BEFORE THE ENVIRONMENTAL QUALITY COUNCIL
STATE OF WYOMING

In the Matter of:	)	
Basin Electric Power Cooperative	)	Docket No. 10-2802
Air Quality Permit No. MD-6047	)	
BART Permit: Laramie River Station	)	

RESPONSE TO BASIN ELECTRIC'S MOTION FOR SUMMARY JUDGMENT

DEQ/AQD's Application Analysis, dated 5/28/09

EXHIBIT 13

DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

BART Application Analysis
AP-6047

May 28, 2009

NAME OF FIRM:	Basin Electric Power Cooperative
NAME OF FACILITY:	Laramie River Station
FACILITY LOCATION:	347 Grayrocks Road Platte County (Wheatland), Wyoming UTM Zone 13, NAD 27: 509,900 m E; 4,661,675 m N
TYPE OF OPERATION:	Electric Power Generating Station
RESPONSIBLE OFFICIAL:	Mr. Robert Eriksen
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REVIEWERS:	Cole Anderson, Air Quality Engineer 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 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 2018 SO_2 milestone. 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 March 5, 2007, in accordance with the requirements of WAQSR Chapter 6 Section 9(e)(i), Basin Electric submitted a BART application for the Laramie River Station.

On February 15, 2008, Basin Electric submitted replacement pages for the BART application based on revised CALPUFF modeling conducted to correct errors in the CALMET windfield discovered by the Division during review of the initial modeling submittal.

On July 28, 2008, Basin Electric submitted an additional report with the results of additional CALPUFF modeling conducted to provide results for each of the three BART-eligible units separately.

On February 25, 2009, Basin Electric submitted additional information on the NO_x emission rates that would be achievable by the BART-eligible units.

On March 16, 2009, Basin Electric submitted a letter with proposed NO_x emission limits for the BART-eligible units.

BART ELIGIBILITY DETERMINATION:

In August of 2005 the Wyoming Air Quality Division (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 any impairment of 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 the

CALPUFF model. 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 with modeled 98th percentile, 24-hour impact (i.e., 8th highest modeled impact) equal to or greater than 0.5 delta deciviews (Δdv) above natural background conditions 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 Basin Electric's Laramie River Station were determined to be subject to BART. Basin Electric was notified in a letter dated June 14, 2006 of the Division's finding.

DESCRIPTION OF BART ELIGIBLE SOURCES:

Basin Electric's Laramie River Station is comprised of three 550 MW (net) dry-bottom, wall-fired boilers burning pulverized coal for a total net generating capacity of 1,650 MW. Laramie River Unit 1 was placed in service in 1980. Unit 2 commenced service in 1981, and Unit 3 entered service in 1982. All three units were manufactured by Babcock & Wilcox (B&W). Each unit is equipped with early generation low NO_x burners (LNBs) to control emission of nitrogen oxides (NO_x). They are also equipped with cold-side electrostatic precipitators (ESPs) to control particulate matter (PM) emissions. To control sulfur dioxide (SO_2) emissions, Units 1 and 2 are equipped with wet flue gas desulfurization (WFGD). Unit 3 is equipped with a dry scrubber (DFGD) for SO_2 removal. All three units burn sub-bituminous coal. Table 1 presents the permitted emission limits for the Laramie River Station prior to 2005, which is considered the baseline year for BART analyses.

Table 1: Laramie River Station Units 1 through 3 (Pre-2005) Emission Limits

Source	Existing Controls	NO_x (lb/MMBtu) [a]	SO_2 (lb/MMBtu) [a]	PM (lb/MMBtu) [a]
Unit 1	LNB, ESP, WFGD	0.5 (3-hour[b])	0.2 (2-hour fixed block)	0.085 (3-hour)
Unit 2	LNB, ESP, WFGD	0.5 (3-hour[b])	0.2 (2-hour fixed block)	0.085 (3-hour)
Unit 3	LNB, ESP, DFGD	0.5 (3-hour[b])	0.2 (2-hour fixed block)	0.083 (3-hour)

(a) Emissions taken from current Operating Permit 3-1-102-1.
(b) Arithmetic average of three contiguous one-hour periods

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. One technology and corresponding emission limit is chosen for each pollutant subject to BART review based on the evaluation.

Visibility control options presented in the application for each of the emission units were reviewed using the methodology prescribed in 40 CFR 51 subpart 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

The Division acknowledges that BART is intended to identify retrofit technology for existing sources and is not the same as the 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 five steps listed above were applied to NO_x, PM, and SO_2 emitted from the Laramie River Station's coal-fired boilers to determine BART control measures.

PRESUMPTIVE LIMITS FOR SO_2 AND NO_X FROM UTILITY BOILERS

EPA conducted detailed analyses of retrofit technology available 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

[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."
[3] 40 CFR Part 51 Appendix Y Guidelines for BART Determinations under the Regional Haze Rule (70 Federal Register 39133).

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 on 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 are 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 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 analyses for NO_x, SO_2, and PM/PM_{10} take into account each of the five statutory factors.

Basin Electric's Laramie River Station generates a net 550 MW from each of three coal-fired units. None of the units has NO_x post-combustion controls. The presumptive NO_x emission limit for dry-bottom, wall-fired boilers burning sub-bituminous coal (i.e., each of the three units) is 0.23 lb/MMBtu.

<u>NO_x: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES</u>

Basin Electric identified six control technology configurations for control of NO_x emissions from Units 1 through 3:

- Overfire Air (OFA)
- New Low NO_x Burners (LNB)
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- SNCR/SCR Hybrid
- Natural Gas Reburn

1. <u>Overfire Air</u> – OFA is a combustion control technology that reduces NO_x emissions by controlling the combustion process within the boiler. Within an initial fuel-rich environment that is used to favor the conversion of fuel-bound nitrogen to N_2 instead of NO_x, additional air (or OFA) is introduced downstream of the main burner zone to burn out any residual material. By injecting the OFA into the lower temperature combustion zone, NO_x is less likely to form, while burning the residual solid fuel (char).
2. <u>New Low NO_x Burners</u> - LNB technologies rely on a combination of fuel staging and combustion

[4] Ibid. (70 Federal Register 39171)

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 converts nitrogen to molecular nitrogen (N_2) rather than using oxygen in the combustion air to oxidize the nitrogen to NO_x. This allows complete combustion of the fuel while reducing both thermal and chemical NO_x formation.

3. Selective Catalytic Reduction – SCR is a post combustion control technique in which vaporized ammonia is injected into the flue gas upstream of a catalyst. NO_x entrained in the flue gas is reduced to N_2 and water. 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.

4. Selective Non-Catalytic Reduction - SNCR involves the injection of a reducing agent such as ammonia or urea into the flue gas stream. Rather than rely on a catalyst, SNCR systems rely on appropriate injection temperatures, proper mixing of the reagent and flue gas, and prolonged retention time. The effective temperature range for SNCR is higher than for SCR, and SNCR systems typically have lower NO_x emissions reductions than SCR. Also, SNCR systems are more prone to ammonia slip than SCR.

5. SNCR/SCR Hybrid – A hybrid SNCR/SCR system combines the lower costs and higher ammonia slip of SNCR with the higher NO_x reduction potential and lower ammonia slip of SCR. During operation, the SNCR system is allowed to inject higher amounts of reagent into the flue gas. The increased reagent flow brings about increased NO_x reduction, but also causes increased ammonia slip which is then consumed by the SCR system. The use of the ammonia slip by the SCR system can reduce the size of the required SCR catalyst.

6. Natural Gas Reburn – Fuel reburning is a method of fuel staging designed to reduce NO_x emissions. It involves the introduction of a supplemental fuel into the main section of the steam generator to produce reducing conditions that convert NO_x to N_2. Natural gas reburn requires three separate combustion zones and sufficient residence time (adequate furnace height).

In addition to applying these controls technologies separately, they can be combined to increase overall NO_x reduction. Basin Electric evaluated the combined application of OFA/LNB and the combined application of OFA/LNB with SNCR.

NO_x: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Natural Gas Reburn - Basin Electric determined that natural gas reburn is technically infeasible because the effectiveness of such a system would be negatively impacted by the amount of space available in the Laramie River Station furnaces.

NO_x: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

The Division considers the control effectiveness of a proposed control technology to be equivalent to the permit limit that would be established for that technology if it were chosen as BART. The permit 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. 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 OFA, generally have inherent variability that must be considered when establishing the permit limit. Otherwise, the source may be out of compliance even though the equipment is operated and maintained as well as possible.

Basin Electric determined that SNCR as the sole control technology would not meet the presumptive emission rate of 0.23 lb/MMBtu. A preliminary evaluation of an SNCR system for Laramie River Station indicated that the controlled NO_x emission would be 0.24 lb/MMBtu. Therefore, SNCR was not further evaluated as the sole control technology.

In the initial BART permit application submitted by Basin Electric, the installation of OFA or new LNB individually were both listed with a control effectiveness of 0.23 lb/MMBtu. A combination of OFA with new LNB was listed with a control effectiveness of 0.15 lb/MMBtu. Subsequent submittals from Basin Electric described that the 0.15 lb/MMBtu control effectiveness was based entirely on computational fluid dynamics (CFD) modeling that was conducted in 2004. The value produced by the CFD modeling was described as the lowest theoretical NO_x level that could be achieved when operating conditions match the optimum conditions simulated in the modeling. Additionally, the 2004 CFD modeling included an error in the use of sea-level conditions and was described by Basin Electric's contractor (Black & Veatch) as representing optimum, steady-state conditions that could not be maintained during normal operation of the Laramie River Station boilers.

More current CFD modeling performed by Reaction Engineering at the request of Basin Electric for the Unit 1 OFA project indicated that the installation of OFA with new LNB would result in a control effectiveness of 0.18 lb/MMBtu (± 0.02 lb/MMBtu). As described by Burns & McDonnell on behalf of Basin Electric, the results of the more recent CFD modeling indicate that an appropriate emissions limit for OFA + new LNB that takes into account the normal operation variability would be 0.23 lb/MMBtu for a 30-day rolling average.

Basin Electric contracted with Black & Veatch to analyze the control effectiveness of other control technologies, including a SNCR/SCR Hybrid (Cascade) system, OFA + new LNB with SNCR, and SCR. Table 2 presents a summary of the effectiveness of the technically feasible control technologies for NO_x.

Table 2: NO_x Emission Rates Per Boiler

Control Technology	Control Effectiveness (lb/MMBtu)
Baseline	0.27
Overfire Air	0.23
New LNB	0.23
New LNB with OFA	0.23
SNCR/SCR Hybrid	0.20
New LNB with OFA and SNCR	0.12
SCR	0.07

Note: Baseline emissions based on continuous emissions monitoring (CEM) annual averages for 2001-2003.

NO_x: EVALUATE IMPACTS AND DOCUMENT RESULTS

Basin Electric quantified the costs of applying the remaining NO_x control technologies by considering the following types of impact:

- Cost of compliance
- Energy impacts
- Non-air quality environmental impacts
- Remaining useful life
- Visibility (described in a later section of the document)

Energy impacts, such as added auxiliary power consumption or the power associated with additional draft systems to overcome resistance to flue gas flow, were calculated for each control technology. Non-air quality environmental impacts were also considered, and for this analysis were limited to the costs associated with disposal of byproducts or waste generated by control technologies. Basin Electric anticipates operating the Laramie River Station 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.

