DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

BART Application Analysis
AP-6041

May 28, 2009

NAME OF FIRM:	PacifiCorp
NAME OF FACILITY:	Dave Johnston Plant
FACILITY LOCATION:	Sections 7 and 18, T33N, R74W UTM Zone: 13 Easting: 436,592 m, Northing: 4,742,918 m Converse County, Wyoming
TYPE OF OPERATION:	Coal-Fired Electric Generating Plant
RESPONSIBLE OFFICIAL:	Gary Slanina, Managing Director
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PURPOSE OF APPLICATION:

Sections 169A and 169B of the 1990 Clean Air Act Amendments require states to improve visibility at Class I areas. On July 1, 1999, EPA first published the Regional Haze Rule, which provided specific details regarding the overall program requirements to improve visibility. The goal of the regional haze program is to achieve natural conditions by 2064.

Section 308 of the Regional Haze Rule (40 CFR part 51) includes discussion on control strategies for improving visibility impairment. One of these strategies is the requirement under 40 CFR 51.308(e) for certain stationary sources to install Best Available Retrofit Technology (BART) to reduce emissions of three (3) visibility impairing pollutants, nitrogen oxides (NO_x), particulate matter (PM), and sulfur dioxide (SO_2). EPA published Appendix Y to part 51 - *Guidelines for BART Determinations Under the Regional Haze Rule* in the July 6, 2005 Federal Register to provide guidance to regulatory authorities for making BART determinations. Chapter 6, Section 9, Best Available Retrofit Technology was adopted into the Wyoming Air Quality Standards and Regulations (WAQSR) and became effective on December 5, 2006. The Wyoming Department of Environmental Quality, Air Quality Division (Division) will determine BART for NO_x and PM_{10} for each source subject to BART and include each determination in the §308 Wyoming Regional Haze State Implementation Plan (SIP).

Section 309 of the Regional Haze Rule (40 CFR part 51), *Requirements related to the Grand Canyon Visibility Transport Commission*, provides states that are included within the Transport Region addressed by the Grand Canyon Visibility Transport Commission (i.e., Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming) an alternative to the requirements established in 40 CFR 51.308. This alternative control strategy for improving visibility contains special provisions for addressing SO_2 emissions, which include a market trading program and a provision for a series of SO_2 milestones. Wyoming submitted a §309 Regional Haze SIP to EPA on December 29, 2003. As of the date of this analysis, EPA has not taken action on the SIP. National litigation issues related to the Regional Haze Rule, including BART, required states to submit revisions. On November 21, 2008, the State of Wyoming submitted revisions to the 2003 §309 Regional Haze SIP submittal. Sources that are subject to BART are required to address SO_2 emissions as part of the BART analysis even though the control strategy has been identified in the Wyoming §309 Regional Haze SIP.

On January 22, 2007 and on January 29, 2007, in accordance with the requirements of WAQSR Chapter 6 Section 9(e)(i), the Division received BART applications for two existing coal-fired boilers, Units 3 and 4, respectively, at the PacifiCorp Dave Johnston Power Plant. A map showing the location of PacifiCorp's Dave Johnston Power Plant is attached as Appendix A.

On June 5, 2007, PacifiCorp submitted additional copies of the January applications for the two (2) units subject to BART at Dave Johnston.

On October 15, 2007, PacifiCorp submitted updated applications for the two (2) units subject to BART at Dave Johnston. Additional modeling performed after the June 5, 2007 submittal and revised emissions reduction calculations were included.

On December 5, 2007, PacifiCorp submitted revised applications incorporating changes to the post-processing of the visibility model runs for each of the two (2) Dave Johnston units.

On March 31, 2008, PacifiCorp submitted addendums to each of the BART applications for Dave Johnston Units 3 and 4. Revised cost estimates and updated visibility modeling for two (2) NO_x control scenarios were included in the addendums.

BART ELIGIBILITY DETERMINATION:

In August of 2005 the Wyoming Air Quality Division began an internal review of sources that could be subject to BART. This initial effort followed the methods prescribed in 40 CFR part 51, Appendix Y: *Guidelines for BART Determinations Under the Regional Haze Rule* to identify sources and facilities. The rule requires that States identify and list BART-eligible sources, which are sources that fall within the 26 source categories, have emission units which were in existence on August 7, 1977 but not in operation before August 7, 1962 and have the potential to emit more than 250 tons per year (tpy) of any visibility impairing pollutant when emissions are aggregated from all eligible emission units at a stationary source. Fifty-one (51) sources at fourteen (14) facilities were identified that could be subject to BART in Wyoming.

The next step for the Division was to identify BART-eligible sources that may emit any air pollutant which may reasonably be anticipated to cause or contribute to impairment of Class I area visibility. Three pollutants are identified by 40 CFR part 51, Appendix Y as visibility impairing pollutants. They are sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM). Particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) was used as an indicator of PM. In order to determine visibility impairment of each source, a screening analysis was performed using CALPUFF. Sources that emitted over 40 tons of SO_2 or NO_x or 15 tons of PM_{10} were included in the screening analysis. Using three years of meteorological data, the screening analysis calculated visibility impacts from sources at nearby Class I areas. Sources whose modeled 98th percentile 24-hour impact or 8th highest modeled impact, by year, was equal to or greater than 0.5 deciviews (dv) above natural background conditions (Δdv) were determined to be subject to BART. For additional information on the Division's screening analysis see the Visibility Improvement Determination: Screening Modeling section of this analysis. Two existing coal-fired boilers at PacifiCorp's Dave Johnston Power Plant, Units 3 and 4, were determined to be subject to BART. PacifiCorp was notified in a letter dated June 14, 2006 of the Division's finding.

DESCRIPTION OF BART ELIGIBLE SOURCES:

PacifiCorp's Dave Johnston Power Plant is comprised of four (4) units burning pulverized sub-bituminous Powder River Basin coal for a total net generating capacity of a nominal 772 megawatts (MW). Dave Johnston Units 1 and 2 are nominal 106 MW pulverized coal-fired units. Unit 1 began operation in 1958 and Unit 2 in 1960. Since both units were in operation before August 7, 1962 they are not subject to BART regulation. However, Dave Johnston Units 3 and 4 are subject to BART review. Dave Johnston Unit 3 is a nominal 230 MW pulverized coal-fired boiler that commenced service in 1964. It was manufactured by Babcock & Wilcox and equipped with burners in a cell configuration. It is the only boiler in Wyoming subject to BART with burners in a cell configuration. The original burners have not been replaced or upgraded to low NO_x burners. Dave Johnston Unit 3 is not equipped with any SO_2 control equipment. Particulate matter (PM) emissions from Unit 3 are controlled using a Lodge-Cottrell single-chamber electrostatic precipitator (ESP) installed in 1976. Dave Johnston Unit 4 is a nominal 330 MW pulverized coal-fired boiler that commenced service in 1972. It is a tangential-fired boiler and was manufactured by Combustion Engineering, now Alstom. The original burners were replaced in 1976 with concentric-firing first generation low NO_x burners (LNB). A Venturi scrubber is used to control PM emissions. Additional SO_2 emission control is achieved in the scrubber by adding lime to the scrubber liquor.

Table 1: Dave Johnston Units 3 & 4 Pre-2005 Emission Limits [a]

Source	Firing Rate (MMBtu/hour)	Existing Controls	NO_x (lb/MMBtu)	SO_2 (lb/MMBtu)	PM/PM_{10} (lb/MMBtu) [c][d]
Unit 3	2,464 [b]	ESP	0.75 (3-hour rolling) 0.59 (annual)	1.2 (2-hour block)	0.23
Unit 4	4,100	LNB, Venturi Scrubber	0.75 (3-hour rolling) 0.53 (annual)	1.2 (3-hour block) 0.5 (30-day rolling)	0.21

[a] Emissions taken from Operating Permit 31-148-1 which does not include the most recent New Source Review construction permit limits.
[b] Boiler heat input reported in the Operating Permit 31-148-1.
[c] Based on PM limit calculation of $0.8963/I^{0.1743}$ lb/MMBtu where I=boiler heat input in MMBtu/hr.
[d] Averaging period is 1 hour as determined by the appropriate test method.

On June 27, 2008, Air Quality Permit MD-5098 was issued to PacifiCorp to replace the original burners on Unit 3 with a new low NO_x firing system including additional advanced overfire air (OFA). In addition, Unit 4's first generation LNB will be replaced with Alstom TFS 2000™ LNB with overfire air. Installation of dry flue gas desulfurization control equipment on both Units 3 and 4 is also authorized by this permitting action. Finally, the replacement of the existing ESP on Unit 3 with a baghouse and the installation of a new baghouse on Unit 4 are authorized by MD-5098. The emission levels established for Dave Johnston Units 3 and 4 in MD-5098 are summarized in Table 2.

Table 2: Dave Johnston Units 3 & 4 MD-5098 Emission Limits [a]

Source	Permitted Controls	NO_x	SO_2	PM/PM_{10}
Unit 3	New LNB with advanced OFA, Dry FGD, Baghouse	0.28 lb/MMBtu (12-month rolling) 784 lb/hr (12-month rolling)	0.15 lb/MMBtu (12-month rolling) 0.5 lb/MMBtu (30-day rolling) 0.5 lb/MMBtu (3-hr block) 420 lb/hr (24-hr rolling)	0.015 lb/MMBtu 42.1 lb/hr 184 tpy
Unit 4	New LNB with advanced OFA, Dry FGD, Baghouse	0.15 lb/MMBtu (12-month rolling) 697 lb/hr (12-month rolling)	0.15 lb/MMBtu (12-month rolling) 0.5 lb/MMBtu (30-day rolling) 0.5 lb/MMBtu (3-hr block) 615 lb/hr (24-hr rolling)	0.015 lb/MMBtu 61.5 lb/hr 269 tpy

[a] Emissions limits effective upon installation or upgrade of the applicable control equipment.

By letter dated July 18, 2008, PacifiCorp notified the Division that construction activities for installation of the FGD/baghouse control equipment on Units 3 and 4 were anticipated to begin July 28, 2008. March 31, 2009, PacifiCorp notified the Division of the anticipated startup of Unit 4, with new LNB and advanced OFA installed, on May 23, 2009. The construction activities are in line with the construction schedule proposed by PacifiCorp in the application for permit MD-5098. A construction summary is provided in Table 3.

Table 3: MD-5098 Permitted Upgrades to Dave Johnston Units 3 & 4

Source	New Low NO_x Burners with advanced Overfire Air (status, year)	New Dry FGD/baghouse (status, year)
Unit 3	Planned, 2010	Initiated, 2008
Unit 4	Initiated, 2009	Initiated, 2008

CHAPTER 6, SECTION 9 – BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

A BART determination is an emission limit based on the application of a continuous emission reduction technology for each visibility impairing pollutant emitted by a source. It is "…established, on a case-by-case basis, taking into consideration (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any pollution equipment in use or in existence at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."[1] A BART analysis is a comprehensive evaluation of potential retrofit technologies with respect to the five criteria above. At the conclusion of the BART analysis, a technology and corresponding emission limit is chosen for each pollutant for each unit subject to BART.

Visibility control options presented in the application for each source were reviewed using the methodology prescribed in 40 CFR 51 Appendix Y, as required in WAQSR Chapter 6 Section 9(c)(i). This methodology is comprised of five basic steps:

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

The Division acknowledges that BART is intended to identify retrofit technology for existing sources and is not the same as a top down analysis required for new sources under the Prevention of Significant Deterioration (PSD) rules known as Best Available Control Technology (BACT). Although BART is not the same as BACT, it is possible that BART may be equivalent to BACT on a case-by-case basis. The Division applied all five steps to each visibility impairing pollutant emitted from Dave Johnston Units 3 and 4 thereby conducting a comprehensive BART analysis for NO_x, SO_2 and PM/PM_{10}.

PRESUMPTIVE LIMITS FOR SO_2 AND NO_X FROM UTILITY BOILERS

EPA conducted detailed analyses of available retrofit technology to control NO_x and SO_2 emissions from coal-fired power plants. These analyses considered unit size, fuel type, cost effectiveness, and existing controls to determine reasonable control levels based on the application of an emissions reduction technology.

EPA's presumptive BART SO_2 limits analysis considered coal-fired units with existing SO_2 controls and units without existing control. Four key elements of the analysis were: "…(1) identification of all potentially BART-eligible EGUs [electric generating units], and (2) technical analyses and industry research to determine applicable and appropriate SO_2 control options, (3) economic analysis to determine cost effectiveness for each potentially BART-eligible EGU, and (4) evaluation of historical emissions and forecast emission reduction for each potentially BART-eligible EGU."[3] 491 BART-eligible coal-fired units were identified and included in the presumptive BART analysis for SO_2. Based on removal

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[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).

efficiencies of 90% for spray dry lime dry flue gas desulfurization systems and 95% for limestone forced oxidation wet flue gas desulfurization systems, EPA calculated projected SO_2 emission reductions and cost effectiveness for each unit. Based on the results of this analysis, EPA concluded that the majority of identified BART-eligible units greater than 200 MW without existing SO_2 control can meet the presumptive limits at a cost of $400 to $2,000 per ton of SO_2 removed.

A presumptive BART NO_x limits analysis was performed using the same 491 BART-eligible coal-fired units identified in the SO_2 presumptive BART analysis. EPA considered the same four key elements and established presumptive NO_x limits for EGUs based coal type and boiler configuration. For all boiler types, except cyclone, presumptive limits were based on combustion control technology (e.g., low NO_x burners and overfire air). Presumptive NO_x limits for cyclone boilers are based on the installation of SCR, a post combustion add-on control. EPA acknowledged that approximately 25% of the reviewed units could not meet the proposed limits based on current combustion control technology, but that nearly all the units could meet the presumptive limits using advanced combustion control technology, such as rotating opposed fire air. National average cost effectiveness values for presumptive NO_x limits ranged from $281 to $1,296 per ton removed.

Based on the results of the analyses for presumptive NO_x and SO_2 limits, EPA established presumptive limits for EGUs greater than 200 MW operating without NO_x post combustion controls or existing SO_2 controls located at facilities with a generating capacity greater than 750 MW. 40 CFR part 51 Appendix Y states that the presumptive SO_2 level for an uncontrolled unit is either 95% control or 0.15 lb/MMBtu. Presumptive NO_x levels for uncontrolled units are listed in Table 1 of Appendix Y and classified by the boiler burner configuration (unit type) and coal type. NO_x emission values range from 0.62 lb/MMBtu down to 0.15 lb/MMBtu. While Appendix Y establishes presumptive SO_2 limits and says that states should require presumptive NO_x, it also clearly gives states discretion to "…determine that an alternative [BART] control level is justified based on a careful consideration of the statutory factors."[4] The Division's following BART analysis for NO_x, SO_2, and PM/PM_{10} takes into account each of the five statutory factors.

PacifiCorp's Dave Johnston Power Plant generates a cumulative nominal 772 MW from all four units. Unit 3, a nominal 230 MW unit, and Unit 4, a nominal 330 MW unit, qualify for presumptive limits. Unit 3 does not have SO_2 controls installed. Unit 4 controls SO_2 emissions using the existing Venturi scrubber. Neither unit currently operates with NO_x post-combustion controls. Presumptive SO_2 limits of 95% reduction or 0.15 lb/MMBtu and presumptive NO_x limits of 0.45 lb/MMBtu and 0.15 lb/MMBtu, based on unit type and coal type, could apply to Unit 3 and Unit 4, respectively. However, the Division required additional analysis of potential retrofit controls for NO_x, SO_2, and PM/PM_{10}, taking into consideration all five statutory factors, before making a BART determination.

NO_x: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

PacifiCorp identified four control technologies to control NO_x emissions: (1) low NO_x burners with advanced overfire air, (2) rotating opposed fire air (ROFA), (3) selective non-catalytic reduction (SNCR), and (4) selective catalytic reduction (SCR). LNB with advanced OFA and ROFA are two combustion control technologies that reduce NO_x emissions by controlling the combustion process within the boiler. These two technologies have been demonstrated to effectively control NO_x emissions by reducing the amount of oxygen directly accessible to the fuel during combustion creating a fuel-rich environment and

[4] Ibid. (70 Federal Register 39171).

by enhancing control of air-fuel mixing throughout the boiler's combustion zone. SNCR and SCR are add-on controls that provide a chemical conversion mechanism for NO_x to form molecular nitrogen (N_2) in the flue gas after combustion occurs. These four technologies are proven emissions controls commonly used on coal-fired electric generating units.

