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October 4, 2012

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Public Utility Commission of Oregon
Attn: Filing Center
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Salem, OR 97308-2148

Re: OR Docket No. UE-246 - Sierra Club's Prehearing Brief and Exhibits

Please find enclosed the original and five (5) copies of Sierra Club's Prehearing Brief and Exhibits.

Please let me know if you require any additional documents or if you have any questions. Thank you.

Sincerely,

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CERTIFICATE OF SERVICE

I hereby certify that on this 4th day of October, 2012, I caused to be served the foregoing Sierra Club's Prehearing Brief and Exhibits on all party representatives on the official service list for this proceeding via electronic mail.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
UE 246

In the Matter of PACIFICORP Request for a General Rate Revision	))))))	PREHEARING BRIEF OF SIERRA CLUB

In accordance with the Joint Prehearing Conference Memorandum issued September 20th, 2012 in the above-captioned proceeding, Sierra Club hereby submits this prehearing brief. This brief identifies and summarizes many of the issues addressed by Sierra Club witnesses Drs. Jeremy Fisher and William Steinhurst and incorporates those issues into Sierra Club's position in this proceeding. The brief also addresses the testimony of PacifiCorp (hereinafter "PacifiCorp" or the "Company") witnesses Mr. Chad Teply and Ms. Cathy Woollums by making legal arguments based on facts currently in the record as well as facts in publicly available documents that Sierra Club intends to introduce as cross-examination exhibits during hearings.

I. INTRODUCTION

Sierra Club's case challenges the prudency of PacifiCorp's capital expenditures of $297 million at the Naughton coal plant and $79 million at the Hunter coal plant.[1] These expenses were not prudent and were not made in the best interest of customers. Rather, these expenses were part of a Company-wide business plan to use pending environmental regulations as a means to increase PacifiCorp's rate base by investing billions of dollars in its old and polluting coal fleet. At every step, the Company's analysis to implement its business plan contained decisions

[1] UE 246/Sierra Club/100, Fisher 100/4.

that bolstered and justified its effort to increase rate base at its coal-fired units. Given its single-minded focus, the Company missed or ignored numerous warning signs indicating that substantial capital expenditures at coal facilities were either unnecessary or not cost effective. Of the coal plants at issue in this proceeding, Sierra Club shows below that the Company sought permits to install retrofits that were not legally required at the Naughton, Hunter, Dave Johnston and Wyodak plants.

Sierra Club understands that it is not the role of this Commission to question the emission limits or permitting requirements set by state or federal environmental agencies. Those questions are and should be within the jurisdiction of agencies such as the Wyoming Department of Environmental Quality ("WYDEQ"), the Utah Department of Environmental Quality, and the Environmental Protection Agency ("EPA"). On the other hand, the record in this proceeding clearly shows that PacifiCorp repeatedly proposed to install pollution control technology that was more elaborate and more expensive than what those environmental agencies determined was necessary to comply with the letter of the law. While the environmental agencies clearly alerted PacifiCorp that its proposals were not cost effective or were unnecessary, it was not the role of those environmental agencies to prevent PacifiCorp from voluntarily over-spending on environmental capital projects. It ***is*** within the jurisdiction and duty of this Commission to question PacifiCorp's decision to spend hundreds of millions of dollars on capital expenditures that were unnecessary or not cost effective, and to disallow those capital expenditures from rate base where it determines that the Company's actions were not prudent.

II. The Coal Fleet Spending Plan

In this proceeding, PacifiCorp seeks to add approximately $661 million to its rate base for major capital expenditures at its coal fleet.[2] This expense is just one piece of a long-term plan by PacifiCorp to spend billions of dollars on its decaying coal fleet. From 2005 through 2010, PacifiCorp spent more than $1.2 billion in capital dollars across the 19 coal-fired units in its fleet.[3] By 2022, PacifiCorp expects to have spent more than $2.7 billion dollars on capital projects.[4]

This massive spending was not necessary. PacifiCorp repeatedly rushed ahead of existing environmental regulations in an effort to provide a basis for major capital increases in its rate base, and the Company failed to reassess its plans in the face of changing circumstances that undermined the rationale for extending the life of its coal fleet. The Company also relied on flawed economic analyses to rationalize their unnecessary proposals to install environmental retrofits. Rather than making prudent management decisions that adjusted to uncertain regulations, falling natural gas prices, and increased risks for coal plants, PacifiCorp doggedly stuck to its business plan to invest billions of dollars in its coal plants (the "Coal Fleet Spending Plan").

The first indications of what became PacifiCorp's Coal Fleet Spending Plan began in 1999 with the development of the "Comprehensive Air Initiative" or CAI, which Mr. Teply testified "was designed to reduce power plant emissions in accordance with Regional Haze Rules and other air quality regulations that would require emissions reductions."[5] However, as uncertainty surrounding the pending regulation dragged on, PacifiCorp's emission reduction plan became a policy that was driven more by internal business decisions than external regulatory compliance

[2] *See* Table 11, CUB/100, Jenks-Feighner/59.
[3] UE 246/Sierra Club/112, Fisher/1.
[4] UE 246/Sierra Club/112, Fisher/1
[5] UE 246/PAC/500, Teply/5.

obligations. Dr. Fisher's testimony included confidential Company documents from 2003 showing that the Company ***voluntarily*** developed the CAI to unilaterally cement emissions controls in place and to provide a basis for future capital expenditures.[6]

Later documents show that the Company was determined to proceed with its path to expend huge capital sums on emissions control projects, regardless of whether or not existing regulations explicitly required those projects. In 2005, internal Company documents explained PacifiCorp's plan to simply begin installing air pollution controls without formal requirements from state or federal authorities.[7] These documents reveal that PacifiCorp's plan was based on ***internal policy decisions*** to expend capital on emission reduction projects rather than state or federal regulations.

At the time the final Coal Fleet Spending Plan was developing from 1999-2005, PacifiCorp may have reasonably assumed that *at some point* it would be required to retrofit some units in order to continue operating its plants within the time frames originally considered in the CAI. However, as discussed in more detail below, PacifiCorp refused to deviate from its Coal Fleet Spending Plan even when it became clear that the Company's proposed emission control projects were either unnecessary, too expensive, or were not yet required given the uncertain compliance deadlines for pending regulations. This trend of PacifiCorp moving forward with unnecessary capital projects is evident in several examples:

- At Naughton, the Company continued to pursue sulfur dioxide ("SO_2") scrubbers, even after Wyoming regulators expressly stated that the Company's proposed $279 million emission control project was unnecessary to meet existing environmental regulations.[8]
- At Naughton and Hunter, state permits reflected compliance deadlines for nitrous oxides ("NO_x") limits that were *proposed by PacifiCorp* and coincided with the

[6] UE 246/Sierra Club/100, Fisher/23-24; Confidential UE 246/Sierra Club/114, Fisher/1: CAI Control Report: Comprehensive Air Initiative Analysis, Feb 2003.
[7] UE 246/Sierra Club/100, Fisher/25.
[8] UE 246/Sierra Club/111, Fisher/53.

overall Coal Fleet Spending Plan, despite the fact that federal and state statutes contemplated much longer compliance windows.