Basin Electric developed estimates for the cost of compliance, including Total Capital Investment (TCI) and annual operation and maintenance (O&M) costs, using the following sources of information:

- Coal Utility Environmental Cost (CUECost) workbook (Version 1.0)
- EPA Air Pollution Control Cost Manual (Sixth Edition)
- Budgetary quotes from equipment vendors
- Cost estimates from previous design/build projects or in-house engineering estimates

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 control technologies. Incremental cost effectiveness is also used extensively by the Division when comparing emission controls under the BACT process. While the BART process and the BACT process are not equivalent, control determinations from either process that are based on cost effectiveness and incremental cost effectiveness are indicative of the economic costs to control emissions.

In addition to providing cost effectiveness and incremental cost effectiveness results, Basin Electric 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 levels 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 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, the Division evaluated the amount of anticipated visibility improvement gained by the application of each proposed emission control technology. The Division considered cost effectiveness and incremental cost effectiveness in the evaluation of each proposed NO_x emission control.

Tables 3 through 5 present the economic and environmental costs associated with the remaining NO_x control technologies for Units 1 through 3.

Table 3: Unit 1 Economic and Environmental Costs for NO_x Control

Parameter	OFA	New LNB	New LNB with OFA	SNCR/SCR Hybrid	New LNB/OFA and SNCR	SCR
Capital Costs	$5,326,000	$15,631,000	$22,096,000	$44,969,000	$43,441,000	$123,101,000
Annualized Costs	$625,000	$1,360,000	$1,944,000	$7,429,000	$7,365,000	$15,787,000
NO_x Emissions (lb/MMBtu)	0.23	0.23	0.23	0.20	0.12	0.07
Annual NO_x Emission (tpy)	5,384	5,384	5,384	4,681	2,809	1,639
Annual NO_x Reduction (tpy)	936	936	936	1,639	3,511	4,681
Cost per ton of Reduction	$668	$1,453	$2,077	$4,534	$2,098	$3,372
Incremental Cost per ton of Reduction[1]	--	--	--	--	$2,105	$7,198
Energy Costs	$140,000	--	--	$77,000	$77,000	$414,000
Non-Air Quality Costs	--	--	--	--	--	$1,000

(1) Incremental costs for new LNB + OFA + SNCR calculated relative to new LNB + OFA. Incremental costs for SCR calculated relative to new LNB + OFA + SNCR. Incremental costs for SNCR/SCR Hybrid not calculated (considered an inferior technology and not considered further in this analysis).

Table 4: Unit 2 Economic and Environmental Costs for NO_x Control

Parameter	OFA	New LNB	New LNB with OFA	SNCR/SCR Hybrid	New LNB/OFA and SNCR	SCR
Capital Costs	$5,326,000	$15,631,000	$22,096,000	$44,969,000	$43,441,000	$123,101,000
Annualized Costs	$625,000	$1,360,000	$1,944,000	$7,429,000	$7,365,000	$15,787,000
NO_x Emissions (lb/MMBtu)	0.23	0.23	0.23	0.20	0.12	0.07
Annual NO_x Emission (tpy)	5,354	5,354	5,354	4,656	2,793	1,630
Annual NO_x Reduction (tpy)	931	931	931	1,630	3,492	4,656
Cost per ton of Reduction	$671	$1,461	$2,088	$4,559	$2,109	$3,391
Incremental Cost per ton of Reduction[1]	--	--	--	--	$2,117	$7,242
Energy Costs	$140,000	--	--	$77,000	$77,000	$414,000
Non-Air Quality Costs	--	--	--	--	--	$1,000

(1) Incremental costs for new LNB + OFA + SNCR calculated relative to new LNB + OFA. Incremental costs for SCR calculated relative to new LNB + OFA + SNCR. Incremental costs for SNCR/SCR Hybrid not calculated (considered an inferior technology and not considered further in this analysis).

Table 5: Unit 3 Economic and Environmental Costs for NO_x Control

Parameter	OFA	New LNB	New LNB with OFA	SNCR/SCR Hybrid	New LNB/OFA and SNCR	SCR
Capital Costs	$5,326,000	$15,631,000	$22,096,000	$44,969,000	$43,441,000	$123,101,000
Annualized Costs	$625,000	$1,360,000	$1,944,000	$7,429,000	$7,365,000	$15,787,000
NO_x Emissions (lb/MMBtu)	0.23	0.23	0.23	0.20	0.12	0.07
Annual NO_x Emission (tpy)	5,493	5,493	5,493	4,777	2,866	1,672
Annual NO_x Reduction (tpy)	955	955	955	1,672	3,582	4,777
Cost per ton of Reduction	$654	$1,424	$2,036	$4,444	$2,056	$3,305
Incremental Cost per ton of Reduction[1]	--	--	--	--	$2,064	$7,054
Energy Costs	$140,000	--	--	$77,000	$77,000	$414,000
Non-Air Quality Costs	--	--	--	--	--	$1,000

(1) Incremental costs for new LNB + OFA + SNCR calculated relative to new LNB + OFA. Incremental costs for SCR calculated relative to new LNB + OFA + SNCR. Incremental costs for SNCR/SCR Hybrid not calculated (considered an inferior technology and not considered further in this analysis).

The cost effectiveness and incremental cost effectiveness of the proposed BART technologies for NO_x are all reasonable. The SNCR/SCR Hybrid was eliminated from further consideration as an inferior technology as compared to New LNB/OFA/SNCR because of the higher costs/higher emissions associated with the Hybrid option. Basin Electric modeled the range of anticipated visibility improvement from the company-proposed BART controls (OFA) by modeling OFA/New LNB and OFA/New LNB/SCR. While OFA/New LNB/SNCR was not individually evaluated in Step 5: Evaluate visibility impact, the anticipated degree of visibility improvement from applying this control option lies within the range of visibility impacts that were modeled.

The final step in the BART NO_x determination process for Laramie River Station Units 1-3, Step 5: Evaluate visibility impacts, is addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants and associate control options. The visibility analysis follows Steps 1-4 for PM_{10} emissions in this application analysis.

SO_2: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Basin Electric identified three control technology configurations for reduction of SO_2 emissions from Units 1 and 2, which are currently equipped with back-end WFGD systems:

- Elimination of Stack Reheat System
- Improvements to Existing WFGD
- Sorbent Injection

1. Elimination of Stack Reheat System – Basin Electric routes a portion of the flue gas on Units 1 and 2 to a reheat system that decreases the moisture in the flues and avoids damage to the flues, which are brick-lined. The elimination of the reheat system would route more of the flue gas through the WFGD and reduce SO_2 emissions, but would place added strain on the scrubber and require a new stack with a liquid collection system.

2. Improvements to Existing WFGD – Units 1 and 2 are equipped with dual-loop, counter-flow absorber towers. Each unit has five absorber towers. Current operation of the system meets the permitted emission limit of 0.20 lb/MMBtu. One possible measure to improve the performance of the system would be the installation of an additional level of perforated tray below the existing perforated tray. This tray would serve to increase the contact time between the flue gas and the reagent liquid (L/G ratio) and increase overall SO_2 removal. This technique, however, would increase the pressure drop in the scrubber vessel, and would require an upgrade to draft system. Another option for enhanced SO_2 removal is to increase the slurry flow rate into the absorber section of the WFGD by adding an additional spray header. The disadvantage of this option is increased erosion on the vaning system in the tower, and the need to enhance the reagent preparation system. A third option for higher SO_2 removal is to upgrade the capacity of the recycle pumps, thus increasing the slurry flow rate. This would increase the L/G ratio. As a fourth option, an additional absorber tower could be installed to allow for the treatment of more flue gas and to increase the L/G ratio by allowing a rebalancing of the flue gas flow rates to a lower flow through each tower. A fifth option is the introduction of chemical additives that enhance the SO_2 capture rate. Three additives that are typically used are dolomitic lime, dibasic (DBA) or adipic acid, and formic acid. Basin Electric chose this option for further evaluation because it had the least plant impacts, outage time, and FGD operation procedure impacts.

3. Sorbent Injection – Components of a reagent injection system typically include an air compressor, sorbent storage tank, heat tracing, controls, injection system, injection platform, and slurry pump. Furnace and duct injection systems require a wet or dry reagent, and are capable of removing 10 to 20 percent of the SO_2 in the flue gas. A dry reagent such as powdered lime is preferred for furnace injection systems. For duct injection systems, a wet reagent such as lime slurry is preferred. Use of a wet reagent upstream of an existing ESP can help reduce the gas temperature, improve ESP performance, and eliminate the need for additional ID fans for draft control.

Basin Electric identified four control technology configurations for reduction of SO_2 emissions from Unit 3, which currently uses a DFGD system:

- Fabric Filter Retrofit into Unit 3 ESP Casing
- Replacement of Dry Scrubber Reactor with New Generation SDA Modules
- New WFGD System
- Sorbent Injection

1. Fabric Filter Retrofit into Unit 3 ESP Casing – Enhanced SO_2 removal can be achieved by retrofitting a fabric filter system into the existing Unit 3 ESP. Removal of SO_2 would occur from contact of the remaining SO_2 molecules in the flue gas with unreacted lime particles in the fly ash cake on the fabric filter bags. With a typical Spray Dryer Absorber (SDA) and pulse jet fabric filter (PJFF) system, additional SO_2 removal can be 10 to 20 percent.

2. Replacement of Dry Scrubber Reactor with New Generation SDA Modules – Existing dry scrubber equipment on Unit 3 was designed by B&W, and achieves an SO_2 removal rate of approximately 85 percent. Replacement of the existing four dry scrubber reactors with two SDA modules could achieve a small increase in SO_2 removal.

3. New WFGD System – A new wet FGD system similar to those used on Units 1 and 2 could be installed on Unit 3 to replace the existing dry scrubber. Unit 3's dry scrubber would be left in place with its internal equipment removed to reduce pressure drop. The Unit 3 ESP would remain in operation to remove fly ash, and the location of the new WFGD would be to the east of the existing chimney. A new stack with a liner capable of wet flue gas operation would be required. Outage time for the unit would only be required for tie-in with the new system. New booster fans would be needed to adjust for additional pressure drop from the scrubber, and the limestone reagent preparation system for Units 1 and 2 might have to be upgraded to accommodate additional material needed for Unit 3.

4. Sorbent Injection – The sorbent injection system described earlier for Units 1 and 2 is also a possibility for Unit3.

SO_2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

All of the control technologies identified for Units 1 and 2 are technically feasible. For Unit 3, two of the listed technologies were deemed by Basin Electric as technically infeasible:

New Generation SDA Modules: Unit 3 is already equipped with a system that is essentially an SDA, and therefore it is not feasible to replace the existing system with a similar system.

Sorbent Injection – Sorbent injection is not technically feasible for Unit 3 because the expected controlled emission level would not meet the presumptive level.

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. 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 generally has 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.

Tables 6 and 7 present the effectiveness of the remaining technically feasible control technologies for SO_2.

Table 6: Units 1 and 2 SO_2 Emission Rates Per Boiler

Control Technology	Control Effectiveness (lb/MMBtu)
Baseline	0.16
Sorbent Injection	0.15
FGD Chemical Additives	0.15
Elimination of Stack Reheat System	0.13

Note: Baseline emissions based on continuous emissions monitoring (CEM) annual averages for 2001-2003.

Table 7: Unit 3 SO_2 Emission Rates

Control Technology	Control Effectiveness (lb/MMBtu)
Baseline	0.17
Fabric Filter Retrofit into Unit 3 ESP	0.13
New WFGD	0.06

Note: Baseline emissions based on continuous emissions monitoring (CEM) annual averages for 2001-2003.