1. Low NO_x Burners with Advanced Overfire Air – LNB technologies can rely on a combination of fuel staging and combustion air control to suppress the formation of thermal NO_x. Fuel staging occurs in the very beginning of combustion, where the pulverized coal is injected through the burner into the furnace. Careful control of the fuel-air mixture leaving the burner can limit the amount of oxygen available to the fuel during combustion creating a fuel rich zone that reduces the nitrogen to molecular nitrogen (N_2) rather than using oxygen in the combustion air to oxidize the nitrogen to NO_x. The addition of advanced overfire air provides additional NO_x control by injecting air into the lower temperature combustion zone when NO_x is less likely to form. This allows complete combustion of the fuel while reducing both thermal and chemical NO_x formation.

2. Rotating Opposed Fire Air – ROFA can be used with LNB technology to control the combustion process inside the boiler. Similar to the advanced overfire air technology discussed above, ROFA manipulates the flow of combustion air to enhance fuel-mixing and air-flow characteristics within the boiler. By inducing rotation of the combustion air within the boiler, ROFA can reduce the number of high temperature combustion zones in the boiler and increase the effective heat absorption. Both of which effectively reduce the formation of NO_x caused by fuel combustion within the boiler.

3. Selective Non-Catalytic Reduction – SNCR is similar to SCR in that it involves the injection of a reducing agent such as ammonia or urea into the flue gas stream. The reduction chemistry, however, takes place without the aid of a catalyst. SNCR systems rely on appropriate injection temperatures, proper mixing of the reagent and flue gas, and prolonged retention time in place of the catalyst. SNCR operates at higher temperatures than SCR. The effective temperature range for SNCR is 1,600 to 2,100°F. SNCR systems are very sensitive to temperature changes and typically have lower NO_x emissions reduction (up to fifty or sixty percent) and may emit ammonia out of the exhaust stack when too much ammonia is added to the system.

4. Selective Catalytic Reduction – SCR is a post combustion control technique in which vaporized ammonia or urea is injected into the flue gas upstream of a catalyst. NO_x entrained in the flue gas is reduced to molecular nitrogen (N_2) and water. The use of a catalyst facilitates the reaction at an exhaust temperature range of 300 to 1,100°F, depending on the application and type of catalyst used. When catalyst temperatures are not in the optimal range for the reduction reaction or when too much ammonia is injected into the process, unreacted ammonia can be released to the atmosphere through the stack. This release is commonly referred to as ammonia slip. A well controlled SCR system typically emits less ammonia than a comparable SNCR control system.

In addition to applying these control technologies separately, they can be combined to increase overall NO_x reduction. PacifiCorp evaluated the application of LNB with advanced OFA in combination with both SNCR and SCR add-on controls.

NO_x: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

None of the four control technologies proposed to control NO_x emissions were deemed technically infeasible by PacifiCorp.

NO_x: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

The Division considers the control effectiveness of a proposed control technology to be equivalent to the BART-determined permit limit. The limit is based on continuous compliance when the control equipment is well maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. In order to demonstrate continuous compliance with the permit limit it is important to consider that even well maintained and operated equipment will have some emissions variability. Complex emission control equipment, such as LNB with advanced OFA, generally have inherent variability that must be considered when establishing the limit. Otherwise, the source will be out of compliance even though the equipment is operated and maintained as well as possible.

PacifiCorp contracted with Sargent and Lundy (S&L) to conduct a study of applicable NO_x control technologies for the Dave Johnston units and to collect data from boiler vendors. Based on results from the study, PacifiCorp indicates that new LNB with advanced OFA on Dave Johnston Units 3 and 4 would result in a NO_x emission rate of 0.24 lb/MMBtu and 0.15 lb/MMBtu, respectively. On page 3-5 of the December 2007 submittal for Dave Johnston Unit 3 and on page 3-4 of the December 2007 submittal for Dave Johnston Unit 4 PacifiCorp states: "PacifiCorp has indicated that this rate [0.24 lb/MMBtu for Unit 3 and 0.15 lb/MMBtu for Unit 4] corresponds to a vendor guarantee plus an added operating margin, not a vendor prediction, and they believe that this emission rate can be sustained as an average between overhauls." However, due to unforeseen operational issues associated with retrofitting the boilers, including site specific challenges on Unit 3 equipped with cell burners, PacifiCorp proposes an additional NO_x increase of 0.04 lb/MMBtu on Unit 3 for a final proposed emission rate of 0.28 lb/MMBtu.

PacifiCorp worked with Mobotec to conduct an analysis of retrofitting the existing boilers at the Dave Johnston Power Plant with Mobotec's ROFA. Mobotec analyzed the operation of existing burners and OFA ports. Typically the existing burner system does not require modification and the existing OFA ports are not used by a new ROFA system. Instead, computational fluid modeling is performed to determine the location of the new ROFA ports. Mobotec concluded that a NO_x emission rate of 0.15 lb/MMBtu was achievable on Units 3 and 4 using ROFA technology. PacifiCorp added an additional operating margin of 0.04 lb/MMBtu to Unit 3 to account for site specific issues, such as burner configuration, for total proposed emission rate of 0.19 lb/MMBtu. No additional operating margin was applied to Unit 4 so the anticipated emission rate is 0.15 lb/MMBtu.

S&L evaluated emission reductions associated with installing SNCR in addition to retrofitting the boilers with LNB with advanced OFA. Based on installing LNB with advanced OFA capable of achieving a NO_x emission rate of 0.24 lb/MMBtu on Unit 3 and 0.15 lb/MMBtu on Unit 4, S&L concluded that SNCR can reduce emissions by 20% resulting in projected emission rates of 0.19 lb/MMBtu for Unit 3 and 0.12 lb/MMBtu for Unit 4. PacifiCorp noted in the analysis that the economics of SNCR are greatly impacted by reagent utilization. When SNCR is used to achieve high levels of NO_x reduction, lower reagent utilization can result in significantly higher operating cost. PacifiCorp did not model visibility improvement from installing SNCR on Unit 3 on account of the expected marginal emission rate improvement, the burden of significant ongoing parasitic costs, the operating difficulties, and the potential ammonia slip.

S&L prepared the design conditions and cost estimates for installing SCR on Dave Johnston Units 3 and 4. A high-dust SCR configuration, where the catalyst is located downstream from the boiler economizer before the air heater and any particulate control equipment, was used in the analysis. The flue gas ducts would be routed to a separate reactor containing the catalyst to increase physical space occupied by the catalyst to improve the NO_x removal rate. Additional catalyst would be added to accommodate nitrogen levels in the coal feedstock. Based on the S&L design, which included installing both LNB with advanced OFA and SCR, PacifiCorp concluded Units 3 and 4 can achieve a NO_x emission rate of 0.07 lb/MMBtu.

Table 4: NO_x Emission Rates Per Boiler

Control Technology	Unit 3 Resulting NO_x Emission Rate (lb/MMBtu)	Unit 4 Resulting NO_x Emission Rate (lb/MMBtu)
Combustion Control	0.70/0.59 [(a)]	0.40/0.53 [(a)]
New LNB with advanced OFA	0.28	0.15
ROFA	0.19	0.15
New LNB with advanced OFA and SNCR	0.19	0.12
New LNB with advanced OFA and SCR	0.07	0.07

[(a)] PacifiCorp proposed emission rate/annual averaged NO_x emissions established through 40 CFR part 76 in Operating Permit 31-148-1.

NO_x: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impacts associated with installing each of the proposed control technologies. Installing new LNB with advanced OFA on Dave Johnston Units 3 and 4 will not significantly impact the boiler efficiency or forced draft fan power usage, two common potential areas for adverse energy impact often affected by changes in boiler combustion.

Installing the Mobotec ROFA system has a significant energy impact on Dave Johnston. One 1,900 horsepower (hp) ROFA fan on Unit 3 and one 3,000-3,700 hp ROFA fan on Unit 4 are required to induct a sufficient volume of air into each boiler to cause rotation of the combustion air throughout the boiler. The annual energy impact from operating the proposed ROFA fans is 21,800 Mega Watt-hour (MW-hr) for Unit 3 and 34,100 MW-hr for Unit 4.

PacifiCorp determined the SNCR system would require between 200 kilo Watt (kW) and 300 kW of additional power to operate pretreatment and injection equipment, pumps, compressors, and control systems. In addition to energy costs associated with the reagent handling and injection, installation of the SCR catalyst will require additional power from the existing flue gas fan systems to overcome the pressure drop across the catalyst. Based on the S&L study, PacifiCorp estimated the additional power requirement for SCR installation on Unit 3 would be approximately 1.6 MW and 2.1 MW for Unit 4.

PacifiCorp evaluated the environmental impacts from the proposed NO_x control technologies. Installing LNB with advanced OFA may increase carbon monoxide (CO) emissions and unburned carbon in the ash, commonly referred to as loss on ignition (LOI). Mobotec has predicted CO emissions and LOI would be the same or lower than prior levels for the ROFA system. The installation of SNCR and SCR could impact the saleability and disposal of fly ash due to higher ammonia levels, and could potentially create a visible stack plume sometimes referred to as a blue plume, if the ammonia injection rate is not well controlled. Other environmental impacts involve the storage of ammonia, especially if anhydrous ammonia is used, and transportation of the ammonia to the power plant site.

PacifiCorp anticipates operating Dave Johnston Units 3 and 4 indefinitely and did not include life extension costs in the economic analysis. A standard control life of 20 years was used to calculate the capital recovery factor. The annual cost to control was determined using a capital recovery factor based on a 7.1% interest rate. PacifiCorp labor and service costs were used to calculate the annual operating and maintenance costs. Annual power costs, including a cost escalation factor, associated with the operation of pollution controls were included.

Several different metrics can be considered when evaluating the cost-benefit relationships of different emission control technologies. In 40 CFR part 51 Appendix Y two metrics are specifically mentioned: cost effectiveness and incremental cost effectiveness. Through the application of BACT, the Division has extensive experience using cost effectiveness (i.e., dollars per ton of pollutant removed) to evaluate different control technologies. Incremental cost effectiveness is also used extensively by the Division when comparing emission controls under the BACT process. While the BART and the BACT processes are not necessarily equivalent, control determinations from either process are based on cost effectiveness and incremental cost effectiveness and are indicative of the economic costs to control emissions. In addition to providing cost effectiveness and incremental cost effectiveness results, PacifiCorp provided cost information in terms of cost of applying emission controls and the level of visibility improvement achieved (i.e., dollars per deciviews). While this metric can illustrate the control cost and visibility improvement differences between control options, it is not commonly used to assess the overall effectiveness of pollution control equipment. When performing the presumptive BART limits analyses for NO_x and SO_2, EPA addressed cost effectiveness and incremental cost effectiveness separate from visibility improvement. EPA did not use the dollars per deciview metric to compare control options. Visibility improvements from the application of the analyzed control measures used to establish presumptive levels were addressed in a separate visibility analysis. As discussed in the comprehensive visibility analysis presented later in this analysis as Step 5: Evaluate visibility impacts, the Division evaluated the amount of anticipated visibility improvement gained by the application of additional emission control technology. The Division considered capital cost, annual cost, cost effectiveness, and incremental cost effectiveness in the evaluation of each proposed NO_x emission control. Economic and environmental costs for additional NO_x controls on Dave Johnston Unit 3 and Unit 4 are summarized in the following tables.

Table 5: Dave Johnston Unit 3 Economic Costs

Cost	Combustion Control	New LNB with advanced OFA	ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
Control Equipment Capital Cost	$0	$17,500,000	$12,054,022	$24,035,544	$129,700,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$1,664,775	$1,146,699	$2,286,501	$12,338,361
Annual O&M Costs	$0	$100,000	$1,237,992	$392,691	$4,009,159
Annual Cost of Control	$0	$1,764,775	$2,384,691	$2,679,192	$16,347,519

Table 6: Dave Johnston Unit 3 Environmental Costs

	Combustion Control	New LNB with advanced OFA	Existing burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
NO_x Emission Rate (lb/MMBtu)	0.59	0.28	0.19	0.19	0.07
Annual NO_x Emission (tpy)	5,814[(a)]	3,091 [(b)]	2,097 [(b)]	2,097 [(b)]	773 [(b)]
Annual NO_x Reduction (tpy)	N/A	2,723	3,717	3,717	5,041
Annual Cost of Control	$0	$1,764,775	$2,384,691	$2,679,192	$16,347,519
Cost per ton of Reduction	N/A	$648	$642	$721	$3,243
Incremental Cost per ton of Reduction	N/A	$648	$623	$920 [(c)]	$10,324

[(a)] Annual emissions based on unit heat input rate of 2,500 MMBtu/hr and 7,884 hours of operation per year.
[(b)] Annual emissions based on unit heat input rate of 2,800 MMBtu/hr and 7,884 hours of operation per year.
[(c)] Incremental cost from installing ROFA cannot be calculated since the reduced tons of NO_x are anticipated to be the same. Therefore, the incremental cost from installing new LNB with advanced OFA was calculated.

Table 7: Dave Johnston Unit 4 Economic Costs

Cost	Combustion Control	New LNB with advanced OFA	Existing burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
Control Equipment Capital Cost	$0	$7,900,000	$14,719,868	$17,905,780	$151,900,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$751,527	$1,400,301	$1,703,377	$14,450,247
Annual O&M Costs	$0	$90,000	$1,841,886	$438,409	$1,980,281
Annual Cost of Control	$0	$841,527	$3,242,187	$2,141,786	$16,430,528

Table 8: Dave Johnston Unit 4 Environmental Costs

	Combustion Control	New LNB with advanced OFA	Existing burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
NO_x Emission Rate (lb/MMBtu)	0.53	0.15	0.15	0.12	0.07
Annual NO_x Emission (tpy) [a]	8,566	2,424	2,424	1,940	1,131
Annual NO_x Reduction (tpy)	N/A	6,142	6,142	6,626	7,435
Annual Cost of Control	$0	$841,527	$3,242,187	$2,141,786	$16,430,528
Cost per ton of Reduction	N/A	$137	$528	$323	$2,210
Incremental Cost per ton of Reduction	N/A	$137	$528 [b]	-$2,274 [c]	$17,662

[a] Annual emissions based on individual heat input rate of 4,100 MMBtu/hr for 7,884 hours of operation per year.
[b] Incremental cost from installing new LNB with advanced OFA cannot be calculated since the reduced tons of NO_x are anticipated to be the same. Therefore, the incremental cost from combustion control was calculated.
[c] Incremental cost is negative because the annual cost of control for existing burners with ROFA is significantly higher than new LNB with advanced OFA and SNCR.

The cost effectiveness of the four proposed BART technologies for NO_x are all reasonable. The incremental cost effectiveness is reasonable for all NO_x control technologies except new LNB with advanced OFA and SCR. PacifiCorp modeled the range of anticipated visibility improvement from the company-proposed BART controls for Units 3 and 4 by modeling LNB with advanced OFA and LNB with advanced OFA and SCR. While the installation of SNCR and ROFA were not individually evaluated in Step 5: Evaluate visibility impact, the anticipated degree of visibility improvement from applying either control lies within the modeled range of visibility impacts.

The final step in the NO_x BART determination process for Dave Johnston Units 3 and 4, Step 5: Evaluate visibility impacts, is addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants. The visibility analysis follows Steps 1-4 for SO_2 emissions in this application analysis. Table 23 on page 34 and Table 24 on page 35 list the modeled control scenarios and associated emission rates.

PM_{10}: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Dave Johnston Unit 3 is currently equipped with an electrostatic precipitator (ESP) to control PM emissions from the boiler. As discussed below in more detail below, ESPs control PM from the flue gas stream by creating a strong electro-magnetic field in which fly ash particles gain an electric charge. The existing ESP controls PM emissions to 0.030 lb/MMBtu. Dave Johnston Unit 4 is equipped with a Venturi particulate scrubber. This technology is no longer the state-of-art and Pacific did not propose keeping the unit in service as an additional particulate control device. Venturi scrubbers are designed with a decreasing throat diameter that mechanically forces particles in the flue gas and water droplets together. They are similar to cyclone systems in that particle momentum greatly influences the control efficiency. A Venturi scrubber is less effective as a control device for smaller particles because they have less momentum. Operating cost is greatly affected by increasing either the water-side or air-side pressure drop, which increases the removal efficiency, but results in increased electricity cost and operating cost from the pump and/or motor power providing the additional pressure. PacifiCorp reports 2001 to 2006 PM emissions data indicate that the Dave Johnston Unit 4 Venturi particulate scrubber controls PM_{10} emissions to 0.061 lb/MMBtu. PacifiCorp analyzed three state-of-the-art PM control technologies for application on Units 3 and 4: fabric filters or baghouses, ESPs, and flue gas conditioning.