- At Wyodak, WYDEQ similarly found in its analysis of PacifiCorp's BART permit application (MD-6043) that the Company's proposed controls for particulate matter ("PM") were not reasonable because of cost: "The cost effectiveness and incremental cost effectiveness of applying a new polishing fabric filter to Unit 1 are not reasonable. However, in the end, the Company requested an even more expensive retrofit, a full-scale fabric filter system that the Company itself had earlier eliminated as cost prohibitive.[9]

- At Dave Johnston, WYDEQ expressly found in its BART permit that the cost of PacifiCorp's proposed PM and SO_2 control technology (both full-scale baghouses) was unreasonable: "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 the control devices…"[10] Despite this finding, PacifiCorp carried forward with construction of baghouses and SO_2scrubbers ***the year prior to the issuance*** of the permits. Worse, the retrofits were not required to control SO_2 because the Wyoming participates in the Regional SO_2 Milestone and Backstop Trading Program.[11]

Early Company documents outlining the Coal Fleet Spending Plan and PacifiCorp's subsequent decisions to rush capital expenditures that were unnecessary or not supported by least-cost alternative analyses at plants like Naughton and Hunter show that the Company failed to prudently manage capital expenses at its coal fleet. Conveniently for PacifiCorp, the management decisions surrounding the Coal Fleet Spending Plan resulted in more than $1.2 billion in rate base increases from 2005 to 2010 that will provide a return on equity for its shareholders. The Coal Fleet Spending Plan works to extend the lives of PacifiCorp's aging coal fleet, which is a significant piece of the Company's total rate base.[12]

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[9] Sierra Club/501, Cross Exhibit/12, 14, 36.
[10] Sierra Club/500, Cross Exhibit/48.
[11] Id. at 4.

[12] It should also be noted that MidAmerican Holdings Company, PacifiCorp's parent company, is in turn a subsidiary of Berkshire Hathaway, which has a substantial financial interest in the continued demand for coal in the United States. According to the Wall Street Journal, electricity flowing to one out of every 10 homes in the United States is generated using coal hauled by BNSF, a subsidiary of Berkshire Hathaway, and the rail company accounted for roughly 19% of Berkshire Hathaway's pretax earnings in 2009. Sierra Club/502, Cross Exhibit/1-2, (http://articles.marketwatch.com/2012-07-18/industries/32710506_1_thermal-coal-powder-river-basin-coal-revenue accessed September 26, 2012.)

PacifiCorp's Coal Fleet Spending Plan hurts ratepayers because it resulted in early and unnecessary capital expenses that were not the least-cost alternative, and it hurts the environment because it commits PacifiCorp to continued reliance on its old and dirty coal fleet.

III. PACIFICORP'S LEAST-COST ECONOMIC ANALYSIS WAS CRITICALLY FLAWED

Sierra Club witness Dr. Jeremy Fisher provided detailed and methodical testimony showing how the Company made massive errors and poor assumptions in its least-cost planning analysis for the retrofit projects. The Company then relied on this flawed analysis to rationalize its pre-existing Coal Fleet Spending Plan at Naughton and Hunter. The flaws and omissions in PacifiCorp's present value revenue requirement differential ("PVRR(d)") analyses were inconsistent with the duties of a reasonable person charged with responsibility for managing a utility business affected with the public interest.[13] PacifiCorp conducted a flawed least-cost analysis, ignored relevant planning information that the Company's management knew or should have known, and put ratepayers at risk for the costs of capital expenses that, when considered as part of a whole, were not cost-effective.[14]

The pre-filed testimony of Drs. Fisher and Steinhurst explained how the company failed to determine in a reasonable manner whether the Company's proposed Coal Fleet Spending Plan at Naughton and Hunter would be cost effective, in general, and, specifically, in the light of known and likely environmental regulations. The Company's analyses of the Naughton and Hunter retrofit projects failed to account for those known and likely regulations and were also fundamentally flawed in their assumptions, methods, scope and timing.[15] Dr. Fisher's analysis showed the Company's imprudent commitment to installing the retrofit projects and extending

[13] UE 246/Sierra Club/200, Steinhurst/2.
[14] UE 246/Sierra Club/100, Fisher/28-57.
[15] UE 246/Sierra Club/200, Steinhurst/2.

the lives of its coal plants subjected the Company to an estimated net ***liability*** of over $342 million at Naughton,[16] and over $522 million at Hunter.[17]

In response to Dr. Fisher's analysis, Mr. Teply submitted rebuttal and surrebuttal testimony that included various adjustments to the Company's PVRR(d) that attempt to provide *post-hoc* support for the Company's preexisting decision to install the Naughton and Hunter retrofit projects. Dr. Fisher addressed Mr. Teply's rebuttal adjustments in his reply testimony and is prepared to explain in detail at hearings the problems with Mr. Teply's additional surrebuttal adjustments to the PVRR(d) analysis. However, it is important to understand that even under PacifiCorp's best case scenario from its ***original*** analysis, the estimated benefits of the capital projects at Naughton and Hunter were marginal. Dr. Fisher's adjustments showed that the analysis turns dramatically negative if certain errors and assumptions are corrected, but regardless of whether the Commission concludes that Dr. Fishers adjustment are reasonable – they are - the Company should have realized under its own analysis that the retrofit projects were very risky. Mr. Teply stated as much in his surrebuttal testimony: "marginally positive or marginally negative PVRR(d) results do not necessarily indicate that shutting down a particular unit is the best outcome for customers."[18] Under the same rationale, neither do marginal PVRR(d) results necessarily indicate that installing hundreds of millions of dollars in capital expenses is the best outcome for customers. PacifiCorp's own analysis simply did not support these massive expenses for its aging and risky coal facilities, particularly when the PVRR(d) analysis showed that planned expenses would not break even until near the end of the planning

[16] UE 246/Sierra Club/100, Fisher/28, line 3.
[17] UE 246/Sierra Club/100, Fisher/52 (assuming a \$45 cost of CO_2).
[18] UE 246/PAC/2000, Teply/4.

period.[19] PacifiCorp should have recognized that the PVRR(d) analysis was a red flag for the projects, and it should have applied additional layers of scrutiny to the decision.

