calculate the impacts to visibility.

All of the refined CALPUFF modeling was conducted with the version of the CALPUFF system that was recognized as the EPA-approved release at the time of the development of the Division’s modeling protocol. Version designations of the key programs are listed in the table below.

Table 26: Key Programs in CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.711a	040716
CALPOST	5.51	030709

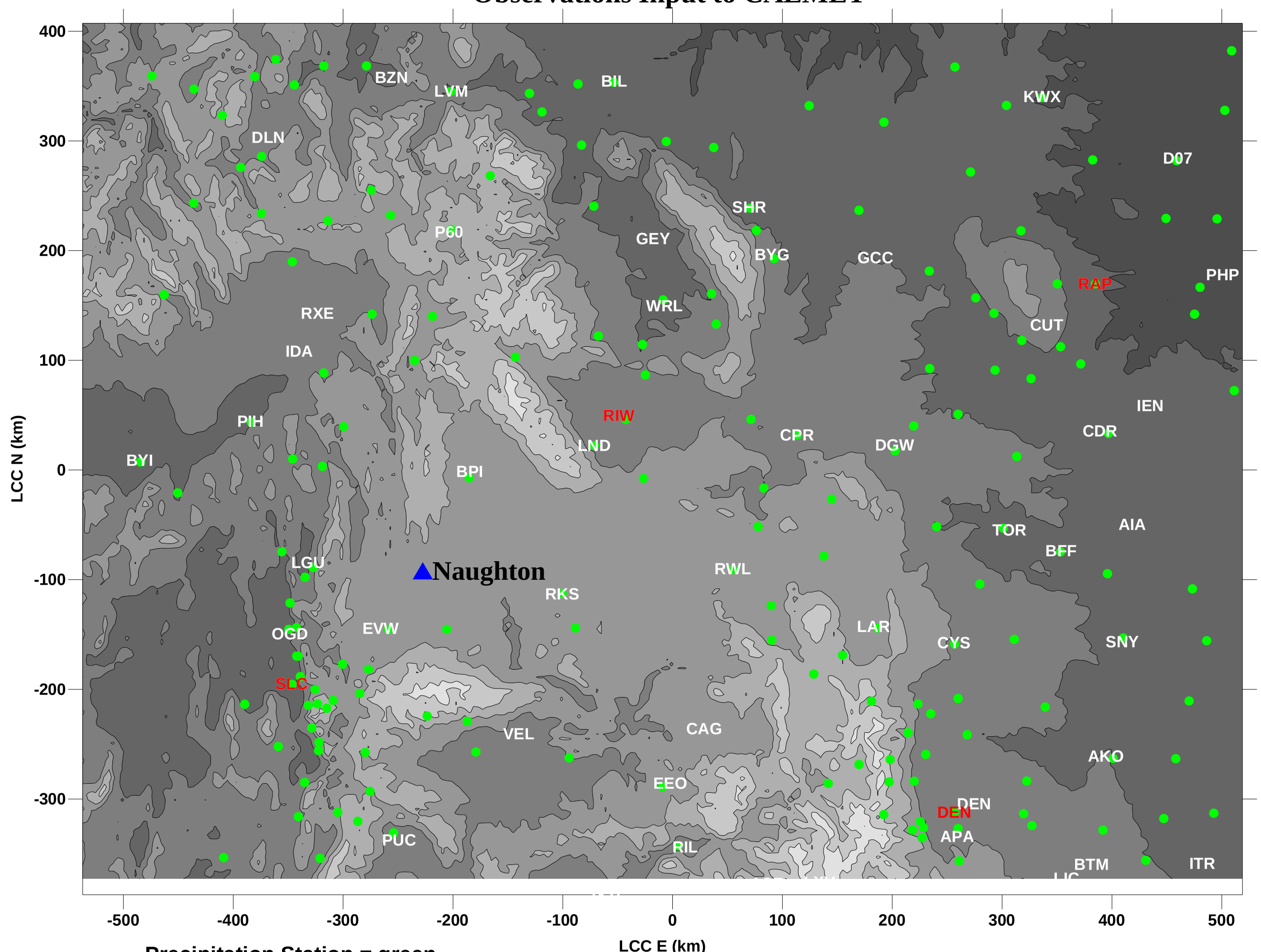
Meteorological Data Processing (CALMET)

As required by the Division's modeling protocol, the CALMET model was used to construct an initial three-dimensional windfield using data from the MM5 model. Surface and upper-air data were input to CALMET to adjust the initial windfield, but because of the relative scarcity of wind observations in the modeling domain, the influence of the observations on the initial windfield was minimized. Because the MM5 data were afforded a high degree of influence on the CALMET windfields, the Division obtained MM5 data at 12-km resolution that spanned the years 2001-2003. Locations of the observations that were input to CALMET, including surface, upper-air, and precipitation stations, are shown in the figure below. Default settings were used in the CALMET input files for most of the technical options. The following table lists the key user-defined CALMET settings that were selected.

Table 27: Key User-Defined CALMET Settings

Variable	Description	Value
PMAP	Map projection	LCC
DGRIDKM	Grid spacing (km)	4
NZ	Number of layers	10
ZFACE	Cell face heights (m)	0, 20, 40, 100, 140, 320, 580, 1020, 1480, 2220, 3400
RMIN2	Minimum distance for extrapolation	-1
IPROG	Use gridded prognostic model output	14
RMAX 1	Maximum radius of influence (surface layer, km)	30
RMAX 2	Maximum radius of influence (layers aloft, km)	50
TERRAD	Radius of influence for terrain (km)	15
R1	Relative weighting of first guess wind field and observations (km)	5
R2	Relative weighting aloft (km)	25

Figure 3
Observations Input to CALMET



Precipitation Station = green
Surface Station = white 3-letter
Upper-Air (+ surface) = red 3-letter

CALPUFF Modeling Setup

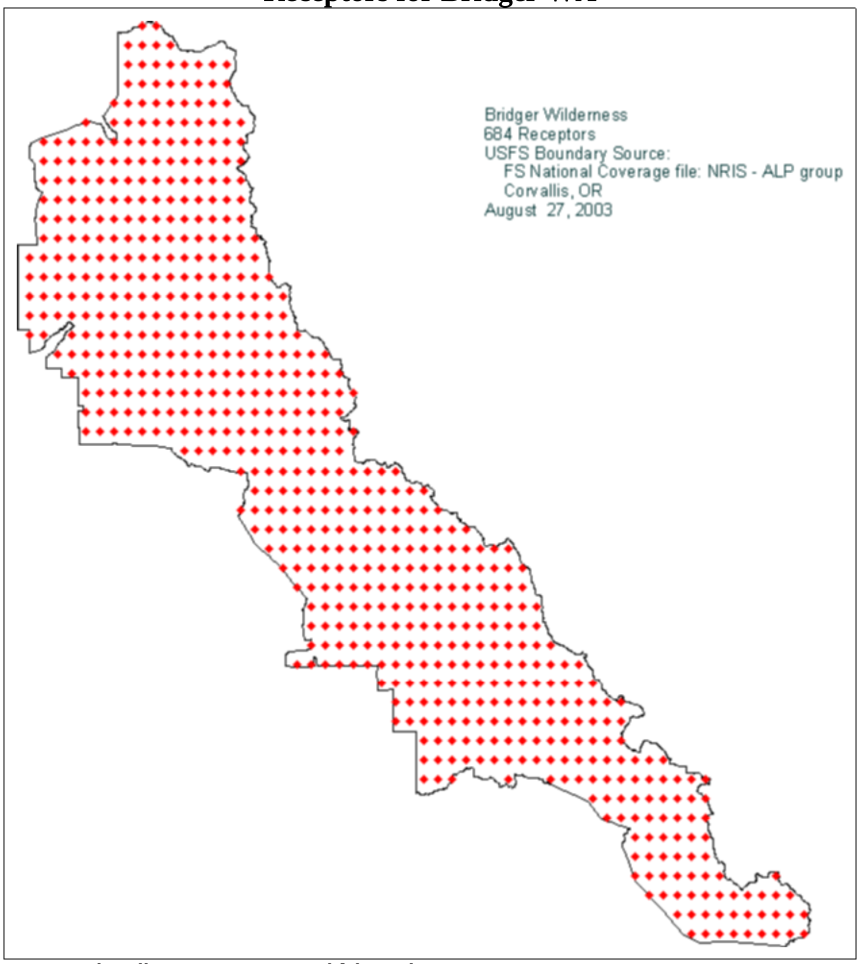
To allow chemical transformations within CALPUFF using the recommended chemistry mechanism (MESOPUFF II), the model required input of background ozone and ammonia concentrations. For ozone, hourly data collected from the following stations were used:

- Rocky Mountain National Park (NP), Colorado
- Craters of the Moon National Monument, Idaho
- Highland, Utah
- Thunder Basin, Wyoming
- Yellowstone NP, Wyoming
- Centennial, Wyoming
- Pinedale, Wyoming

For any hour that was missing ozone data from all stations, a default value of 44 parts per billion (ppb) was used by the model as a substitute. For ammonia, a domain-wide background value of 2 ppb was used.

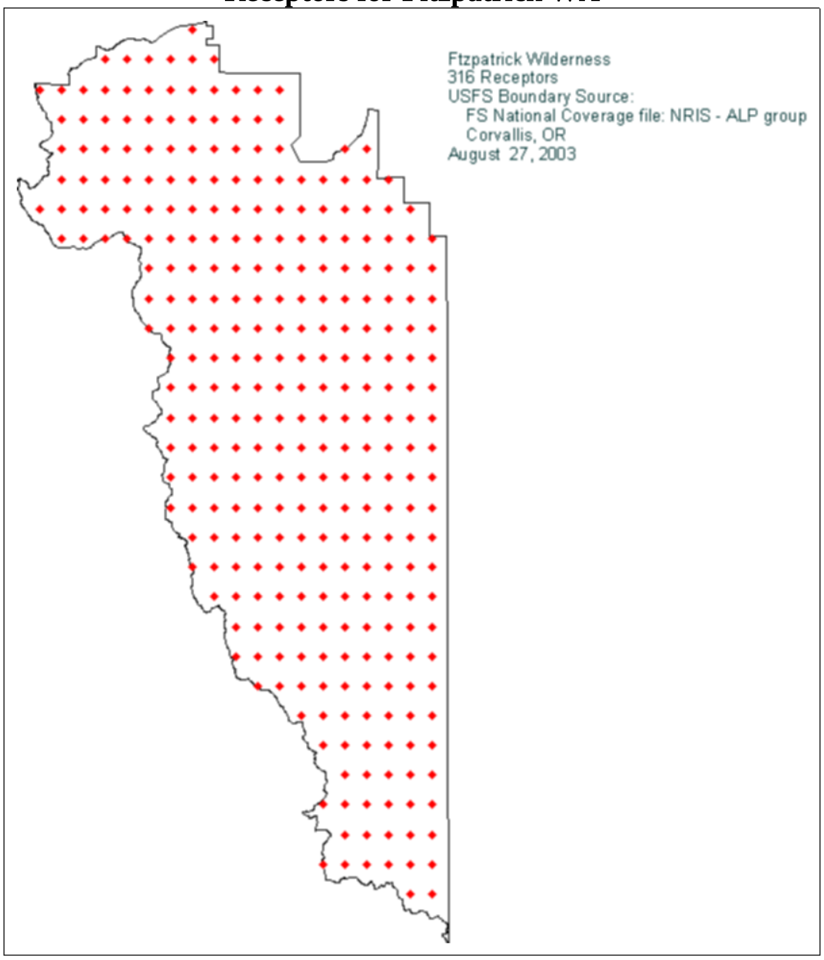
Latitude and longitude coordinates for Class I area discrete receptors were taken from the National Park Service (NPS) Class I Receptors database and converted to the appropriate Lambert Conformal Conic coordinates. Figures 4 and 5 show the receptor configurations that were used for Bridger WA and Fitzpatrick WA. Receptor spacing for the modeled areas was approximately 1.3 km in the east-west direction and approximately 1.8 km in the north-south direction.

Figure 4
Receptors for Bridger WA



Source: http://www.nature.nps.gov/air/Maps/Receptors

Figure 5
Receptors for Fitzpatrick WA



Source: http://www.nature.nps.gov/air/Maps/Receptors/index.cfm

<u>CALPUFF Inputs – Baseline and Control Options</u>

Source release parameters and emissions for baseline and control options for each unit at the Naughton Plant are shown in the tables below.

Table 28: CALPUFF Inputs for Naughton Unit 1

Naughton Unit 1	**Baseline**	**Post-Control Scenario 1**	**Post-Control Scenario 2**	**Post-Control Scenario 3**	**Post-Control Scenario 4**	**Post-Control Scenario A**	**Post-Control Scenario B**
Model Input Data	Current Operation with ESP	LNB with advanced OFA, Dry FGD, ESP with Flue Gas Conditioning	LNB with advanced OFA, Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Wet FGD, ESP with Sulfur Trioxide Injection, New Stack	PacifiCorp Committed Controls: LNB with advanced OFA, Wet FGD, ESP with Flue Gas Conditioning, New Stack	PacifiCorp Committed Controls and SCR
Hourly Heat Input (mmBtu/hour)	1,850	1,850	1,850	1,850	1,850	1,850	1,850
Sulfur Dioxide (SO_2) (lb/mmBtu)	1.20	0.41	0.15	0.15	0.10	0.15	0.15
Sulfur Dioxide (SO_2) pounds per hour (lb/hr)	2,220	759	278	278	185	278	278
Nitrogen Oxide (NOx) (lb/mmBtu)	0.58	0.24	0.24	0.07	0.07	0.26	0.07
Nitrogen Oxide (NOx) (lb/hr)	1,073	444	444	130	130	481	130
PM_{10} (lb/mmBtu)	0.056	0.040	0.015	0.015	0.040	0.040	0.040
PM_{10} (lb/hr)	103.6	74.0	27.8	27.8	74.0	77.7	77.7
Coarse Particulate ($PM_{2.5}$<diameter< PM_{10}) (lb/hr)[(a)]	44.5	31.8	15.8	15.8	31.8	33.4	33.4
Fine Particulate (diameter<$PM_{2.5}$) (lb/hr)[(b)]	59.1	42.2	11.9	11.9	42.2	44.3	44.3
Sulfuric Acid (H_2SO_4) (lb/hr)	34.0	1.7	1.7	2.4	29.2	17.0	29.3
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	--	0.4	2.1	--	2.1
Ammonium Bisulfate ($NH_4)HSO_4$ (lb/hr)	--	--	--	0.7	3.7	--	3.7
H_2SO_4 as Sulfate (SO_4) (lb/hr)	33.3	1.6	1.6	2.4	28.6	16.7	28.7
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	--	--	--	0.3	1.6	--	1.5
$(NH_4)HSO_4$ as SO_4 (lb/hr)	--	--	--	0.6	3.1	--	3.1
Total Sulfate (SO_4) (lb/hr)	33.3	1.6	1.6	3.3	33.2	16.7	33.3
Stack Conditions							
Stack Height (meters)	61	61	61	61	152	145	145
Stack Exit Diameter (meters)	4.27	4.27	4.27	4.27	4.88	4.88	4.88
Stack Exit Temperature (Kelvin)	411	350	342.6	342.6	323	323	323
Stack Exit Velocity (meters per second)	28.1	19.7	24.6	24.6	18.1	18.1	18.1

Notes:

(a) AP-42, Table 1.1-6: coarse PM counted as a percentage of PM_{10}. This equates to 43 percent for ESP and 57 percent for Baghouse.