SO_2: EVALUATE IMPACTS AND DOCUMENT RESULTS

Basin Electric quantified the costs of applying the remaining SO_2 control technologies at the Laramie River Station by considering the following types of impact:

- Cost of compliance
- Energy Impacts
- Non-air quality environmental impacts
- Remaining useful life
- Visibility (described in later section of the document)

Basin Electric anticipates operating the Laramie River Station 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.

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 control technologies. Incremental cost effectiveness is also used extensively by the Division when comparing emission controls under the BACT process. While the BACT process and the BACT process are not equivalent, control determinations from either process that are based on cost effectiveness and incremental cost effectiveness are indicative of the economic costs to control emissions.

In addition to providing cost effectiveness and incremental cost effectiveness results, Basin Electric 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 levels 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 control measures used to establish presumptive levels were addressed in a separate visibility analysis. The Division considered cost effectiveness and incremental cost effectiveness in the evaluation of each proposed emission control. Tables 8 through 10 present the economic and environmental costs associated with the remaining SO_2 control technologies for Units 1 through 3.

Table 8: Unit 1 Economic and Environmental Costs for SO_2 Control

Parameter	Sorbent Injection	FGD Chemical Additives	Eliminate Stack Reheat System
Capital Costs	$7,453,000	$2,363,000	$63,845,000
Annualized Costs	$906,000	$366,000	$6,664,000
SO_2 Emissions (lb/MMBtu)	0.15	0.15	0.13
Annual SO_2 Emission (tpy)	3,511	3,511	3,043
Annual SO_2 Reduction (tpy)	234	234	702
Cost per ton of Reduction	$3,871	$1,564	$9,490
Incremental Cost per ton of Reduction[1]	--	--	$13,453
Energy Costs	$62,000	$6,000	$459,000
Non-Air Quality Costs	--	--	--

[1] Incremental costs for Eliminate Stack Reheat System relative to FGD Chemical Additives

Table 9: Unit 2 Economic and Environmental Costs for SO_2 Control

Parameter	Sorbent Injection	FGD Chemical Additives	Eliminate Stack Reheat System
Capital Costs	$7,453,000	$2,363,000	$63,845,000
Annualized Costs	$906,000	$366,000	$6,664,000
SO_2 Emissions (lb/MMBtu)	0.15	0.15	0.13
Annual SO_2 Emission (tpy)	3,492	3,492	3,026
Annual SO_2 Reduction (tpy)	233	233	698
Cost per ton of Reduction	$3,892	$1,572	$9,542
Incremental Cost per ton of Reduction(1)	--	--	$13,527
Energy Costs	$62,000	$6,000	$459,000
Non-Air Quality Costs	--	--	--

(1) Incremental costs for Eliminate Stack Reheat System relative to FGD Chemical Additives

Table 10: Unit 3 Economic and Environmental Costs for SO_2 Control

Parameter	Fabric Filter Retrofit into Unit 3 ESP (peak rate for lost gen. costs)	Fabric Filter Retrofit into Unit 3 ESP (non-peak rate for lost gen. costs)	New WFGD
Capital Costs	$194,809,000	$134,934,000	$240,777,000
Annualized Costs	$19,585,000	$14,376,000	$31,243,000
SO_2 Emissions (lb/MMBtu)	0.13	0.13	0.06
Annual SO_2 Emission (tpy)	3,105	3,105	1,433
Annual SO_2 Reduction (tpy)	955	955	2,627
Cost per ton of Reduction	$20,501	$15,049	$11,893
Incremental Cost per ton of Reduction(1)	--	--	$10,089
Energy Costs	$242,000	$243,000	$3,858,000
Non-Air Quality Costs	--	--	$715,000

(1) Incremental costs for new WFGD for Unit 3 relative to Fabric Filter Retrofit

Several of the technically feasible control options for SO_2 are not cost effective, including all proposed options for Unit 3, and the elimination of the stack reheat system for Units 1 and 2. The remaining options for Units 1 and 2, Sorbent Injection and FGD Chemical Additives, were modeled by the applicant to determine Class I area visibility improvement. Results of the modeling showed that visibility improvement would be insignificant. For example, the predicted visibility improvement at Badlands National Park, based on the modeled 98th percentile result for all three units combined, would be (at most) 0.02 delta deciview. Therefore, none of the proposed control options for SO_2 were carried forward for further analysis.

PM/PM$_{10}$: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Basin Electric identified four control technology configurations for control of PM emissions from Units 1 through 3:

- Flue Gas Treatment
- Existing ESP Performance Enhancements
- PJFF Retrofit into ESP (Unit 3 only)
- GE Max-9 Hybrid

1. Flue Gas Treatment – One option for flue gas treatment is flue gas "conditioning", for which flue gas is conditioned by adding ionic compounds such as sulfur trioxide and ammonia to improve the PM capture rate in the ESP. Moisture in the flue gas combines with the ionic compounds and the mixture is deposited on the surface of the fly ash particles. In this way, the conductivity of the fly ash is increased and the capture rate of the ESP is improved. Another option is in-duct humidification, for which moisture is added to the flue gas upstream of the ESP. This serves to reduce the temperature (and volume) of the flue gas, and a denser flue gas allows for an increase in the Specific Collection Area (SCA) of the ESP without a physical modification to the ESP. The humidification would have to be limited to avoid an outlet temperature that would promote the formation of H_2SO_4. Particle agglomeration is another option for flue gas treatment. For this process, the flue gas is pretreated with electrostatic charges upstream of the ESP to promote agglomeration of the particles. By agglomerating the particles into larger sizes and reducing the number of particles to be collected by the ESP, the overall removal efficiency of the ESP is improved.

2. Existing ESP Performance Enhancements – The ESP imparts an electrical charge to particles in the flue gas, and the particles adhere to metal plates inside the precipitator. Rapping on the plates removes the particles from the plates for disposal. One technology for improving rapping efficiency and preventing re-entrainment of the fly ash into the flue gas is the use of a computerized rapping system. This has already been implemented at the Laramie River Station. Another option for improving the ESP performance is to upgrade the electrical and control system. This type of upgrade can not only enhance the particle collection efficiency, but will also allow the ESP to operate more efficiently and therefore lower the auxiliary power use. This also has already been implemented at the Laramie River Station.

3. Pulse Jet Fabric Filter Retrofit into ESP – Retrofit of a PJFF into the existing Unit 3 ESP casing would require several physical modifications to the system, including the construction of a tubesheet to hold the fabric filter bags and the installation of a compressed air system for cleaning

the bags. A new booster fan system would be required to offset the added pressure drop from the filter bags. The additional auxiliary power consumption from the new booster fan would be offset by power savings from not operating the ESP. The PJFF retrofit is a viable option only for Unit 3. Units 1 and 2 utilize wet flue gas desulfurization (WFGD), and a PJFF is not feasible for use downstream of a WFGD system.

4. GE Max-9 Hybrid – The GE Max-9 Electrostatic Fabric Filter (ESFF) is an electrostatic precipitator/pulse-jet baghouse hybrid, using high-voltage discharge electrodes to charge flue gas particles, but with fabric filters instead of collecting plates in the casing. The system can provide high collection efficiency while operating at a lower system pressure drop. Pressure drop is lower because particles are charged positively and repel each other on the surface of the filter, making the dust cake very porous. Compressed air pulses are used to clean the filters.

PM/PM_{10}: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Basin Electric identified three of the four potential control technologies for PM as technically infeasible:

Flue Gas Treatment: This option would not increase the level of emissions control to a higher level than is currently achieved with the existing ESP, and is therefore considered to be technically infeasible.

Existing ESP Performance Enhancement – The ESP performance enhancements, as described earlier, are already in use at the Laramie River Station.

GE Max-9 Hybrid – The GE Max-9 Hybrid has been recently installed in a smaller utility boiler, but not with a boiler of the size used at the Laramie River Station. Therefore, the GE Max-9 is not considered as a technically feasible technology.

PM/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. 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 generally has 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. Table 11 presents the control effectiveness associated with the remaining technically feasible PM controls.

Table 11: PM Emission Rates Per Boiler

Control Technology	Control Effectiveness (lb/MMBtu)
Baseline	0.030
Retrofit Fabric Filter into Unit 3 ESP	0.015

PM/PM_{10}: EVALUATE IMPACTS AND DOCUMENT RESULTS

Basin Electric quantified the costs of applying the remaining technologies at the Laramie River Station by considering the following types of impact:

- Cost of compliance
- Energy Impacts
- Non-air quality environmental impacts
- Remaining useful life
- Visibility (described in later section of the document)

Basin Electric anticipates operating each of the Laramie River Station units 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.

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 control technologies. Incremental cost effectiveness is also used extensively by the Division when comparing emission controls under the BACT process. While the BART process and the BACT process are not equivalent, control determinations from either process that are based on cost effectiveness and incremental cost effectiveness are indicative of the economic costs to control emissions.

In addition to providing cost effectiveness and incremental cost effectiveness results, Basin Electric 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 levels 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 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, the Division evaluated the amount of visibility improvement gained in relation to each proposed emission control technology. The Division considered cost effectiveness and incremental cost effectiveness in the evaluation of each proposed PM emission control. Table 12 present the economic and environmental costs associated with the remaining PM technologies.

Table 12: Unit 3 Economic and Environmental Costs for PM Control

Parameter	Fabric Filter Retrofit into Unit 3 ESP (peak rate for lost gen. costs)	Fabric Filter Retrofit into Unit 3 ESP (non-peak rate for lost gen. costs)
Capital Costs	$194,809,000	$134,934,000
Annualized Costs	$19,585,000	$14,376,000
PM Emissions (lb/MMBtu)	0.015	0.015
Annual PM Emission (tpy)	358	358
Annual PM Reduction (tpy)	358	358
Cost per ton of Reduction	$54,707	$40,156
Energy Costs	$242,000	$243,000

The remaining technically feasible PM_{10} control option for Unit 3 is not cost effective, and was not carried forward for further analysis.

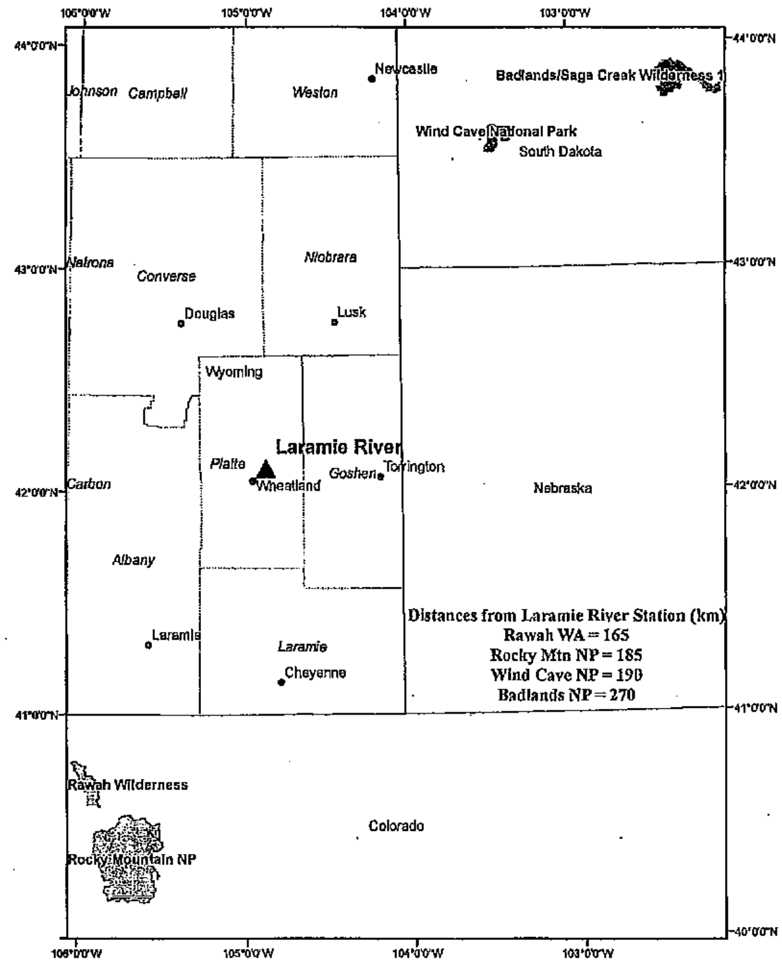
VISIBILITY IMPROVEMENT DETERMINATION:

The fifth of five factors that must be considered for a BART determination analysis, as required by 40 CFR part 51 - Appendix Y, is the degree of Class I area visibility improvement that would result from the installation of the various options for control technology. This factor was evaluated for the Basin Electric Power Cooperative (BEPC) Laramie River Station 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 Laramie River Station 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.