The red flags raised by the Company's original PVRR(d) analysis, not to mention the huge liabilities that would have been revealed in a correctly executed analysis, should have led the Company to conduct a much more comprehensive effort to evaluate if it was appropriate to retrofit the Naughton and Hunter units. The Company had several tools available to further scrutinize the expenses: (1) The Company should have conducted a much more comprehensive analysis exploring the risks and potential downsides of pursuing the retrofits, including risks built into but not utilized in the original tool. (2) The Company should have carefully checked to ensure that any analysis supporting the retrofits conformed to their expectations of the unit's declining availability and degradation. (3) The Company should have deferred the investment to gain clarity on ***other known emerging regulatory risks*** such as the mercury rule and the coal combustion residuals rule. (4) The Company should have utilized more appropriate tools in their planning portfolio, such as System Optimizer, to determine if the retrofits could be avoided through better build-out options. (5) Finally, if the Company had still decided to pursue the retrofits despite the lack of a regulatory requirement and a poor economic outcome, the Company should have regularly and rigorously re-evaluated their expected spending in light of changing economic and regulatory pressures.[20] The Company failed to take any of these actions and instead plowed ahead with its Coal Fleet Spending Plan, which PacifiCorp estimates will result in more than $2.7 billion in capital spending on its coal fleet by 2022.[21]

Sierra Club's review of the Company's flawed PVRR(d) analysis demonstrated that the Company acted imprudently ***even if it had been necessary*** to comply with some sort of emission

[19] UE 246/Sierra Club/116; UE 246/Sierra Club/200, Steinhurst/16; UE 246/Sierra Club/300, Fisher/9-10.
[20] UE 246/Sierra Club/300, Fisher/22.
[21] UE 246/Sierra Club/112, Fisher/1.

control requirement. Those arguments are compelling and stand on their own to demonstrate that the Company acted imprudently when it spent hundreds of millions of dollars on controls that were not in best economic interests of ratepayers. However, Sierra Club's testimony also addressed in detail the fact that PacifiCorp spent hundreds of millions of dollars on pollution retrofit projects that were not necessary to meet any state or federal regulatory requirements.

IV. NAUGHTON CAPITAL EXPENSES WERE NOT REQUIRED BY REGULATIONS

PacifiCorp's application for this proceeding included an increase of $297 million in rate base for retrofits at Naughton Units 1 & 2.[22] Those costs break down into two categories: (1) SO_2 scrubbers (i.e. flue gas desulfurization or "FGD"); and (2) low-NO_x burners (i.e. "LNB").[23] As the names suggest, SO_2 scrubbers primarily reduce emissions of SO_2, and low-NO_x burners reduce emissions of NO_x. The regulatory requirements for addressing these pollutants are different, and therefore the decisions to install each type of control should be considered in turn.

A. Wyoming Permits and State Regulations did not Require SO_2 Scrubbers

PacifiCorp's application included approximately $279 million in capital expenditures for the SO_2 scrubber projects at Naughton Units 1 & 2.[24] This amount is by far the largest class of capital expenses contested by the Sierra Club in this proceeding. Strikingly, the SO_2 scrubbers at Naughton were not required by any state or federal permit, regulation, or statute. Even today, there is simply no requirement anywhere that compelled PacifiCorp to expend $279 million to control SO_2 emissions.

PacifiCorp contends that it was required to install the SO_2 scrubbers at Naughton to comply with the National Ambient Air Quality Standards ("NAAQS"), the state of Wyoming's § 309

[22] UE 246/Sierra Club/100, Fisher/4.

[23] Testimony in this proceeding frequently referred to the acronyms FGD and LNB to identify the specific projects at issue. In an attempt to help clarify the nature and purpose of each project, this brief will refer to the FGD projects as "SO_2 scrubbers" and the LNB projects as "low-NO_x burners."

[24] UE 246/Sierra Club/100, Fisher/4.

Regional Haze Implementation Plant, and the State of Wyoming's permit MD-5156.[25] However, not one of these regulations or permits expressly required the Naughton plant to install the SO_2 scrubbers on Units 1 & 2.

1. <u>The Regional Haze Rules and Wyoming BART Determination Did Not Require Naughton to Install the SO_2 Scrubbers</u>

According to Ms. Woollums' rebuttal testimony, the Regional Haze Rules and Wyoming BART determinations were the basis for the Naughton "emission controls," but Ms. Woollums is tellingly vague on asserting where to find the specific regulatory trigger for the SO_2 scrubbers at Naughton.[26] To be clear, there was no required unit-by-unit BART determination for SO_2 emissions in Wyoming.[27] Instead, Wyoming treated SO_2 emissions differently than NO_x and PM in implementing the Regional Haze Rule by participating in the § 309 Regional SO_2 Milestone and Backstop Trading Program authorized under the regional haze regulations (at 40 C.F.R. 51.309). Wyoming, along with Utah and New Mexico, addressed SO_2 on a regional basis rather than setting plant-by-plant BART requirements for SO_2.

Despite this difference in the regulatory regime applicable to SO_2 emissions in Wyoming, PacifiCorp treated SO_2 at Naughton as if there was a unit-specific BART requirement for the plant. On June 14, 2006, the State of Wyoming sent a letter to PacifiCorp informing the Company that the Naughton Plant was a "BART Eligible" source and requesting that the Company conduct a five-factor analysis of BART options in accordance with EPA BART guidelines.[28] This 2006 letter made clear that Wyoming would base their final control requirements on the BART analyses for NO_x and PM; however, for SO_2 Wyoming would only,

[25] UE 246/PAC/500, Teply/41.
[26] UE 246/PAC/1400, Woollums/8-16
[27] UE 246/PAC/1400, Woollums/10; *see, also*, UE 246/Sierra Club/111, Fisher/53
[28] UE 246/PAC/1901, Woollums/1.

"institute SO_2 BART controls if the [Western Backstop Trading] program fails."[29] In response, PacifiCorp commissioned a Naughton BART Analysis from CH2MHill that expressly requested a BART analysis for SO_2, as well as NO_x and PM.[30] The consultant's Naughton BART Analysis found that an SO_2 scrubber would qualify as BART, should the Company be required to pursue BART under a state unit-specific determination.

At this point in early 2007, there was no Regional Haze requirement or BART determination to install any specific SO_2 control technology at Naughton. Wyoming had only asked for a BART analysis, not any type of specific implementation. Further, the Company knew that SO_2 would be covered by the regional trading program.[31] Yet on January 25, 2007, PacifiCorp voluntarily submitted a construction permit application for the installation of SO_2 scrubbers (ie. FGD) and low-NO_x burners (i.e. LNB).[32] There was simply no unit-specific SO_2 requirement in effect at the time that required PacifiCorp to install a $279 million SO_2 scrubber, nor was any unit-specific SO_2 requirement expected under Wyoming's planned implementation of the Regional Haze rule for SO_2.