(b) AP-42, Table 1.1-6: fine PM counted as a percentage of PM_{10}. This equates to 57 percent for ESP and 43 percent for Baghouse.

Table 29: CALPUFF Inputs for Naughton Unit 2

Naughton Unit 2	Baseline	Post-Control Scenario 1	Post-Control Scenario 2	Post-Control Scenario 3	Post-Control Scenario 4	Post-Control Scenario A	Post-Control Scenario B
Model Input Data	Current Operations with ESP	LNB with advanced OFA, Dry FGD, ESP with Flue Gas Conditioning	LNB with advanced OFA, Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Dry FGD, Fabric Filter	LNB with advanced OFA and SCR, Wet FGD, ESP, New Stack	PacifiCorp Committed Controls: LNB with advanced OFA, Wet FGD, ESP with Flue Gas Conditioning, New Stack	PacifiCorp Committed Controls and SCR
Hourly Heat Input (mmBtu/hour)	2,400	2,400	2,400	2,400	2,400	2,400	2,400
Sulfur Dioxide (SO_2) (lb/mmBtu)	1.20	0.41	0.15	0.15	0.10	0.15	0.15
Sulfur Dioxide (SO_2) pounds per hour (lb/hr)	2,868	984	360	360	240	360	360
Nitrogen Oxide (NOx) (lb/mmBtu)	0.54	0.24	0.24	0.07	0.07	0.26	0.07
Nitrogen Oxide (NOx) (lb/hr)	1,291	576	576	168	168	624	168
PM_{10} (lb/mmBtu)	0.064	0.040	0.015	0.015	0.040	0.050	0.040
PM_{10} (lb/hr)	153.6	96.0	36.0	36.0	96.0	129.6	129.6
Coarse Particulate ($PM_{2.5}$<diameter< PM_{10}) (lb/hr)[(a)]	65.8	41.3	20.5	20.5	41.3	55.7	55.7
Fine Particulate (diameter<$PM_{2.5}$) (lb/hr)[(b)]	87.2	54.7	15.5	15.5	54.7	73.9	73.9
Sulfuric Acid (H_2SO_4) (lb/hr)	44.2	2.2	2.2	3.1	37.9	22.1	38.0
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	--	0.6	2.8	--	2.8
Ammonium Bisulfate $(NH_4)HSO_4$ (lb/hr)	--	--	--	1.0	4.8	--	4.8
H_2SO_4 as Sulfate (SO_4) (lb/hr)	--	--	--	0.4	2.0	--	2.0
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	43.3	2.1	2.1	3.1	37.2	21.6	37.2
$(NH_4)HSO_4$ as SO_4 (lb/hr)				0.8	4.0		4.0
Total Sulfate (SO_4) (lb/hr)	43.3	2.1	2.1	4.3	43.2	21.6	43.2
Stack Conditions							
Stack Height (meters)	68	68	68	68	152	145	145
Stack Exit Diameter (meters)	4.88	4.88	4.88	4.88	5.49	5.49	5.49
Stack Exit Temperature (Kelvin)	411	350	343	343	323	323	323
Stack Exit Velocity (meters per second)	27.8	20.2	24.3	24.3	18.5	18.5	18.5

Notes:

(a) AP-42, Table 1.1-6: coarse PM counted as a percentage of PM_{10}. This equates to 43 percent for ESP and 57 percent for Baghouse.

(b) AP-42, Table 1.1-6: fine PM counted as a percentage of PM_{10}. This equates to 57 percent for ESP and 43 percent for Baghouse.

Table 30: CALPUFF Inputs for Naughton Unit 3

Naughton Unit 3	**Baseline**	**Post-Control Scenario 1**	**Post-Control Scenario 2**	**Post-Control Scenario 3**	**Post-Control Scenario 4**	**Post-Control Scenario A**	**Post-Control Scenario B**
Model Input Data	Current Operations with Wet FGD and ESP	Tuning Existing LNB with OFA, Wet FGD with Waste Liquor, Existing ESP	Tuning Existing LNB with OFA & SCR, Wet FGD with Waste Liquor, Enhanced ESP	Tuning Existing LNB with OFA and SCR, Wet FGD with Waste Liquor, Fabric Filter	Tuning Existing LNB with OFA and SCR, Wet FGD with Soda Ash, Fabric Filter	PacifiCorp Committed Controls: Tuning Existing LNB with OFA, Wet Sodium FGD, New Fabric Filter	PacifiCorp Committed Controls and SCR
Hourly Heat Input (mmBtu/hour)	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Sulfur Dioxide (SO_2) (lb/mmBtu)	0.50	0.21	0.21	0.21	0.10	0.22	0.22
Sulfur Dioxide (SO_2) pounds per hour (lb/hr)	1,840	777	777	777	370	814	814
Nitrogen Oxide (NOx) (lb/mmBtu)	0.45	0.35	0.07	0.07	0.07	0.37	0.07
Nitrogen Oxide (NOx) (lb/hr)	1,656	1,295	259	259	259	1,369	259
PM_{10} (lb/mmBtu)	0.094	0.040	0.040	0.015	0.015	0.015	0.015
PM_{10} (lb/hr)	348.0	148.0	148.0	55.5	55.5	55.5	55.5
Coarse Particulate ($PM_{2.5}$<diameter< PM_{10}) (lb/hr)[(a)]	149.6	63.6	63.6	31.6	31.6	23.9	23.9
Fine Particulate (diameter<$PM_{2.5}$) (lb/hr)[(b)]	198.4	84.4	84.4	23.9	23.9	31.6	31.6
Sulfuric Acid (H_2SO_4) (lb/hr)	34.0	34.0	58.7	58.7	58.7	34.0	58.5
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	4.3	4.3	4.3	--	4.3
Ammonium Bisulfate $(NH_4)HSO_4$ (lb/hr)	--	--	7.4	7.4	7.4	--	7.4
H_2SO_4 as Sulfate (SO_4) (lb/hr)	33.4	33.4	57.3	57.3	57.3	33.3	57.3
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	--	--	3.1	3.1	3.1	--	3.1
$(NH_4)HSO_4$ as SO_4 (lb/hr)	--	--	6.2	6.2	6.2	--	6.2
Total Sulfate (SO_4) (lb/hr)	33.2	33.4	66.6	66.6	66.6	33.3	66.6
Stack Conditions							
Stack Height (meters)	145	145	145	145	145	145	145
Stack Exit Diameter (meters)	8.08	8.08	8.08	8.08	8.08	8.08	8.08
Stack Exit Temperature (Kelvin)	323	322	322	322	323	322	322
Stack Exit Velocity (meters per second)	23.8	20.2	20.2	20.2	18.6	20.2	20.2

Notes:

(a) AP-42, Table 1.1-6: coarse PM counted as a percentage of PM_{10}. This equates to 43 percent for ESP and 57 percent for Baghouse.

(b) AP-42, Table 1.1-6: fine PM counted as a percentage of PM_{10}. This equates to 57 percent for ESP and 43 percent for Baghouse.

Visibility Post-Processing (CALPOST)

The changes in visibility were modeled using Method 6 within the CALPOST post-processor. Method 6 requires input of monthly relative humidity factors [f(RH)] for each Class I area. Monthly f(RH) factors that were used for Bridger WA and Fitzpatrick WA are shown in the table below.

Table 31: Relative Humidity Factors for CALPOST

Month	Bridger WA & Fitzpatrick WA
January	2.50
February	2.30
March	2.30
April	2.10
May	2.10
June	1.80
July	1.50
August	1.50
September	1.80
October	2.00
November	2.50
December	2.40

According to the final BART rule, natural background conditions as a reference for determination of the modeled Δdv change should be representative of the 20 percent best natural visibility days in a given Class I area. EPA BART guidance provides the 20 percent best days deciview values for each Class I area on an annual basis, but does not provide the individual species concentration data required for input to CALPOST.

Species concentrations corresponding to the 20 percent best days were calculated for each Class I area by scaling back the annual average (natural background) concentrations given in Table 2-1 of the EPA document *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule.* A separate scaling factor was derived for each Class I area such that, when multiplied by the guidance table annual concentrations, the 20% best days deciview values for that particular Class I area would be calculated.

The scaling procedure is illustrated here for Bridger WA. From Appendix B in the EPA natural visibility guidance document, the deciview value for the 20 percent best days at Bridger WA is 1.96 dv. To obtain the speciated background concentrations representative of the 20 percent best days, the deciview value (1.96 dv) was first converted to light extinction. The relationship between deciviews and light extinction is expressed as follows:

$dv = 10 \ln (b_{ext}/10)$ or $b_{ext} = 10 \exp (dv/10)$

where: b_{ext} = light extinction expressed in inverse megameters (Mm^{-1}).

Using this relationship with the known deciview value of 1.96, one obtains an equivalent light extinction value of 12.17 Mm^{-1}. Next, the annual average natural visibility concentrations were set equal to a total extinction value of 12.17 Mm^{-1}. The relationship between total light extinction and the individual components of the light extinction is as follows:

b_{ext} = (3)f(RH)[ammonium sulfate] + (3)f(RH)[ammonium nitrate] + (0.6)[coarse mass] + (4)[organic carbon] + (1)[soil] + (10)[elemental carbon] + b_{ray}

where:

- bracketed quantities represent background concentrations in μg/m^3
- values in parenthesis represent scattering efficiencies
- f(RH) is the relative humidity adjustment factor (applied to hygroscopic species only)
- b_{ray} is light extinction due to Rayleigh scattering (10 Mm^{-1} used for all Class I areas)

Substituting the annual average natural background concentrations, the average f(RH) for Bridger WA, and including a coefficient for scaling, one obtains:

12.17 = (3)(2.1)[0.12]X + (3)(2.1)[0.1]X + (0.6)[3.0]X + (4)[0.47]X + (1)[0.5]X + (10)[0.02]X + 10

In the equation above, X represents a scaling factor needed to convert the annual average natural background concentrations to values representative of the 20 percent best days. Solving for X provides a value of 0.376. Table 32 presents the annual average natural background concentrations, the calculated scaling factor, and the calculated background concentrations for the 20 percent best days for Bridger WA.

Table 32: Calculated Background Components for Bridger WA

Component	Annual Average for West Region (μg/m^3)	Calculated Scaling Factor	20% Best Days for Bridger WA (μg/m^3)
Ammonium Sulfate	0.12	0.376	0.045
Ammonium Nitrate	0.10	0.376	0.038
Organic Carbon	0.47	0.376	0.176
Elemental Carbon	0.02	0.376	0.008
Soil	0.50	0.376	0.188
Coarse Mass	3.00	0.376	1.127

The scaled aerosol concentrations were averaged for Bridger WA and Fitzpatrick WA because of their geographical proximity and similar annual background visibility. The 20 percent best days aerosol concentrations for the two Class I areas in question are listed in the table below.

Table 33: Natural Background Aerosol Concentrations (μg/m^3)

Aerosol Component	Fitzpatrick WA & Bridger WA
Ammonium Sulfate	0.045
Ammonium Nitrate	0.038
Organic Carbon	0.178
Elemental Carbon	0.008
Soil	0.189
Coarse Mass	1.136

Visibility Post-Processing Results

The results of the visibility modeling for each of the three units for the baseline and control scenarios are shown in the tables below. For each scenario, the 98th percentile Δdv results are reported along with the total number of days for which the predicted impacts exceeded 0.5 dv. Following the tables are figures that present the results graphically for baseline, the BART configuration proposed by PacifiCorp, and for the proposed BART configuration with the addition of SCR.

Table 34: CALPUFF Visibility Modeling Results: Unit 1

Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Current Operations with ESP								
Bridger WA	1.777	48	1.763	41	1.797	45	1.779	45
Fitzpatrick WA	0.966	23	0.881	18	0.840	20	0.896	20
Post-Control Scenario 1 – LNB with advanced OFA, Dry FGD, ESP with Flue Gas Conditioning								
Bridger WA	0.644	14	0.741	14	0.694	16	0.693	15
Fitzpatrick WA	0.357	3	0.314	5	0.361	5	0.344	4
Post-Control Scenario 2 – LNB with advanced OFA, Dry FGD, New Fabric Filter								
Bridger WA	0.479	7	0.635	9	0.493	7	0.536	8
Fitzpatrick WA	0.235	2	0.205	2	0.266	3	0.235	2
Post-Control Scenario 3 – LNB with advanced OFA and SCR, Dry FGD, New Fabric Filter								
Bridger WA	0.217	1	0.274	1	0.234	3	0.242	2
Fitzpatrick WA	0.119	0	0.105	0	0.123	0	0.116	0
Post-Control Scenario 4 – LNB with advanced OFA and SCR, Wet FGD, ESP with Sulfur Trioxide Injection, New Stack								
Bridger WA	0.387	4	0.288	3	0.397	4	0.357	4
Fitzpatrick WA	0.153	1	0.108	1	0.135	0	0.132	1
Post-Control Scenario A – Committed Controls: LNB with advanced OFA, Wet FGD, ESP with Flue Gas Conditioning								
Bridger WA	0.733	14	0.623	9	0.698	12	0.685	12
Fitzpatrick WA	0.320	3	0.221	2	0.280	2	0.274	2
Post-Control Scenario B – Committed Controls and SCR								
Bridger WA	0.406	5	0.370	4	0.413	5	0.396	5
Fitzpatrick WA	0.175	1	0.131	1	0.168	0	0.158	1

Table 35: CALPUFF Visibility Modeling Results: Unit 2

Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Current Operations with ESP								
Bridger WA	2.127	61	1.860	56	2.087	55	2.025	57
Fitzpatrick WA	1.158	26	1.099	24	1.110	22	1.122	24
Post-Control Scenario 1 – LNB with advanced OFA, Dry FGD, ESP with flue gas conditioning								
Bridger WA	0.838	28	0.926	18	0.882	19	0.882	22
Fitzpatrick WA	0.462	6	0.413	5	0.448	6	0.441	6
Post-Control Scenario 2 – LNB with advanced OFA, Dry FGD, New Fabric Filter								
Bridger WA	0.642	14	0.745	11	0.614	12	0.667	12
Fitzpatrick WA	0.312	3	0.286	4	0.313	4	0.304	4
Post-Control Scenario 3 – LNB with advanced OFA and SCR, Dry FGD, Fabric Filter								
Bridger WA	0.284	2	0.321	3	0.291	3	0.299	3
Fitzpatrick WA	0.158	1	0.141	1	0.148	0	0.149	1
Post-Control Scenario 4 – LNB with advanced OFA and SCR, Wet FGD, ESP, New Stack								
Bridger WA	0.482	7	0.354	4	0.526	8	0.454	6
Fitzpatrick WA	0.208	2	0.138	1	0.162	0	0.169	1
Post-Control Scenario A – Committed Controls: LNB with advanced OFA, Wet FGD, ESP with Flue Gas Conditioning								
Bridger WA	0.944	20	0.757	14	0.921	15	0.874	16
Fitzpatrick WA	0.404	4	0.288	4	0.326	2	0.339	3
Post-Control Scenario B – Committed Controls and SCR								
Bridger WA	0.544	10	0.450	7	0.555	9	0.516	9
Fitzpatrick WA	0.221	2	0.167	1	0.186	0	0.191	1