Rocky Mountain National Park (NP) and Rawah Wilderness Area in Colorado are the closest Class I areas to the Laramie River Station, as shown in Figure 1 below. Rawah WA is located approximately 165 kilometers (km) to the southwest of the station and Rocky Mountain NP is located approximately 185 km to the southwest of the station. Wind Cave NP and Badlands NP are located to the northeast of the station, at distances of approximately 190 km and 270 km, respectively.

Only those Class I areas most likely to be impacted by the Laramie River 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 two modeled areas.

Figure 1
Laramie River Station and Class I Areas



SCREENING MODELING

To determine if the Laramie River Station would be subject to BART, the Division conducted CALPUFF modeling using three years of meteorological data. These data, from 2001-2003, 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. Sources input to the modeling included the potential emissions (current operation) from the three coal-fired boilers at the facility. The Division chose to model the impacts at Wind Cave NP and Badlands NP for the screening, using the assumption that these areas would yield larger impacts than the Colorado Class I areas due to the predominant wind direction.

Results of the modeling showed that the 98th percentile value for the change in visibility (delta deciview [Δdv]) was above 0.5 Δdv at Wind Cave NP and Badlands NP for all three years of meteorology. As defined in EPA's final BART rule, a 98th percentile 0.5 Δdv impact or more 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 Table 13 below.

Table 13: Results of the Class I Area Screening Modeling

Year and Class I Area	Maximum Modeled Value (Δdv)	98th Percentile Value (Δdv)
2001		
Wind Cave NP	6.27	3.30
Badlands NP	5.50	3.68
2002		
Wind Cave NP	7.71	3.14
Badlands NP	5.88	2.78
2003		
Wind Cave NP	8.52	3.21
Badlands NP	5.44	2.67

Δdv = delta deciview
NP = National Park

REFINED MODELING

Because of the results of the Division's screening modeling for the Laramie River Station, BEPC 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 Laramie River Station 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 sources in question, 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 the CALMET model. 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 14; 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 the initial three-dimensional windfield using data from the MM5 model. Surface and upper-air data were also input to CALMET to adjust the initial windfield, but because of the relative scarcity of observations in the modeling domain, the influence of the observations was limited within CALMET. Because the MM5 data were afforded a high degree of influence on the CALMET windfields, the Division obtained MM5 data with 12-km resolution that spanned the years 2001-2003 for use in the analysis. The Division provided the BART applicants all of the raw meteorological inputs for the CALMET model 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 15: Key User-Defined CALMET Settings

Variable	Description	Value
PMAP	Map projection	LCC (Lambert Conformal Conic)
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 (MM5 data)
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

Two CALMET windfields were used for the Laramie River station BART modeling. The initial windfield was developed by BEPC to model the impacts at Wind Cave NP and Badlands NP, as directed by the Division and as specified in the Division's modeling protocol. A second, larger windfield was developed by the Division to model the impacts at Rawah WA and Rocky Mountain NP and to model an additional control scenario at Wind Cave NP and Badlands NP. Surface, upper-air, and precipitation data for the domains were incorporated into the CALMET windfields. Figures 2 and 3 below show the locations of surface, upper-air, and precipitation stations used for the two windfields.

Figure 2: Observations Input to CALMET (BEPC Windfield)

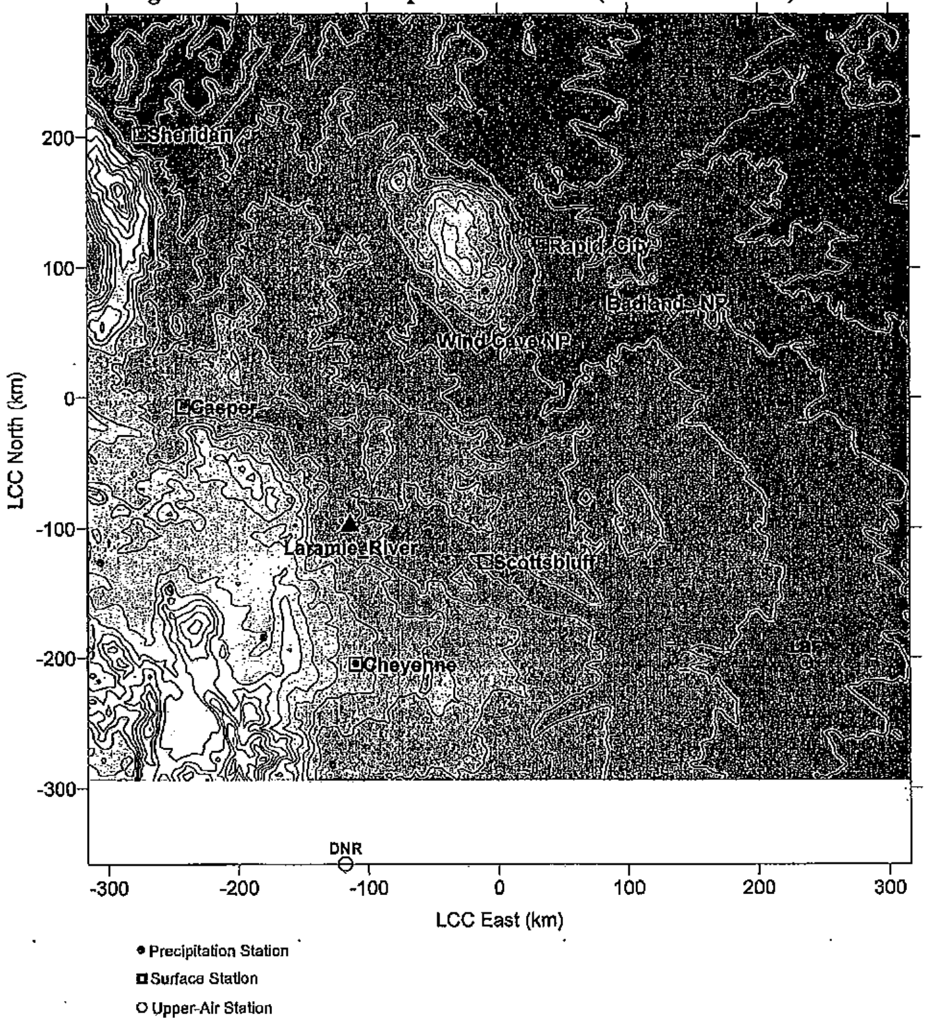
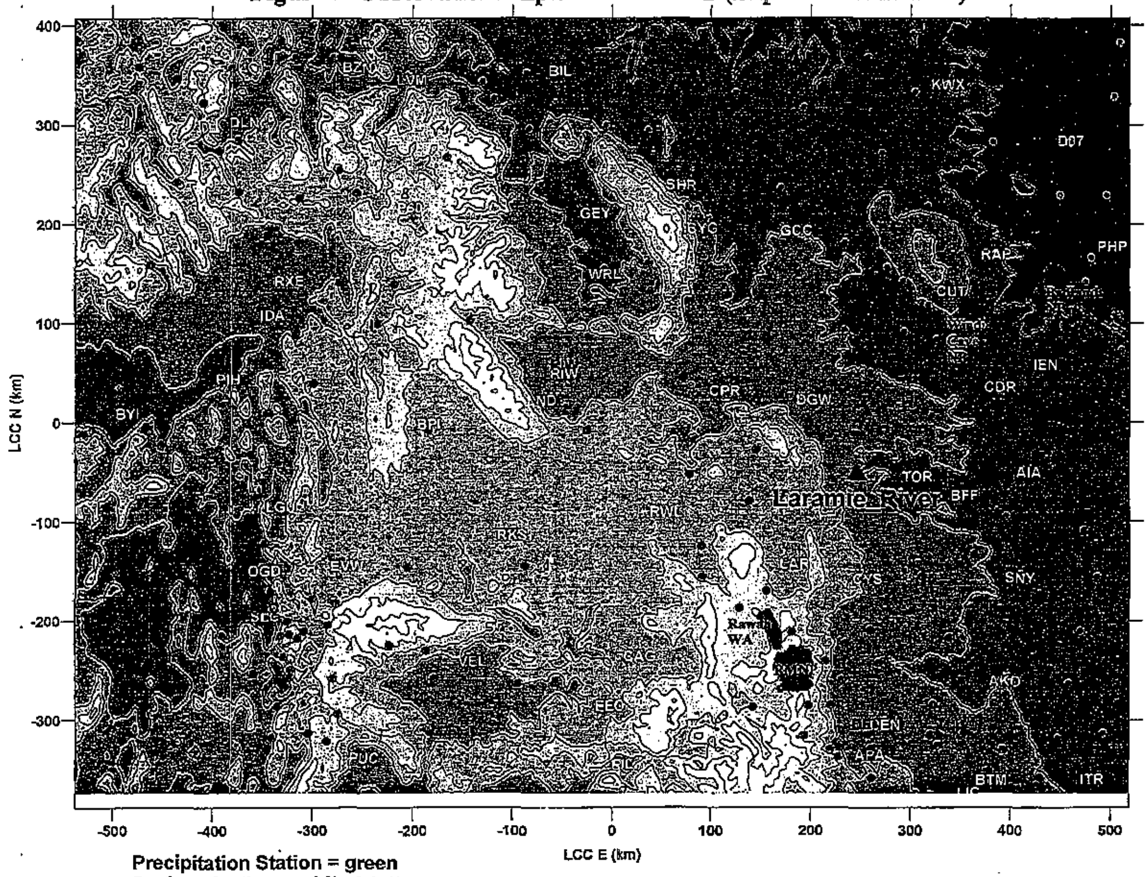


Figure 3: Observations Input to CALMET (Expanded Windfield)



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. For ozone, hourly data collected from the following stations were used:

- Rocky Mountain National Park, Colorado (NP)
- 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 4-7 show the receptor configurations that were used for Rawah WA, Rocky Mountain NP, Badlands NP, and Wind Cave NP. Receptor spacing within Wind Cave NP is approximately 0.7 km in the east-west direction and approximately 0.9 km in the north-south direction. For Rawah WA, Rocky Mountain NP, and Badlands NP, the receptor spacing is approximately 1.4 km in the east-west direction and approximately 1.8 km in the north-south direction.