Shortly after requesting construction permit MD-5156, PacifiCorp submitted its BART permit application for the Naughton units on February 12, 2007, which ultimately was issued as Wyoming permit MD-6042 several month later on December 21, 2009.[33] Significantly, the construction permit application in January 2007 came ***before*** the BART permit application and ***before*** Wyoming had made any unit-specific BART determination for Naughton. In other words, PacifiCorp jumped the gun. It requested a construction permit before there was a unit-specific regulatory basis that required the control projects that PacifiCorp requested. This inexplicable

[29] Id. at 2.
[30] UE 246/PAC/2002, Teply/2, 125.
[31] *See* February 28, 2007 Letter from Basin Electric to WDEQ re Laramie River. Sierra Club/503, Cross Exhibit/2.
[32] UE 246/Sierra Club/105.
[33] UE 246/Sierra Club/111, Fisher/2.

rush put PacifiCorp at risk of pursuing projects that Wyoming or the EPA could later determine were either inadequate or unnecessary. In fact, that is exactly what happened with the proposed SO_2 scrubbers.

On May 28, 2009, WYDEQ issued its analysis of PacifiCorp's application for BART permit MD-6042 and found the following for SO_2: "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."[34] In other words, Wyoming expressly informed PacifiCorp that it did not require the SO_2 scrubbers at Naughton to meet specific BART requirements. However, PacifiCorp ignored this finding and continued to pursue the $279 million Naughton SO_2 scrubber projects, signing the contracts to begin construction immediately.

In December 2009, WYDEQ issued its BART permit MD-6042 for the Naughton plant, and that permit did not include any requirement to install a SO_2 scrubber or to meet any specific SO_2 emission limit. The only requirement applicable to the SO_2 emissions at Naughton was for the plant to comply with the requirements of the Regional SO_2 Milestone and Backstop SO_2 Trading Program.[35]

Any contention by PacifiCorp that the Regional Haze Rule, and specifically a unit-by-unit BART determination, was the basis for the SO_2 scrubbers at Naughton is not credible. WYDEQ expressly informed PacifiCorp that its proposal to install SO_2 scrubbers as BART was not

[34] UE 246/Sierra Club/111, Fisher/53 (emphasis added).
[35] UE 246/PAC/2002, Teply/252, Condition 11.

necessary. Similarly, PacifiCorp's alternative bases for a regulatory requirement do stand up to scrutiny.

2. The Regional SO_2 Milestone and Backstop Trading Program Did Not Require Naughton to Install SO_2 Scrubbers

The requirements of Wyoming's § 309 Regional Haze SIP and the Regional SO_2 Milestone and Backstop Trading Program did not require PacifiCorp to install any specific controls at Naughton, or to meet any particular SO_2 emissions limit at Naughton. PacifiCorp's implication that the Regional SO_2 Milestone and Backstop Trading Program required Naughton to meet an SO_2 emissions limit of 0.15 lbs/mmBtu is incorrect.

The Regional SO_2 Milestone and Backstop Trading program includes region-wide SO_2 emission caps or "milestones" that decline over time through the year 2018, and the backstop SO_2 trading program is not triggered unless a milestone is not met. Prior to triggering the trading program, which has not yet happened, the Regional SO_2 Milestone and Backstop Trading Program does not require sources to take any action other than monitoring and reporting their emissions. "Until the program has been triggered and source compliance is required, the Department shall submit an annual emissions report for Wyoming sources to the WRAP and all participating states and tribes by September 30 of each year."[36] In May 2009 when PacifiCorp signed the contracts for the SO_2 scrubbers at Naughton, the trading program had not been triggered because the states were ***well below*** the regional milestones. WYDEQ explained this in its analysis of PacifiCorp's BART permit MD-6042: "Each year states have been able to demonstrate that actual SO_2 emissions are well below the milestones."[37] To this day, the states participating in the program have not exceeded the SO_2 emissions milestones and in 2010, SO_2

[36] Wyoming 2011 309 SIP, ¶A3.1 (emphasis added). Sierra Club/504, Cross Exhibit/11.
[37] UE 246/Sierra Club/111, Fisher/52 (emphasis added).

emissions for the three states were in fact below the 2018 SO_2 Milestone.[38] There has never been any indication that the regional SO_2 milestones would not be met. The Naughton SO_2 scrubbers went into service in November 2011 and May 2012, long after the regional SO_2 milestones for 2018 had been met. If the scrubbers were installed to meet this target, they were truly an excessive expense.

Ms. Woollums' testimony implied that Naughton, as a BART-eligible source, was required to participate in the SO_2 Backstop Trading Program.[39] This is true, but "participation" in the SO_2 Backstop Trading Program did not trigger any specific SO_2 emissions limit or unit-specific pollution controls. States participate in the SO_2 Backstop Trading Program *in lieu of* adopting source-specific SO_2 BART requirements.[40] Prior to the trading program trigger, there is no source-specific emissions limit or required control technology.

Ms. Woollums' testimony misleadingly stated that the SO_2 Backstop Trading Program in Wyoming required Naughton to meet an SO_2 emissions limit of 0.15 lbs/mmBtu: "[T]he Company was also required to meet the requirements of the Western Backstop Trading Program for SO_2, which utilized an emission rate of 0.15 lb/mmBtu for SO_2 at all BART-eligible units, including the Naughton units."[41] This statement is incorrect. There are no source-specific SO_2 emissions limits in the Western Backstop Trading Program. In response to comments from the U.S. Forest Service for PacifiCorp's Naughton BART permit (MD-6042), WYDEQ explained that, "BART limits for SO_2 will not be set because Wyoming is a §309 state participating in the Regional SO_2 Milestone and Backstop Trading Program."[42]

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[38] 2011 WRAP SO_2 Milestone Tracking Audit; 2010 Regional SO_2 Emissions and Milestone Report, Western Regional Air Partnership, Draft January 19, 2012. Sierra Club/505, Cross Exhibit/2.
[39] UE 246/PAC/1400, Woollums/13.
[40] UE 246/Sierra Club/100, Fisher/10.
[41] UE 246/PAC/1900, Woollums/7.
[42] UE 246/PAC/1403, Woollums/3.