Table 36: CALPUFF Visibility Modeling Results: Unit 3

Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Current Operations with Wet FGD and ESP								
Bridger WA	1.978	66	1.618	56	2.171	53	1.922	58
Fitzpatrick WA	1.126	24	0.893	21	0.871	21	0.963	22
Post-Control Scenario 1 – Tuning Existing LNB with OFA, Wet FGD with Waste Liquor, Existing ESP								
Bridger WA	1.413	12	1.175	32	1.555	39	1.381	28
Fitzpatrick WA	0.735	16	0.564	11	0.549	9	0.616	12
Post-Control Scenario 2 – Tuning Existing LNB with OFA & SCR, Wet FGD with Waste Liquor, Enhanced ESP								
Bridger WA	0.716	19	0.650	10	0.828	14	0.731	14
Fitzpatrick WA	0.371	4	0.290	3	0.260	1	0.307	3
Post-Control Scenario 3 – Tuning Existing LNB with OFA and SCR, Wet FGD with Waste Liquor, Fabric Filter								
Bridger WA	0.697	16	0.635	10	0.810	14	0.714	13
Fitzpatrick WA	0.363	4	0.279	3	0.253	1	0.298	3
Post-Control Scenario 4 – Tuning Existing LNB with OFA and SCR, Wet FGD with Soda Ash, Fabric Filter								
Bridger WA	0.553	12	0.494	7	0.662	11	0.570	10
Fitzpatrick WA	0.265	2	0.203	3	0.214	0	0.227	2
Post-Control Scenario A – Committed Controls: Tuning Existing LNB with OFA, Wet FGD, New Fabric Filter								
Bridger WA	1.460	45	1.21	34	1.583	40	1.418	40
Fitzpatrick WA	0.766	17	0.586	11	0.572	11	0.641	13
Post-Control Scenario B – Committed Controls and SCR								
Bridger WA	0.710	17	0.650	10	0.830	14	0.730	14
Fitzpatrick WA	0.372	4	0.287	3	0.259	1	0.306	3

Figure 6
Modeled BART Impacts: 98th Percentile (delta-dv)

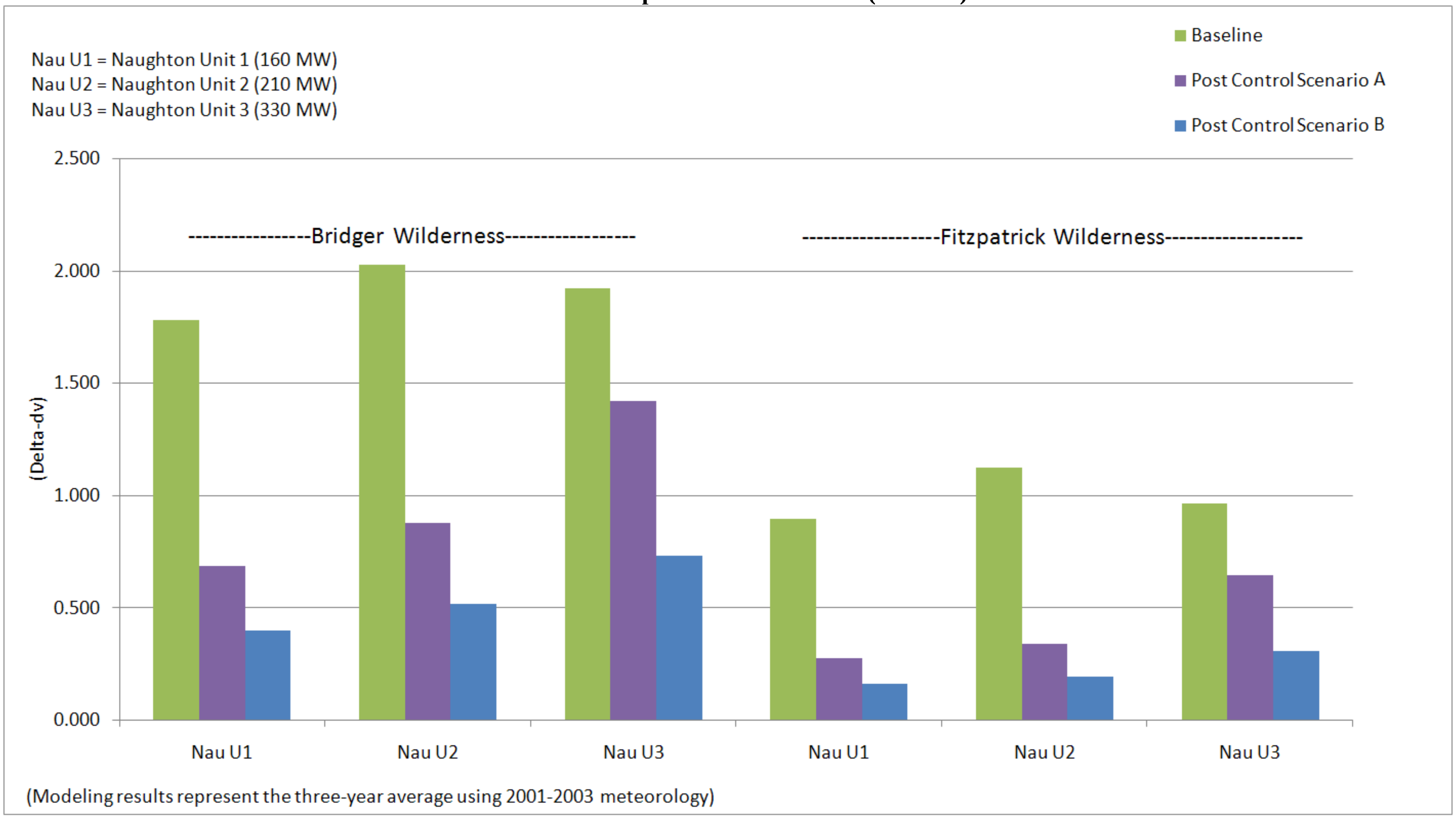
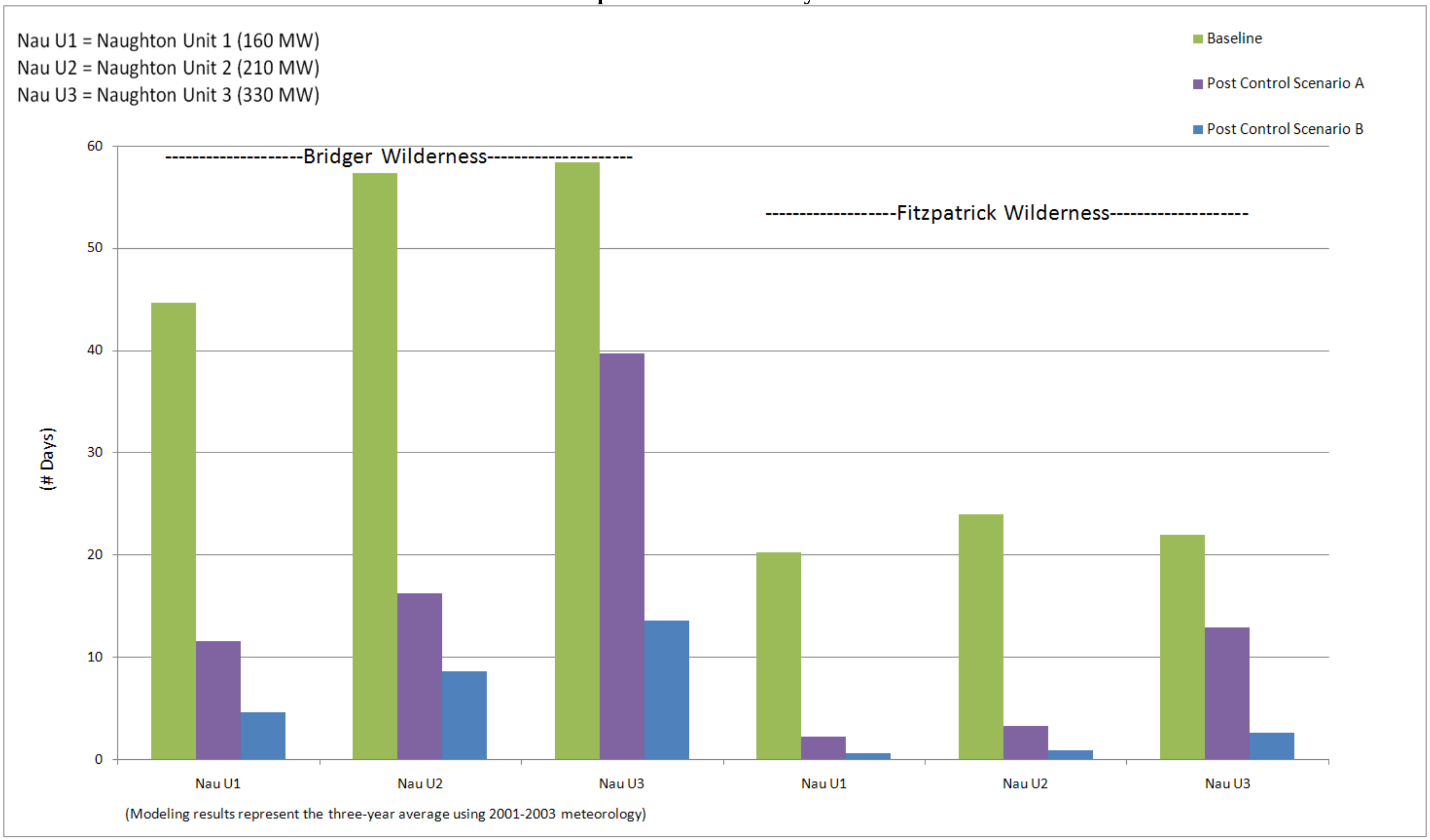


Figure 7
Modeled BART Impacts: Number of Days > 0.5 delta-dv



BART CONCLUSIONS:

After considering (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any pollution equipment in use or in existence at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility (all five statutory factors) from each proposed control technology, the Division determined BART for each visibility impairing pollutant emitted from the three units subject to BART at the Naughton Power Plant.

NO_x

LNB with advanced OFA is determined to be BART for Units 1 and 2 for NO_x based, in part, on the following conclusions:

1. LNB with advanced OFA on Units 1and 2 was cost effective with a capital cost of $9,600,000 and $9,100,000 per unit, respectively. The average cost effectiveness, over a twenty year operational life, is $426 per ton of NO_x removed for Unit 1 and $357 per ton for Unit 2.

2. Combustion control using LNB with advanced OFA does not require non-air quality environmental mitigation for the use of chemical reagents (i.e., ammonia or urea) and there is a minimal energy impact.

3. After careful consideration of the five statutory factors, especially the costs of compliance and the existing pollution control equipment, a NO_x control level of 0.26 lb/MMBtu on a 30-day rolling average, above EPA's established presumptive limit of 0.15 lb/MMBtu for tangential-fired boilers burning sub-bituminous coal, though not applicable, is justified.

4. Visibility impacts were addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants and associated control options. The cumulative 3-year averaged 98th percentile visibility improvement from the baseline summed across both Class I areas achieved with LNB with advanced OFA, wet FGD, and existing ESP with FGC (Post-Control Scenario A) was 1.716 Δdv from Unit 1 and 1.934 Δdv from Unit 2.

5. Annual NO_x emission reductions from baseline achieved by applying LNB with advanced OFA on Units 1 and 2 are 2,334 tons and 2,649 tons, respectively.

LNB with advanced OFA and SCR was not determined to be BART for Units 1and 2 for NO_x based, in part, on the following conclusions:

1. The cost of compliance for installing SCR on each unit is significantly higher than LNB with advanced OFA. Capital cost for SCR on Unit 1 is $94,600,000 and $115,900,000 for Unit 2. Annual SCR O&M costs for Unit 1 are $1,231,912 and $1,639,352 for Unit 2.

2. Additional non-air quality environmental mitigation is required for the use of chemical reagents.

3. Operation of LNB with advanced OFA and SCR is parasitic and requires an estimated 1.0 MW from Unit 1 and 1.3 MW from Unit 2.

4. While visibility impacts were addressed in a cumulative analysis of all three pollutants, Post-Control Scenario B is directly comparable to Post-Control Scenario A as the only difference is directly attributable to the installation of SCR. Subtracting the modeled 98th percentile values from each other yield the incremental 98th percentile visibility improvement from SCR. The cumulative 3-year averaged 98th percentile visibility improvement from Post-Control Scenario A across both Class I areas achieved with Post-Control Scenario B was 0.405 Δdv from Unit 1 and 0.506 Δdv from Unit 2.

Tuning the existing LNB with OFA and installing SCR is determined to be BART for Unit 3 for NO_x based, in part, on the following conclusions:

1. The cost effectiveness of tuning the existing LNB with OFA and installing SCR on Unit 3 was reasonable at $2,830 per ton of NO_x removed. The incremental cost effectiveness when compared to existing LNB with ROFA was $1,783 per ton of NO_x and reasonable as well. Both the cost effectiveness and average cost effectiveness were based on a twenty year operational life for the proposed controls.

2. The cumulative 3-year averaged 98th percentile visibility improvement from the baseline summed across both Class I areas achieved by tuning the existing LNB with OFA, wet FGD and installing a new full-scale fabric filter, Post-Control Scenario A, was 0.826 Δdv from Unit 3. Units 1 and 2 yielded notably higher visibility improvements from baseline, 1.716 Δdv and 1.934 Δdv, respectively, using Post-Control Scenario A which included new LNB with advanced OFA, but not SCR.

3. Modeled 98th percentile visibility results from Unit 3 Post-Control Scenario B are directly comparable to those from Post-Control Scenario A, as the only difference is directly attributable to the installation of SCR. The cumulative 3-year averaged 98th percentile visibility improvement across the two Class I areas achieved by installing SCR on Unit 3 was 1.023 Δdv, approximately twice the 98th percentile visibility improvements, 0.405 Δdv from Unit 1 and 0.506 Δdv from Unit 2, using Post-Control Scenario B which included installing SCR.

4. The cumulative 3-year averaged 98th percentile visibility improvement from the baseline summed across both Class I areas achieved by tuning the existing LNB with OFA, SCR, wet FGD, and installing a new full-scale fabric filter, Post-Control Scenario B, was 1.849 Δdv. This visibility improvement is less than the improvement achieved by Post-Control Scenario A using new LNB and advanced OFA on Unit 2, 1.934 Δdv, but higher than Post-Control Scenario A using new LNB and advanced OFA on Unit 1, 1.716 Δdv.