1. Fabric filters (FF) – FF are woven pieces of material that collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99%. The layer of dust trapped on the surface of the fabric, commonly referred to as dust cake, is primarily responsible for such high efficiency. Joined pores within the cake act as barriers to trap particulate matter too large to flow through the pores as it travels through the cake. Limitations are imposed by the temperature and corrosivity of the gas and by adhesive properties of the particles. Most of the energy used to operate the system results from pressure drop across the bags and associated hardware and ducting.

2. Electrostatic precipitators – ESPs use electrical forces (charge) to move particulate matter out the gas stream onto collection plates. The particles are given an electrical charge by directing the gas stream through a corona, or region of gaseous ion flow. The charged particles are acted upon by an induced electrical field from high voltage electrodes in the gas flow that forces them to the walls or collection plates. Once the particles couple with the collection plates, they must be removed without re-entraining them into the gas stream. In dry ESP applications, this is usually accomplished by physically knocking them loose from the plates and into a hopper for disposal. Wet ESPs use water to wash the particles from the collector plates into a sump. The efficiency of an ESP is primarily determined by the resistivity of the particle, which is dependent on chemical composition, and also by the ability to clean the collector plates without reintroducing the particles back into the flue gas stream.

3. Flue Gas Conditioning (FGC) – Injecting a conditioning medium, typically SO_3, into the flue gas can lower the resistivity of the fly ash, improving the particles' ability to gain an electric charge. If the material is injected upstream of an ESP the flue gas particles more readily accept charge from the corona and are drawn to the collection plates. Adding FGC can account for large improvements in PM collection efficiency for existing ESPs that are constrained by space and flue gas residence time.

PM_{10}: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

PacifiCorp did not eliminate the use of either the baghouse or an ESP to control PM emissions as technically infeasible. However, PacifiCorp did not further analyze the use of FGC. According to PacifiCorp, the existing ESP on Unit 3 is well designed and provides adequate space and residence time for the flue gas particles to gain an electric charge and migrate to the collection plate. The application of FGC is not expected to significantly improve PM/PM_{10} removal efficiency. PacifiCorp did not evaluate the application of FGC on Unit 4 because it is typically used to enhance the removal efficiency of an existing, constrained ESP. The existing Venturi scrubber will likely be replaced by an entirely new PM control device and the co-benefit of enhancing dry flue gas desulfurization makes the installation of a more effective state-of-the-art fabric filter the company-preferred PM control measure over installing a FGC system.

PM_{10}: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

The Division considers the control effectiveness of a proposed control technology to be equivalent to the BART-determined permit limit. The limit is based on continuous compliance when the control equipment is well maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. In order to demonstrate continuous compliance with the permit limit it is important to consider that even well maintained and operated equipment will have some emissions variability. Complex emission control equipment, such as electrostatic precipitators, generally have inherent variability that must be considered when establishing the limit. Otherwise, the source will be out of compliance even though the equipment is operated and maintained as well as possible.

Unit 3 has an existing ESP and rather than evaluate costs of replacing the unit, PacifiCorp evaluated additional controls to improve the PM removal efficiency. An ESP is an effective PM control device, as the existing units are already capable of controlling PM_{10} emissions from Unit 3 to 0.030 lb/MMBtu. The technology continually improves and is commonly proposed for consideration in BACT analyses to control particulate emissions from new PC boilers. In addition to maintaining the existing ESP, a polishing fabric filter can be installed downstream of the existing ESPs. PacifiCorp proposed the use of Compact Hybrid Particulate Collector (COHPAC) licensed by Electric Power Research Institute (EPRI). The COHPAC unit is smaller than a full-scale fabric filter and has a higher air-to-cloth ratio (7 to 9:1), compared to a full-size pulse jet fabric filter (3.5 to 4:1). COHPAC is effective at controlling particulates not captured by the primary PM control device, but is not designed to treat high PM concentrations in the entire flue gas stream immediately downstream of the boiler. The existing ESP must remain in service for the COHPAC fabric filter to effectively reduce PM/PM_{10} emissions. PacifiCorp estimates the application of the COHPAC unit in addition to using FGC with the existing ESP on Unit 3 can reduce emissions an additional 50% resulting in a PM emission rate of 0.015 lb/MMBtu. PacifiCorp did not further evaluate the installation on a new full-scale fabric filter on Unit 3 since there is a substantial capital cost associated with the control and no anticipated benefit when compared to COHPAC.

Unit 4 has an existing Venturi scrubber. PacifiCorp determined that continued operation of this control technology was not cost effective. In place of the scrubber, a new ESP or a new FF was evaluated for additional PM control. Due to the higher electrical resistivity of western coals, the ESP is not able to reduce PM emissions as well as a FF. An ESP is not as effective as a FF at capturing small particles. For these reasons, a fabric filter is the company-preferred particulate control device, especially for use with a dry FGD system. PacifiCorp's proposed emission rates for each technology as applied to Units 3 and 4 are shown in Table 9.

Table 9: PM_{10} Emission Rates Per Boiler

Source	Existing ESP PM_{10} Emission (lb/MMBtu)	Polishing FF & Existing ESP PM_{10} Emission (lb/MMBtu)	Existing Venturi Scrubber PM_{10} Emission (lb/MMBtu)	New ESP PM_{10} Emission (lb/MMBtu)	New Full-scale FF PM_{10} Emission (lb/MMBtu)
Unit 3	0.030	0.015	--	--	--
Unit 4	--	--	0.061	0.030	0.015

<u>PM_{10}: EVALUATE IMPACTS AND DOCUMENT RESULTS</u>

PacifiCorp evaluated the energy impact of installing the COHPAC retrofit on Unit 3. The pressure drop created by the fabric filter and associated ductwork requires additional energy from the existing draft fan, which will have to be upgraded. PacifiCorp calculated the additional energy costs based on an 85 percent annual plant capacity factor. The installation of a COHPAC fabric filter would require approximately 1.4 MW of power, equating to an annual power usage of approximately 10.3 million kW-hr. Similar to the installation of the COHPAC on Unit 3, the installation of a full-scale fabric filter on Unit 4 would incur energy losses from the additional pressure drop. PacifiCorp calculated the additional energy costs from the installation of the fabric filter based on a 90 percent annual plant capacity factor. The fabric filter would require approximately 2.4 MW of power, equating to an annual power usage of approximately 18.5 million kW-hr. PacifiCorp's proposed PM control on Unit 4 is the full-scale fabric filter. No costs were provided for the installation and operation of a new ESP on Unit 4.

PacifiCorp evaluated the environmental impacts from the proposed installation of COHPAC on Unit 3 and the installation of a new fabric filter on Unit 4. PacifiCorp did not anticipate negative environmental impacts from the addition of either control technologies on the two units.

PacifiCorp anticipates operating Dave Johnston Units 3 and 4 indefinitely and did not include life extension costs in the economic analysis. A standard control life of 20 years was used to calculate the capital recovery factor. The annual cost to control was determined using a capital recovery factor based on a 7.1% interest rate. PacifiCorp labor and service costs were used to calculate the annual operating and maintenance costs. Annual power costs, including a cost escalation factor, associated with the operation of pollution controls were included.

Several different metrics can be considered when evaluating the cost-benefit relationships of different emission control technologies. In 40 CFR part 51 Appendix Y two metrics are specifically mentioned: cost effectiveness and incremental cost effectiveness. Through the application of BACT, the Division has extensive experience using cost effectiveness (i.e., dollars per ton of pollutant removed) to evaluate different control technologies. Incremental cost effectiveness is also used extensively by the Division when comparing emission controls under the BACT process. While the BART and the BACT processes are not necessarily equivalent, control determinations from either process are based on cost effectiveness and incremental cost effectiveness and are indicative of the economic costs to control emissions. In addition to providing cost effectiveness and incremental cost effectiveness results, PacifiCorp provided cost information in terms of cost of applying emission controls and the level of visibility improvement achieved (i.e., dollars per deciviews). While this metric can illustrate the control cost and visibility improvement differences between control options, it is not commonly used to assess the overall effectiveness of pollution control equipment. When performing the presumptive BART limits analyses for NO_x and SO_2, EPA addressed cost effectiveness and incremental cost effectiveness separate from visibility improvement. EPA did not use the dollars per deciview metric to compare control options. Visibility improvements from the application of the analyzed control measures used to establish presumptive levels were addressed in a separate visibility analysis. As discussed in the comprehensive visibility analysis presented later in this analysis as Step 5: Evaluate visibility impacts, the Division evaluated the amount of anticipated visibility improvement gained by the application of additional emission control technology. The Division considered capital cost, annual cost, cost effectiveness, and incremental cost effectiveness in the evaluation of each proposed PM/PM_{10} emission control. Economic and environmental costs for additional PM/PM_{10} controls on Dave Johnston Unit 3 and Unit 4 are summarized in the following tables.

Table 10: Dave Johnston Unit 3 Economic Costs

Cost	Existing ESP	Existing ESP and New COHPAC Fabric Filter
Control Equipment Capital Cost	$0	$29,795,555
Capital Recovery Factor	N/A	0.09513
Annual Capital Recovery Costs	$0	$2,834,451
Annual O&M Costs	$0	$809,282
Annual Cost of Control	$0	$3,643,733

Table 11: Dave Johnston Unit 3 Environmental Costs

	Existing ESP	Existing ESP and New COHPAC Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.030	0.015
Annual PM_{10} Emission (tpy) [(a)]	331	165
Annual PM_{10} Reduction (tpy)	N/A	166
Annual Cost of Control	$0	$3,643,733
Cost per ton of Reduction	N/A	$21,950
Incremental Cost per ton of Reduction	N/A	$21,950

[(a)] Annual emissions based on unit heat input rate of 2,800 MMBtu/hr and 7,884 hours of operation per year.

Table 12: Dave Johnston Unit 4 Economic Costs

Cost	Existing Venturi Scrubber	New Fabric Filter
Control Equipment Capital Cost	$0	$50,073,428
Capital Recovery Factor	N/A	0.09513
Annual Capital Recovery Costs	$0	$4,763,485
Annual O&M Costs	$0	$1,284,088
Annual Cost of Control	$0	$6,047,573

Table 13: Dave Johnston Unit 4 Environmental Costs

	Existing Venturi Scrubber	New Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.061	0.015
Annual PM_{10} Emission (tpy) [(a)]	986	242
Annual PM_{10} Reduction (tpy)	N/A	744
Annual Cost of Control	$0	$6,047,573
Cost per ton of Reduction	N/A	$8,129
Incremental Cost per ton of Reduction	N/A	$8,129

[(a)] Annual emissions based on unit heat input rate of 4,100 MMBtu/hr and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of applying a new polishing fabric filter to Unit 3 and a new full-scale fabric filter on Unit 4 are not reasonable. However, the controls were included in the final step in the PM/PM_{10} BART determination process for Dave Johnston Units 3 and 4, Step 5: Evaluate visibility impacts, which is addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants. The visibility analysis follows Steps 1-4 for SO_2 emissions in this application analysis. Table 23 on page 34 and Table 24 on page 35 list the modeled control scenarios and associated emission rates.

SO_2: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

PacifiCorp reviewed a broad range of informative sources, including EPA's RACT/BACT/LAER clearinghouse, in an effort to identify applicable SO_2 emission control technologies for Dave Johnston Units 3 and 4. Based on the results of this review, PacifiCorp proposed wet flue gas desulfurization (WFGD) and dry flue gas desulfurization (DFGD) as potential retrofit technologies to reduced SO_2 emissions.

1. Wet FGD – SO_2 is removed through absorption by mass transfer as soluble SO_2 in the exhaust gas mixture is dissolved in an alkaline water solvent that has low volatility under process conditions. SO_2 diffuses from the gas into the scrubber water when the liquid contains less than the equilibrium concentration of the gaseous SO_2. The rate of SO_2 mass transfer between the two phases is largely dependent on the surface area exposed and the time of contact. A properly designed wet scrubber or gas absorber will provide sufficient contact between the gas and the liquid solvent to allow diffusion of SO_2. Once the SO_2 enters the alkaline water phase, it will form a weak acid and react with the alkaline component dissolved in the scrubber water to form a sulfate (SO_4) or sulfite (SO_3). The acid/alkali chemical reaction prevents the SO_2 from diffusing back into the flue gas stream. When the alkaline scrubber water is saturated with sulfur compounds, it can be converted to a wet gypsum by-product that may be sold. SO_2 removal efficiencies for wet scrubbers can be as high as 99%.

2. Dry FGD – Dry scrubbers are similar to sorbent injection systems in that both systems introduce media directly into the flue gas stream, however the addition of the dry scrubber vessel provides greater contact area for adsorption and enhances chemical reactivity. A spray dryer dry scrubber sprays an atomized alkaline slurry into the flue gas upstream of particulate control system, often a fabric filter. Water in the slurry evaporates, hydrolizing the SO_2 into a weak acid, which reacts with the alkali to form a sulfate or sulfite. The resulting dry product is captured in the particulate control and physically moved from the exhaust gas into a storage bin. The dry by-product may be dissolved back into the lime slurry or dried and sold as a gypsum by-product. Spray dryer dry scrubbers typically require lower capital cost than a wet scrubber. They also require less flue gas after-treatment. When exhaust gas leaves the wet scrubber, it is at or near saturation. A wet scrubber can lower exhaust gas temperatures down into a temperature range of 110 to 140°F, which may lead to corrosive condensation in the exhaust stack. A spray dryer dry scrubber does not enhance stack corrosion like a wet scrubber because it will not saturate the exhaust gas or significantly lower the gas temperature. Removal efficiencies for spray dryer dry scrubbers can range from 70% to 95%.

SO_2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

PacifiCorp did not eliminate either control technology listed above as technically infeasible. Both dry FGD and wet FGD are proven SO_2 control technologies. PacifiCorp analyzed the impact of both SO_2 emission reduction technologies on Dave Johnston Units 3 and 4.

SO_2: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

The Division considers the control effectiveness of a proposed control technology to be equivalent to the BART-determined permit limit. The limit is based on continuous compliance when the control equipment is well maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. In order to demonstrate continuous compliance with the permit limit it is important to consider that even well maintained and operated equipment will have some emissions variability. Complex emission control equipment, such as wet FGD, generally have inherent variability that must be considered when establishing the limit. Otherwise, the source will be out of compliance even though the equipment is operated and maintained as well as possible.

PacifiCorp evaluated the application of DFGD on Unit 3 using the existing ESP to remove particulates formed by injecting the lime slurry into the flue gas. This combination of control devices is projected to achieve 81.7 % SO_2 removal resulting in a SO_2 emission rate of 0.22 lb/MMBtu, based on a average sulfur content of 0.47% by weight in the feed coal. The combination of the existing ESP and a new polishing fabric filter is projected to reduce SO_2 emissions by 87.5%, resulting in a controlled SO_2 emission rate of 0.15 lb/MMBtu from Unit 3 using a 0.47% coal sulfur content. If the existing ESP on Unit 3 is replaced with a new full-scale fabric filter, DFGD is anticipated to reduce SO_2 emissions down to 0.12 lb/MMBtu. PacifiCorp did not provide cost information for installing a full-scale fabric filter on Unit 3, so the technology was not considered any further in the SO_2 analysis.

DFGD with a new full-scale fabric filter capable of treating the entire flue gas stream on Unit 4 is projected to achieve 87.5% SO_2 removal, resulting in an emission rate of 0.15 lb/MMBtu. An average coal sulfur content of 0.47% by weight was used to calculate the emission reduction.

The application of wet FGD on Unit 3 would likely use lime/limestone scrubbing, which is available in several variations from vendors. Wet lime/limestone scrubbing is projected to achieve a SO_2 removal rate of 95% and an outlet SO_2 emission rate of 0.058 lb/MMBtu, based on a sulfur content of 0.47% by weight in the feed coal.

A new wet lime/limestone FGD system with a new full-scale fabric filter applied to Unit 4 is projected to achieve 91.7% SO_2 removal, resulting in an outlet emission rate of 0.10 lb/MMBtu based on a sulfur content of 0.47% by weight. PacifiCorp noted in the analysis for Unit 4 that they consider it to be technically infeasible for a new wet FGD system to achieve a 95% SO_2 removal, 0.06 lb/MMBtu, on a continuous basis. PacifiCorp evaluated SO_2 controls for Unit 4 to meet presumptive levels for SO_2. The application of wet FGD with a new full-scale fabric filter on Unit 4 is capable of continuously reducing SO_2 emissions by 90% resulting in a SO_2 emission rate of 0.10 lb/MMBtu, below the 0.15 lb/MMBtu presumptive SO_2 limit.