There are no source-specific SO_2 requirements under the SO_2 Backstop Trading Program. While it is true that one of the requirements for EPA to approve the SO_2 Backstop Trading Program is for the state to show that the program will improve regional haze better than would be achieved with unit-specific BART, that requirement does not in any way mean that SO_2 BART requirements apply to facilities like Naughton under the SO_2 Backstop Trading Program. Again, as WYDEQ explained in response to U.S. Forest Service Comments on the Naughton BART permit described above, "Part of the SIP submittal is a 'Better than BART' demonstration, required by rule, which <u>does not require that each and every unit demonstrate emission controls</u> that are 'Better than BART'. The demonstration is a regional demonstration."[43] In short, the SO_2 Backstop Trading Program did not impose any SO_2 emissions limit on Naughton, and therefore the SO_2 Backstop Trading Program did not provide any regulatory basis for concluding that the \$279 million SO_2 scrubbers at Naughton were necessary.

Other utilities with coal plants in Wyoming understood the distinction between the regional trading program and the requirements to meet source-specific limits. Basin Electric, who owns the Laramie River plant in Wyoming, submitted a letter to WYDEQ on February 28, 2007 stating that for purposes of SO_2 controls, "Basin Electric will participate in the Western Regional Air Partnership (WRAP) SO_2 emission trading program. <u>Should the WRAP trading program not be implemented</u>, Basin Electric will commit to meeting an equivalent to the presumptive level of 0.15 lb/mmBtu…"[44] Basin Electric knew that a source-specific SO_2 BART determination was unnecessary because of the SO_2 trading program, and therefore Basin Electric only committed to meeting the presumptive BART limit of 0.15 lbs/mmBtu ***if the trading program was not***

[43] UE 246/PAC/1403, Woollums/8 (emphasis added).
[44] Basin Electric February 28, 2007 Letter to WYDEQ (emphasis added). Sierra Club/503, Cross Exhibit/2.

approved by EPA. Unlike PacifiCorp, Basin Electric did not rush out to install unnecessary SO_2 controls.

Even if regional SO_2 emissions eventually trigger the trading program, PacifiCorp will have at least six years to meet any compliance obligations. "For each source that is a [Western Backstop] source on or before the program trigger date, <u>the first control period is the calendar year that is six (6) years following the calendar year for which sulfur dioxide emissions exceeded the milestone</u>…"[45] This compliance period provides plenty of time for PacifiCorp to determine whether the least-cost alternative would involve trading emissions credits, installing emissions controls, or finding an alternative generating source to meet customer needs. Therefore, while Ms. Woollums may be correct that, "[t]he [Section 309 SO_2] SIPs are currently enforceable by the states,"[46] there are no emission limits or control technology requirements to enforce. Sources must monitor and report their SO_2 emissions, but specific sources are not required to reduce their emissions until the program is triggered.

3. <u>NAAQS Did Not Require Naughton to Install SO_2 Scrubbers</u>

As discussed above, the Regional Haze rule did not require any source-specific SO_2 BART determination for Naughton. By May of 2009, WYDEQ had unambiguously explained that "PacifiCorp will not be required to install the company-proposed [SO_2] BART technology."[47] In rebuttal testimony, the Company attempted to rationalize its decision to carry on with installation of the \$279 million SO_2 scrubbers, by citing a concern about exceeding the National Ambient Air Quality Standards ("NAAQS") for SO_2.[48] Ms. Woollums relied on a 2006 email from the

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[45] Wyoming 2011 309 SIP, Appendix B, WYDEQ Chapter 14, Section 2(k)(i)(A)(I) (emphasis added). Sierra Club/504, Cross Exhibit/113.
[46] UE 246/PAC/1400, Woollums/14.
[47] UE 246/Sierra Club/111, Fisher/53.
[48] UE 246/PAC/1400, Woollums/30.

Company's Bill Lawson indicating that there was a "modeling snag" related to SO_2 emissions.[49] According to PacifiCorp, this internal modeling raised a concern that SO_2 emissions could feasibly, under select circumstances, exceed NAAQS, meaning that the plant could be found to be causing non-attainment problems for the region.[50] The concern was apparently resolved in conjunction with the Regional Haze requirement discussions with WYDEQ in 2006, and the Company concluded that installation of an SO_2 scrubber could resolve any potential NAAQS problems.[51]

In 2006, even if the Company believed that the SO_2 scrubbers would conveniently resolve both its Regional Haze compliance requirements and the potential NAAQS problem, that rationale was completely undermined by WYDEQ's 2009 determination that PacifiCorp would not be required to install the SO_2 scrubbers to meet BART. Once PacifiCorp unambiguously knew that the Regional Haze rule would not require it to install SO_2 scrubbers, it should have reconsidered the necessity of installing the very expensive SO_2 scrubbers for purposes of the potential NAAQS problem. As of 2009, the only basis for determining that there was a potential SO_2 NAAQS problem was the 2006 modeling discussed in Exhibit PAC/1904. As evidenced by Sierra Club data request 4.1(f), there was no follow-up correspondence with WYDEQ about this issue:

> **Sierra Club Request 4.1(f):** Please provide copies of all correspondence between PacifiCorp and the Environmental Protection Agency and/or WYDEQ regarding any SO_2 modeling analyses conducted from 2005 to the present that indicated that any Naughton unit may be causing exceedances of the 3-hr and/or 24-hr SO_2 NAAQS.
>
> **PacifiCorp Response**: PacifiCorp does not have any correspondence with the Environmental Protection Agency and/or

[49] UE 246/PAC/1904, Wollums/1.
[50] UE 246/PAC/1900, Woollums/7.
[51] UE 246/PAC/1900, Woollums/7.

> WYDEQ regarding the Naughton SO_2 modeling. The modeling issue was discussed verbally with the WYDEQ in a meeting in 2006. Because PacifiCorp was addressing the modeling issue in conjunction with the WYDEQ regional haze requirements, no further documentation or correspondence was necessary or required by the WYDEQ.[52]

Following WYDEQ's 2009 determination that SO_2 scrubbers were not required to comply with Regional Haze, there was no longer any reason to assume that SO_2 scrubbers, "would have been required notwithstanding any regional haze implications."[53] The Company provided no evidence whatsoever that the $279 million SO_2 scrubbers would be the best control alternative to address any potential NAAQS problem. In fact, there was no confirmed basis for assuming that PacifiCorp even had a NAAQS problem that would require the installation of pollution controls. As Ms. Woollums herself stated in her surrebuttal testimony, several additional steps would have occurred prior to making any determination of a NAAQS violation based solely off of the 2006 "modeling snag" identified in Exhibit PAC/1904. Ms. Woollums denied Sierra Club's assertion that PacifiCorp "knowingly violated" the SO_2 NAAQS for six years, stating that "[a]ir quality modeling data is predictive and, when the model predicts an exceedance, additional (and perhaps more refined) modeling is typically conducted, and ambient air quality monitoring data may be utilized to confirm or refute the modeled results."[54] Thus, as Woolems makes clear in her surrebuttal testimony, the "modeling snag" did not mean that there was an imminent SO_2 reduction requirement for Naughton.