5. Annual NO_x emission reductions from baseline achieved by tuning existing LNB with OFA and installing SCR are 5,542 tons as compared to only 1,167 tons from tuning existing LNB with OFA.

6. After careful consideration of the five statutory factors, especially the costs of compliance and the existing pollution control equipment, a NO_x control level of 0.37 lb/MMBtu on a 30-day rolling average for Unit 3, above EPA's established presumptive limit of 0.15 lb/MMBtu for tangential-fired boilers burning sub-bituminous coal, though not applicable, is not justified.

The Division considers the installation and operation of the BART-determined NO_x controls, new LNB with advanced OFA on Units 1 and 2 and tuning existing LNB with OFA and installing SCR on Unit 3 to meet corresponding emission limits on a continuous basis, to meet the statutory requirements of BART.

Unit-by-unit NO_x BART determinations:

Naughton Unit 1: Installing new LNB with advanced OFA and meeting NO_x emission limits of 0.26 lb/MMBtu (30-day rolling average), 481 lb/hr (30-day rolling average), and 2,107 tpy as BART for NO_x.

Naughton Unit 2: Installing new LNB with advanced OFA and meeting NO_x emission limits of 0.26 lb/MMBtu (30-day rolling average), 624 /hr (30-day rolling average), and 2,733 tpy as BART for NO_x.

Naughton Unit 3: Tuning existing LNB with OFA and installing SCR meeting NO_x emission limits of 0.07 lb/MMBtu (30-day rolling average), 259 lb/hr (30-day rolling average), and 1,134 tpy as BART for NO_x.

PM/PM_{10}

Existing ESP with FGC is determined to be BART for Units 1 and 2 for PM/PM_{10} based, in part, on the following conclusions:

1. Recognizing the cost benefit associated with using the existing ESPs and the minimal energy impact of installing FGC, the cost of compliance for the control technology is cost effective for each unit, over a twenty year operational life, for reducing PM emissions. The cost effectiveness for existing ESP with FGC is $1,721 for Unit 1 and $949 for Unit 2.

2. No negative non-air environmental impacts are anticipated from existing ESPs with FGC.

3. Visibility impacts were addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants and associated control options. The cumulative 3-year averaged 98th percentile visibility improvement from the baseline summed across both Class I areas achieved with LNB with advanced OFA, wet FGD, and existing ESP with FGC (Post-Control Scenario A) was 1.716 Δdv from Unit 1 and 1.934 Δdv from Unit 2. While the visibility improvement attributable to the installation of FGC on existing ESPs can't be directly determined from the visibility modeling, the Division does not anticipate the PM contribution to be significant when compared to NO_x and SO_2 contributions.

Existing ESP with FGC and a polishing fabric filter was not determined to be BART for Units 1 and 2 for PM/PM_{10} based, in part, on the following conclusions:

1. The cost of compliance for a polishing fabric filter on each unit is not reasonable over a twenty year operational life. The cost effectiveness for installing a new polishing fabric filter on the existing ESP is $8,848 for Unit 1 and, $11,494 for Unit 2. Incremental cost effectiveness is $17,748 for Unit 1 and $16,431 for Unit 2.

2. The cumulative 3-year averaged 98th percentile visibility improvement from applying a polishing fabric filter can be calculated by subtracting Post-Control Scenario 2 results from Post-Control Scenario 1 results and summing across both Class I areas. The achieved 98th percentile visibility improvement was 0.266 Δdv from Unit 1 and 0.352 Δdv from Unit 2.

A new full-scale fabric filter is determined to be BART for Unit 3 for PM/PM_{10} based, in part, on the following conclusions:

1. While the Division considers the cost of compliance for a full-scale fabric filter on Unit 3 not reasonable, PacifiCorp is committed to installing this control device and has permitted the installation of a full-scale fabric filter on Unit 3 in a recently issued New Source Review construction permit. A full-scale fabric filter is the most stringent PM/PM_{10} control technology and therefore the Division will accept it as BART.

The Division considers the installation and operation of the BART-determined PM/PM_{10} controls, existing ESP with FGC on Units 1 and 2 and a new full-scale fabric filter on Unit 3 to meet corresponding emission limits on a continuous basis, to meet the statutory requirements of BART.

Unit-by-unit PM/PM_{10} BART determinations:

<u>Naughton Unit 1</u>:	Installing FGC on the existing ESP and meeting PM/PM_{10} emission limits of 0.040 lb/MMBtu, 74 lb/hr, and 324 tpy as BART for PM/PM_{10}.
<u>Naughton Unit 2</u>:	Installing FGC on the existing ESP and meeting PM/PM_{10} emission limits of 0.040 lb/MMBtu, 96 lb/hr, and 421 tpy as BART for PM/PM_{10}.
<u>Naughton Unit 3</u>:	Installing a new full-scale fabric filter and meeting PM/PM_{10} emission limits of 0.015 lb/MMBtu, 56 lb/hr, and 243 tpy as BART for PM/PM_{10}.

<u>SO_2: WESTERN BACKSTOP SULFUR DIOXIDE TRADING PROGRAM</u>

PacifiCorp evaluated control SO_2 control technologies that can achieve a SO_2 emission rate of 0.15 lb/MMBtu or lower from the coal-fired boilers. PacifiCorp proposed SO_2 BART controls are installing wet FGD with FGC using the existing ESPs on Units 1 and 2, and upgrading the existing wet FGD using waste liquor and removing the existing ESP and installing a new full-scale fabric filter on Unit 3.

Wyoming is a §309 state participating in the Regional SO_2 Milestone and Backstop Trading Program. §308(e)(2) provides States with the option to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain additional control technology to meet an established emission limit on a continuous basis. However, the alternate program must achieve greater reasonable progress than would be accomplished by installing BART. A demonstration that the alternate program can achieve greater reasonable progress is prescribed by §308(e)(2)(i). Since the pollutant of concern is SO_2, this demonstration has been performed under §309 as part of the state implementation plan. §309(d)(4)(i) requires that the SO_2 milestones established under the plan "…must be shown to provide for greater reasonable progress than would be achieved by application of BART pursuant to §51.308(e)(2)."

Wyoming participated in creating a detailed report entitled **Demonstration that the SO_2 Milestones Provide Greater Reasonable Progress than BART** covering SO_2 emissions from all states participating in the Regional SO_2 Milestone and Backstop Trading Program. The document was submitted to EPA in support of the §309 Wyoming Regional Haze SIP in November of 2008.

As part of the §309 program, participating states, including Wyoming, must submit an annual Regional Sulfur Dioxide Emissions and Milestone Report that compares actual emissions to pre-established milestones. Participating states have been filing these reports since 2003. Each year, states have been able to demonstrate that actual SO_2 emissions are well below the milestones. The actual emissions and their respective milestones are shown in Table 37.

Table 37: Regional Sulfur Dioxide Emissions and Milestone Report Summary

Year	Reported SO_2 Emissions (tons)	3-year Milestone Average (tons)
2003	330,679	447,383
2004	337,970	448,259
2005	304,591	446,903
2006	279,134	420,194
2007	273,663	420,637

In addition to demonstrating successful SO_2 emission reductions, §309 states have also relied on visibility modeling conducted by the WRAP to demonstrate improvement at Class I areas. The complete modeling demonstration showing deciview values was included as part of the visibility improvement section of the §309 SIP, but the SO_2 portion of the demonstration has been included as Table 38 to underscore the improvements associated with SO_2 reductions.

Table 38: Visibility - Sulfate Extinction Only

Class I Area Monitor (Class I Areas Represented)	**20% Worst Visibility Days (Monthly Average, Mm^{-1})**		**20% Best Visibility Days (Monthly Average, Mm^{-1})**	
	2018 [1] Base Case (Base 18b)	**2018 [2] Preliminary Reasonable Progress Case (PRP18a)**	**2018 [1] Base Case (Base 18b)**	**2018 [2] Preliminary Reasonable Progress Case (PRP18a)**
Bridger, WY (Bridger WA and Fitzpatrick WA)	5.2	4.3	1.6	1.3
North Absaroka, WY (North Absaroka WA and Washakie WA)	4.8	4.5	1.1	1.1
Yellowstone, WY (Yellowstone NP, Grand Teton NP and Teton WA)	4.3	3.9	1.6	1.4
Badlands, SD	17.8	16.0	3.5	3.1
Wind Cave, SD	13.0	12.1	2.7	2.5
Mount Zirkel, CO (Mt. Zirkel WA and Rawah WA)	4.6	4.1	1.4	1.3
Rocky Mountain, CO	6.8	6.2	1.3	1.1
Gates of the Mountains, MT	5.3	5.1	1.0	1.0
UL Bend, MT	9.7	9.6	1.8	1.7
Craters of the Moon, ID	5.8	5.5	1.5	1.5
Sawtooth, ID	3.0	2.8	1.2	1.1
Canyonlands, UT (Canyonlands NP and Arches NP)	5.4	4.8	2.1	1.9
Capitol Reef, UT	5.7	5.4	1.9	1.8

[1] Represents 2018 Base Case growth plus all established controls as of Dec. 2004. No BART or SO_2 Milestone assumptions were included.
[2] Represents 2018 Preliminary Reasonable Progress growth estimates and established SO_2 limits.

All Class I areas in the surrounding states show a projected visibility improvement for 2018 with respect to SO_2 on the worst days and no degradation on the best days. More discussion on the visibility improvement of the §309 program can be found in the Wyoming §309 Regional Haze SIP revision submitted to EPA in November 2008.

Therefore, in accordance with §308(e)(2), Wyoming's §309 Regional Haze SIP, and WAQSR Chapter 6, Section 9, PacifiCorp will not be required to install the company-proposed BART technology and meet the corresponding achievable emission limit. Instead, PacifiCorp is required to participate in the Regional SO_2 Milestone and Backstop Trading Program authorized under Chapter 14 of the WAQSR.

LONG-TERM STRATEGY FOR REGIONAL HAZE:

In this BART analysis, the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology were taken into consideration when determining BART. When evaluating the costs of compliance the Division recognized a time limitation to install BART-determined controls imposed by the Regional Haze Rule. In addressing the required elements, including documentation for all required analyses, to be submitted in the state implementation plan, 40 CFR 51.308(e)(1)(iv) states: "A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision." As a practical measure, the Division anticipates the requirement to install the BART-determined controls to occur as early as 2015.

PacifiCorp used the **EPA Air Pollution Control Cost Manual**, which is identified in 40 CFR part 51 Appendix Y(IV)(D)(4)(a)(5) as a reference source, to estimate capital costs and calculate cost effectiveness. Section 1 Chapter 2 of the **EPA Air Pollution Control Cost Manual - Sixth Edition** (EPA 452/B-02-001) describes the concepts and methodology of cost estimation used in the manual. Beginning on page 2-28 of Chapter 2.5.4.2, the manual discusses retrofit cost consideration including the practice of developing a retrofit factor to account for unanticipated additional costs of installation not directly related to the capital cost of the controls themselves. However, PacifiCorp did not present a retrofit factor in their cost analyses. PacifiCorp estimated that the installation of SCR requires a minimum of 6 years of advanced planning and engineering before the control can be successfully installed and operated. This planning horizon would necessarily be considered in the scheduled maintenance turnarounds for existing units to minimize the installation costs of the pollution control systems.

PacifiCorp's BART-eligible or subject-to-BART power plant fleet is shown in Table 39. While the majority of affected units are in Wyoming, there are four units in Utah and one in Arizona. Since the 5-year control installation requirement is stated in the federal rule it applies to all of PacifiCorp's units requiring additional BART-determined controls. Although BART is determined on a unit-by-unit basis taking into consideration the statutory factors, consideration for additional installation costs related to the logistics of managing more than one control installation, which are indirect retrofit costs, was afforded under the statutory factor: costs of compliance.

Table 39: PacifiCorp's BART-Eligible/Subject Units

Source	State
Hunter Unit 1 [a]	Utah
Hunter Unit 2 [a]	Utah
Huntington Unit 1 [a]	Utah
Huntington Unit 2 [a]	Utah
Cholla Unit 4 [b]	Arizona
Dave Johnston Unit 3	Wyoming
Dave Johnston Unit 4	Wyoming
Jim Bridger Unit 1	Wyoming
Jim Bridger Unit 2	Wyoming
Jim Bridger Unit 3	Wyoming
Jim Bridger Unit 4	Wyoming
Naughton Unit 1	Wyoming
Naughton Unit 2	Wyoming
Naughton Unit 3	Wyoming
Wyodak	Wyoming

[a] Units identified in Utah's §308 Regional Haze SIP.
[b] Unit identified on the Western Regional Air Partnership's BART Clearinghouse.

Based on the cost of compliance and visibility improvement presented by PacifiCorp in the BART applications for Naughton Units 1-3 and taking into consideration the logistical challenge of managing multiple pollution control installations within the regulatory time allotted for installation of BART by the Regional Haze Rule, the Division is not requiring additional controls under the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan in this permitting action. Additional controls may be required in future actions related to the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan.

CHAPTER 6, SECTION 4 – PREVENTION OF SIGNIFICANT DETERIORATION (PSD):

PacifiCorp's Naughton Power Plant is a "major emitting facility" under Chapter 6, Section 4, of the Wyoming Air Quality Standards and Regulations because emissions of a criteria pollutant are greater than 100 tpy for a listed categorical source. PacifiCorp should comply with the permitting requirements of Chapter 6, Section 4 as they apply to the installation of controls determined to meet BART.

CHAPTER 5, SECTION 2 – NEW SOURCE PERFORMANCE STANDARDS (NSPS):

The installation of controls determined to meet BART will not change New Source Performance Standard applicability for Naughton Units 1-3.

CHAPTER 5, SECTION 3 – NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPs) AND CHAPTER 6, SECTION 6 – HAZARDOUS AIR POLLUTANT (HAP) EMISSIONS AND MAXIMUM AVAILABLE CONTROL TECHNOLOGY (MACT):

The installation of controls determined to meet BART will not change Nation Emission Standards For Hazardous Air Pollutants applicability for Naughton Units 1-3.

CHAPTER 6, SECTION 3 – OPERATING PERMIT:

The Naughton Power Plant is a major source under Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations. The most recent Operating Permit, 3-2-121, was issued for the facility on March 19, 2008. In accordance with Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations (WAQSR), PacifiCorp will need to modify their operating permit to include the changes authorized in this permitting action.

CONCLUSION:

The Division is satisfied that PacifiCorp's Naughton Power Plant will comply with all applicable Wyoming Air Quality Standards and Regulations. The Division proposes to issue a BART Air Quality Permit for modification to install new LNB with advanced OFA on Naughton Units 1 and 2, and install FGC in combination with the existing ESPs to meet the statutory requirements of BART. Before December 31, 2014, PacifiCorp shall tune the existing LNB and OFA on Naughton Unit 3 and install SCR and a new full-scale fabric filter to meet the statutory requirements of BART.

PROPOSED PERMIT CONDITIONS:

The Division proposes to issue an Air Quality Permit to PacifiCorp for the modification of the Naughton Power Plant with the following conditions:

1. Authorized representatives of the Division of Air Quality be given permission to enter and inspect any property, premise or place on or at which an air pollution source is located or is being constructed or installed for the purpose of investigating actual or potential sources of air pollution, and for determining compliance or non-compliance with any rules, standards, permits or orders.