Figure 4
Receptors for Rawah WA

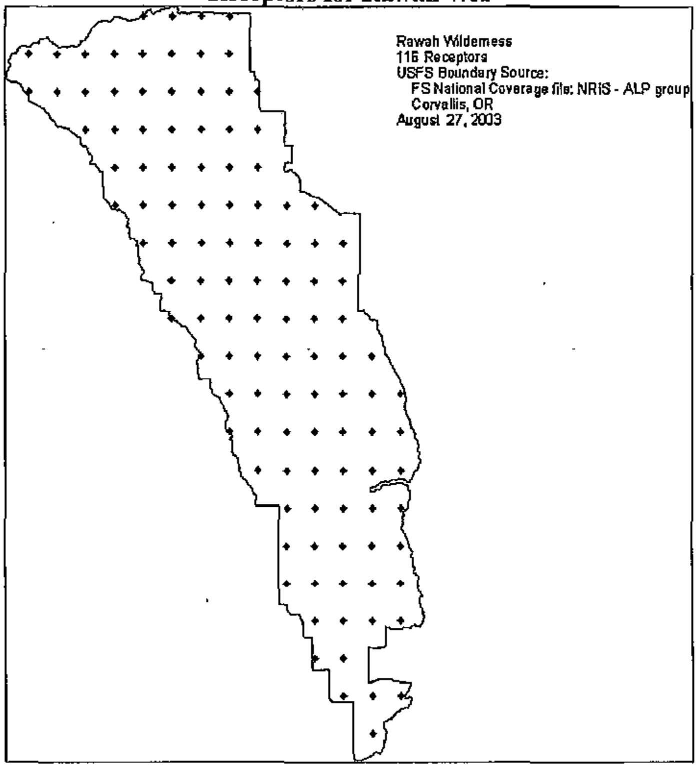


Figure 5
Receptors for Rocky Mountain NP

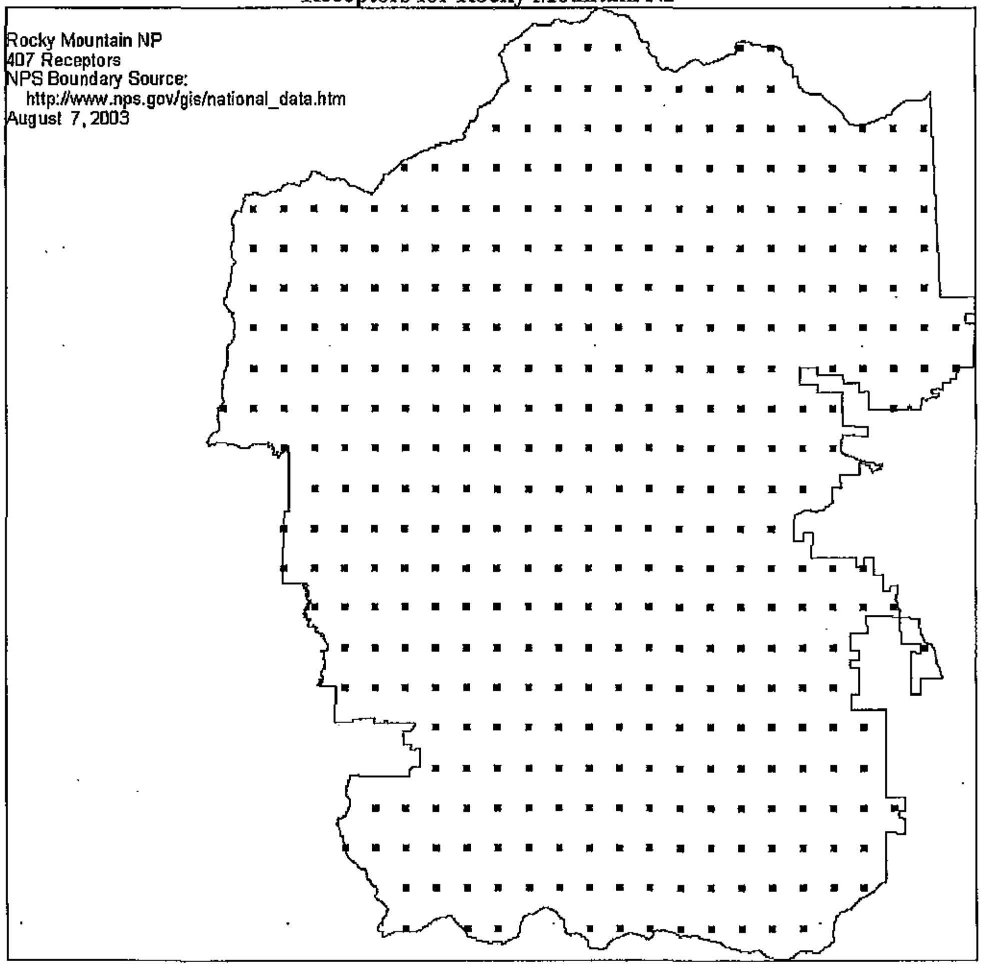


Figure 6
Receptors for Wind Cave NP

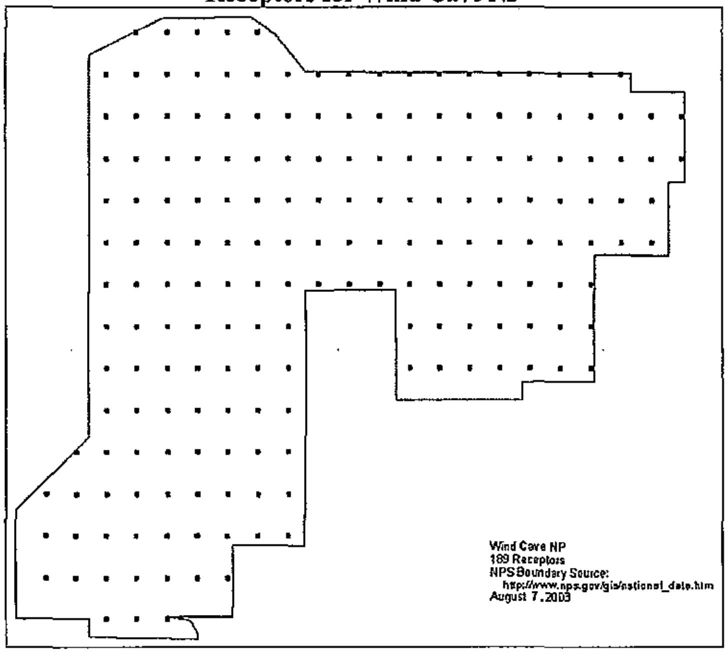
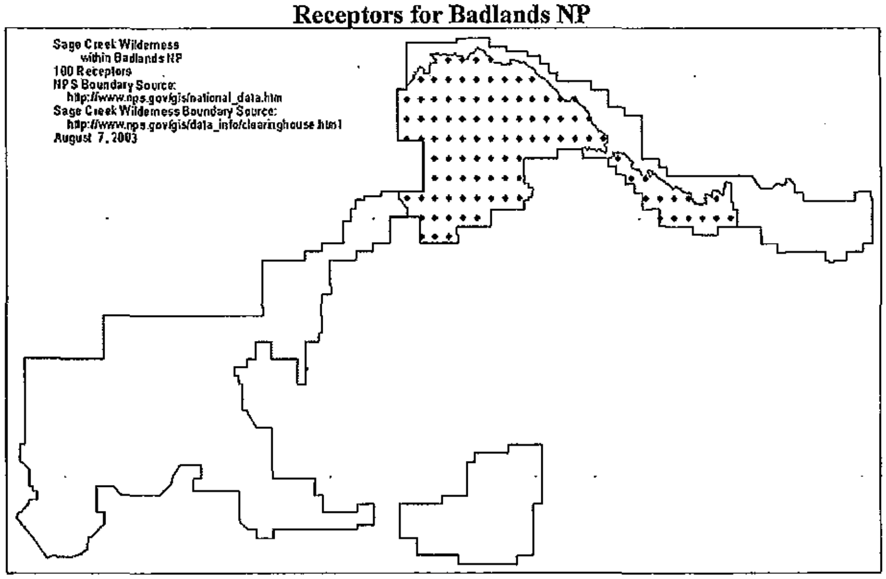


Figure 7
Receptors for Badlands NP



CALPUFF Inputs – Baseline and Control Options

The first step in the refined modeling analysis was to perform visibility modeling for current (baseline) operations at the facility. Emissions of NO_x and SO_2 for the baseline runs were established based on CEM annual emissions averages for years 2001 to 2003. All particulate emissions (PM) were based on an emission rate of 0.03 lb/MMBtu and were treated as $PM_{2.5}$ (fine PM) within CALPUFF and CALPOST. Direct emissions of sulfate were based on the values calculated for the Toxic Release Inventory (TRI) for the years modeled.

Baseline source release parameters and emissions are shown in the table below, followed by tables with data for the various control options. No attempt was made by the applicant to estimate the increase in sulfate emissions that would result from operation of SCR and SNCR/SCR hybrid controls, and as a result the visibility improvement for those scenarios may be overestimated by some undetermined amount.

Table 16: Baseline Source Parameters

	Baseline		
	Coal-Fired Unit 1 (P1)	Coal-Fired Unit 2 (P2)	Coal-Fired Unit 3 (P3)
Parameter	LNB, WFGD, ESP	LNB, WFGD, ESP	LNB, DFGD, ESP
Heat Input (MMBtu/yr)	46,814,433	46,557,738	47,765,529
Base Elevation (m)	1348	1348	1348
Stack Height (m)	184.4	184.4	184.40
Stack Diameter (m)	8.69	8.69	8.69
Stack Temperature (K)	338.7	338.7	352.0
Exit Velocity (m/s)	21.33	21.03	22.25
SO_2 Emissions (lb/MMBtu)	0.16	0.16	0.17
SO_2 Emissions (tpy)	3745	3725	4060
HS_2O_4 Emissions (tpy)	3.06	2.80	0.22
NO_x Emissions (lb/MMBtu)	0.27	0.27	0.27
NO_x Emissions (tpy)	6320	6285	6448
PM Fine Emissions (lb/MMBtu)	0.03	0.03	0.03
PM Fine Emissions (tpy)	702	698	716

Note: Boiler heat input and lb/MMBtu emissions for NO_x and SO_2 based on continuous emissions monitoring (CEM) annual averages for 2001-2003.