Table 14: Dave Johnston Unit 3 SO_2 Emission Rates

Control Technology	SO_2 Emission Rate (lb/MMBtu)
Combustion Control	1.20
Dry FGD with existing ESP	0.22
Dry FGD with existing ESP and Polishing Fabric Filter	0.15
Dry FGD with Fabric Filter	0.12
Wet Lime FGD with existing ESP	0.06

Table 15: Dave Johnston Unit 4 SO_2 Emission Rates

Control Technology	SO_2 Emission Rate (lb/MMBtu)
Combustion Control	1.20
Dry FGD with Fabric Filter	0.15
Wet FGD with Fabric Filter	0.10

SO_2: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impacts of applying a dry FGD system with the existing ESP on Unit 3. DFGD requires less electric power than a wet FGD system. A dry FGD system on Dave Johnston 3 using the existing ESP would require approximately 2.5 MW of power, while a wet FGD would require approximately 3.5 MW. This equates to an annual power savings of approximately 7.5 million kW-hr for dry FGD, when the plant operates at 90% capacity for the year. Applying a dry FGD system with a new full-scale fabric filter to Dave Johnston Unit 4 requires 4.5 MW of power, compared to approximately 6.3 MW for wet FGD with a new fabric filter. Dry FGD on Unit 4 to control SO_2 emission could generate a power savings of approximately 13.8 million kW-hr if the unit operates for 90% of its annual capacity.

PacifiCorp compared the environmental impacts of dry FGD versus wet FGD technology. PacifiCorp concluded that dry FGD has five significant environmental advantages over wet FGD. These advantages are taken directly from PacifiCorp's environmental analyses for SO_2 controls on Dave Johnston Units 3 and 4 and listed below.

- <u>Sulfuric Acid Mist</u> Sulfur trioxide (SO_3) in the flue gas, which condenses to liquid sulfuric acid at temperatures below the acid dew point, is removed efficiently with a lime spray dryer system. Wet scrubbers capture less than 40 to 60 percent of SO_3 and may require the addition of a wet electrostatic precipitator (ESP) or hydrated lime injection when medium to high sulfur coal is burned in a unit to remove the balance of SO_3. Otherwise, the emission of sulfuric acid mist, if above a threshold value, may result in a visible plume after the vapor plume dissipates.

- <u>Plume Buoyancy</u> Flue gas following a dry FGD system is not saturated with water (gas temperature 30°F to 50°F above dew point), which reduces or eliminates a visible moisture plume. Wet FGD scrubbers produce flue gas saturated with water, which would require a gas-gas heat exchanger to reheat the flue gas if it were to operate as a dry stack. Because of the high capital and operating costs associated with heating the flue gas, all recent wet FGD systems in the United States have used wet stack operation.

- <u>Liquid Waste Disposal</u> There is no liquid waste from a dry FGD system. However, wet FGD systems produce a wastewater blowdown stream that must be treated to limit chloride buildup in the absorber scrubbing loop. In some cases, a wastewater treatment plant must be installed to treat the liquid waste prior to disposal. The wastewater treatment plant would produce a small volume of solid waste, which may be contaminated with toxic metals (including mercury), requiring proper disposal.

- Solid Waste Disposal The creation of a wet sludge from the wet FGD process creates a solid waste handling and disposal challenge. This sludge must be handled properly to prevent groundwater contamination. Wet FGD systems can produce saleable gypsum if a gypsum market is available, reducing the quantity of solid waste from the power plant to be disposed.

- Makeup Water Requirements Dry FGD has advantages over a wet scrubber, producing a dry waste material and requiring less makeup water in the absorber. Given that water is a valuable commodity in Wyoming, the reduced water consumption required for dry FGD is major advantage for this technology.

PacifiCorp anticipates operating Dave Johnston Units 3 and 4 indefinitely and did not include life extension costs in the economic analysis. A standard control life of 20 years was used to calculate the capital recovery factor. The annual cost to control was determined using a capital recovery factor based on a 7.1% interest rate. PacifiCorp labor and service costs were used to calculate the annual operating and maintenance costs. Annual power costs, including a cost escalation factor, associated with the operation of pollution controls were included.

Several different metrics can be considered when evaluating the cost-benefit relationships of different emission control technologies. In 40 CFR part 51 Appendix Y two metrics are specifically mentioned: cost effectiveness and incremental cost effectiveness. Through the application of BACT, the Division has extensive experience using cost effectiveness (i.e., dollars per ton of pollutant removed) to evaluate different control technologies. Incremental cost effectiveness is also used extensively by the Division when comparing emission controls under the BACT process. While the BART and the BACT processes are not necessarily equivalent, control determinations from either process are based on cost effectiveness and incremental cost effectiveness and are indicative of the economic costs to control emissions. In addition to providing cost effectiveness and incremental cost effectiveness results, PacifiCorp provided cost information in terms of cost of applying emission controls and the level of visibility improvement achieved (i.e., dollars per deciviews). While this metric can illustrate the control cost and visibility improvement differences between control options, it is not commonly used to assess the overall effectiveness of pollution control equipment. When performing the presumptive BART limits analyses for NO_x and SO_2, EPA addressed cost effectiveness and incremental cost effectiveness separate from visibility improvement. EPA did not use the dollars per deciview metric to compare control options. Visibility improvements from the application of the analyzed control measures used to establish presumptive levels were addressed in a separate visibility analysis. As discussed in the comprehensive visibility analysis presented later in this analysis as Step 5: Evaluate visibility impacts, the Division evaluated the amount of anticipated visibility improvement gained by the application of additional emission control technology. The Division considered capital cost, annual cost, cost effectiveness, and incremental cost effectiveness in the evaluation of each proposed SO_2 emission control. Economic and environmental costs for additional SO_2 controls on Dave Johnston Unit 3 and Unit 4 are summarized in the following tables.

Table 16: Dave Johnston Unit 3 Economic Costs

Cost	Existing Combustion Control	Dry FGD with ESP	Dry FGD with ESP and Polishing Fabric Filter	Wet FGD with ESP
Control Equipment Capital Cost	$0	$91,499,734	$169,500,000	$144,300,464
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$8,704,370	$16,124,535	$13,727,303
Annual O&M Costs	$0	$4,455,188	$5,295,598	$6,044,908
Annual Cost of Control	$0	$13,159,558	$21,420,133	$19,772,211

Table 17: Dave Johnston Unit 3 Environmental Costs

	Existing Combustion Control	Dry FGD with ESP	Dry FGD with ESP and Polishing Fabric Filter	Wet FGD with ESP
SO_2 Emission Rate (lb/MMBtu)	1.2	0.22	0.15	0.06
Annual SO_2 Emission (tpy) [a]	13,316	2,428	1,656	662
Annual SO_2 Reduction (tpy)	N/A	10,888	11,660	12,654
Annual Cost of Control	$0	$13,159,558	$21,420,133	$19,772,211
Cost per ton of Reduction	N/A	$1,209	$1,837	$1,563
Incremental Cost per ton of Reduction	N/A	$1,209	$10,700	-$1,658 [b]

[a] Annual emissions based on unit heat input rate of 2,800 MMBtu/hr and 7,884 hours of operation per year.
[b] Incremental cost from dry FGD with ESP and fabric filter is negative as a result of the lower annual cost of control for wet FGD with ESP.

Table 18: Dave Johnston Unit 4 Economic Costs

Cost	Existing Combustion Control	Dry FGD with Full-scale Fabric Filter	Wet FGD with Full-scale Fabric Filter
Control Equipment Capital Cost	$0	$243,100,000	$289,166,335
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	$23,126,103	$27,508,393
Annual O&M Costs	$0	$5,318,117	$6,961,183
Annual Cost of Control	$0	$28,444,220	$34,469,576

Table 19: Dave Johnston Unit 4 Environmental Costs

	Existing Combustion Control	Dry FGD with Full-scale Fabric Filter	Wet FGD with Full-scale Fabric Filter
SO_2 Emission Rate (lb/MMBtu)	0.5 [a]	0.15	0.10
Annual SO_2 Emission (tpy) [b]	8,081	2,424	1,616
Annual SO_2 Reduction (tpy)	0	5,657	6,465
Annual Cost of Control	$0	$28,444,220	$34,469,576
Cost per ton of Reduction	N/A	$5,028	$5,332
Incremental Cost per ton of Reduction	N/A	$5,028	$7,457

[a] 30-day rolling average SO_2 limit from Operating Permit 31-148-1 used as baseline.
[b] Annual emissions based on unit heat input rate of 4,100 MMBtu/hr and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of the proposed wet FGD and dry FGD controls for Units 3 and 4 are reasonable, except for the incremental cost effectiveness of installing a new polishing fabric filter with dry FGD on Unit 3. The final step in the SO_2 BART determination process for Dave Johnston Units 3 and 4, Step 5: Evaluate visibility impacts, is addressed in a comprehensive visibility analysis presented in the next section of this BART application analysis. The Division evaluated the amount of visibility improvement gained from the application of additional NO_x, PM/PM_{10}, and SO_2 emission control technology in relation to all three visibility impairing pollutants. Table 23 on page 34 and Table 24 on page 35 list the modeled control scenarios and associated emission rates.

VISIBILITY IMPROVEMENT DETERMINATION:

The fifth of five steps in a BART determination analysis, as required by 40 CFR part 51 Appendix Y, is the determination of the degree of Class I area visibility improvement that would result from installation of the various options for control technology. This factor was evaluated for the PacifiCorp Dave Johnston plant with an EPA-approved dispersion modeling system (CALPUFF) to predict the changes in Class I area visibility. The Division had previously determined that the facility was subject to BART based on the results of initial screening modeling 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.

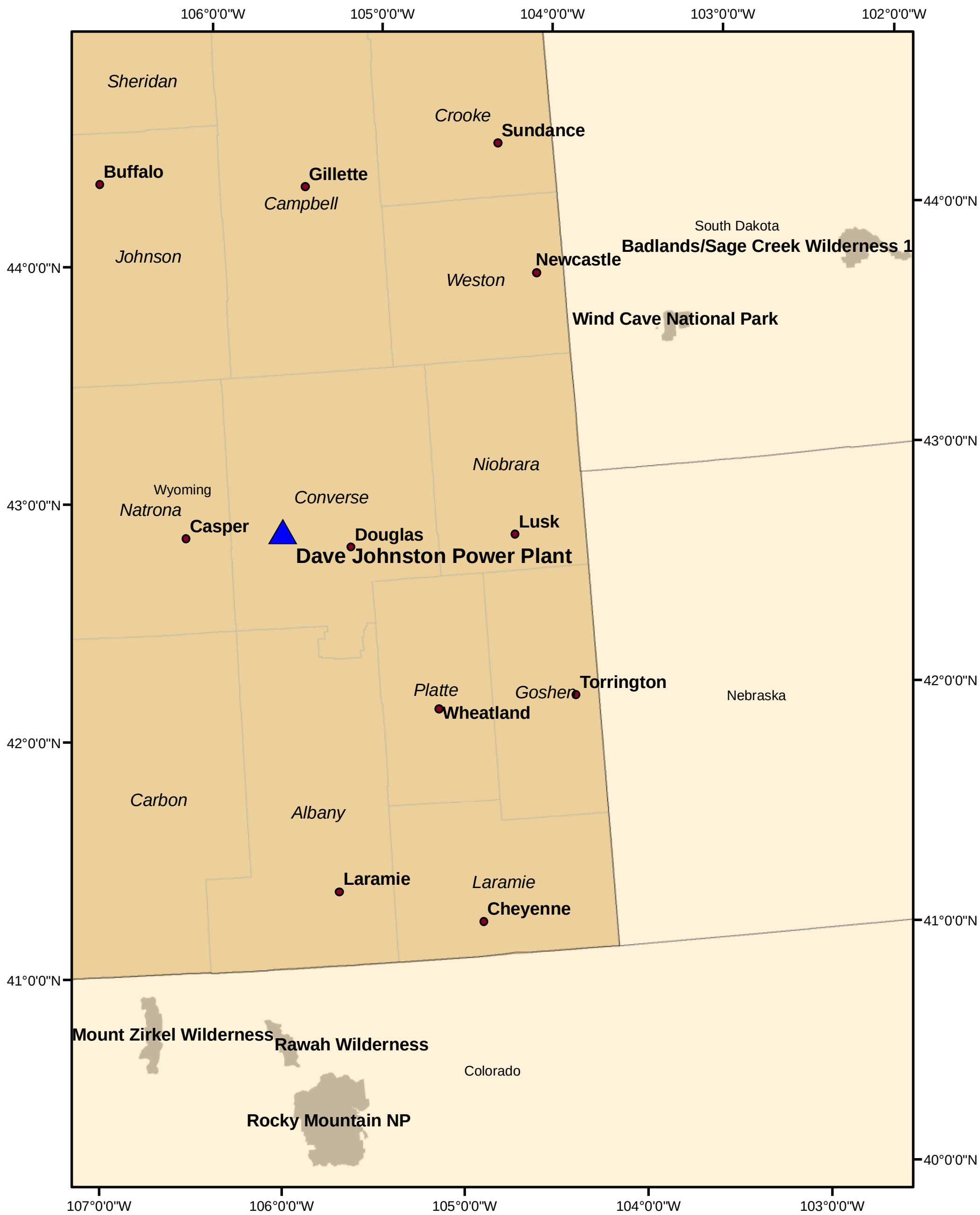
Wind Cave and Badlands National Parks (NP) in South Dakota are Class I areas located to the northeast of the plant at a distance of approximately 200 kilometers (km) and 290 km, respectively. Toward the south in Colorado, Rawah Wilderness Area (WA) and Mount Zirkel WA are both located approximately 220 km from the plant, with Rocky Mountain NP located beyond Rawah WA.

Only those Class I areas most likely to be impacted by the Dave Johnston sources were modeled, as determined by source/Class I area locations and professional judgment considering meteorological and terrain factors. Those areas chosen for modeling the Dave Johnston sources were the following:

- Wind Cave NP
- Badlands NP
- Rawah WA
- Mount Zirkel WA

Rocky Mountain National Park (RMNP) was not modeled because it is located along a similar direction from the plant as Rawah WA (a path of less frequent plume transport), and it can be reasonably assumed that RMNP would experience lower predicted impacts than those at Rawah WA. Figure 1 shows the relative locations of the plant and the nearest Class I areas.

Figure 1
Dave Johnston Power Plant and Class I Areas



SCREENING MODELING

To determine if the Dave Johnston plant would be subject to BART, the Division conducted CALPUFF visibility modeling for the closest Class I areas downwind of predominant wind flows (Wind Cave NP and Badlands NP) using three years of meteorological data. These data, from 2001-2003, consisted of surface and upper-air observations from individual weather stations and gridded output from the Mesoscale Model (MM5). Resolution of the MM5 data was 36-km for all three of the modeled years. Potential emissions for current operation from the two BART-eligible, coal-fired boilers at the Dave Johnston plant were input to the model.

Results of the modeling showed that the 98^{th} percentile value for the change in visibility (in units of delta deciview [Δdv]) was above 0.5 Δdv for Badlands NP and Wind Cave NP for all three years of meteorology. As defined in EPA's final BART rule, a predicted 98^{th} percentile impact equal to or greater than 0.5 Δdv from a given source indicates that the source contributes to visibility impairment, and therefore is subject to BART. The results of the screening modeling are shown in the table below.

Table 20: Results of the Class I Area Screening Modeling

Class I Area	Maximum Modeled Value (Δdv)	98^{th} Percentile Value (Δdv)
2001		
Badlands NP	4.3	2.6
Wind Cave NP	4.5	2.5
2002		
Badlands NP	4.0	2.0
Wind Cave NP	4.7	2.2
2003		
Badlands NP	3.5	2.4
Wind Cave NP	4.3	3.3

Δdv = delta deciview
NP = national park

REFINED MODELING

Because of the results of the Division's screening modeling, PacifiCorp was required to conduct a BART analysis that included refined 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). Pacificorp's modeling included assessments of the impacts at Wind Cave NP and Badlands NP, as required by the Division's BART modeling protocol. The Division supplemented PacifiCorp's analyses with model runs for Rawah and Mount Zirkel Wilderness Areas in Colorado.