2. All substantive commitments and descriptions set forth in the application for this permit, unless superseded by a specific condition of this permit, are incorporated herein by this reference and are enforceable as conditions of this permit.

3. That PacifiCorp shall modify their Operating Permit in accordance with Chapter 6, Section 9(e)(iv) and Chapter 6, Section 3 of the WAQSR.

4. All notifications, reports and correspondence associated with this permit shall be submitted to the Stationary Source Compliance Program Manager, Air Quality Division, 122 West 25th Street, Cheyenne, WY 82002 and a copy shall be submitted to the District Engineer, Air Quality Division, 510 Meadowview Drive, Lander, WY 82520.

5. Effective upon completion of the performance tests to verify the emission levels below, as required by Condition 6 of this permit, emissions from Naughton Units 1 and 2 shall not exceed the levels below. The lb/hr and tpy limits shall apply during all operating periods. The lb/MMBtu limits shall apply during all operating periods, except startup. Startup begins with the introduction of natural gas into the boiler and ends no later than the point in time when the ESP reaches a temperature of 225°F.

Unit	Pollutant	lb/MMBtu	lb/hr	tpy
1	PM/PM_{10} [a]	0.040	74	324
2	PM/PM_{10} [a]	0.040	96	421

[a] Filterable portion only.

6. That no later than 90 days after the installation of new low NO_x burners with advanced overfire air PM/PM_{10} performance tests shall be conducted and a written report of the results shall be submitted. If a maximum design rate is not achieved within 90 days of installing new low NO_x burners with advanced overfire air, the Administrator may require testing be done at the rate achieved and again when a maximum rate is achieved.

7. Effective upon completion of the initial performance tests to verify the emission levels below, as required by Condition 8 of this permit, emissions from Naughton Units 1-3 shall not exceed the levels below. The NO_x limits shall apply during all operating periods. Unit 3 PM/PM_{10} lb/hr and tpy limits shall apply during all operating periods. Unit 3 PM/PM_{10} lb/MMBtu limit shall apply during all operating periods except startup. Startup begins with the introduction of natural gas into the boiler and ends when the boiler is switched over to coal as fuel.

Unit	Pollutant	lb/MMBtu	lb/hr	tpy
1	NO_x	0.26 (30-day rolling)	481 (30-day rolling)	2,107
2	NO_x	0.26 (30-day rolling)	624 (30-day rolling)	2,733
3	NO_x	0.07 (30-day rolling)	259 (30-day rolling)	1,134
3	PM/PM_{10} [a]	0.015 [b]	56 [b]	243

[a] Filterable portion only.
[b] Upon installation of a PM continuous emissions monitoring system, the averaging period shall become a 24-hour block average.

8. That initial performance tests be conducted, in accordance with Chapter 6, Section 2(j) of the WAQSR, within 30 days of achieving a maximum design rate but not later than 90 days following initial start-up, and a written report of the results be submitted. If a maximum design rate is not achieved within 90 days of start-up, the Administrator may require testing be done at the rate achieved and again when a maximum rate is achieved.

9. Performance tests shall consist of the following:

Coal-fired Boilers (Naughton Units 1 through 3):

NO_x Emissions – Compliance with the NO_x 30-day rolling average shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 60.

PM/PM_{10} Emissions – Testing shall follow 40 CFR 60.46 and EPA Reference Test Methods 1-4 and 5.

Testing required by the Chapter 6, Section 3, Operating Permit may be submitted to satisfy the testing required by this condition. If a PM CEMS is installed on Unit 3, PM CEMS monitoring data collected in accordance with 40 CFR part 60, subpart Da may be submitted to satisfy the testing required by this condition for Unit 3.

10. Prior to any testing required by this permit, a test protocol shall be submitted to the Division for approval, at least 30 days prior to testing. Notification should be provided to the Division at least 15 days prior to any testing. Results of the tests shall be submitted to this office within 45 days of completing the tests.

11. PacifiCorp shall comply with all requirements of the Regional SO_2 Milestone and Backstop Trading Program in accordance with Chapter 14, Sections 2 and 3, of the WAQSR.

12. Compliance with the NO_x limits set forth in this permit for the coal-fired boilers (Naughton Units 1-3) shall be determined with data from the continuous monitoring systems required by 40 CFR Part 75 as follows:

a. Exceedances of the NO_x limits shall be defined as follows:

i. Any 30-day rolling average of NO_x emissions which exceeds the lb/MMBtu limits calculated in accordance with the compliance provisions and monitoring requirements of §60.48Da and §60.49Da. The definition of "boiler operating day" shall be consistent with the definition as specified in 40 CFR part 60, subpart Da.

ii. Any 30-day rolling average calculated using valid data (output concentration and average hourly volumetric flowrate) from the existing CEM equipment which exceeds the lb/hr NO_x limit established in this permit. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j) and follow the compliance provisions and monitoring requirements of §60.48Da and §60.49Da. The 30-day average emission rate shall be calculated as the arithmetic average of hourly emissions with valid data during the previous 30-day period. The definition of "boiler operating day" shall be consistent with the definition as specified in 40 CFR part 60, subpart Da.

b. PacifiCorp shall comply with all reporting and record keeping requirements as specified in WAQSR, Chapter 5, Section 2(g) and 40 CFR part 60, subpart D. All excess emissions shall be reported using the procedures and reporting format specified in WAQSR, Chapter 5, Section 2(g).

13. PacifiCorp shall use EPA's Clean Air Markets reporting program to convert the monitoring system data to annual emissions. PacifiCorp shall provide substituted data according to the missing data procedures of 40 CFR, Part 75 during any period of time that there is not monitoring data. All monitoring data must meet the requirements of WAQSR, Chapter 5, Section 2(j).

14. Compliance with the PM/PM_{10} limits set forth in this permit for Naughton Units 1-3 shall be determined with data from testing for PM conducted annually, or more frequently as specified by the Administrator, following 40 CFR 60.46 and EPA Reference Test Methods 1-4 and 5. Testing required by the Chapter 6, Section 3, Operating Permit may be submitted to satisfy the testing required by this condition. If a PM CEMS is installed on Unit 3, PM CEMS monitoring data collected in accordance with 40 CFR part 60, subpart Da may be submitted to satisfy the testing required by this condition for Unit 3.

15. Records required by this permit shall be maintained for a period of at least five (5) years and shall be made available to the Division upon request.

16. PacifiCorp shall install new low NO_x burners with advanced overfire air on Units 1 and 2, in accordance with the Division's BART determination, and conduct the performance tests required in Conditions 6 and 8 no later than December 31, 2012 and June 1, 2012, respectively.

17. PacifiCorp shall, for Units 1 and 2, install flue gas conditioning on the existing ESPs, in accordance with the Division's BART determination, within 90 days of permit issuance.

18. PacifiCorp shall tune the existing low NO_x burners with overfire air and install selective catalytic reduction and a full-scale fabric filter on Unit 3, in accordance with the Division's BART determination, and conduct the initial performance tests required in Condition 8 no later than December 31, 2014.

Appendix A
Facility Location

PUBLIC UTILITY COMMISSION OF OREGON

UE 246

SIERRA CLUB EXHIBIT 112

PacifiCorp's Emissions Reductions Plan
2010

November 2, 2010

Exhibit A

PacifiCorp's Emissions Reductions Plan

In connection with its Best Available Retrofit Technology ("BART") determinations and its other regional haze planning activities, the Wyoming Department of Environmental Quality, Air Quality Division ("AQD") asked PacifiCorp to provide additional information about its overall emission reduction plans through 2023. The purpose is to more fully address the costs of compliance on both a unit and system-wide basis. PacifiCorp is committed to reduce emissions in a reasonable, systematic, economically sustainable and environmentally sound manner while meeting applicable legal requirements. These legal requirements include complying with the regional haze rules which encompass a national goal to achieve natural visibility conditions in Class 1 areas by 2064

Summary

PacifiCorp owns and operates 19 coal-fueled generating units in Utah and Wyoming, and owns 100% of Cholla Unit 4, which is a coal-fueled generating unit located in Arizona. PacifiCorp is in the process of implementing an emission reduction program that has reduced, and will continue to significantly reduce emissions at its existing coal-fueled generation units over the next several years. From 2005 through 2010 PacifiCorp has spent more than $1.2 billion in capital dollars. It is anticipated that the total costs for all projects that have been committed to will exceed $2.7 billion by the end of 2022. The total costs (which include capital, O&M and other costs) that will have been incurred by customers to pay for these pollution control projects during the period 2005 through 2023, are expected to exceed $4.2 billion, and by 2023 the annual costs to customers for these projects will have reached $360 million per year.

Environmental benefits, including visibility improvements will flow from these planned emission reductions. PacifiCorp believes that the emission reduction projects and their timing appropriately balance the need for emission reductions over time with the cost and other concerns of our customers, our state utility regulatory commissions, and other stakeholders. PacifiCorp believes this plan is complementary to and consistent with the state's BART and regional haze planning requirements, and that it is a reasonable approach to achieving emission reductions in Wyoming and other states.

PacifiCorp's Long-Term Emission Reduction Commitment

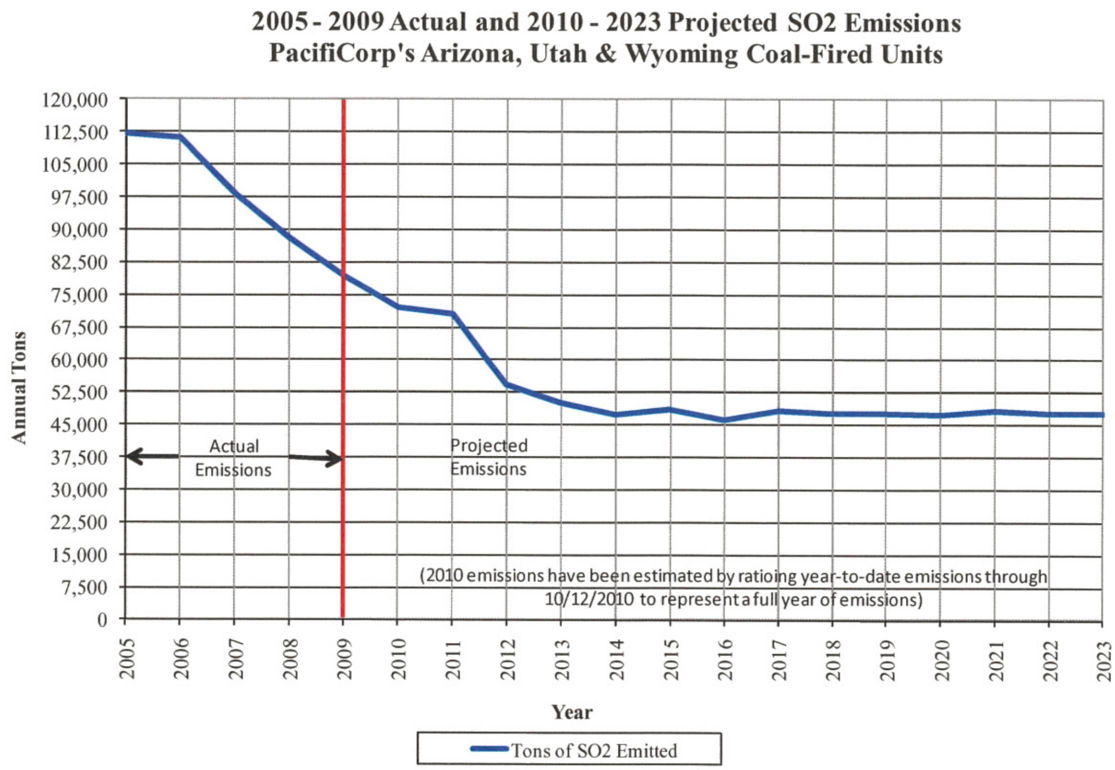
Table 1 below identifies the emission reduction projects and related construction schedules as currently included in PacifiCorp's reduction plan.

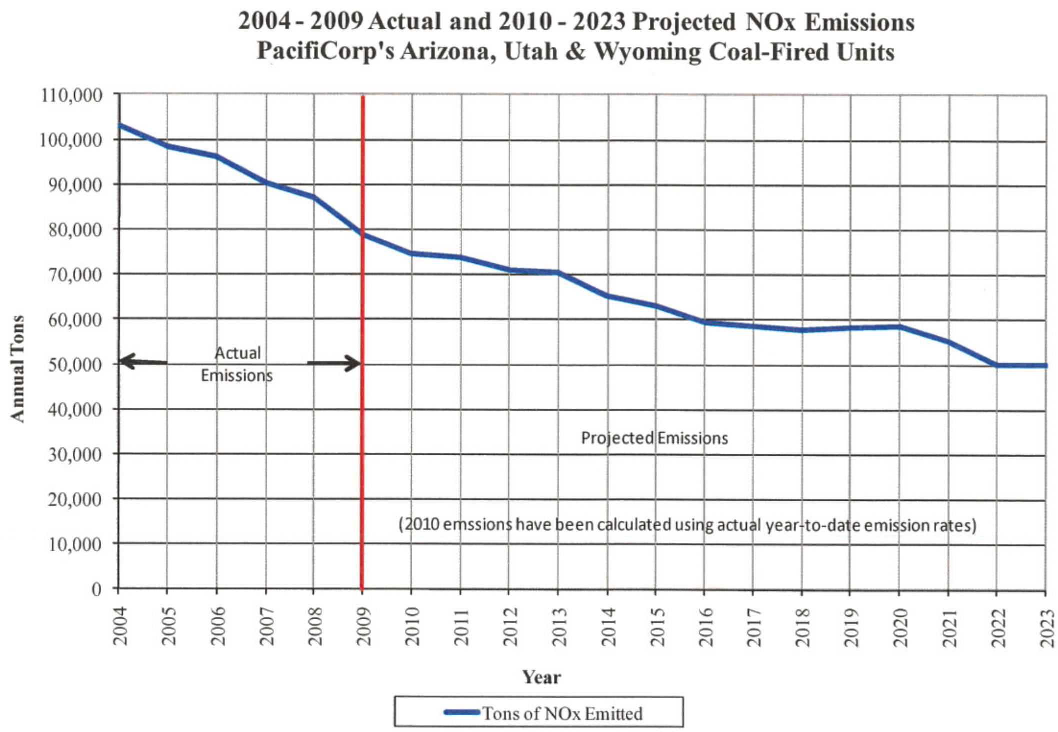
Table 1: Long-Term Reduction Plan

Plant Name	SO2 Scrubbers Installation - I Upgrades - U	Low NOx Burner Installations	Baghouse Installations	Status of SO2 / LNB / Baghouse Permitting	Selective Catalytic Reduction
Hunter 1	2014 - U	2014	2014	Permitted	
Hunter 2	2011 - U	2011	2011	Under Construction	
Hunter 3	Existing	2008	Existing	Completed	
Huntington 1	2010 - U	2010	2010	Under Construction	
Huntington 2	2007 - I	2007	2007	Completed	
Dave Johnston 3	2010 - I	2010	2010	Completed	
Dave Johnston 4	2012 - I	2009	2012	Under Construction	
Jim Bridger 1	2010 - U	2010		Completed	2022
Jim Bridger 2	2009 - U	2005		Completed	2021
Jim Bridger 3	2011 - U	2007		Permitted	2015
Jim Bridger 4	2008 - U	2008		Completed	2016
Naughton 1	2012 - I	2012		Under Construction	
Naughton 2	2011 - I	2011		Under Construction	
Naughton 3	2014 - U	2014	2014	Baghouse Permitted	2014
Wyodak	2011 - U	2011	2011	Under Construction	
Cholla 4	2008 - U	2008	2008	Completed	

The following charts represent the reductions in emissions that will occur at units owned by PacifiCorp in Utah, Wyoming and Arizona[1]. It is significant to note that permitting has been completed for all but the SCR projects; permitting for the SCR projects will be completed as needed in advance of project construction. The emission estimates shown in these charts have been calculated using projected unit generation and heat rate data in conjunction with each unit's permitted emission rate. In those cases were the units do not have emissions controls the estimates have been based on projections of the future coal quality. All projections used are from PacifiCorp's ten-year business plan. Actual future emissions will be less than those estimated in these charts since the units will operate below their permitted rates.