Rather than conducting additional and more refined modeling or analyzing ambient air quality monitoring data to confirm or refute any potential NAAQS problem, PacifiCorp simply carried on with its plan to install the $279 million SO_2 scrubbers, irrespective of whether new

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[52] Sierra Club Data Request 4.1. Sierra Club/506, Cross Exhibit/3.
[53] UE 246/PAC/1400, Woollums/30.
[54] UE 246/PAC/1900, Woollums/8.

SO_2 scrubbers were required to address the modeled SO_2 NAAQS violations or whether other, less costly, options could be utilized to ensure the facility did not cause SO_2 NAAQS issues. In fact, the Company did not even keep the original modeling that it had done in 2006 that purportedly indicated there may be a problem.[55] The Company wasted ratepayer money by moving forward with a risky and expensive capital expense project even after it knew that there was no sound regulatory requirement that necessitated the SO_2 scrubbers.

4. Wyoming Permit Conditions did not Require the SO_2 Scrubbers

As discussed above, there was no statutory or regulatory basis for the SO_2 scrubbers based on the Regional Haze Rule, the Regional SO_2 Backstop Trading Program, or any SO_2 NAAQS requirements at Naughton. There also were no unit-specific permit requirements that compelled PacifiCorp to install the SO_2 scrubbers. PacifiCorp cited two permits applicable to the Naughton units: MD-6042 (BART Permit) and MD-5156 (construction permit).[56] Neither of these permits contained any explicit requirements that would have compelled PacifiCorp to install SO_2 scrubbers at Naughton.

The Naughton BART permit, MD-6042 (December 2009), did not require any installation of SO_2 scrubbers. Ms. Woollums described the MD-6042 BART permit in her rebuttal testimony as part of the process undertaken by WYDEQ to meet its Regional Haze rule obligations.[57] Ms. Woollums later stated in her surrebuttal testimony that, “if a state implements and enforces a legal obligation, it is a legal obligation regardless of whether it is federally enforceable.”[58] Ms. Woollums fails to explain, however, that Wyoming permit MD-6042 did not seek to implement or enforce any legal obligations with respect to SO_2. To the contrary, as discussed above,

[55] Sierra Club Data Request 4.1. Sierra Club/506, Cross Exhibit/3.
[56] UE 246/PAC/500, Teply/31-32, 41-42.
[57] UE 246/PAC/1400, Woollums/9.
[58] UE 246/PAC/1900, Woollums/4.

WYDEQ expressly stated in its BART analysis for the BART permit MD-6042 that, "PacifiCorp will not be required to install the company-proposed [SO_2] BART technology..."[59] There was no legally enforceable requirement for SO_2 in MD-6042.

The Naughton construction permit, MD-5156 (May 2009), also did not require PacifiCorp to install SO_2 scrubbers. The construction permit was responsive to a voluntarily-submitted *request* by PacifiCorp to install certain environmental pollution controls.[60] The permit, once it issued, gave PacifiCorp permission to install the SO_2 scrubbers, along with other controls. Once the permitted construction projects (i.e. the SO_2 scrubbers) were installed, PacifiCorp had to meet a performance limit of 0.15 lbs/mmBtu, but the permit expressly stated that the emissions limit was, "effective upon installation or upgrade of the control equipment."[61] The emission limit was a condition of moving forward with the proposed controls; the construction permit MD-5156 did not by itself require PacifiCorp to install the controls. There was no binding legal obligation in the permit to actually go through with the construction of the SO_2 scrubber. MD-5156 therefore did not create a legal obligation to install the SO_2 scrubbers; it was a construction permit that PacifiCorp voluntarily requested and that WYDEQ granted.

B. Wyoming Set Compliance Deadlines for Low-NO_x Burners at PacifiCorp's Request

PacifiCorp's application included approximately $17.5 million in capital expenditures for the low-NO_x burners at Naughton Units 1 & 2.[62] This amount is substantially less than the $279 million PacifiCorp included in rate base to control SO_2 emissions, but it is not a trivial expense. PacifiCorp rushed its implementation of these NO_x BART controls and requested premature compliance deadlines to solidify the Company's plan to install the controls. Had the Company

[59] UE 246/Sierra Club/111, Fisher/53.
[60] UE 246/Sierra Club/105, Fisher/11.
[61] Id. p. 11.
[62] UE 246/Sierra Club/100, Fisher/4.

waited for the regulatory process to work its course, it would have realized that the low-NO_x burners and other proposed pollution controls at Naughton were not the least-cost alternative for ratepayers.

Sierra Club acknowledges that for the low-NO_x burners at Naughton, unlike the SO_2 scrubbers, PacifiCorp can at least point to the existence of specific permit language in MD-6042 that required the Company to install the low-NO_x burners at Unit 1 by December 31, 2012 and at Unit 2 by June 1, 2012.[63] However, this compliance schedule came at the request of PacifiCorp. In analyzing the Naughton BART permit application in May 2009, WYDEQ noted that, "[a]s a practical measure, the Division anticipates the requirement to install the BART-determined controls to occur as early as 2015."[64] WYDEQ based its assessment on the federal rule that requires compliance within five years: "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."[65] PacifiCorp therefore would have had a reasonable basis to request a compliance date that would have allowed the Company to wait to install the low-NO_x burners until five years after EPA approved Wyoming's SIP. However, PacifiCorp requested, or at least acquiesced, to a 2012 compliance deadline for the installation of low-NO_x burners because the timing fit within the Company's internal planning assumptions.

Wyoming regulations did not provide PacifiCorp with any requirement to deviate from the Regional Haze rule's five-year compliance window. On December 5, 2006, Wyoming finalized rules addressing the process for implementing the BART requirements of 40 CFR Part 51, Appendix Y.[66] The Wyoming regulations implementing the BART process expressly stated,

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[63] MD-6042. Sierra Club/507. Cross Exhibit/2. *See also*, UE 246/PAC/2002, Teply/253.
[64] UE 246/Sierra Club/111, Fisher/54 (emphasis added).
[65] Id. p. 54.
[66] UE 246/PAC/1903, Woollums/2.

"Any control equipment required under a permit issued in this section shall be installed and operated as expeditiously as practicable but in no event later than five years after the United States Environmental Protection Agency's approval of Wyoming's State Implementation Plan revision for Regional Haze."[67] The rule also required sources to submit a BART permit application that included a compliance schedule, but it gave no direction to sources about the specific timing of compliance.