CALPUFF System

Predicted visibility impacts from the Dave Johnston plant sources were determined with the EPA CALPUFF modeling system, which is the EPA-preferred modeling system for long-range transport. As described in the EPA Guideline on Air Quality Models (Appendix W of 40 CFR part 51), long-range transport is defined as modeling with source-receptor distances greater than 50 km. Because all modeled areas are located more than 50 km from the facility, the CALPUFF system was appropriate for use.

The CALPUFF modeling system consists of a meteorological data pre-processor (CALMET), an air dispersion model (CALPUFF), and post-processor programs (POSTUTIL, CALSUM, CALPOST). The CALPUFF model was developed as a non-steady-state air quality modeling system for assessing the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal.

CALMET is a diagnostic wind model that develops hourly wind and temperature fields in a three-dimensional, gridded modeling domain. Meteorological inputs to CALMET can include surface and upper-air observations from multiple meteorological monitoring stations. Additionally, the CALMET model can utilize gridded analysis fields from various mesoscale models such as MM5 to better represent regional wind flows and complex terrain circulations. Associated two-dimensional fields such as mixing height, land use, and surface roughness are included in the input to CALMET. The CALMET model allows the user to "weight" various terrain influence parameters in the vertical and horizontal directions by defining the radius of influence for surface and upper-air stations.

CALPUFF is a multi-layer, Lagrangian puff dispersion model. CALPUFF can be driven by the three-dimensional wind fields developed by the CALMET model (refined mode), or by data from a single surface and upper-air station in a format consistent with the meteorological files used to drive steady-state dispersion models. All far-field modeling assessments described here were completed using the CALPUFF model in a refined mode.

CALSUM is a post-processing program that can operate on multiple CALPUFF output files to combine the results for further post-processing. POSTUTIL is a post-processing program that processes CALPUFF concentrations and wet/dry flux files. The POSTUTIL model operates on one or more output data files from CALPUFF to sum, scale, and/or compute species derived from those that are modeled, and outputs selected species to a file for further post-processing. CALPOST is a post-processing program that can read the CALPUFF (or POSTUTIL or CALSUM) output files and calculate the impacts to visibility.

All of the refined CALPUFF modeling was conducted with the version of the CALPUFF system that was recognized as the EPA-approved release at the time of the development of the Division's modeling protocol. Version designations of the key programs are listed in the table below.

Table 21: Key Programs in CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.711a	040716
CALPOST	5.51	030709

<u>Meteorological Data Processing (CALMET)</u>

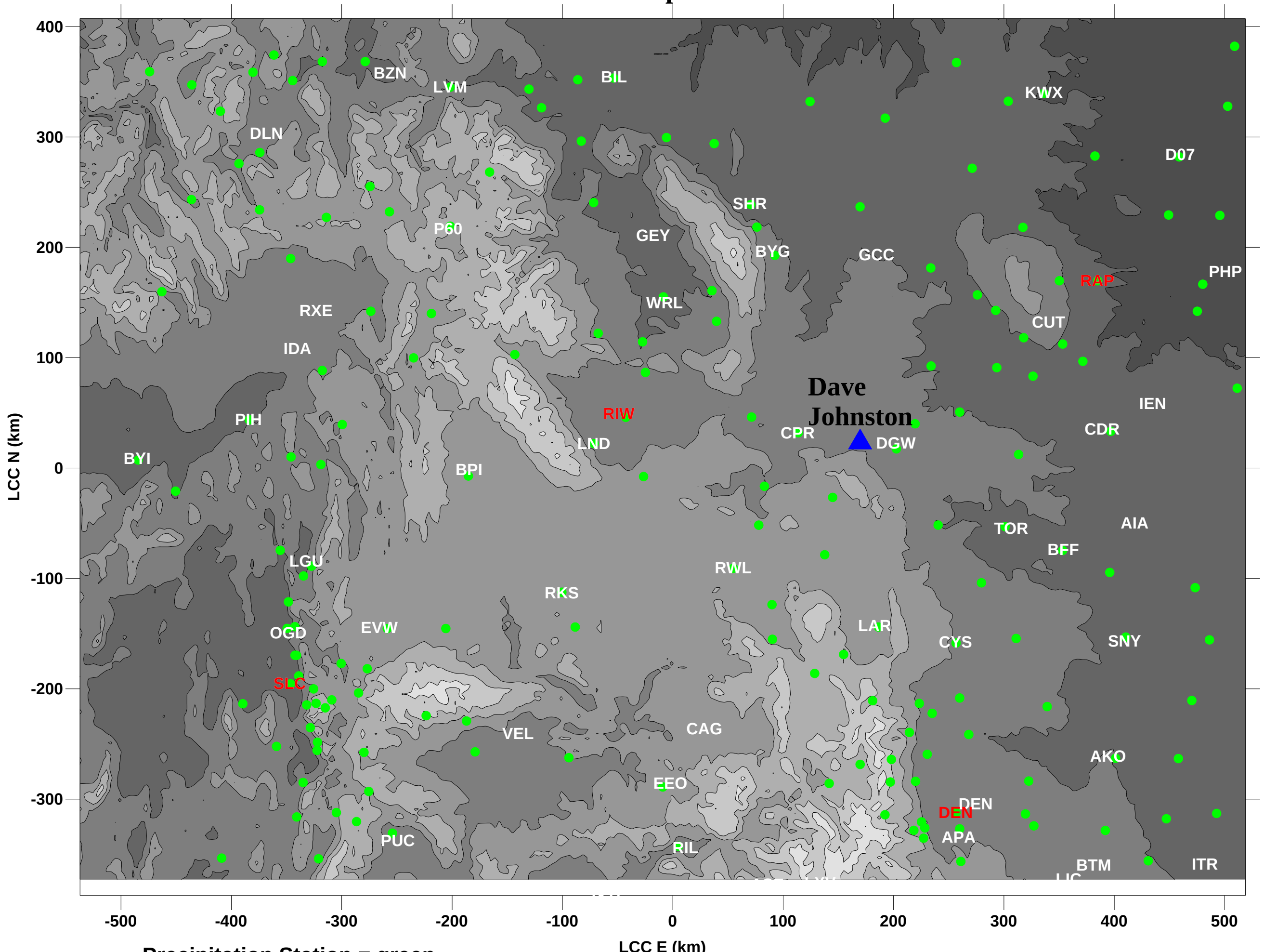
As required by the Division's modeling protocol, the CALMET model was used to construct an initial three-dimensional windfield using data from the MM5 model. Surface and upper-air observations were input to CALMET to adjust the initial windfield, but because of the relative scarcity of wind observations in the modeling domain, the influence of the observations on the initial windfield was minimized. Because the MM5 data were afforded a high degree of influence on the CALMET windfields, the Division obtained MM5 data at 12-km resolution that spanned the years 2001-2003.

Locations of the observations that were input to CALMET, including surface, upper-air, and precipitation stations, are shown in the figure below. Default settings were used in the CALMET input files for most of the technical options. The following table lists the key user-defined CALMET settings that were selected.

Table 22: Key User-Defined CALMET Settings

Variable	Description	Value
PMAP	Map projection	LCC
DGRIDKM	Grid spacing (km)	4
NZ	Number of layers	10
ZFACE	Cell face heights (m)	0, 20, 40, 100, 140, 320, 580, 1020, 1480, 2220, 3400
RMIN2	Minimum distance for extrapolation	-1
IPROG	Use gridded prognostic model output	14
RMAX 1	Maximum radius of influence (surface layer, km)	30
RMAX 2	Maximum radius of influence (layers aloft, km)	50
TERRAD	Radius of influence for terrain (km)	15
R1	Relative weighting of first guess wind field and observations (km)	5
R2	Relative weighting aloft (km)	25

Figure 2
Observations Input to CALMET



Precipitation Station = green
Surface Station = white 3-letter
Upper-Air (+ surface) = red 3-letter

CALPUFF Modeling Setup

To allow chemical transformations within CALPUFF using the recommended chemistry mechanism (MESOPUFF II), the model required input of background ozone and ammonia concentrations. For ozone, hourly data collected from the following stations were used:

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

For any hour that was missing ozone data from all stations, a default value of 44 parts per billion (ppb) was used by the model as a substitute. For ammonia, a domain-wide background value of 2 ppb was used.

Latitude and longitude coordinates for Class I area discrete receptors were taken from the National Park Service (NPS) Class I Receptors database and converted to the appropriate Lambert Conformal Conic coordinates. Figures 3-6 show the receptor configurations that were used for Badlands NP, Wind Cave NP, Rawah WA, and Mount Zirkel WA. 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 Badlands NP, the receptor spacing is approximately 1.3 km in the east-west direction and approximately 1.8 km in the north-south direction. For the Colorado Class I areas (Rawah and Mount Zirkel), the spacing is approximately 1.4 km in the east-west direction and approximately 1.9 km in the north-south direction.

Figure 3
Receptors for Wind Cave NP

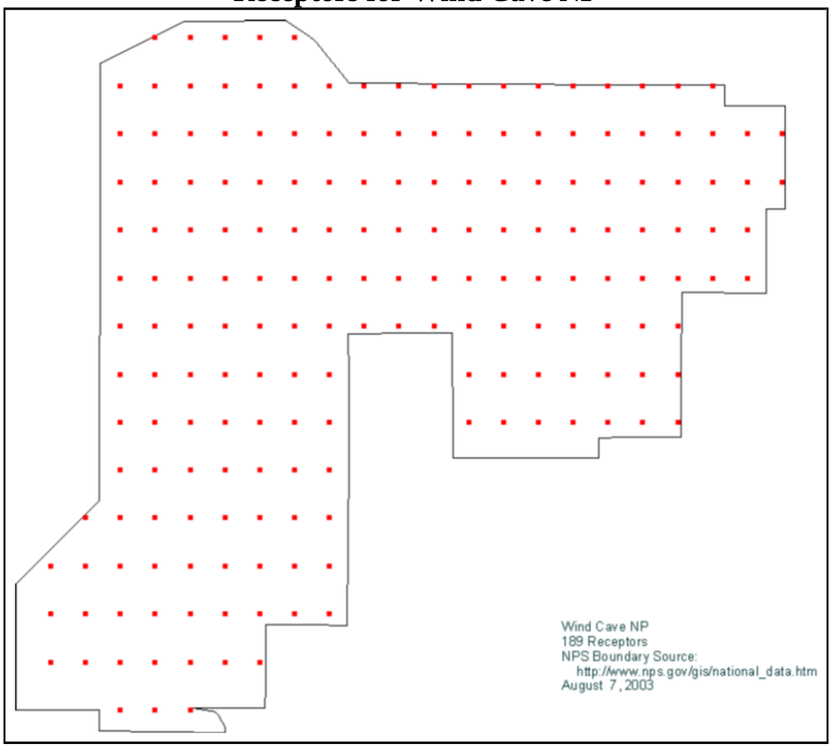


Figure 4
Receptors for Badlands NP

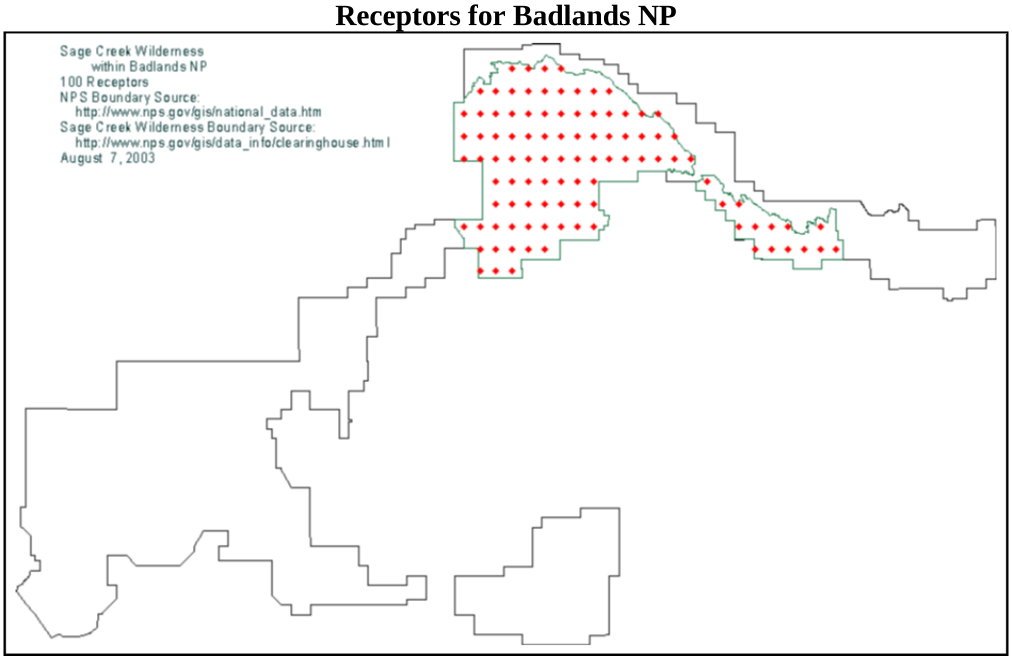


Figure 5
Receptors for Rawah WA

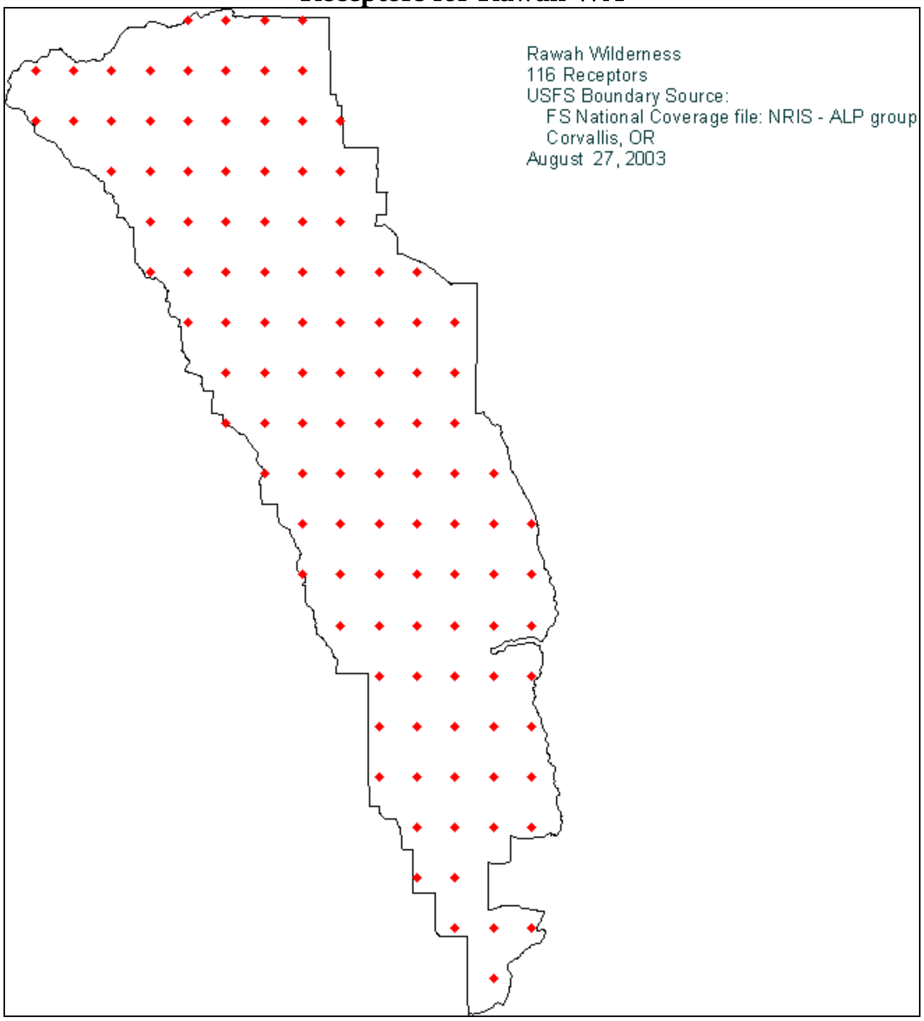
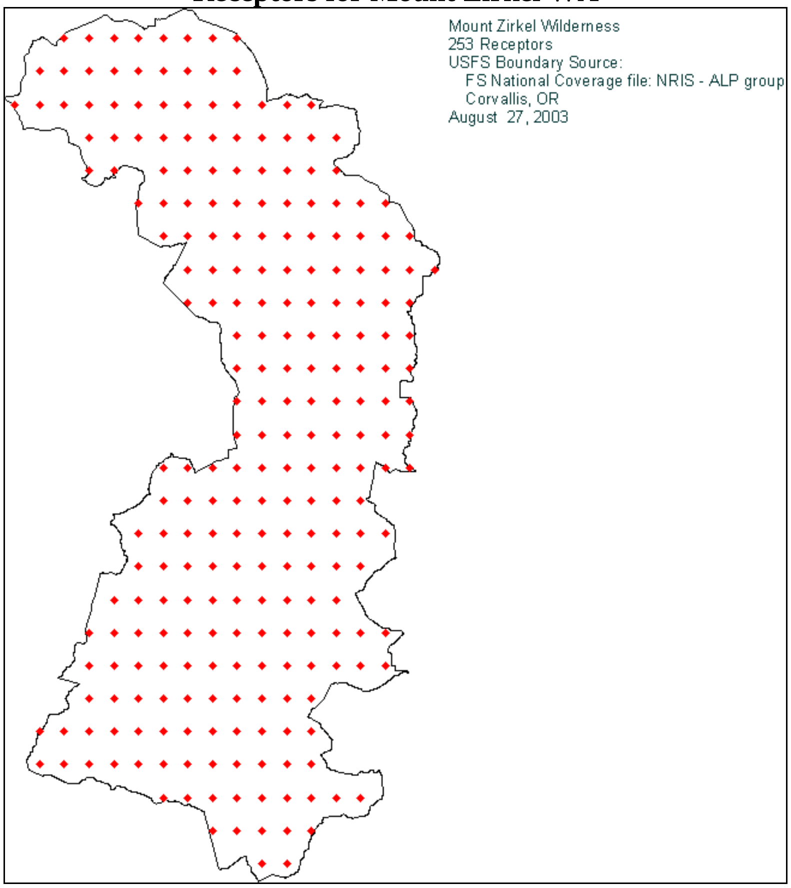


Figure 6
Receptors for Mount Zirkel WA



CALPUFF Inputs – Baseline and Control Options

Source release parameters and emissions for baseline and control options for Unit 3 and Unit 4 at the Dave Johnston plant are shown in the tables below.