[1] PacifiCorp is also a joint owner of coal-fueled facilities in Colorado and Montana that are subject to regional haze planning requirements and for which PacifiCorp will incur associated costs of emissions controls.


2005 - 2009 Actual and 2010 - 2023 Projected SO2 Emissions
PacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units
Annual Tons
120,000
112,500
105,000
97,500
90,000
82,500
75,000
67,500
60,000
52,500
45,000
37,500
30,000
22,500
15,000
7,500
0
Actual Emissions
Projected Emissions
(2010 emissions have been estimated by ratioing year-to-date emissions through 10/12/2010 to represent a full year of emissions)
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year
Tons of SO2 Emitted


2004 - 2009 Actual and 2010 - 2023 Projected NOx Emissions
PacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units
Annual Tons
110,000
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Actual Emissions
Projected Emissions
(2010 emssions have been calculated using actual year-to-date emission rates)
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year
Tons of NOx Emitted

Project Installation Schedule

Emission reduction projects of the number and size described above take many years to engineer, plan and build. When considering a fleet the size of PacifiCorp's, there is a practical limitation on available construction resources and labor. There is also a limit on the number of units that may be taken out of service at any given time as well as the level of construction activities that can be supported by the local infrastructures at and around these facilities. Such limitations directly impact both the overall timing of these projects as well as their timing in relation to each other. Additional cost and construction timing limitations include the loss of large generating resources during some parts of construction and the associated impact on the reliability of PacifiCorp's electrical system during these extended outages. In other words, it is not practical, and it is unduly expensive, to expect to build these emission reduction projects all at once or even in a compressed time period. The pressure on emission reduction equipment and skilled labor is likely to be exacerbated by the significant emission reduction requirements necessitated by the Environmental Protection Agency's Clean Air Transport Rule which requires emission reductions in 31 Eastern states and the District of Columbia beginning in 2012 and 2014. The Environmental Protection Agency has indicated that a second Transport Rule is likely to be issued in 2011, requiring additional reductions in the Eastern U.S. beyond those effective in 2014. The balancing of these concerns is reflected in the timing of PacifiCorp's emission reduction commitments.

Priority of Emission Reductions

PacifiCorp's initial focus has been on installing controls to reduce SO_2 emissions which are the most significant contributors to regional haze in the western US. In addition, PacifiCorp continues to rely on the rapid installation of low NO_x burners to significantly reduce NOx emissions. Also, the installation of five SCRs (or similar NOx-reducing technologies) will be completed by 2023 and reduce NOx emissions even further. PacifiCorp's commitment also includes the installation of several baghouses to control particulate matter emissions. For those units which utilize dry scrubbers, baghouses have the added benefit of improving SO2 removal. Baghouses also significantly reduce mercury emissions.

In addition to reducing emissions at existing facilities, PacifiCorp has avoided increasing emissions by adding more than 1,400 megawatts of renewable generation between 2006 and 2010. In order to meet growing demand for electricity, PacifiCorp added non-emitting wind generation to its portfolio at a cost of over $2 billion and has dismissed further consideration of a new coal-fueled unit.

Emission Reductions and BART Deadlines

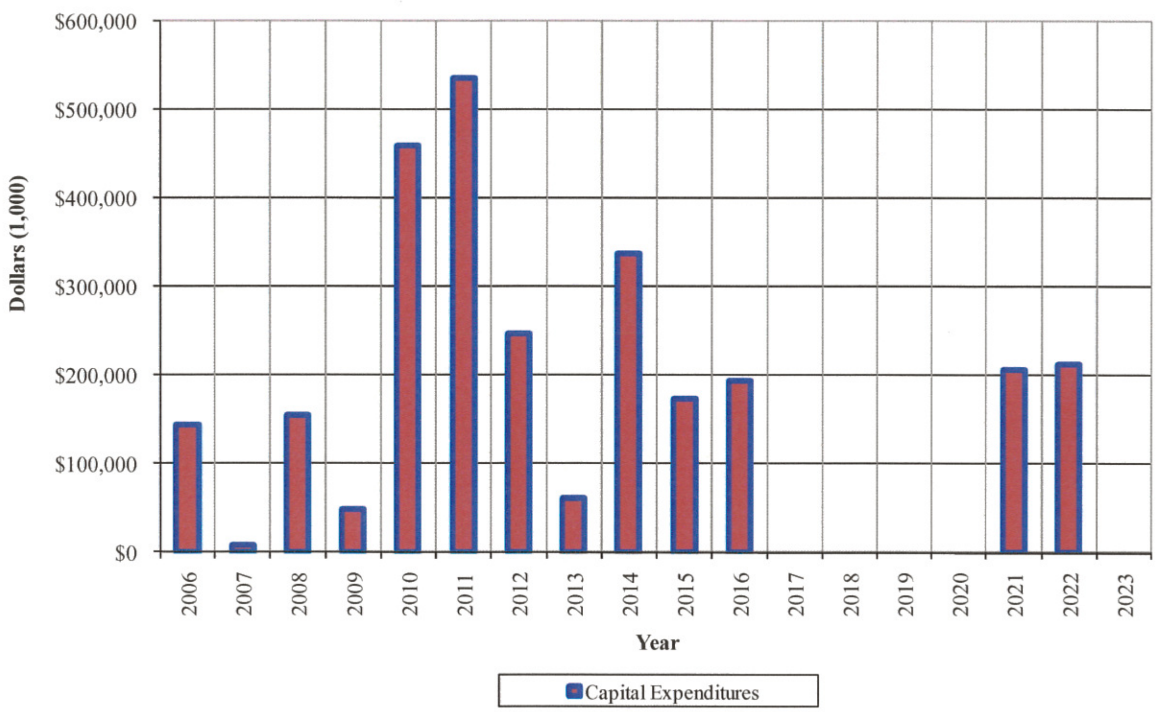
As depicted in the table and charts above, PacifiCorp began implementing its emission reduction commitments in 2005. This was well ahead of the emission reduction timelines under the regional haze rules which require BART to be installed no later than five years following approval of the applicable Regional Haze SIP. This also provides a graphic demonstration of the construction schedule and other limitations described above, as PacifiCorp was required to begin installing emission control projects at some units earlier in order to complete projects at other units within the five years after SIP approval. The table above demonstrates that most of the projects to be built between 2010 and 2014, likewise, will be installed in advance of the required completion date under BART requirements.

Customer Impacts

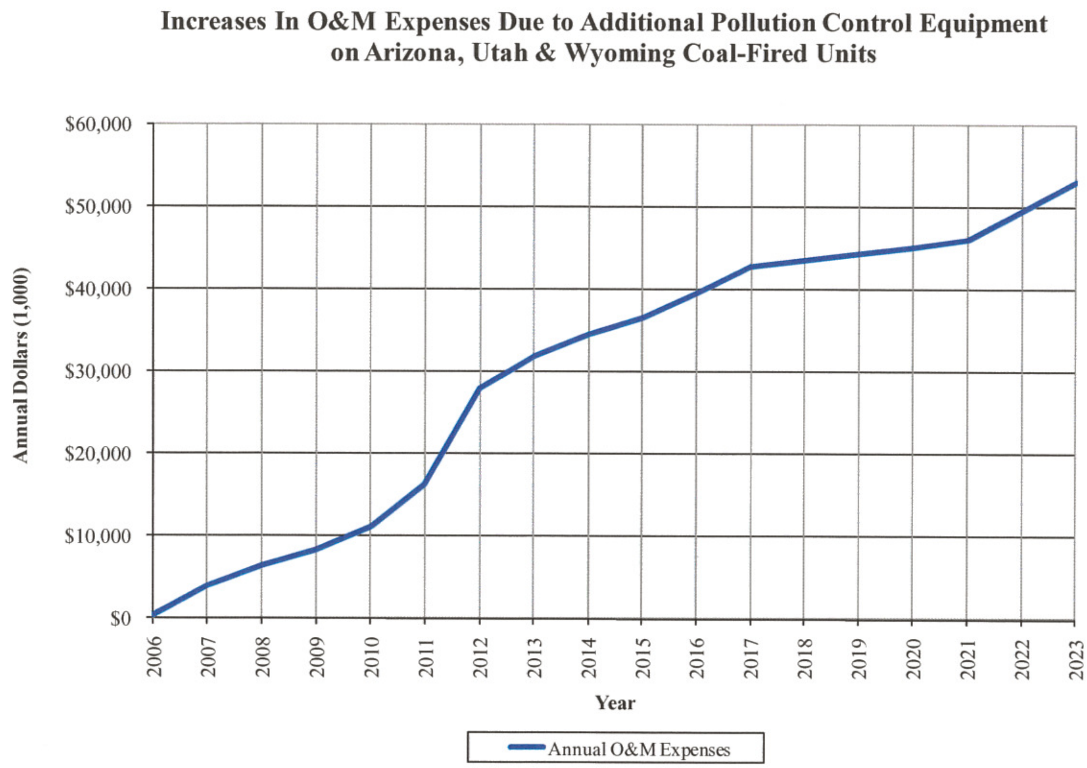
The following charts identify the timing and magnitude of the capital and O&M expenses that will be incurred due to the projects identified in Table 1. The charts identify:

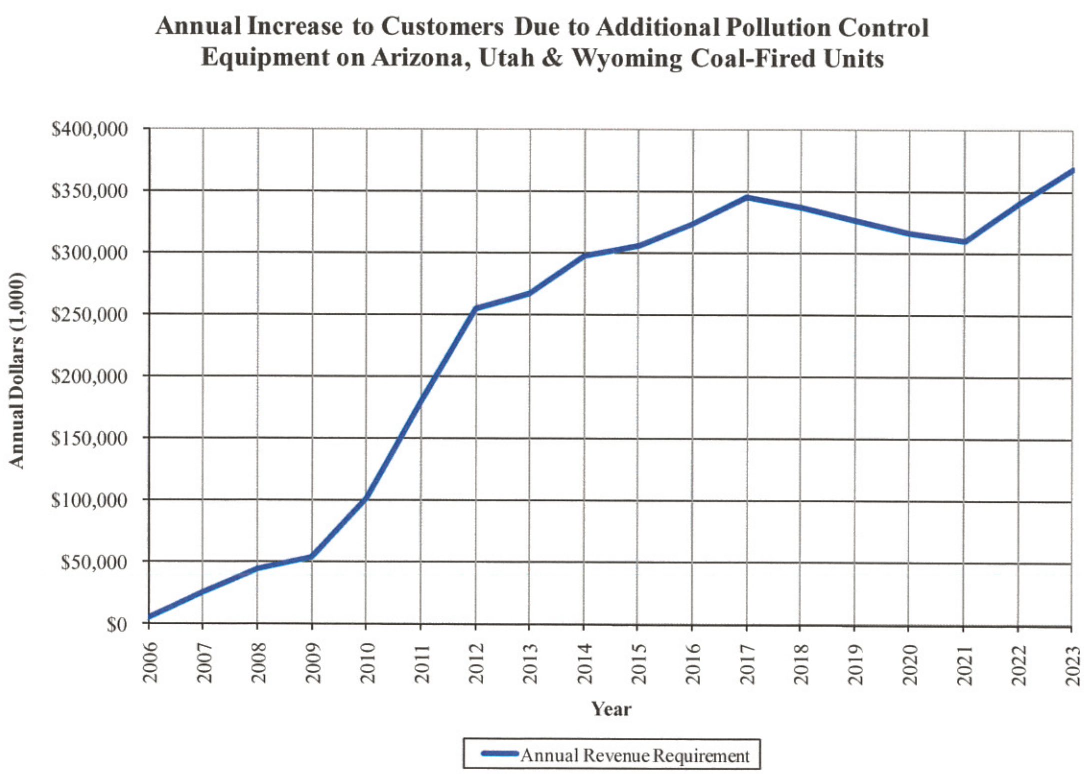
1. The timing and magnitude of the capital costs.
2. The O&M expenses that will be incurred due to these projects.
3. The expected annual costs[2] through 2023 that customers will be incur as a result of these specific pollution control projects.

Capital Expenditures to Add Pollution Control Equipment onPacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units



[2] PacifiCorp has made every attempt to provide an accurate estimate of the anticipated increase in annual revenue requirements that will ultimately be translated to increases in customers' electricity rates. However, there are several variables such as interest rates, inflation rates, discount rates, depreciation lives, and final construction costs and operating and maintenance expenses that will be considered at the time these projects actually go into rate base and will influence the actual revenue requirements associated with these capital projects.


Increases In O&M Expenses Due to Additional Pollution Control Equipment on Arizona, Utah & Wyoming Coal-Fired Units
Annual Dollars (1,000)
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year
Annual O&M Expenses


Annual Increase to Customers Due to Additional Pollution Control Equipment on Arizona, Utah & Wyoming Coal-Fired Units
Annual Dollars (1,000)
$400,000
$350,000
$300,000
$250,000
$200,000
$150,000
$100,000
$50,000
$0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year
Annual Revenue Requirement

As can be seen from the previous charts, the rate increases for PacifiCorp customers associated with PacifiCorp's emission reduction strategy alone will be significant. In the event that PacifiCorp is required to accelerate or add to the planned emission reduction projects, the cost impacts to our customers can be expected to increase incrementally, particularly as plant outage schedules are extended and the need for skilled labor and material increases in the near term.

Of particular note, the projected costs reflect only the installation of the noted emission reduction equipment. These cost increases do not include other costs expected to be incurred in the future to meet further emission reduction measures or address other environmental initiatives, including but not limited to (see Attachment 1):

1. Implementation of Utah's Long Term Strategy for meeting regional haze requirements during the 2018-2023 time period.

2. The addition of mercury control equipment under the requirements of the upcoming mercury MACT provisions. PacifiCorp estimates that \$68 million in capital will be incurred by 2015 and annual operating expenses will increase by \$21million per year to comply with mercury reduction requirements. In addition, anticipated regulation to address non-mercury hazardous air pollutant (HAPs) emissions may require significant additional reductions of SO_2, as a precursor to sulfuric acid mist, from non-BART units that currently do not have specific controls to reduce SO_2 emissions.