On January 25, 2007, PacifiCorp submitted its construction permit application for the installation of the low-NO_x burners, along with other controls, which was ultimately approved as permit MD-5156.[68] ***The Company submitted this application before any state or federal BART determination and before any deadline existed for complying with the Regional Haze rule.*** In a subsequent filing on March 7, 2008 for this same construction permit, PacifiCorp submitted a project schedule that proposed installation of low-NO_x burners at Naughton 2 between September 17-November 12, 2011 and at Naughton 1 between March 24-May 19, 2012.[69] PacifiCorp submitted this Naughton project schedule before the Company's least-cost analysis was performed, and it was submitted to Wyoming before any NO_x BART determination or NO_x BART compliance deadline existed.[70]

There was no basis, other than the Company's internal planning, for the project schedule included in the permit application. Internal Company documents show that the Company was fully aware in 2007-2008 that there was no deadline to install its proposed low-NO_x burners as "BART equipment."[71] Other internal Company documents show that the proposed installation dates were part of a concerted plan to get out ahead of pending regulations without formal

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[67] Id. p. 10 (emphasis added).
[68] UE 246/Sierra Club/105.
[69] Sierra Club/508, Cross Exhibit/2.
[70] UE 246/Sierra Club/100, Fisher/31.
[71] Id. p. 22.

requirements and to provide a sound basis for future capital expenditures at PacifiCorp's coal plants.[72]

V. Hunter Capital Expenses were Not Required By Regulations

PacifiCorp's Hunter coal plant is located in Utah and therefore is subject to Utah's SIP. Similar to the controls discussed above for the Naughton plant in Wyoming, PacifiCorp requested the inclusion in rate base of SO_2 scrubber upgrades at Hunter Units 1 & 2 and additional associated capital projects.[73]

A. Utah Permits and State Regulations did not Require the SO_2 Scrubber Upgrades

PacifiCorp had no statutory or regulatory obligation to upgrade the SO_2 scrubbers at Hunter Units 1 & 2. Combined, the SO_2 scrubber upgrade projects wasted approximately $77 million in capital spending.[74] Mr. Teply stated in his direct testimony that the Hunter 1 and 2 SO_2 scrubber upgrades were necessary to comply with the Regional SO_2 Milestone and Backstop Trading program.[75] However, the trading program in Utah did not require any source-specific limits or pollution controls. As discussed above with respect to the Wyoming program, the regional trading program was based on region-wide performance milestones for SO_2 reductions. Prior to triggering the trading program, which has not yet happened, the §309 program does not require sources to take any action other than monitoring and reporting their emissions. The Utah Regional Haze SIP clearly states that source-specific compliance does not require pre-trigger modifications or emissions limits:

> The long-term strategy for stationary sources is implemented through the following documents: … R307-250, Western Backstop Sulfur Dioxide Trading Program, contains the requirements that <u>will apply</u> to major industrial sources of sulfur dioxide as a

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[72] Id. pp. 23-25.
[73] UE 246/Sierra Club/100, Fisher/4.
[74] Id. p. 4.
[75] UE 246/PAC/500, Teply/64.

> backstop regulatory program <u>if the SO_2 milestones are exceeded. The rule may never be implemented</u> if the goal to meet the regional SO_2 milestones through voluntary means is achieved…[76]

Utah's Regional Haze SIP and the Regional Backstop Trading Program did not require Hunter or any other sources to meet a specific SO_2 emissions limit or to install a specific SO_2 control technology. PacifiCorp's decision to upgrade its SO_2 scrubbers at Hunter was voluntary.

Mr. Teply references Section XX D6 Table 5 of the Utah SIP to support PacifiCorp's contention that the SO_2 scrubber upgrades were required by state law.[77] However, the table that Mr. Teply cites does not show that Hunter was required to meet any specific emission rate for SO_2.[78] Rather, the table simply reflects the ***existing permitted*** emission rates at the Hunter plant. The actual Utah permit, DAQE-AN0102370012-08 is a construction permit.[79] The permit represents the granting of a construction request ***initiated by PacifiCorp*** for the installation of the SO_2 scrubbers. The permit does not contain any explicit requirement for PacifiCorp to install the SO_2 upgrades, and the relevant SO_2 emissions limit of 0.12 lbs/mmBtu was, "Effective upon installation or upgrade of the control equipment."[80] In other words, there was no specific requirement in the permit to move forward with the proposed upgrade of the SO_2 scrubbers, nor was there an independent deadline that required PacifiCorp to meet the 0.12 lbs/mmBtu SO_2 emissions limit by any particular date if PacifiCorp had decided to forego the project.

The SO_2 scrubber upgrade projects at Hunter Units 1 & 2 are another example of PacifiCorp jumping the gun on SO_2 controls in its fleet. The Regional SO_2 Backstop Trading Program did not require unit-specific performance, and the Utah permit that granted PacifiCorp permission to move forward with its proposed SO_2 upgrade projects did not contain any specific deadlines or

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[76] Utah Regional Haze SIP, Section XX, D3. Sierra Club/509, Cross Exhibit/16-17 (emphasis added).
[77] UE 246/PAC/500, Teply/64.
[78] Utah Regional Haze SIP, Section XX, D6, Table 5. Sierra Club/509, Cross Exhibit/16.
[79] UE 246/PAC/2003, Teply/56.
[80] UE 246/PAC/2003, Teply/64.

control technology mandates. The fact that Utah's SIP reflected the emission rates and control technologies that Hunter had previously requested permission to install did not create a regulatory requirement to install those controls. The choice to spend capital dollars on these projects was PacifiCorp's.

VI. PacifiCorp Repeatedly Demonstrated a Practice of Requesting Authorization to Install Pollution Controls that were Not Required and not Cost Effective

PacifiCorp owns several coal plants in Wyoming that were subject to the Regional Haze rule and Wyoming's § 309 Regional Milestone and Backstop Trading Program. Sierra Club's expert testimony and this brief addressed in detail the retrofit projects installed at Naughton and Hunter. Sierra Club focused on those plants because from early on it was clear that the economics of those proposed retrofits were a very bad deal for ratepayers. As Sierra Club continued to investigate the permitting requirements at Naughton and Hunter, it became clear that PacifiCorp's pattern of over-spending on retrofit projects at coal plants was evident at other facilities as well. While Sierra Club's pre-filed testimony did not directly raise a prudency challenge to projects at those other facilities, the retrofits at Wyodak and Dave Johnston provide further evidence that PacifiCorp was engaged in a concerted, fleet-wide effort to increase its rate base by over-spending on capital projects.

A. Wyoming Permits and State Regulations did not Require a Full-scale Fabric Filter Baghouse to Control Particulate Matter or SO_2 at Wyodak

PacifiCorp's Wyodak is a single unit, 335 MW coal-fired plant located in Wyoming and is subject to that state's SIP. Similar to the emission control technology discussed above for Naughton and Hunter, PacifiCorp spent approximately $103 million to retrofit the Wyodak plant with a full-scale fabric filter baghouse designed to control PM.[81] Particulate matter (PM), like

[81] UE 246/PAC/500 Teply/71 line 14.