DFGD = dry flue gas desulfurization
ESP = electrostatic precipitator
H_2SO_4 = sulfuric acid
K = Kelvin
lb/MMBtu = pounds per million British thermal units
LNB = low-NO_x burners
m = meters
m/s = meters per second
MMBtu/yr = million British thermal units per year
NO_x = nitrogen oxides
PM = particulate matter
SO_2 = sulfur dioxide
tpy = tons per year
WFGD = wet flue gas desulfurization

Table 17: Source Parameters and Emissions for BART Control Options

	Control Option 1			Control Option 2		
	NO_x Control: Overfire Air (OFA) or New LNB			NO_x Control: New LNB with OFA		
Parameter	Coal-Fired Unit 1 (P1)	Coal-Fired Unit 2 (P2)	Coal-Fired Unit 3 (P3)	Coal-Fired Unit 1 (P1)	Coal-Fired Unit 2 (P2)	Coal-Fired Unit 3 (P3)
Base Elevation (m)	1348	1348	1348	1348	1348	1348
Stack Height (m)	184.4	184.4	184.4	184.4	184.4	184.4
Stack Diameter (m)	8.69	8.69	8.69	8.69	8.69	8.69
Stack Temperature (K)	338.7	338.7	352.0	338.7	338.7	352.0
Exit Velocity (m/s)	21.33	21.03	22.25	21.33	21.03	22.25
SO_2 Emissions (lb/MMBtu)	0.16	0.16	0.17	0.16	0.16	0.17
SO_2 Emissions (tpy)	3745	3725	4060	3745	3725	4060
H_2SO_4 Emissions (tpy)	3.18	3.25	0.22	3.18	3.25	0.22
NO_x Emissions (lb/MMBtu)	0.23	0.23	0.23	0.23	0.23	0.23
NO_x Emissions (tpy)	5384	5354	5493	5384	5354	5493
PM Fine Emissions (lb/MMBtu)	0.030	0.030	0.030	0.030	0.030	0.030
PM Fine Emissions (tpy)	702	698	716	702	698	716

H_2SO_4 = sulfuric acid
K = Kelvin
lb/MMBtu = pounds per million British thermal units
LNB = low NO_x burners
m = meters
m/s = meters per second
NO_x = nitrogen oxides
OFA = overfire air
PM = particulate matter
SCR = selective catalytic reduction
SO_2 = sulfur dioxide
tpy = tons per year

Table 17: Source Parameters and Emissions for BART Control Options (cont.)

	Control Option 4		
	NO_x Control: SCR		
Parameter	**Coal-Fired Unit 1 (P1)**	**Coal-Fired Unit 2 (P2)**	**Coal-Fired Unit 3 (P3)**
Base Elevation (m)	1348	1348	1348
Stack Height (m)	184.4	184.4	184.4
Stack Diameter (m)	8.69	8.69	8.69
Stack Temperature (K)	338.7	338.7	352.0
Exit Velocity (m/s)	21.33	21.03	22.25
SO_2 Emissions (lb/MMBtu)	0.16	0.16	0.17
SO_2 Emissions (tpy)	3745	3725	4060
H_2SO_4 Emissions (tpy)	3.18	3.25	0.22
NO_x Emissions (lb/MMBtu)	0.07	0.07	0.07
NO_x Emissions (tpy)	1639	1630	1672
PM Fine Emissions (lb/MMBtu)	0.030	0.030	0.030
PM Fine Emissions (tpy)	702	698	716

H_2SO_4 = sulfuric acid
K = Kelvin
lb/MMBtu = pounds per million British thermal units
LNB = low NO_x burners
m = meters
m/s = meters per second
NO_x = nitrogen oxides
OFA = overfire air
PM = particulate matter
SCR = selective catalytic reduction
SO_2 = sulfur dioxide
tpy = tons per year

Visibility Post-Processing (CALPOST) Setup

The changes in visibility were calculated using Method 6 within the CALPOST post-processor. Method 6 requires input of monthly relative humidity factors [f(RH)] for each Class I area that is being modeled. Monthly f(RH) factors that were used for this analysis are shown in the table below.

Table 18: Relative Humidity Factors for CALPOST

Month	Rocky Mountain NP	Rawah WA	Wind Cave NP and Badlands NP
January	1.7	2.1	2.65
February	1.9	2.1	2.65
March	1.9	2.0	2.65
April	2.1	2.1	2.55
May	2.3	2.3	2.70
June	2.0	2.0	2.60
July	1.8	1.8	2.30
August	2.0	2.0	2.30
September	1.9	2.0	2.20
October	1.8	1.9	2.25
November	1.8	2.1	2.75
December	1.7	2.0	2.65

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 percent best days deciview values for that particular Class I area would be calculated.

The scaling procedure is illustrated here for Badlands NP. From Appendix B in the EPA natural visibility guidance document, the deciview value for the 20 percent best days at Badlands NP is 2.18 dv. To obtain the speciated background concentrations representative of the 20 percent best days, the deciview value (2.18 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 2.18, one obtains an equivalent light extinction value of 12.44 Mm^{-1}. Next, the annual average natural visibility concentrations were set equal to a total extinction value of 12.44 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 $\mu g/m^3$
- 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 Badlands NP, and including a coefficient for scaling, one obtains:

$$12.44 = (3)(2.55)[0.12]X + (3)(2.55)[0.1]X + (0.6)[3.0]X + (4)[0.47]X + (1)[0.5]X + (10)[0.02]X + 10$$

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 0.402. Table 19 presents the annual average natural background concentrations, the calculated scaling factor, and the calculated background concentrations for the 20 percent best days for Badlands NP.

Table 19: Calculated Background Components for Badlands NP

Component	Annual Average for West Region ($\mu g/m^3$)	Calculated Scaling Factor	20% Best Days for Badlands NP ($\mu g/m^3$)
Ammonium Sulfate	0.12	0.402	0.048
Ammonium Nitrate	0.10	0.402	0.040
Organic Carbon	0.47	0.402	0.189
Elemental Carbon	0.02	0.402	0.008
Soil	0.50	0.402	0.201
Coarse Mass	3.00	0.402	1.205

The scaled aerosol concentrations were averaged for Badlands NP and Wind Cave NP because of their geographical proximity and similar annual background visibility. The 20 percent best days aerosol concentrations for the Class I areas in question are listed in the table below.

Table 20: Natural Background Aerosol Concentrations ($\mu g/m^3$)

Aerosol Component	Rawah WA	Rocky Mountain NP	Wind Cave NP & Badlands NP
Ammonium Sulfate	0.045	0.045	0.047
Ammonium Nitrate	0.038	0.038	0.040
Organic Carbon	0.178	0.177	0.186
Elemental Carbon	0.008	0.008	0.008
Soil	0.189	0.189	0.198
Coarse Mass	1.135	1.132	1.191

The results of the visibility modeling for each of the three units for the baseline and control scenarios are shown in the tables below. Results for the Colorado Class I areas are presented for the baseline scenario only because the results for this scenario were well below 0.5 Δdv. For each scenario, the 98[th] 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 Wind Cave NP and Badlands NP.

Table 21: CALPUFF Visibility Modeling Results for Laramie River 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 – LNB, Wet FGD, ESP								
Badlands NP	0.643	14	0.841	17	0.599	9	0.694	13
Wind Cave NP	0.732	17	0.700	16	0.542	9	0.658	14
Post-Control Scenario 1 – OFA								
Badlands NP	0.574	12	0.761	16	0.532	9	0.622	12
Wind Cave NP	0.662	15	0.619	11	0.496	7	0.592	11
Post-Control Scenario 2 – OFA + New LNB								
Badlands NP	0.574	12	0.761	16	0.532	9	0.622	12
Wind Cave NP	0.662	15	0.619	11	0.496	7	0.592	11
Post-Control Scenario 4 – SCR								
Badlands NP	0.322	4	0.402	4	0.303	5	0.342	4
Wind Cave NP	0.378	3	0.320	1	0.307	3	0.335	2

Table 22: CALPUFF Visibility Modeling Results for Laramie River 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 – LNB, Wet FGD, ESP								
Badlands NP	0.642	14	0.842	17	0.594	10	0.693	14
Wind Cave NP	0.725	17	0.699	16	0.546	9	0.657	14
Post-Control Scenario 1 – OFA								
Badlands NP	0.573	12	0.762	16	0.530	9	0.622	12
Wind Cave NP	0.658	15	0.615	11	0.498	7	0.590	11
Post-Control Scenario 2 – OFA + New LNB								
Badlands NP	0.573	12	0.762	16	0.530	9	0.622	12
Wind Cave NP	0.658	15	0.615	11	0.498	7	0.590	11
Post-Control Scenario 4 – SCR								
Badlands NP	0.320	4	0.399	4	0.302	5	0.340	4
Wind Cave NP	0.384	3	0.319	1	0.310	3	0.338	2

Table 23: CALPUFF Visibility Modeling Results for Laramie River Unit 3

Class I Area	2001 98th Percentile Value (Δdv)	2001 No. of Days > 0.5 Δdv	2002 98th Percentile Value (Δdv)	2002 No. of Days > 0.5 Δdv	2003 98th Percentile Value (Δdv)	2003 No. of Days > 0.5 Δdv	3-Year Average 98th Percentile Value (Δdv)	3-Year Average No. of Days > 0.5 Δdv
Baseline – LNB, Wet FGD, ESP								
Badlands NP	0.639	14	0.886	18	0.630	8	0.718	13
Wind Cave NP	0.680	17	0.717	16	0.553	10	0.650	14
Post-Control Scenario 1 – OFA								
Badlands NP	0.572	11	0.803	17	0.561	8	0.645	12
Wind Cave NP	0.609	14	0.643	13	0.502	8	0.585	12
Post-Control Scenario 2 – OFA + New LNB								
Badlands NP	0.572	11	0.803	17	0.561	8	0.645	12
Wind Cave NP	0.609	14	0.643	13	0.502	8	0.585	12
Post-Control Scenario 4 – SCR								
Badlands NP	0.336	4	0.446	4	0.323	4	0.368	4
Wind Cave NP	0.381	4	0.348	2	0.297	3	0.342	3

Table 24: CALPUFF Visibility Modeling Results for Laramie River Station: Rocky Mountain National Park & Rawah WA (Baseline Scenario)

Class I Area	2001 98th Percentile Value (Δdv)	2001 No. of Days > 0.5 Δdv	2002 98th Percentile Value (Δdv)	2002 No. of Days > 0.5 Δdv	2003 98th Percentile Value (Δdv)	2003 No. of Days > 0.5 Δdv	3-Year Average 98th Percentile Value (Δdv)	3-Year Average No. of Days > 0.5 Δdv
Unit 1								
Rawah WA	0.308	3	0.425	7	0.287	2	0.340	4
Rocky Mtn. NP	0.414	6	0.447	7	0.441	5	0.434	6
Unit 2								
Rawah WA	0.309	3	0.422	7	0.279	2	0.337	4
Rocky Mtn. NP	0.415	6	0.455	7	0.437	5	0.436	6
Unit 3								
Rawah WA	0.295	3	0.440	6	0.301	2	0.345	4
Rocky Mtn. NP	0.433	7	0.481	7	0.448	4	0.454	6