3. Mitigating and controlling CO_2 emissions. While Congress has not yet passed comprehensive climate change legislation, in December 2009, the Administrator of the Environmental Protection Agency made a finding that greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations. Having made the so-called "endangerment finding," EPA issued the final greenhouse gas tailoring rule, effective January 2, 2011, which will require greenhouse gas emissions to be addressed under PSD and Title V permits[3]. Likewise, mandatory reporting of greenhouse gas emissions to the Environmental Protection Agency commenced beginning in January 2010.

4. In addition, there are a number of regional regulatory initiatives, including the Western Climate Initiative that may ultimately impact PacifiCorp's coal-fueled facilities. PacifiCorp's generating units are utilized to serve customers in six states – Wyoming, Idaho, Utah, Washington, Oregon and California. California, Washington and Oregon are participants in the Western Climate Initiative, a comprehensive regional effort to reduce greenhouse gas emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector; each state has implemented state-level emissions reduction goals. California, Washington and Oregon have also adopted greenhouse gas emissions performance standards for base load electrical generating resources under which emissions must not exceed 1,100 pounds of CO_2 per megawatt

[3] The Environmental Protection Agency has not yet published its proposed guidance on what constitutes Best Available Control Technology for greenhouses gases.

hour. The emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of 5 or more years) unless the base load generation supplied under long-term financial commitments comply with the greenhouse gas emissions performance standards. While these requirements have not been implemented in Wyoming, due to the treatment of PacifiCorp's generation on a system-wide basis (i.e., electricity generated in Wyoming may be deemed to be consumed in California based on a multi-state protocol), PacifiCorp's facilities may be subject to out-of-state requirements.

5. Regulations associated with coal combustion byproducts. In June 2010, the Environmental Protection Agency published a proposal to regulate the disposal of coal combustion byproducts under the Resource Conservation and Recovery Act's Subtitle C or D. Under either regulatory scenario, regulated entities, including PacifiCorp, would be required, at a minimum; to retrofit/upgrade or discontinue utilization of existing surface impoundments within five years after the Environmental Protection Agency issues a final rule and state adoption of the appropriate controlling regulations. It is anticipated that the requirements under the final rule will impose significant costs on PacifiCorp's coal-fueled facilities within the next eight to ten years.

6. The installation of significant amounts of new generation, including gas-fueled generation and renewable resources.

7. The addition of major transmission lines to support the renewable resources and other added generation.

8. Increasing escalation rates on fuel costs and other commodities

BART and Regional Haze Compliance

PacifiCorp firmly believes that the commitments described above meet the letter and intent of the regional haze rules, including the guidance provided by the EPA known as "Appendix Y." The regional haze program is a long-term effort with long-term goals ending in 2064. It must be approached from that perspective. It was never intended to require SCR on BART-eligible units within the first five years of the program. Rather, it calls for a transition to lower emissions exactly as PacifiCorp has implemented to date and as it has proposed going forward through 2023.

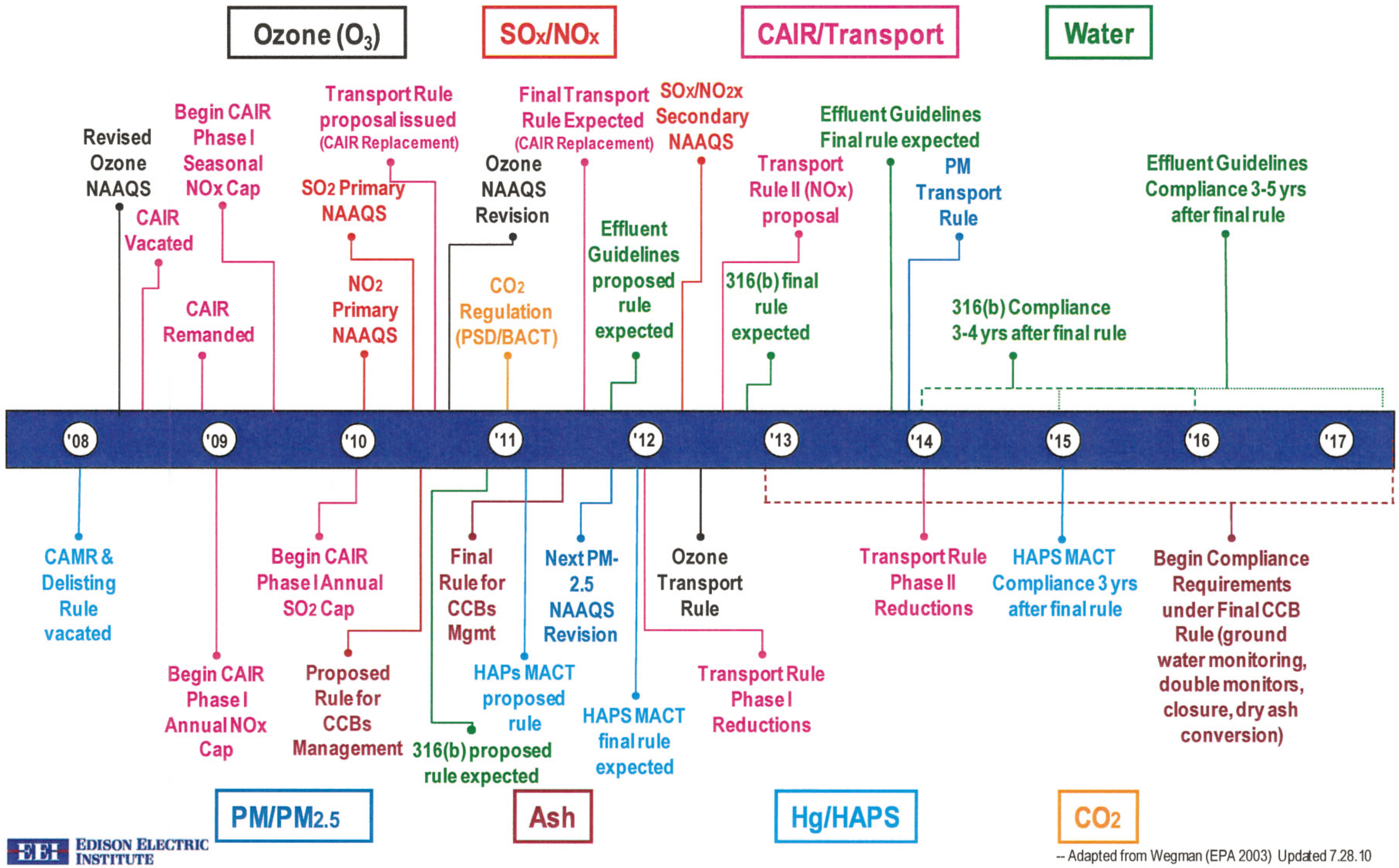
In its evaluation of emission reductions for regional haze purposes, the state should also consider several other variables which will significantly affect emissions and costs over the next ten years. These include such things as the development of new emission control technology, anticipated new emission reduction legislation and rules, the new ozone standard, the one hour SO_2 and NO_2 standards, the $PM_{2.5}$ standard, potential CO_2 regulation and costs, an aging fleet, and changing economic conditions. All of these variables matter and will affect the long-term viability of each PacifiCorp coal unit and will contribute to the reduction of regional haze in the course of the implementation of these programs. This, in turn, will affect the controls, costs and future operational expectations associated with these generating resources.

Conclusion

PacifiCorp has made a significant, long-term commitment to reducing emissions from its coal-fueled facilities and requests that the AQD consider this commitment as a reasonable approach to achieving emission reductions in Wyoming.

November 2, 2010

Attachment 1 Possible Timeline for Environmental Regulatory Requirements for the Utility Industry



-- Adapted from Wegman (EPA 2003) Updated 7.28.10

PUBLIC UTILITY COMMISSION OF OREGON

UE 246

SIERRA CLUB EXHIBIT 113

EPA Comments on Naughton
AP-9861

Sierra Club/113
Fisher/1

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

AUG 16 2010

Ref: 8P-AR

Steven A. Dietrich, Administrator
Air Quality Division
Wyoming Dept. of Environmental Quality
122 West 25th Street
Cheyenne, WY 82002

RE: Comments on the Draft Prevention of Significant Deterioration (PSD) and Minor Construction Permit, AP-9861, to Modify Operations at PacifiCorp's Naughton Power Plant

Dear Mr. Dietrich:

This letter provides the Environmental Protection Agency Region 8's (EPA's) comments on the draft Wyoming Air Quality Standards and Regulations (WAQSR) Chapter 6, Section 4 (PSD), and Chapter 6, Section 2 (minor construction) Permit AP-9861, for proposed modifications at PacifiCorp's Naughton Power Plant in Lincoln County, Wyoming. We received the Application Analysis with draft permit conditions on July 20, 2010. The air permit application and air dispersion modeling files were sent in advance of the draft permit and analysis.

We note that the proposed pollution control project that is the subject of this permit action was originally permitted by Permit MD-5156. Permit action MD-5156 involved the installation of flue gas conditioning systems (FGC) and Low NO_x Burner systems on Units 1 and 2. The objective of FGC installation was to enhance particulate control efficiency achieved by the electrostatic precipitators. Units 1 and 2 were also to be equipped with flue gas desulfurization systems (FGD). However, since PacifiCorp proposed to operate the FGC prior to the FGD upgrade, this pollution control project was expected to increase the sulfuric acid mist (H_2SO_4) emissions. The WDEQ determined this project to be a PSD significant modification for H_2SO_4.

The first draft permit package for MD-5156 was received by EPA on January 5, 2009. On January 16, 2009, EPA received notice that the Division had withdrawn the public notice for this permit action. The Division then issued a revised permit package for public notice dated March 9, 2009, which included revised draft permit conditions. EPA reviewed and commented on April 10, 2009. Permit MD-5156 was issued on May 20, 2009 with a Response-to-Comments document.

PacifiCorp later informed the WDEQ that the H_2SO_4 emissions, using the EPRI LARK-TRIPP method, were underestimated in Permit MD-5156. As a result, PacifiCorp has now applied to increase the existing H_2SO_4 BACT limits set in Permit MD-5156.

Due to the fact that BACT limits for H_2SO_4 will be increased, the modification is being processed by the WDEQ as a revised PSD major modification review for H_2SO_4 (including BACT, air quality impacts analysis, and additional impacts analysis). The revised air quality impacts analysis includes an analysis of one-hour NO_2 impacts for compliance with the new one-hour NO_2 National Ambient Air Quality Standard.

Enclosed are our comments on the following topics: H_2SO_4 BACT, Regional Haze/Best Available Retrofit Technology (BART), compliance demonstration with H_2SO_4 limits and SO_3 injection limits, the SO_3 injection limit averaging period, clarification of the H_2SO_4 limit averaging period, clarification of the origin of modeled emission rates, soils and vegetation analysis, inclusion of additional Class I areas in visibility modeling, and typographical errors. We have organized our comments in the enclosure to this letter by importance and by category.

Thank you for the opportunity to comment. If you have any questions or concerns, please contact me at (303) 312-6434 or your staff may contact Christopher Razzazian at (303) 312-6648.

Sincerely,

Callie A. Videtich

Callie A. Videtich, Director
Air Program

Enclosure

cc: Chad Schlichtemeier

Enclosure

Environmental Protection Agency (EPA) Region 8 Comments on the Draft Construction Permit AP-9861, for the Major Modification at PacifiCorp's Naughton Power Plant

I. H_2SO_4 Best Available Control Technology (BACT)

The H_2SO_4 BACT limits in the current permit MD-5156 are: 0.0014 lb/MMBtu at Unit 1, and 0.00054 lb/MMBtu at Unit 2. The revised H_2SO_4 BACT limits in the draft permit AP-9861 are: 0.009 lb/MMBtu at both units as interim limits before Flue Gas Desulfurization (FGD) installation; and 0.004 lb/MMBtu at both units after FGD installation. For Unit 1 this proposed revision represents increases of 542% and 186% for the interim and post-FGD limits respectively. For Unit 2 this proposed revision represents increases of 1567% and 641% for the interim and post-FGD limits respectively. The proposed permit limit increases for the two units combined, prior to FGD installation, are equivalent to an increase in allowed H_2SO_4 emissions of 150.5 tons per year. (Ref: page 4 of the Division's Application Analysis.) Also proposed are the following limits on sulfur trioxide (SO_3) injection rates: 6 parts per million (ppm) prior to FGD installation, and 8 ppm after FGD installation.

Because of the magnitude of the proposed increase in allowed H_2SO_4 emissions we recommend the Division conduct an analysis of the relative environmental benefits (in terms of visibility and acid deposition) of increased particulate matter (PM) control associated with the Flue Gas Conditioning (FGC) system, versus the environmental cost of a large increase in H_2SO_4 emissions. To conduct such an analysis, we recommend the Division consider three BACT control options for H_2SO_4 that do not currently appear in the Application Analysis: (1) reduced use of SO_3 injection, below the currently proposed limits (6 ppm prior to FGD installation and 8 ppm after FGD installation); (2) no use of FGC at all prior to FGD installation; and (3) do not construct or operate FGC systems (i.e. use of another control technology that achieves PM reductions without collateral pollutant emission increases).

EPA appreciates that use of FGC will result in reduced levels of PM. However, the Application Analysis does not explain the source of the requirement to reduce PM, and does not relate levels of PM reduction and H_2SO_4 increase to the proposed rates of SO_3 injection. Therefore, it cannot be readily determined whether reduced levels (as compared with the proposed levels) of SO_3 injection would still meet whatever requirements for PM reduction exist while achieving lower emissions of H_2SO_4. Furthermore, there are other control technologies for PM that do not create a collateral increase in H_2SO_4. Although the FGC is an add-on control device for PM, other PM control technologies seem, in this particular context, to be akin to inherently-lower emitting processes with regards to H_2SO_4. The Application Analysis only mentions that FGC will reduce PM, but does not explain why FGC is the only inherently-lower emitting process option being considered to achieve that purpose. The Division should consider other PM control technologies as BACT control options for H_2SO_4 or explain why FGC is fundamental to achieving PM reductions to justify the exclusion of other PM control options that would not increase H_2SO_4 emissions.

Also, since the limit on SO_3 injection rate is the only method specified in the draft permit for demonstrating ongoing compliance with the H_2SO_4 BACT limits (as opposed to periodic stack testing), we recommend the Division explain whether, or how, a correlation has been established between the SO_3 injection rate and H_2SO_4 emissions in lb/MMBtu.

II. Regional Haze (RH) – Best Available Retrofit Technology (BART)

EPA is also aware that FGC has been presented by PacifiCorp as a control option under RH requirements for the Naughton Plant. We have questioned the appropriateness of FGC as a control technology to address RH since FGC installed without FGD could cause an increase in visibility impairing pollutants. Furthermore, the visibility impacts due to the increase in H_2SO_4 emissions may not be fully reflected by CALPUFF visibility modeling, which underestimates sulfate chemistry under wet conditions that may be present in topographically complex regions like Fitzpatrick Wilderness Area (WA), Bridger WA and Mount Zirkel WA (all Class 1 areas).