Table 23: CALPUFF Inputs for Dave Johnston Unit 3

DAVE JOHNSTON UNIT 3	Baseline	Post-Control Scenario 1	Post-Control Scenario 2	Post-Control Scenario 3	Post-Control Scenario 4	Post-Control Scenario A	Post-Control Scenario B
Model Input Data	Current Operation with Electrostatic Precipitator (ESP)	Low-NOx Burners (LNBs) with advanced Over-fire Air (OFA), Dry FGD, ESP	LNB with advanced OFA, Dry FGD, New Fabric Filter	LNB with advanced OFA and Selective Catalytic Reduction (SCR), Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Wet FGD, Existing ESP, New Stack	Committed Controls: LNB with advanced OFA, Dry FGD, New Fabric Filter	Committed Controls and SCR
Hourly Heat Input (mmBtu/hour)	2,500	2,800	2,800	2,800	2,800	2,800	2,800
Sulfur Dioxide (SO_2) (lb/mmBtu)	1.20	0.22	0.12	0.12	0.06	0.15	0.15
Sulfur Dioxide (SO_2) (lb/hr)	3,000	616	336	336	162	420	420
Nitrogen Oxide (NO_x) (lb/mmBtu)	0.70	0.24	0.24	0.07	0.07	0.28	0.07
Nitrogen Oxide (NO_x) (lb/hr)	1,750	672	672	196	196	784	196
PM_{10} (lb/mmBtu)	0.030	0.030	0.015	0.015	0.030	0.015	0.015
PM_{10} (lb/hr)	75.0	75.0	42.0	42.0	75.0	42.0	42.0
Coarse Particulate ($PM_{2.5}$ <diameter < PM_{10}) (lb/hr)[(a)]	32.3	32.3	23.9	23.9	32.3	23.9	23.9
Fine Particulate (diameter < $PM_{2.5}$) (lb/hr)[(b)]	42.8	42.8	18.1	18.1	42.8	18.1	18.1
Sulfuric Acid (H_2SO_4) (lb/hr)	46.0	2.6	2.6	3.6	43.9	2.6	3.7
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	--	0.7	3.3	--	0.7
$(NH_4)HSO_4$ (lb/hr)	--	--	--	1.1	5.8	--	1.2
H_2SO_4 as Sulfate (SO_4) (lb/hr)	45.1	2.5	2.5	3.6	43.1	2.5	3.6
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	--	--	--	0.5	2.4	--	0.5
$(NH_4)HSO_4$ as SO_4 (lb/hr)	--	--	--	0.9	4.8	--	1.0
Total Sulfate (SO_4) (lb/hr)[(c)]	45.1	2.5	2.5	5.0	50.3	2.5	5.1
Stack Conditions							
Stack Height (meters)	152.4	152.4	152.4	152.4	152.4	152.4	152.4
Stack Exit Diameter (meters)	4.57	4.57	4.57	4.57	4.57	4.57	4.57
Stack Exit Temperature (Kelvin)	445	350	355	355	322	348	348
Stack Exit Velocity (meters per second)	32.0	25.1	25.5	25.5	16.7	25.5	25.5

Notes:

(a) AP-42, Table 1.1-6: coarse PM counted as a percentage of PM_{10}. This equates to 43 percent for ESP and 57 percent for Baghouse.

(b) AP-42, Table 1.1-6: fine PM counted as a percentage of PM_{10}. This equates to 57 percent for ESP and 43 percent for Baghouse.

(c) Total Sulfate (SO4) (lb/hr) = H2SO4 as Sulfate (SO4) Stack Emissions (lb/hr) + (NH4)2SO4 as SO4 Stack Emissions (lb/hr) + (NH4)HSO4 as SO4 Stack Emissions (lb/hr).

Table 24: CALPUFF Inputs for Dave Johnston Unit 4

DAVE JOHNSTON UNIT 4	Baseline	Post-control Scenario 1	Post-Control Scenario 2	Post-Control Scenario 3	Post-Control Scenario 4	Post-Control Scenario A	Post-Control Scenario B
Model Input Data	Existing Operations with Venturi Scrubber	Low-NOx Burner (LNB) with advanced Over-Fire Air (OFA), Dry FGD, Fabric Filter	LNB with advanced OFA, Wet FGD, Fabric Filter	LNB with advanced OFA and Selective Catalytic Reduction (SCR), Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Wet FGD, Fabric Filter	Committed Controls: LNB with advanced OFA, Dry FGD, New Fabric Filter	Committed Controls and SCR
Hourly Heat Input (mmBtu/hour)	4,100	4,100	4,100	4,100	4,100	4,100	4,100
Sulfur Dioxide (SO_2) (lb/mmBtu)	0.50	0.15	0.10	0.15	0.10	0.15	0.15
Sulfur Dioxide (SO_2) (lb/hr)	2,050	615	410	615	410	615	615
Nitrogen Oxide (NO_x) (lb/mmBtu)	0.40	0.15	0.15	0.07	0.07	0.15	0.07
Nitrogen Oxide (NO_x) (lb/hr)	1,640	615	615	287	287	615	287
PM_{10} (lb/mmBtu)	0.061	0.015	0.015	0.015	0.015	0.015	0.015
PM_{10} (lb/hr)	250.0	61.5	61.5	61.5	61.5	61.5	61.5
Coarse Particulate ($PM_{2.5}$ <diameter < PM_{10}) (lb/hr)[(a)]	107.5	35.1	35.1	35.1	35.1	35.1	35.1
Fine Particulate (diameter < $PM_{2.5}$) (lb/hr)[(b)]	142.5	26.4	26.4	26.4	26.4	26.4	26.4
Sulfuric Acid (H_2SO_4) (lb/hr)	37.7	3.7	37.7	5.3	64.1	3.8	5.8
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	--	1.0	4.8	--	0.8
$(NH_4)HSO_4$ (lb/hr)	--	--	--	1.6	8.5	--	1.4
H_2SO_4 as Sulfate (SO_4) (lb/hr)	37.0	3.6	37.0	5.2	63.1	3.7	5.6
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	--	--	--	0.7	3.5	--	0.6
$(NH_4)HSO_4$ as SO_4 (lb/hr)	--	--	--	1.4	7.1	--	1.2
Total Sulfate (SO_4) (lb/hr)[(c)]	37.0	3.6	37.0	7.3	73.6	3.7	7.4
Stack Conditions							
Stack Height (meters)	76	152	152	152	152	152	152
Stack Exit Diameter (meters)	9.75	5.79	7.01	5.79	7.01	5.79	5.79
Stack Exit Temperature (Kelvin)	322	350	322	350	322	350	350
Stack Exit Velocity (meters per second)	8.5	25.7	16.5	25.7	16.5	25.7	25.7

NOTES:

(a) AP-42, Table 1.1-6: coarse PM counted as a percentage of PM_{10}. This equates to 43 percent for ESP and 57 percent for Baghouse.

(b) AP-42, Table 1.1-6: fine PM counted as a percentage of PM_{10}. This equates to 57 percent for ESP and 43 percent for Baghouse.

(c) Total Sulfate (SO4) (lb/hr) = H2SO4 as Sulfate (SO4) Stack Emissions (lb/hr) + (NH4)2SO4 as SO4 Stack Emissions (lb/hr) + (NH4)HSO4 as SO4 Stack Emissions (lb/hr).

<u>Visibility Post-Processing (CALPOST)</u>

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

Table 25: Relative Humidity Factors for CALPOST

Month	Rawah WA	Mount Zirkel WA	Badlands NP & Wind Cave NP
January	2.10	2.20	2.65
February	2.10	2.20	2.65
March	2.00	2.00	2.65
April	2.10	2.10	2.55
May	2.30	2.20	2.70
June	2.00	1.80	2.60
July	1.80	1.70	2.30
August	2.00	1.80	2.30
September	2.00	2.00	2.20
October	1.90	1.90	2.25
November	2.10	2.10	2.75
December	2.00	2.10	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 26 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 26: 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 four Class I areas in question are listed in the table below.

Table 27: Natural Background Aerosol Concentrations (μg/m^3)

Aerosol Component	Rawah WA	Mount Zirkel WA	Wind Cave NP & Badlands NP
Ammonium Sulfate	0.045	0.046	0.047
Ammonium Nitrate	0.038	0.038	0.040
Organic Carbon	0.178	0.179	0.186
Elemental Carbon	0.008	0.008	0.008
Soil	0.189	0.190	0.198
Coarse Mass	1.135	1.141	1.191

Visibility Post-Processing Results

The results of the visibility modeling for each of the two units for the baseline and control scenarios are shown in the tables below. For each scenario, the 98th percentile Δdv results are reported, along with the total number of days for which the predicted impacts exceeded 0.5 dv. Following the tables are figures that present the results graphically for baseline, the BART configuration proposed by PacifiCorp, and for the proposed BART configuration with the addition of SCR. Note that the Division's modeling for the Class I areas in northern Colorado examined baseline, Scenario A (proposed BART), and Scenario B (proposed BART + SCR) only.

Table 28: CALPUFF Visibility Modeling Results for Dave Johnston Unit 3 (South Dakota Class I Areas)

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 – ESP								
Badlands NP	1.635	59	1.176	37	1.652	47	1.488	48
Wind Cave NP	1.596	57	1.806	43	2.406	49	1.936	50
Post-Control Scenario 1 – LNB w/ advanced OFA, Dry FGD, ESP								
Badlands NP	0.477	7	0.351	4	0.478	7	0.435	6
Wind Cave NP	0.567	10	0.488	7	0.748	11	0.601	9
Post-Control Scenario 2 – LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Badlands NP	0.378	6	0.305	0	0.401	3	0.361	3
Wind Cave NP	0.481	5	0.404	5	0.624	10	0.503	7
Post-Control Scenario 3 – LNB w/ advanced OFA and SCR, Dry FGD, Fabric Filter								
Badlands NP	0.208	1	0.143	0	0.188	0	0.180	0
Wind Cave NP	0.213	1	0.211	0	0.305	1	0.243	1
Post-Control Scenario 4 – LNB w/ advanced OFA and SCR, Wet FGD, ESP, New Stack								
Badlands NP	0.253	3	0.155	0	0.233	0	0.214	1
Wind Cave NP	0.269	1	0.205	0	0.312	1	0.262	1
Post-Control Scenario A – Committed Controls: LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Badlands NP	0.448	7	0.360	4	0.469	6	0.426	6
Wind Cave NP	0.570	10	0.480	5	0.735	11	0.595	9
Post-Control Scenario B – Committed Controls + SCR								
Badlands NP	0.230	3	0.168	0	0.218	0	0.205	1
Wind Cave NP	0.249	1	0.241	0	0.345	2	0.278	1

Table 29: CALPUFF Visibility Modeling Results for Dave Johnston Unit 4 (South Dakota Class I Areas)

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 – Venturi Scrubber								
Badlands NP	1.347	50	1.100	29	1.449	45	1.299	41
Wind Cave NP	1.527	47	1.344	37	2.078	40	1.650	41
Post-Control Scenario 1 – LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Badlands NP	0.456	6	0.340	3	0.480	7	0.425	5
Wind Cave NP	0.467	7	0.465	7	0.751	10	0.561	8
Post-Control Scenario 2 – LNB w/ advanced OFA, Wet FGD, Fabric Filter								
Badlands NP	0.454	7	0.336	2	0.437	5	0.409	5
Wind Cave NP	0.551	9	0.460	5	0.663	10	0.558	8
Post-Control Scenario 3 – LNB w/ advanced OFA and SCR, Dry FGD, Fabric Filter								
Badlands NP	0.326	4	0.230	1	0.329	1	0.295	2
Wind Cave NP	0.353	3	0.347	3	0.492	7	0.397	4
Post-Control Scenario 4 – LNB w/ advanced OFA and SCR, Wet FGD, Fabric Filter								
Badlands NP	0.409	4	0.262	0	0.327	1	0.333	2
Wind Cave NP	0.443	4	0.339	3	0.518	8	0.433	5
Post-Control Scenario A – Committed Controls: LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Badlands NP	0.456	6	0.340	3	0.480	7	0.425	5
Wind Cave NP	0.469	7	0.465	7	0.751	10	0.562	8
Post-Control Scenario B – Committed Controls + SCR								
Badlands NP	0.326	4	0.230	1	0.327	1	0.294	2
Wind Cave NP	0.354	3	0.347	3	0.492	7	0.398	4

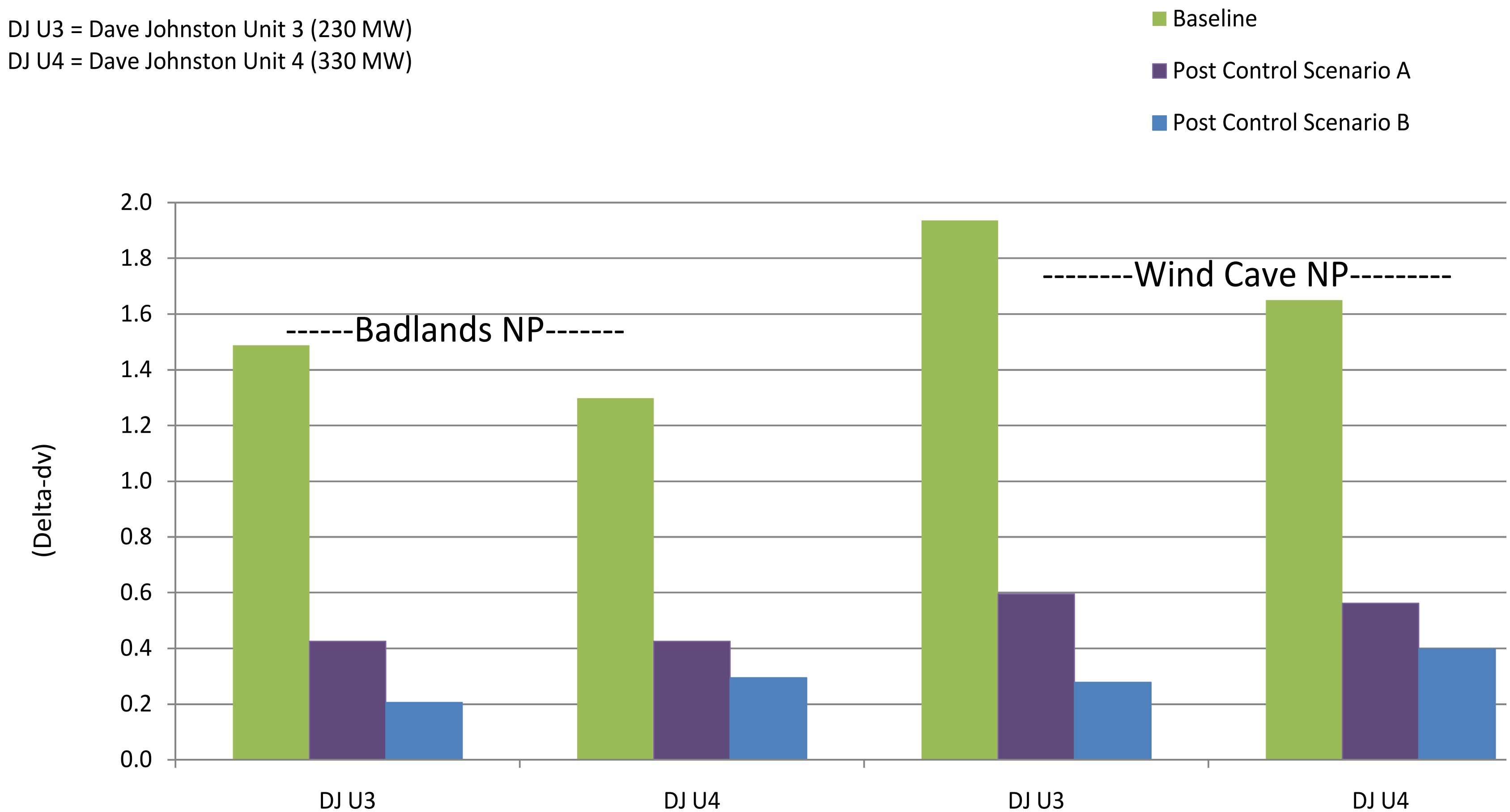
Table 30: CALPUFF Visibility Modeling Results for Dave Johnston Unit 3 (Colorado Class I Areas)