Figure 8 – Modeled BART Impacts: Number of Days > 0.5 delta-dv

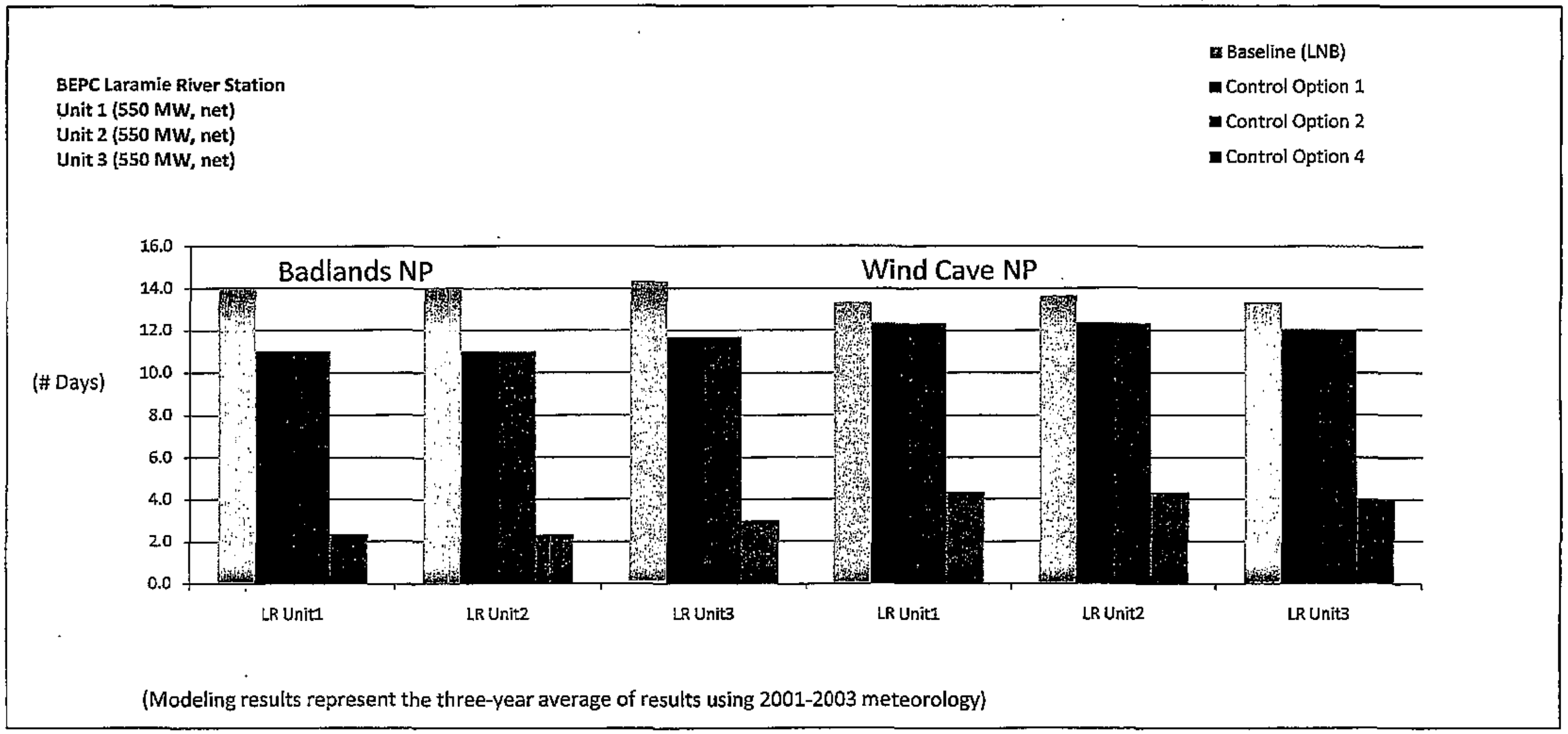
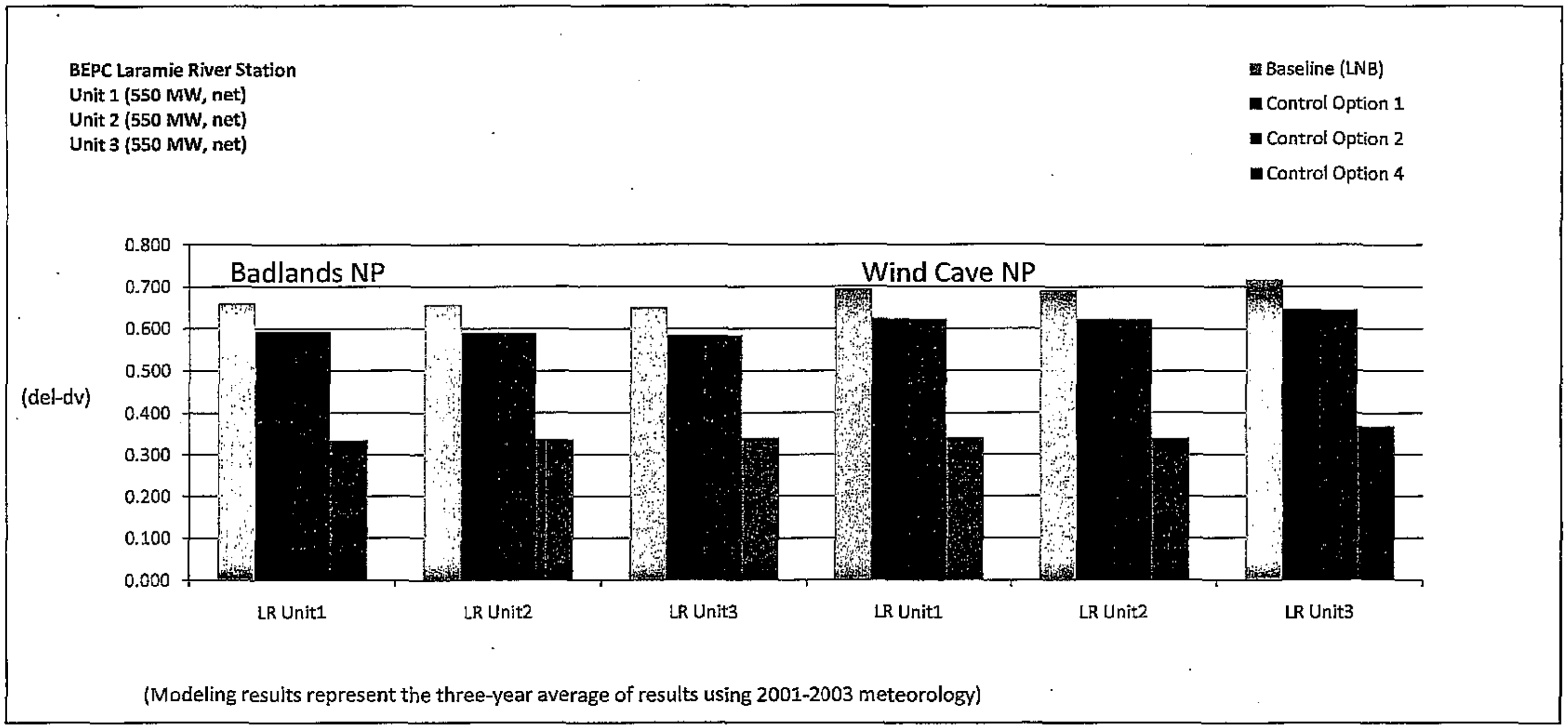


Figure 9 – Modeled BART Impacts: 98th Percentile (delta-dv)



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 the three units at the Laramie River Station.

NO_x

New LNB with OFA is determined to be BART for NO_x control for Units 1-3 based, in part, on the following conclusions:

1. Installation of new LNB with OFA was cost effective, with a capital cost of $22,096,000 per unit and $2,036-$2,088 per ton of NO_x removed based on the average cost effectiveness for each unit over a twenty year operational life.

2. Combustion control using LNB with 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 0.23 lb/MMBtu on a 30-day rolling average, equal to EPA's established presumptive limit for dry-bottom, wall-fired boilers burning sub-bituminous coal, is justified.

4. Visibility impacts were addressed in a comprehensive visibility analysis covering three visibility impairing pollutants and the associated control options. The cumulative visibility improvement as compared to the baseline across Wind Cave NP and Badlands NP achieved with new LNB with OFA at the 30-day limit of 0.23 lb/MMBtu (based on the 98th percentile modeled results) was 0.14 Δdv from each of the three units. The expected visibility improvement over the course of a full annual period would be even greater due to the annual BART limit that is based on 0.19 lb/MMBtu.

5. Annual NO_x emission reductions from new LNB with OFA on Units 1, 2, and 3 are 1,862-1,910 tons per unit for a total annual reduction of 5,645 tons.

LNB with OFA and SCR was not determined to be BART for NO_x control for Units 1-3 based, in part, on the following conclusions:

1. The cost of compliance for installing SCR on each unit is significantly higher than the cost for LNB with OFA. Additional capital costs for SCR on Units 1-3 are $101,005,000 per unit. Annual operating costs for SCR on Units 1-3 are $4,608,000 per unit.

2. Additional non-air quality environmental mitigation is required for the use of chemical reagents.

3. Operation of LNB with OFA and SCR is parasitic and requires an estimated 4.8 MW of power from each unit.

4. The cumulative visibility improvement for SCR, as compared to LNB/OFA, across Wind Cave NP and Badlands NP (based on the 98th percentile modeled results) was 0.52-0.54 Δdv for each of the three units.

The Division considers the installation and operation of the BART-determined NO_x controls, new LNB with OFA, to meet the statutory requirements of BART.

Unit-by-unit NO_x BART determinations:

<u>Laramie River Unit 1</u>: New LNB with OFA and meeting NO_x emission limits of 0.23 lb/MMBtu (30-day rolling average), 1,348 lb/hr (30-day rolling average), and 5,343 tpy (12-month rolling) as BART for NO_x.

<u>Laramie River Unit 2</u>: New LNB with OFA and meeting NO_x emission limits of 0.23 lb/MMBtu (30-day rolling average), 1,348 lb/hr (30-day rolling average), and 5,343 tpy (12-month rolling) as BART for NO_x.

<u>Laramie River Unit 3</u>: New LNB with OFA and meeting NO_x emission limits of 0.23 lb/MMBtu (30-day rolling average), 1,386 lb/hr (30-day rolling average), and 5,493 tpy (12-month rolling) as BART for NO_x.

The performance/efficiency-based, 30-day rolling average emission rate of 0.23 lb/MMBtu is set to allow for continuous compliance with proper operation of the control equipment, while taking into account the normal operational variability that is typical for a boiler. The 30-day limits that are expressed in terms of mass emissions (lb/hr) are based on 0.21 lb/MMBtu. Because reduced steam loads on a boiler can result in periods of increased emissions in terms of lb/MMBtu but lower emissions in terms of lb/hr, the Division has chosen to set the dual 30-day limits, one set at 0.23 lb/MMBtu and one expressed in lb/hr based on 0.21 lb/MMBtu. For the 12-month rolling emission limits, the Division considered the ability of the source to maintain a lower emission rate over a longer time period and set the long-term limit (expressed in tpy) based on 0.19 lb/MMBtu.

<u>PM/PM_{10}</u>

Existing ESP is determined to be BART for Units 1-3 for PM/PM_{10} based, in part, on the following conclusions:

1. The cost of compliance for the sole technically feasible control option, a retrofit fabric filter on the Unit 3 ESP, is not reasonable over a twenty year operational life. The cost effectiveness for installing the retrofit fabric filter is $40,156 per ton of PM/$PM_{10}$ removed. No additional control technologies were deemed to be technically feasible for Units 1 and 2.

2. Visibility impacts from the installation of controls on PM/PM_{10} emissions, in general, are not expected to produce significant visibility improvements. In particular for the Laramie River Station, Basin Electric modeled the fabric filter retrofit on Unit 3, and the predicted improvement in visibility as compared to baseline at Wind Cave NP or Badlands NP was at most 0.07 Δdv.

The Division considers the operation of the BART-determined PM/PM_{10} controls, existing ESP, to meet the statutory requirements of BART.

Unit-by-unit PM/PM_{10} BART determinations:

Laramie River Unit 1:	Continuing to use the existing ESP to meet the established PM/PM_{10} emission limits of 0.030 lb/MMBtu, 193 lb/hr, and 844 tpy as BART for PM/PM_{10}.
Laramie River Unit 2:	Continuing to use the existing ESP to meet the established PM/PM_{10} emission limits of 0.030 lb/MMBtu, 193 lb/hr, and 844 tpy as BART for PM/PM_{10}.
Laramie River Unit 3:	Continuing to use the existing ESP to meet the established PM/PM_{10} emission limits of 0.030 lb/MMBtu, 198 lb/hr, and 867 tpy as BART for PM/PM_{10}.