We have commented on this issue in our letter to the Division regarding BART, dated August 3, 2009:

> "Flue gas conditioning (FGC) is presented as a control option for PM. FGC is a low-cost option because it involves the injection of sulfur trioxide (SO_3) in the flue gas to make the PM more easily collectable by an ESP. We caution the Division that FGC must be applied after flue gas desulfurization (FGD) is installed or upgraded, to assure that there is not a collateral increase in emissions of sulfuric acid mist. In the case of Naughton, there is projected to be an interim period when sulfuric acid mist emissions will exceed the PSD significance threshold. This increase is due to the operation of the FGC prior to FGD upgrades. For the purposes of BART a control option should not be considered as a BART option if it will result in increased emissions of visibility degrading pollutants (sulfuric acid mist)."

(August 3, 2009 EPA BART letter, page 3-4)

Also, our facility-specific comments for Naughton directly addressed FGC. Comment 30 from EPA's August 3, 2009 letter stated:

> "FGC will be applied to Naughton Units 1 and 2 and decommissioned from Unit 3 upon installation of a fabric filter [permitted] under PSD. The application of FGC prior to FGD upgrades will result in a PSD significant increase in sulfuric acid mist. This collateral increase should be avoided to maintain continuous visibility improvements at Class I areas impacted by Naughton."

(August 3, 2009 EPA BART letter, page 8)

New information referenced in the Application Analysis shows that application of FGC (at the rates proposed in the permit) **after** installation of FGD will result in increases of H_4SO_4. Table 3 on page 5 of the Application Analysis indicates that H_2SO_4 emissions will increase by 57.4 tpy (from the baseline emissions to post FGD installation), 8 times greater than the PSD significance threshold for H_2SO_4. Therefore, not only the interim period control (FGC only) but the final control (FGC + FGD) should not be considered as a BART option at currently proposed SO_3 injection rates.

Please be aware that the State's PSD BACT determination does not necessarily constitute BART. Any proposed BART determinations by the State will be reviewed by EPA within the context of the five factor analysis in Wyoming Department of Environmental Quality's (WDEQ's) RH State Implementation Program (SIP) and BART permits.

III. Compliance Demonstration

A. Sulfuric Acid Mist Compliance Demonstration

The draft permit AP-9861 only requires an initial stack test for demonstrating compliance with the H_2SO_4 BACT limits in lb/MMBtu. Periodic stack tests (at least annual) should be required. We note that PacifiCorp's theoretical calculations have underestimated H_2SO_4 emissions in the past for the Jim Bridger Plant (see page 4 of EPA's March 30, 2007 letter for Jim Bridger Plant) and now at the Naughton Plant (see Section 5.0 on pages 3 and 4 of the Division's Application Analysis). Since PacifiCorp's calculations have apparently not accurately captured the emissions profile for H_2SO_4, periodic stack testing for H_2SO_4 should be required in the permit.

Proposed Condition 11 does not specify a stack test method for H_2SO_4. We recommend that for measurement of H_2SO_4 at the pulverized coal (PC) boiler exhaust stack, the permit specify 40 CFR 60, Appendix A, Method 8, or in lieu of Method 8, the Permittee be allowed to use NCASI Method 8A.[1] Method 8A could be used as an alternative to Method 8 because Method 8 was developed for Sulfuric Acid plants, which have neither the moisture nor CO_2, that are in the exhaust from coal-fired boilers, both of which interfere with the proper measurement of H_2SO_4. Once the method for compliance demonstration has been chosen, the same method should be consistently used. This comment was also made in EPA's March 30, 2007 letter for the Jim Bridger PSD major modification, at Comment 4.

B. Sulfur Trioxide (SO_3) Injection Rate Compliance Demonstration

As noted above in II.A., there is no requirement in draft permit AP-9861 for an ongoing compliance demonstration for H_2SO_4 in terms of direct measurement of H_2SO_4

[1] Published by the National Council for Air and Stream Improvement, Inc. (NCASI), December 1996, available at: http://www.ncasi.org.

emissions. Instead, the draft permit uses a limit on SO_3 injection, in ppm, and continuous plant data acquisition to show compliance with the H_2SO_4 lb/MMBtu BACT limits. However, for reasons explained below, we find that proposed Condition 9, which limits the SO_3 injection rate to 6 ppm and 8 ppm (before and after FGD upgrade respectively), is not enforceable as a practical matter. Therefore, the proposed permit lacks not only direct compliance measures for H_2SO_4 BACT, but also lacks practically enforceable surrogate compliance measures.

Proposed Condition 9 does not specify the method and location for testing the concentration of SO_3 injected, nor does any other condition in the draft permit. The condition only specifies that the injection rate "shall be monitored by plant data acquisition." There is no explanation of whether the measurement will be calculated from the flow rate through the injector, actual direct measurement of SO_3 concentration (in ppm) at the injection site, or measurement further downstream in the exhaust gas. If the Division decides to retain a ppm limit on the SO_3 injection rate, it should be made clear in the permit where and how the concentration of SO_3 will be measured, to demonstrate compliance with Condition 9. The permit should also specify that the maximum injection rate shall be established at the time of compliance testing for PM and H_2SO_4 such that the resulting emissions are minimized. See Comment VII from EPA's April 10, 2009 comment letter regarding Naughton Plant, as well as Comment 5 from EPA's March 30, 2007 comment letter regarding Jim Bridger Plant.

IV. SO_3 Injection Limit Averaging Periods

Proposed Condition 9 specifies SO_3 injection rate limitations on a 30-day rolling average. As we have explained above in Comment II.B., it appears that these limits are intended to correspond to the lb/MMBtu BACT limits for H_2SO_4 in proposed Condition 8 and would be the only real-time indicator that the BACT limits are being met at all times. Therefore, the averaging period of the SO_3 injection rate limits should match that (or be shorter than that) of the lb/MMBtu H_2SO_4 BACT limits. After discussion with the Division (see Comment V, below) EPA has received clarification that the H_2SO_4 BACT limits are based on a 1-hour average. The SO_3 injection rate limits should, therefore, also be based on a 1-hour average, matching the averaging period for the H_2SO_4 BACT limits. Since the proposed H_2SO_4 emission limit is on a short averaging period, it is reasonable to expect that the corresponding SO_3 injection rate would be achievable over the same averaging period.

V. H_2SO_4 Limit Averaging Periods

Proposed Conditions 8.i., and 8.ii., contain the H_2SO_4 BACT emission limits. There are no averaging periods specified with these limits. As EPA has previously commented, the H_2SO_4 limits' averaging periods should be listed as part of the BACT limit. See EPA's letters on the draft permits for the Jim Bridger, Dave Johnston, and Dry Fork Power Plants, as well as numerous comments related to PM averaging periods.

As mentioned in comment III.A., above, proposed Condition 11 does not specify the test method for the H_2SO_4 initial performance test, just that the testing shall consist of three 1-hour tests. Past correspondence with the Division (including Response to Comments (RTC) documents) has indicated that if an averaging period is not specified it defaults to the averaging period of the test method. Through conversations with the Division regarding the proposed action, EPA has been made aware that the Division considers the H_2SO_4 limits to be based on a 1-hour averaging period. This should be clearly stated in the permit with the numeric limit.

VI. Modeling

A. Modeled Emission Rates versus Emission Limit Averaging Periods

Modeled H_2SO_4 visibility impacts at Bridger Wilderness area were just below the Federal Land Managers (FLM) "level of concern" of 0.5 deciviews. Modeled emission rates of H_2SO_4 were 18.5 lbs/hr for Unit 1 and 24 lb/hr for Unit 2. The CALPUFF visibility modeling is based on 24-hour average emission rates and it determines the number of days over the FLM's 0.5 and 1.0 deciview thresholds. However, the draft permit limits do not appear to restrict 24-hour average sulfate (SO_4) emissions. The H_2SO_4 BACT limits are on a shorter averaging period than 24 hours. However, the parameter that will be monitored continuously will be the SO_3 injection rates, which are limited on a 30-day rolling average basis.

Either the modeled emission rates should be indicative of short term emission spikes, or the permit should contain limits that assure that the modeled scenario will be the actual conditions under which the facility will operate (i.e. for the actual emissions to mirror the modeled 24 hour period, a 24-hour average SO_3 emission limit, or shorter, is needed). Page 23 of the Application Analysis indicates that the modeling was "conservatively conducted with emissions based on 0.01 lb H_2SO_4/MMBtu and a SO_3 injection rate of 8 ppm." Conversation with the Division indicates that SO_4 emissions rates used in the model were based on the conservative emission rate of 0.01 lb/MMBtu, not the SO_3 injection rate limit of 8 ppm based on a 30-day rolling average. Since 0.01 lb/MMBtu is greater than the BACT limit, which is on a 1-hour average, the modeled emissions should be indicative of short term emission spikes. We suggest the Division reaffirm in the RTC that the SO_3 injection limit was not used to set the SO_4 modeled emission rate.

In general short term emissions used in modeling should not be based on long term average emission limits. We note that page 4 indicates that "Short-term baseline lb/hr and lb/MMBtu emissions [were] derived from annual emissions." Annual emissions will not provide realistic information on the actual potential emissions over short term periods. To the extent that modeled short term emission rates (other than the increased SO_4 emission rate discussed above) were based on emission limits with averaging periods that are longer than the modeled time period, an explanation should be provided as to why that practice is appropriate, or the Division should rely on limitations that assure that permitted emissions impacts have been accurately portrayed in the modeled scenarios.

B. Soils and Vegetation

Please explain how H_2SO_4 will impact soils and vegetation surrounding Naughton or why NO_2 should be indicative of impacts associated with H_2SO_4. This action proposes an increase in H_2SO_4 emission rates by 542 % and 1,647 % from Units 1 and 2. The current permit MD-5156 includes an H_2SO_4 BACT limit for Unit 3. This limit will be removed with the proposed action (AP-9861), which may result in increased H_2SO_4 emissions at Unit 3 above modeled emission rates evaluated through the MD-5156 permit action. These H_2SO_4 increases will further affect the surrounding environment and a discussion of the differences created by this permitting action should be provided.

In EPA's April 10, 2009 comment letter regarding the Naughton Plant we pointed out that the soils and vegetation analysis required by PSD regulation was lacking. The Division's RTC responded to that comment by analyzing the NO_2 levels that impact vegetation. We believe an increase in H_2SO_4 (or sulfates) will be associated with this project, not in increase in NO_2, or nitrates. Please explain why the Division has relied on NO_2 rather than H_2SO_4 to analyze impacts on soils and vegetation.

By letter dated July 13, 2010, the Division alerted EPA that the discussion of the soils and vegetation analysis was inadvertently left out of the Application Analysis. Included with that letter were the amended pages of draft permit AP-9861 including Section 12, for soils and vegetation analysis. The information presented indicates that the Division is relying on an analysis performed for permit MD-5156 and information presented in the Division's RTC for MD-5156. As discussed above, neither MD-5156, nor the RTC for MD-5156 directly address H_2SO_4 impacts to soils and vegetation surrounding Naughton.

D. Class I Areas Analyzed

EPA recommends that the Division include the Mount Zirkel WA in the visibility modeling for this project. Although farther from the source than the Fitzpatrick and Bridger WAs, dispersion patterns can cause higher impacts at locations farther from the source of the emissions. A discussion of visibility impacts at the Mount Zirkel WA should be found in the public record.

VII. Typographical Errors

A. Table 4: Sulfuric Acid Mist PSD Applicability

According to Tables 2 and 3 on pages 4 and 5, Table 4 on page 5 should list the "Potential Emissions" as 167.5 tpy (not 150.5), and the "Net Emissions Change" should be 150.5 tpy (not 133.5). Although this does not affect the PSD review requirements we recommend clarifying these values for the public record.

B. Section 6.2 Sulfuric Acid Mist Interim Emissions

The BACT determination on page 7 states that "PacifiCorp anticipates a potential reduction of 110.1 tpy of sulfuric acid mist emissions when the new alkali wet scrubbers are installed on Units 1 and 2." This figure is listed a second time in the next sentence as well. According to Tables 2 and 3 (and similarly to the typographical error above) the decrease in emissions would be 167.5 – 74.4 = 93.1 tpy not 110.1 tpy.

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SIERRA CLUB EXHIBIT 114

CONFIDENTIAL
PacifiCorp Control Report
2003

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SIERRA CLUB EXHIBIT 115

CONFIDENTIAL
Air Quality Reference Case Investments
2005

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SIERRA CLUB EXHIBIT 116

CONFIDENTIAL
Accumulated NPV in Naughton PVRR(d)

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SIERRA CLUB EXHIBIT 117

CONFIDENTIAL

2009 Strategic Asset Plan:
Hunter Power Plant

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UE 246

SIERRA CLUB EXHIBIT 118

Sierra Club Data Request 1.36
May 11, 2012

UE-246/PacifiCorp
May 11, 2012
Sierra Club Data Request 1.36

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Retirement of Carbon plant. Reference the Direct Testimony of Chad A. Teply, Exhibit PAC/500, page 4 line 21 to page 5 line 8.

a. When did the Company first contemplate the retirement of the Carbon plant?
b. When did the Company finalize the decision to retire the Carbon plant?
c. Is the retirement of the Carbon power plant the subject of any legal settlement with the US EPA, DOJ, or any other State or Federal agency? If so, please provide the citation to the case, and the settlement agreement from the Company.
d. Please list the analyses performed by the Company regarding the economic condition of the Carbon power plant.
e. Please provide the analyses performed by the Company regarding the economic condition of the Carbon power plant.

Response to Sierra Club Data Request 1.36

a. The key environmental compliance requirement associated with the Company's anticipated retirement of the Carbon plant is the U.S. Environmental Protection Agency's recently promulgated Mercury and Air Toxics Standards (MATS). The rule was initially proposed in March 2011 and was ultimately published in the Federal Register February 16, 2012, following a public comment process. Retirement of the Carbon plant has been contemplated as a potential compliance alternative since the rule was proposed for review.

b. As indicated in the direct testimony of Mr. Teply referenced in this question, no final decision has been made. The Company continues to assess potential MATS compliance alternatives; however, the Company currently anticipates that retirement of Carbon Units 1 and 2 will be the least cost alternative for its customers.

c. No.

d. The Company objects to this request as overly broad and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections, the Company responds as follows:
The Company has provided copies of its Strategic Asset Plans for the Carbon plant in Attachment Sierra Club 1.35. Those plans provide the Company's assessment of the economic condition of the Carbon plant. As mentioned above, the Company's assessment of feasible MATS compliance solutions is ongoing. Identifying feasible technical compliance alternatives is a precursor to any further assessment of the

economic condition of the plant with respect to environmental compliance alternatives.

e. Please refer to the Company's response to part d. above.

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SIERRA CLUB EXHIBIT 119

CONFIDENTIAL
2009 Strategic Asset Plan:
Carbon Power Plant

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