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 – ESP								
Rawah WA	0.718	11	1.075	14	0.918	14	0.904	13
Mt Zirkel WA	0.515	8	0.707	14	0.802	16	0.675	13
Post-Control Scenario A – Committed Controls: LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Rawah WA	0.163	2	0.283	5	0.265	2	0.237	3
Mt Zirkel WA	0.125	0	0.191	1	0.245	0	0.187	0
Post-Control Scenario B – Committed Controls + SCR								
Rawah WA	0.087	0	0.142	0	0.119	0	0.116	0
Mt Zirkel WA	0.066	0	0.100	0	0.109	0	0.092	0

Table 31: CALPUFF Visibility Modeling Results for Dave Johnston Unit 4 (Colorado Class I Areas)

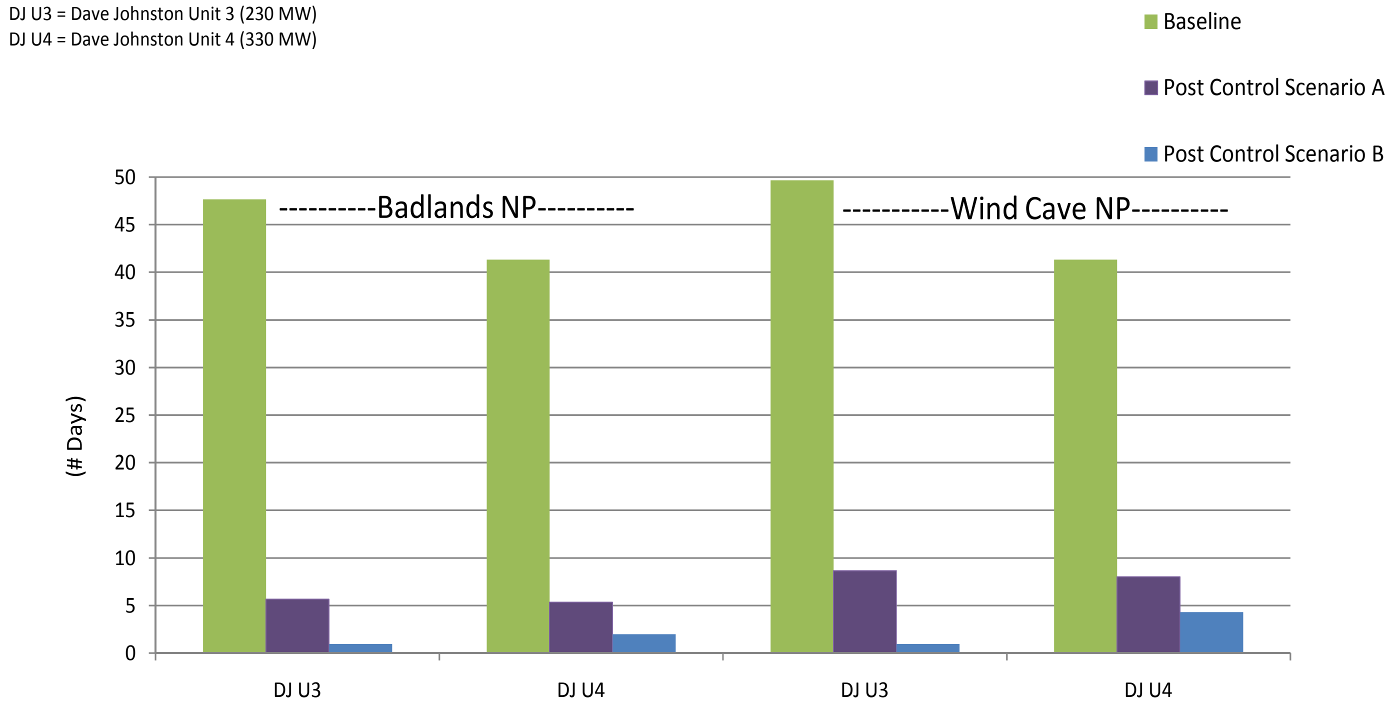
Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Venturi Scrubber								
Rawah WA	0.514	8	0.841	14	0.827	13	0.727	12
Mt Zirkel WA	0.387	6	0.659	11	0.654	11	0.567	9
Post-Control Scenario A – Committed Controls: LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Rawah WA	0.178	1	0.284	3	0.240	2	0.234	2
Mt Zirkel WA	0.127	0	0.190	0	0.238	0	0.185	0
Post-Control Scenario B – Committed Controls + SCR								
Rawah WA	0.133	0	0.214	1	0.172	1	0.173	1
Mt Zirkel WA	0.103	0	0.142	0	0.164	0	0.136	0

Figure 7
Modeled BART Impacts at South Dakota Class I Areas: 98th Percentile (delta-dv)



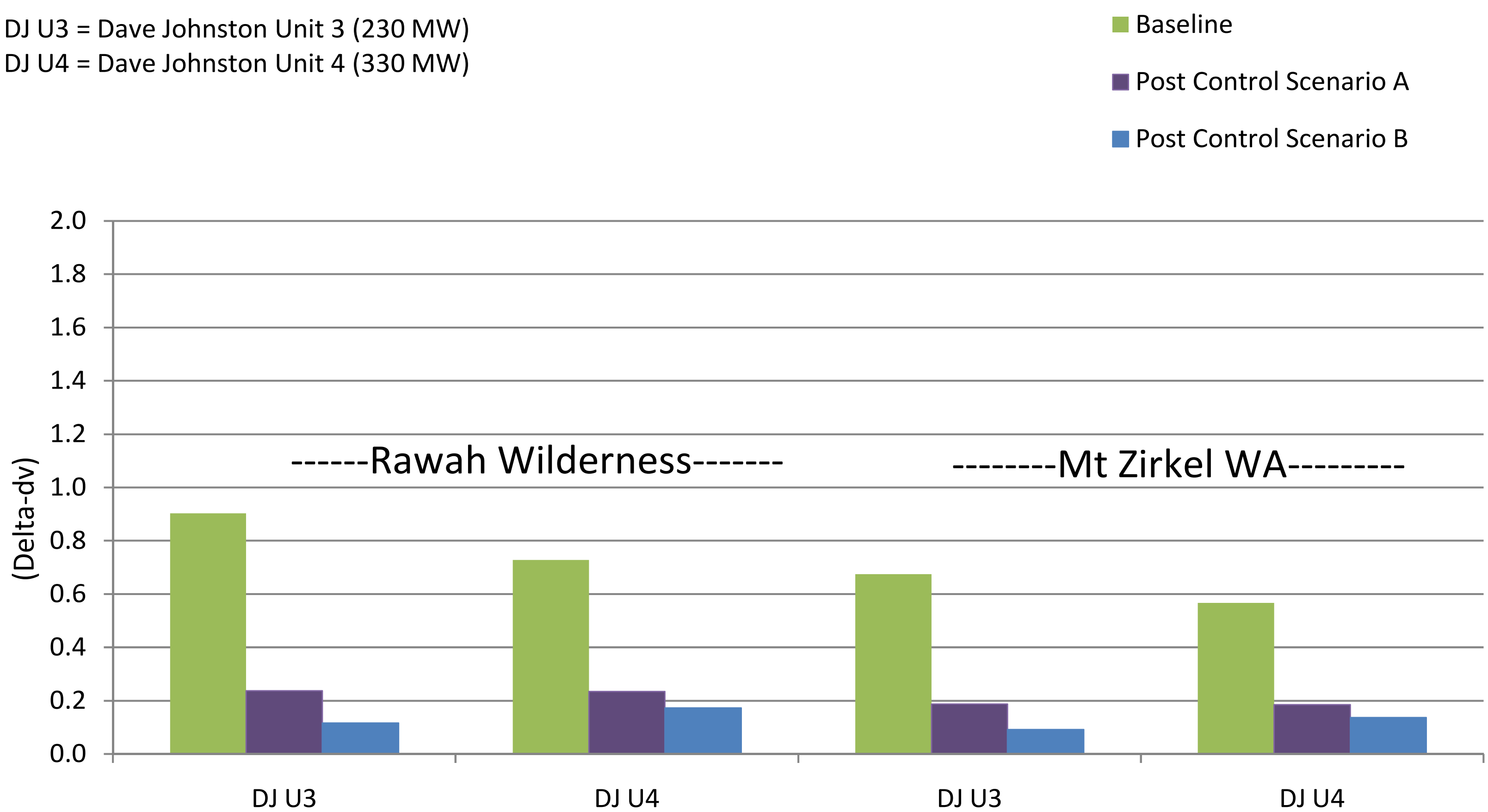
(Modeling results represent the three-year average of results using 2001-2003 meteorology)

Figure 8
Modeled BART Impacts at South Dakota Class I Areas: Number of Days > 0.5 delta-dv



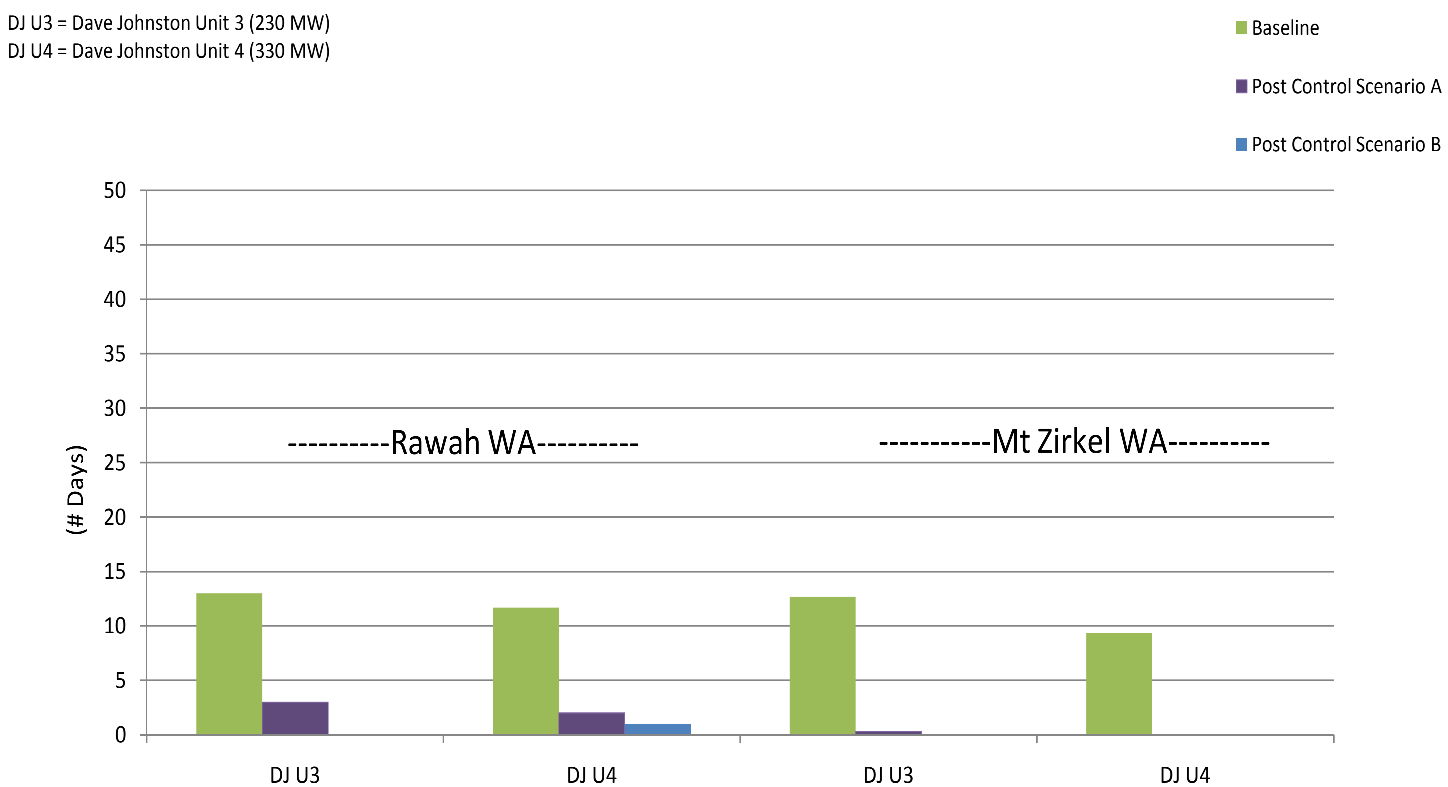
(Modeling results represent the three-year average of results using 2001-2003 meteorology)

Figure 9
Modeled BART Impacts at Colorado Class I Areas: 98th Percentile (delta-dv)



(Modeling results represent the three-year average of results using 2001-2003 meteorology)

Figure 10
Modeled BART Impacts at Colorado Class I Areas: Number of Days > 0.5 delta-dv



(Modeling results represent the three-year average of results using 2001-2003 meteorology)

BART CONCLUSIONS:

After considering (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any pollution equipment in use or in existence at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility (all five statutory factors) from each proposed control technology, the Division determined BART for each visibility impairing pollutant emitted from the two units subject to BART at the Dave Johnston Power Plant.

NO_x

LNB with advanced OFA is determined to be BART for Units 3 and 4 for NO_x based, in part, on the following conclusions:

1. LNB with advanced OFA on Units 3 and 4 was cost effective with a capital cost of $17,500,000 and $7,900,000 per unit, respectively. The average cost effectiveness, over a twenty year operational life, is $648 per ton of NO_x removed for Unit 3 and $137 per ton for Unit 4.

2. Combustion control using LNB with advanced OFA does not require non-air quality environmental mitigation for the use of chemical reagents (i.e., ammonia or urea) and there is a minimal energy impact.

3. After careful consideration of the five statutory factors, especially the costs of compliance and the existing pollution control equipment, a NO_x control level of 0.28 lb/MMBtu on a 30-day rolling average, below EPA's applicable presumptive limit of 0.45 lb/MMBtu for cell-fired boilers burning sub-bituminous coal, is justified for Unit 3.

4. 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 0.15 lb/MMBtu on a 30-day rolling average, equal to EPA's applicable presumptive limit for tangential-fired boilers burning sub-bituminous coal, is justified for Unit 4.

5. Visibility impacts were addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants and associated control options. The cumulative 3-year averaged 98th percentile visibility improvement from the baseline summed across all four Class I areas achieved with LNB with advanced OFA, dry FGD, and a new full-scale fabric filter, Post-Control Scenario A for each unit, was 3.558 Δdv from Unit 3 and 1.963 Δdv from Unit 4.

6. Annual NO_x emission reductions from baseline achieved by applying LNB with advanced OFA on Units 3 and 4 are 2,723 tons and 6,142 tons, respectively.

LNB with advanced OFA and SCR was not determined to be BART for Units 3 and 4 for NO_x based, in part, on the following conclusions:

1. The cost of compliance for installing SCR on each unit is significantly higher than LNB with advanced OFA. Capital cost for SCR on Unit 3 is $129,700,000 and $151,900,000 for Unit 4. Annual SCR O&M costs for Unit 3 are $4,009,159 and $1,980,281 for Unit 4.