SO_2: REGIONAL SO_2 MILESTONE AND BACKSTOP TRADING PROGRAM

Basin Electric evaluated SO_2 control technologies that can achieve a SO_2 emission rate of 0.15 lb/MMBtu or lower from the coal-fired boilers. Basin Electric proposed BART controls include using chemical additives in the Unit 1 and 2 WFGD systems.

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 below:

Table 25: 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 26 to underscore the improvements associated with SO_2 reductions.

Table 26: 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 submitted in November 2008.

Therefore, in accordance with §308(e)(2), Wyoming's §309 Regional Haze SIP, and WAQSR Chapter 6, Section 9, Basin Electric will not be required to install the company-proposed BART technology and meet the corresponding achievable emission limit. Instead, Basin Electric 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. When 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 possibly occur as early as 2015.

Based on the costs and visibility improvement presented by Basin Electric in the BART applications for Laramie River Station Units 1-3, and taking into consideration the logistical challenge of managing multiple pollution control installations within the regulatory timeframe allotted for BART installations by the Regional Haze Rule, the Division is requiring the installation of additional controls under the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan. The Division is requiring Basin Electric submit a permit application to install additional add-on NO_x control that includes an analysis of: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of existing sources that contribute to visibility impairment (i.e., the four statutory factors taken into consideration when establishing reasonable progress goals[5]) and the associated visibility impacts from the application of each proposed NO_x control. Each proposed add-on NO_x control shall achieve an emission rate, on an individual unit basis, at or below 0.07 lb/MMBtu on a 30-day rolling average. Additional add-on controls shall be installed and operational on one of the Laramie River Station units by December 31, 2018 and on a second Laramie River Station unit by December 31, 2023.

CHAPTER 6, SECTION 4 – PREVENTION OF SIGNIFICANT DETERIORATION (PSD):

Basin Electric's Laramie River Station 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. Basin Electric should comply with the permitting requirements of Chapter 6, Section 4 as they apply to the installation of controls determined to meet BART.

[5] 40 CFR 51.308(d)(1)(i)(A).

CHAPTER 5, SECTION 2 – NEW SOURCE PERFORMANCE STANDARDS (NSPS):

The installation of the controls determined to meet BART will not change New Source Performance Standard applicability for the coal-fired boilers at Laramie River Station.

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 the controls determined to meet BART will not change NESHAP/MACT applicability for the coal-fired boilers at Laramie River Station.

CHAPTER 6, SECTION 3 – OPERATING PERMIT:

The Laramie River Station is a major source under Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations. Operating Permit 3-1-102-2 was issued for the facility on November 15, 2005. In accordance with Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations (WAQSR), Basin Electric will need to modify their operating permit to include the changes authorized in this permitting action.

CONCLUSION:

The Division is satisfied that Basin Electric's Laramie River Station will comply with all applicable Wyoming Air Quality Standards and Regulations. The Division proposes to issue a BART Air Quality Permit for the Laramie River Station modification to install OFA and new LNB on Laramie River Station Units 1-3 to meet the statutory requirements of BART. Two (2) of the three (3) units must install add-on NO_x control that achieves an emission rate, on an individual unit basis, at or below 0.07 lb/MMBtu on a 30-day rolling average by December 31, 2018 and December 31, 2023, respectively, under the Long-Term Strategy of the Wyoming §308 Regional Haze State Implementation Plan.

PROPOSED PERMIT CONDITIONS:

The Division proposes to issue an Air Quality Permit to Basin Electric for the modification of the Laramie River Station 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 Basin Electric 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, at the same address.

5. Effective upon completion of the performance tests to verify the emission levels below, as required by Condition 6 of this permit, emissions from Laramie River Station Units 1 through 3 shall not exceed the levels below. PM/PM_{10} lb/hr and tpy limits shall apply during all operating periods. PM/PM_{10} lb/MMBtu limits shall apply during all operating periods except startup. Startup begins with the introduction of fuel oil into the boiler and ends no later than the point in time when the electricity generators are put online.

Pollutant	lb/MMBtu	lb/hr	tpy
PM/PM_{10}[a]	0.030	Unit 1: 193 Unit 2: 193 Unit 3: 198	Unit 1: 844 Unit 2: 844 Unit 3: 867

[a] Filterable portion only

6. That no later than 90 days after permit issuance PM/PM_{10} performance tests shall be conducted on Units 1-3 and a written report of the results be submitted. If a maximum design rate is not achieved within 90 days of permit issuance, 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 Laramie River Station Units 1 through 3 shall not exceed the levels below. The NO_x limits shall apply during all operating periods.

Pollutant	lb/MMBtu	lb/hr	tpy
NO_x	0.23 (30-day rolling)	Unit 1: 1,348 Unit 2: 1,348 Unit 3: 1,386 (all 30-day rolling)	Unit 1: 5,343 Unit 2: 5,343 Unit 3: 5,493 (all 12-month rolling)

8. That initial NO_x 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 (Laramie River Station Units 1 through 3):

<u>NO_x Emissions</u> – 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.

<u>PM/PM_{10} Emissions</u> – Testing shall follow 40 CFR 60.46 and EPA Reference Test Methods 1-4 and 5.

Testing required by the WAQSR Chapter 6, Section 3 operating permit may be submitted to satisfy the testing required by this condition.

10. Prior to any performance 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. Basin Electric 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. After the installation or upgrade of control equipment, compliance with the limits set forth in this permit for the coal-fired boilers (Laramie River Station Units 1 through 3) shall be determined with data from the existing 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.

iii. Any 12-month rolling emission rate which exceeds the tpy NO_x limit as calculated using the following formula:

$$E = \frac{\sum_{h=1} (C)_h}{2,000}$$

Where:

C = 1-hour average emission rate (lb/hr) for hour "h" calculated using data from the CEM equipment required by 40 CFR Part 75. For monitoring data not meeting the requirements of WAQSR, Chapter 5, Section 2(j), Basin Electric shall provide substituted data for an emissions unit according to the missing data procedures of 40 CFR, Part 75 during any period of time that there is not monitoring data.

E = 12-month rolling emission rate (tpy).

b. Basin Electric 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).

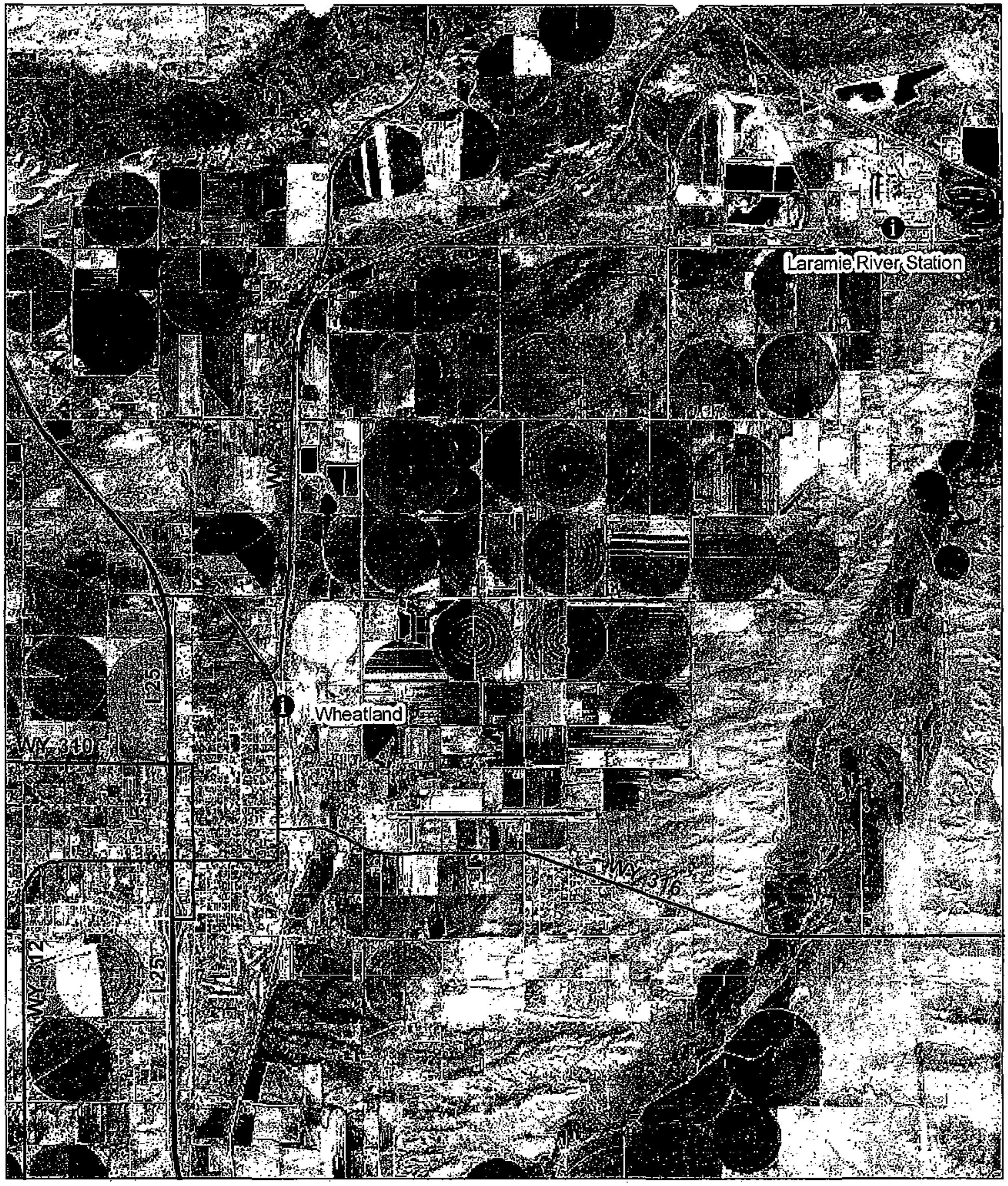
13. Compliance with the PM/PM_{10} limits set forth in this permit for the coal-fired boilers (Laramie River Units 1-3) shall be determined with data from testing for PM conducted annually, or more frequently as specified by the Administrator, following 40 CFR 60.46 and EPA Reference Test Methods 1-4 and 5. Testing required by the WAQSR Chapter 6, Section 3 operating permit may be submitted to satisfy the testing required by this condition.

14. 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.

15. Basin Electric shall install new low NO_x burners with overfire air on Units 1 through 3, in accordance with the Division's BART determination, and conduct the initial performance tests required in Condition 8 no later than December 31, 2012 for Unit 1; December 31, 2013 for Unit 2; and December 31, 2014 for Unit 3.

16. Basin Electric shall submit permit applications for the installation of additional add-on NO_x control on two units at the Laramie River Station to the Division no later than six (6) years prior to installation, under the Long-Term Strategy of the Wyoming §308 Regional Haze State Implementation Plan. It shall include an analysis of the four statutory factors and the associated visibility impacts from the application of each proposed NO_x control and resulting emission levels. This application shall address each add-on NO_x control as a system of continuous emissions reduction achieving the lowest viable NO_x emission, not to exceed a maximum of 0.07 lb/MMBtu on a 30-day rolling average as measured by a certified CEM. Additional add-on NO_x control shall be installed and operational on one (1) unit by December 31, 2018 and on a second unit by December 31, 2023.

Appendix A
Facility Location



Basin Electric Power Cooperative
Laramie River Station
347 Grayrocks Road
Platte County, Wyoming