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

3. Operation of LNB with advanced OFA and SCR is parasitic and requires an estimated 1.6 MW from Unit 3 and 2.1 MW from Unit 4.

4. While visibility impacts were addressed in a cumulative analysis of all three pollutants, Post-Control Scenario B is directly comparable to Post-Control Scenario A as the only difference is directly attributable to the installation of SCR. Subtracting the modeled 98th percentile values from each other yield the incremental 98th percentile visibility improvement from SCR. The cumulative 3-year averaged 98th percentile visibility improvement from Post-Control Scenario A summed across all four Class I areas achieved with Post-Control Scenario B was 0.754 Δdv from Unit 3 and 0.405 Δdv from Unit 4.

The Division considers the installation and operation of the BART-determined NO_x controls, new LNB with advanced OFA on Units 3 and 4 to meet corresponding emission limits on a continuous basis, to meet the statutory requirements of BART.

Unit-by-unit NO_x BART determinations:

<u>Dave Johnston Unit 3</u>: Installing new LNB with advanced OFA and meeting NO_x emission limits of 0.28 lb/MMBtu (30-day rolling average), 784 lb/hr (30-day rolling average), and 3,434 tpy as BART for NO_x.

<u>Dave Johnston Unit 4</u>: Installing new LNB with advanced OFA and meeting NO_x emission limits of 0.15 lb/MMBtu (30-day rolling average), 615 /hr (30-day rolling average), and 2,694 tpy as BART for NO_x.

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

A new full-scale fabric filter is determined to be BART for Units 3 and 4 for PM/PM_{10} based, in part, on the following conclusions:

1. While the Division considers the costs of compliance for full-scale fabric filters on Units 3 and 4 not reasonable, PacifiCorp is committed to installing this control device and has permitted the installation of a full-scale fabric filter Unit 3 and Unit 4 in Air Quality Permit MD-5098. A full-scale fabric filter is the most stringent PM/PM_{10} control technology and therefore the Division will accept it as BART.

The Division considers the installation and operation of the BART-determined PM/PM_{10} controls, new full-scale fabric filter on Units 3 and 4 to meet corresponding emission limits on a continuous basis, to meet the statutory requirements of BART.

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

<u>Dave Johnston Unit 3</u>: Installing a new full-scale fabric filter and meeting PM/PM_{10} emission limits of 0.015 lb/MMBtu, 42.1 lb/hr, and 184 tpy as BART for PM/PM_{10}.

Dave Johnston Unit 4: Installing a new full-scale fabric filter and meeting PM/PM_{10} emission limits of 0.015 lb/MMBtu, 61.5 lb/hr, and 269 tpy as BART for PM/PM_{10}.

SO_2: WESTERN BACKSTOP SULFUR DIOXIDE TRADING PROGRAM

PacifiCorp evaluated control SO_2 control technologies that can achieve a SO_2 emission rate of 0.15 lb/MMBtu or lower from the coal-fired boilers. PacifiCorp proposed dry FGD, and a full-scale fabric filter as SO_2 BART controls on both Units 3 and 4.

Wyoming is a §309 state participating in the Regional SO_2 Milestone and Backstop Trading Program. §308(e)(2) provides States with the option to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain additional control technology to meet an established emission limit on a continuous basis. However, the alternate program must achieve greater reasonable progress than would be accomplished by installing BART. A demonstration that the alternate program can achieve greater reasonable progress is prescribed by §308(e)(2)(i). Since the pollutant of concern is SO_2, this demonstration has been performed under §309 as part of the state implementation plan. §309(d)(4)(i) requires that the SO_2 milestones established under the plan "…must be shown to provide for greater reasonable progress than would be achieved by application of BART pursuant to §51.308(e)(2)."

Wyoming participated in creating a detailed report entitled **Demonstration that the SO_2 Milestones Provide Greater Reasonable Progress than BART** covering SO_2 emissions from all states participating in the Regional SO_2 Milestone and Backstop Trading Program. The document was submitted to EPA in support of the §309 Wyoming Regional Haze SIP in November of 2008.

As part of the §309 program, participating states, including Wyoming, must submit an annual Regional Sulfur Dioxide Emissions and Milestone Report that compares actual emissions to pre-established milestones. Participating states have been filing these reports since 2003. Each year, states have been able to demonstrate that actual SO_2 emissions are well below the milestones. The actual emissions and their respective milestones are shown in Table 32.

Table 32: 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 33 to underscore the improvements associated with SO_2 reductions.

Table 33: Visibility - Sulfate Extinction Only

Class I Area Monitor (Class I Areas Represented)	**20% Worst Visibility Days (Monthly Average, Mm^{-1})**		**20% Best Visibility Days (Monthly Average, Mm^{-1})**	
	2018 [1] Base Case (Base 18b)	**2018 [2] Preliminary Reasonable Progress Case (PRP18a)**	**2018 [1] Base Case (Base 18b)**	**2018 [2] Preliminary Reasonable Progress Case (PRP18a)**
Bridger, WY (Bridger WA and Fitzpatrick WA)	5.2	4.3	1.6	1.3
North Absaroka, WY (North Absaroka WA and Washakie WA)	4.8	4.5	1.1	1.1
Yellowstone, WY (Yellowstone NP, Grand Teton NP and Teton WA)	4.3	3.9	1.6	1.4
Badlands, SD	17.8	16.0	3.5	3.1
Wind Cave, SD	13.0	12.1	2.7	2.5
Mount Zirkel, CO (Mt. Zirkel WA and Rawah WA)	4.6	4.1	1.4	1.3
Rocky Mountain, CO	6.8	6.2	1.3	1.1
Gates of the Mountains, MT	5.3	5.1	1.0	1.0
UL Bend, MT	9.7	9.6	1.8	1.7
Craters of the Moon, ID	5.8	5.5	1.5	1.5
Sawtooth, ID	3.0	2.8	1.2	1.1
Canyonlands, UT (Canyonlands NP and Arches NP)	5.4	4.8	2.1	1.9
Capitol Reef, UT	5.7	5.4	1.9	1.8

[1] Represents 2018 Base Case growth plus all established controls as of Dec. 2004. No BART or SO_2 Milestone assumptions were included.
[2] Represents 2018 Preliminary Reasonable Progress growth estimates and established SO_2 limits.

All Class I areas in the surrounding states show a projected visibility improvement for 2018 with respect to SO_2 on the worst days and no degradation on the best days. More discussion on the visibility improvement of the §309 program can be found in the Wyoming §309 Regional Haze SIP revision submitted to EPA in November 2008.

Therefore, in accordance with §308(e)(2), Wyoming's §309 Regional Haze SIP, and WAQSR Chapter 6, Section 9, PacifiCorp will not be required to install the company-proposed BART technology and meet the corresponding achievable emission limit. Instead, PacifiCorp is required to participate in the Regional SO_2 Milestone and Backstop Trading Program authorized under Chapter 14 of the WAQSR.

LONG-TERM STRATEGY FOR REGIONAL HAZE:

In this BART analysis, the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology were taken into consideration when determining BART. When evaluating the costs of compliance the Division recognized a time limitation to install BART-determined controls imposed by the Regional Haze Rule. In addressing the required elements, including documentation for all required analyses, to be submitted in the state implementation plan, 40 CFR

51.308(e)(1)(iv) states: "A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision." As a practical measure, the Division anticipates the requirement to install the BART-determined controls to occur as early as 2015.

PacifiCorp used the **EPA Air Pollution Control Cost Manual**, which is identified in 40 CFR part 51 Appendix Y(IV)(D)(4)(a)(5) as a reference source, to estimate capital costs and calculate cost effectiveness. Section 1 Chapter 2 of the **EPA Air Pollution Control Cost Manual - Sixth Edition** (EPA 452/B-02-001) describes the concepts and methodology of cost estimation used in the manual. Beginning on page 2-28 of Chapter 2.5.4.2, the manual discusses retrofit cost consideration including the practice of developing a retrofit factor to account for unanticipated additional costs of installation not directly related to the capital cost of the controls themselves. However, PacifiCorp did not present a retrofit factor in their cost analyses. PacifiCorp estimated that the installation of SCR requires a minimum of 6 years of advanced planning and engineering before the control can be successfully installed and operated. This planning horizon would necessarily be considered in the scheduled maintenance turnarounds for existing units to minimize the installation costs of the pollution control systems.

PacifiCorp's BART-eligible or subject-to-BART power plant fleet is shown in Table 34. While the majority of affected units are in Wyoming, there are four units in Utah and one in Arizona. Since the 5-year control installation requirement is stated in the federal rule it applies to all of PacifiCorp's units requiring additional BART-determined controls. Although BART is determined on a unit-by-unit basis taking into consideration the statutory factors, consideration for additional installation costs related to the logistics of managing more than one control installation, which are indirect retrofit costs, was afforded under the statutory factor: costs of compliance.

Table 34: PacifiCorp's BART-Eligible/Subject Units

Source	State
Hunter Unit 1 [a]	Utah
Hunter Unit 2 [a]	Utah
Huntington Unit 1 [a]	Utah
Huntington Unit 2 [a]	Utah
Cholla Unit 4 [b]	Arizona
Dave Johnston Unit 3	Wyoming
Dave Johnston Unit 4	Wyoming
Jim Bridger Unit 1	Wyoming
Jim Bridger Unit 2	Wyoming
Jim Bridger Unit 3	Wyoming
Jim Bridger Unit 4	Wyoming
Naughton Unit 1	Wyoming
Naughton Unit 2	Wyoming
Naughton Unit 3	Wyoming
Wyodak	Wyoming

[a] Units identified in Utah's §308 Regional Haze SIP.
[b] Unit identified on the Western Regional Air Partnership's BART Clearinghouse.

Based on the cost of compliance and visibility improvement presented by PacifiCorp in the BART applications for Dave Johnston Units 3 and 4, and taking into consideration the logistical challenge of managing multiple pollution control installations within the regulatory time allotted for installation of BART by the Regional Haze Rule, the Division is not requiring additional controls under the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan in this permitting action. Additional controls may be required in future actions related to the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan.

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

PacifiCorp's Dave Johnston Power Plant is a "major emitting facility" under Chapter 6, Section 4, of the Wyoming Air Quality Standards and Regulations because emissions of a criteria pollutant are greater than 100 tpy for a listed categorical source. PacifiCorp should comply with the permitting requirements of Chapter 6, Section 4 as they apply to the installation of controls determined to meet BART.

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

The installation of controls determined to meet BART will not change New Source Performance Standard applicability for Dave Johnston Units 3 and 4.

CHAPTER 5, SECTION 3 – NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPs) AND CHAPTER 6, SECTION 6 – HAZARDOUS AIR POLLUTANT (HAP) EMISSIONS AND MAXIMUM AVAILABLE CONTROL TECHNOLOGY (MACT):

The installation of controls determined to meet BART will not change Nation Emission Standards For Hazardous Air Pollutants applicability for Dave Johnston Units 3 and 4.

CHAPTER 6, SECTION 3 – OPERATING PERMIT:

The Dave Johnston Power Plant is a major source under Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations. The most recent Operating Permit, 3-2-148, was issued for the facility on September 2, 2008. In accordance with Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations (WAQSR), PacifiCorp will need to modify their operating permit to include the changes authorized in this permitting action.

CONCLUSION:

The Division is satisfied that PacifiCorp's Dave Johnston Power Plant will comply with all applicable Wyoming Air Quality Standards and Regulations. The Division proposes to issue a BART Air Quality Permit for modification to install new LNB with advanced OFA and a new full-scale fabric filter on Units 3 and 4.

PROPOSED PERMIT CONDITIONS:

The Division proposes to issue an Air Quality Permit to PacifiCorp for the modification of the Dave Johnston Power Plant with the following conditions:

1. Authorized representatives of the Division of Air Quality be given permission to enter and inspect any property, premise or place on or at which an air pollution source is located or is being constructed or installed for the purpose of investigating actual or potential sources of air pollution, and for determining compliance or non-compliance with any rules, standards, permits or orders.

2. All substantive commitments and descriptions set forth in the application for this permit, unless superseded by a specific condition of this permit, are incorporated herein by this reference and are enforceable as conditions of this permit.

3. That PacifiCorp shall modify their Operating Permit in accordance with Chapter 6, Section 9(e)(iv) and Chapter 6, Section 3 of the WAQSR.

4. All notifications, reports and correspondence associated with this permit shall be submitted to the Stationary Source Compliance Program Manager, Air Quality Division, 122 West 25th Street, Cheyenne, WY 82002 and a copy shall be submitted to the District Engineer, Air Quality Division, 152 North Durbin Street, Suite 100, Casper, WY 82601.

5. Effective upon completion of the initial performance tests to verify the emission levels below, as required by Condition 6 of this permit, emissions from Dave Johnston Units 3 and 4 shall not exceed the levels below. The NO_x limits shall apply during all operating periods. 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 coal is introduced as fuel.

Unit	Pollutant	lb/MMBtu	lb/hr	tpy
3	NO_x	0.28 (30-day rolling)	784 (30-day rolling)	3,434
4	NO_x	0.15 (30-day rolling)	615 (30-day rolling)	2,694
3	PM/PM_{10} [(a)]	0.015	42.1	184
4	PM/PM_{10} [(a)]	0.015	61.5	269

[(a)] Filterable portion only

6. That initial performance tests be conducted, in accordance with Chapter 6, Section 2(j) of the WAQSR, within 30 days of achieving a maximum design rate but not later than 90 days following initial start-up, and a written report of the results be submitted. If a maximum design rate is not achieved within 90 days of start-up, the Administrator may require testing be done at the rate achieved and again when a maximum rate is achieved.

7. Performance tests shall consist of the following:

Coal-fired Boilers (Dave Johnston Units 3 and 4):

NO_x Emissions – Compliance with the NO_x 30-day rolling average shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 60.

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

Testing required by the Chapter 6, Section 3, Operating Permit may be submitted to satisfy the testing required by this condition.

8. Prior to any testing required by this permit, a test protocol shall be submitted to the Division for approval, at least 30 days prior to testing. Notification should be provided to the Division at least 15 days prior to any testing. Results of the tests shall be submitted to this office within 45 days of completing the tests.

9. PacifiCorp shall comply with all requirements of the Regional SO_2 Milestone and Backstop Trading Program in accordance with Chapter 14, Sections 2 and 3, of the WAQSR.

10. Compliance with the NO_x limits set forth in this permit for the coal-fired boilers (Dave Johnston Units 3 and 4) shall be determined with data from the continuous monitoring systems required by 40 CFR Part 75 as follows:

a. Exceedances of the NO_x limits shall be defined as follows:

i. Any 30-day rolling average of NO_x emissions which exceeds the lb/MMBtu limits calculated in accordance with the compliance provisions and monitoring requirements of §60.48Da and §60.49Da. The definition of "boiler operating day" shall be consistent with the definition as specified in 40 CFR part 60, subpart Da.

ii. Any 30-day rolling average calculated using valid data (output concentration and average hourly volumetric flowrate) from the existing CEM equipment which exceeds the lb/hr NO_x limit established in this permit. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j) and follow the compliance provisions and monitoring requirements of §60.48Da and §60.49Da. The 30-day average emission rate shall be calculated as the arithmetic average of hourly emissions with valid data during the previous 30-day period. The definition of "boiler operating day" shall be consistent with the definition as specified in 40 CFR part 60, subpart Da.

b. PacifiCorp shall comply with all reporting and record keeping requirements as specified in WAQSR, Chapter 5, Section 2(g) and 40 CFR part 60, subpart D. All excess emissions shall be reported using the procedures and reporting format specified in WAQSR, Chapter 5, Section 2(g).

11. PacifiCorp shall use EPA's Clean Air Markets reporting program to convert the monitoring system data to annual emissions. PacifiCorp shall provide substituted data according to the missing data procedures of 40 CFR, Part 75 during any period of time that there is not monitoring data. All monitoring data must meet the requirements of WAQSR, Chapter 5, Section 2(j).

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

13. 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.

14. PacifiCorp shall install new low NO_x burners with advanced overfire air on Units 3 and 4, in accordance with the Division's BART determination, and conduct the initial performance tests required in Condition 6 no later than December 31, 2010 and December 31, 2009, respectively.

15. PacifiCorp shall install new full-scale fabric filters on Units 3 and 4, in accordance with the Division's BART determination, and conduct the initial performance tests required in Condition 6 no later than December 31, 2010 and December 31, 2012, respectively.

Appendix A
Facility Location