NO_x and SO_2 is a haze forming pollutant regulated under EPA's Regional Haze program. Under the Regional Haze Program, PM, like NOx is regulated on a plant-specific basis, rather than under the SO_2Milestone and Backstop Trading Program.

In February 2007, PacifiCorp submitted several iterations of a BART application to WYDEQ proposing retrofits for all three haze-forming pollutants, SO_2, NO_x and PM. For NO_x, the Company employed EPA's Appendix Y five-factor analysis for BART determinations and proposed LNB/OFA. Sierra Club does not dispute the LNB retrofit.

The company also utilized EPA's five-factor analysis to evaluate three technologies to control PM.[82] The Wyodak plant was already equipped with an electrostatic precipitator ("ESP") to control PM, but the Company analyzed (1) a new full-scale fabric filter baghouse; (2) installing a polishing fabric filter on its existing ESP; and, (3) flue gas conditioning ("FGC").[83] In its own BART analysis, the Company eliminated installing a new full-scale fabric filter baghouse as "cost-prohibitive," especially as compared to installing a polishing fabric filter on the existing ESP.[84] However, when WYDEQ independently analyzed this PM control, it concluded that "[t]he cost effectiveness and incremental cost effectiveness of applying a new polishing fabric filter to Unit 1 are not reasonable."[85] In other words, neither the full-scale fabric filter baghouse nor the less expensive polishing fabric filter were cost effective.

WYDEQ rejected any type of fabric filter retrofits on grounds that the technology offered very little benefit: "visibility modeling described in the Division's BART analysis for the Jim Bridger plant [another PacifiCorp plant] showed that the addition of a fabric filter to replace an

[82] BART Application Analysis AP-6043. Sierra Club/501, Cross Exhibit/11-14.
[83] Id. pp. 11-12.
[84] Id. pp. 12, 18.
[85] Id. p. 14.

Electrostatic Precipitator (ESP) provided very little in the way of visibility improvement."[86] Moreover, WYDEQ found that, "the existing ESP 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."[87] According to WYDEQ, the existing technology was working just fine to control PM; fabric filter technology added very little benefit, especially in light of its expense.

Nevertheless, despite both the Company and WYDEQ determining that additional control technology was either not necessary or prohibitively expensive to meet PM BART limits, the Company reversed course and included PM retrofits in its BART permit application, proposing a full-scale fabric filter baghouse to meet PM and SO_2 limits. The Company's proposal was the most expensive option by far. Based on the Company's clear resolve to upgrade the plant, WYDEQ included the $67 million full-scale fabric filter baghouse as BART for both PM and SO_2, finding that: "While the Division considers the cost of compliance for a full-scale fabric filter on Unit 1 not reasonable, PacifiCorp is committed to installing this control device…"[88] As shown above, the retrofit was not required to meet PM BART.

This expensive retrofit was also not necessary to control SO_2. WYDEQ expressly notified the Company of the state's participation in the SO2 Milestone Program: "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 WASQSR."[89] PacifiCorp elected to spend millions of ratepayer funds on an unnecessary retrofit absent any state or federal regulatory requirement.

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[86] UE 246/PAC/2006 Teply/145.
[87] Id.
[88] BART Application Analysis AP-6043. Sierra Club/501, Cross Exhibit/11-14.
[89] Id. at p. 38.

B. Wyoming Permits and State Regulations did not Require Full-scale Fabric Filter Baghouses and SO_2 Scrubbers to Control SO_2 at Dave Johnston Units 3 and 4

PacifiCorp's Dave Johnston plant is a 772 MW, 4-unit coal-fired plant located in Wyoming, and subject to that state's SIP. At Dave Johnston units 3 and 4, PacifiCorp committed to installing dry SO_2 scrubbers and full-scale fabric filter baghouses for both units to control SO_2. Remarkably, PacifiCorp notified WYDEQ that the Company had already commenced these BART projects before it had even finalized its regional haze analyses.[90] Similar to the emission control technology discussed above for Wyodak, Naughton and Hunter, here PacifiCorp spent hundreds of millions of dollars to retrofit Dave Johnston units 3 and 4 with full-scale fabric filter baghouses and SO_2 scrubbers without any regulatory requirement to do so to control SO_2. In this proceeding, PacifiCorp is requesting to include in rate base over $104 million for the unit 4 controls.[91]

The Company utilized EPA's five-factor analysis to evaluate retrofit technologies to control all three haze forming pollutants at Dave Johnston units 3 and 4.[92] In its independent analysis, WYDEQ determined that the Company's proposed retrofits to control haze forming particulate matter ("PM") were unreasonable. "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 4 in Air Quality Permit MD-5098."[93]

Because WYDEQ determined new baghouses at units 3 and 4 were not cost effective to control PM, the Company simply changed its rationale for selecting this technology and proposed the most expensive full-scale fabric filter baghouses *along with* SO_2 Scubbers to meet

[90] Sierra Club/500, Cross Exhibit/4.
[91] UE 246/PAC/1102, Dalley/8.6.5.
[92] Sierra Club/500, Cross Exhibit/47-50.
[93] Id. at 48.

SO_2 BART requirements instead. However, as repeatedly pointed out above, PacifiCorp was not required to install *any* retrofit technology to control SO_2 emissions because WYDEQ required it to participate in the Regional SO_2 Milestone and Backstop Trading Program. Therefore, at the time the Company made these significant expenditures to control SO_2 emissions, there was no regulatory requirement to do so.

VII. CONCLUSION

PacifiCorp engaged in a company-wide business plan to use pending environmental regulations as a means to increase PacifiCorp's rate base by investing billions of dollars in its old and polluting coal fleet. The Company conducted flawed least-cost planning analyses to bolster its Coal Fleet Spending Plan and missed or ignored numerous warning signs indicating that the substantial capital expenditures at its coal facilities were either unnecessary or not cost effective. PacifiCorp's capital expenditures of $297 million at the Naughton coal plant and $79 million at

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the Hunter coal plant were not necessary under existing regulations, and even if they had been necessary they were not the least cost options for ratepayers. The Commission should reject PacifiCorp's request to include those expenses in its rate base.

Dated: October 4, 2012

Respectfully submitted,

___*/s/__Gloria Smith*__________________

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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
MAILING ADDRESS:	1591 Tank Farm Road Glenrock, WY 82637
TELEPHONE NUMBER:	(307) 436-2001
REVIEWERS:	Cole Anderson, Air Quality Engineer Josh Nall, Air Quality Modeler

PURPOSE OF APPLICATION:

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

Section 308 of the Regional Haze Rule (40 CFR 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

[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.

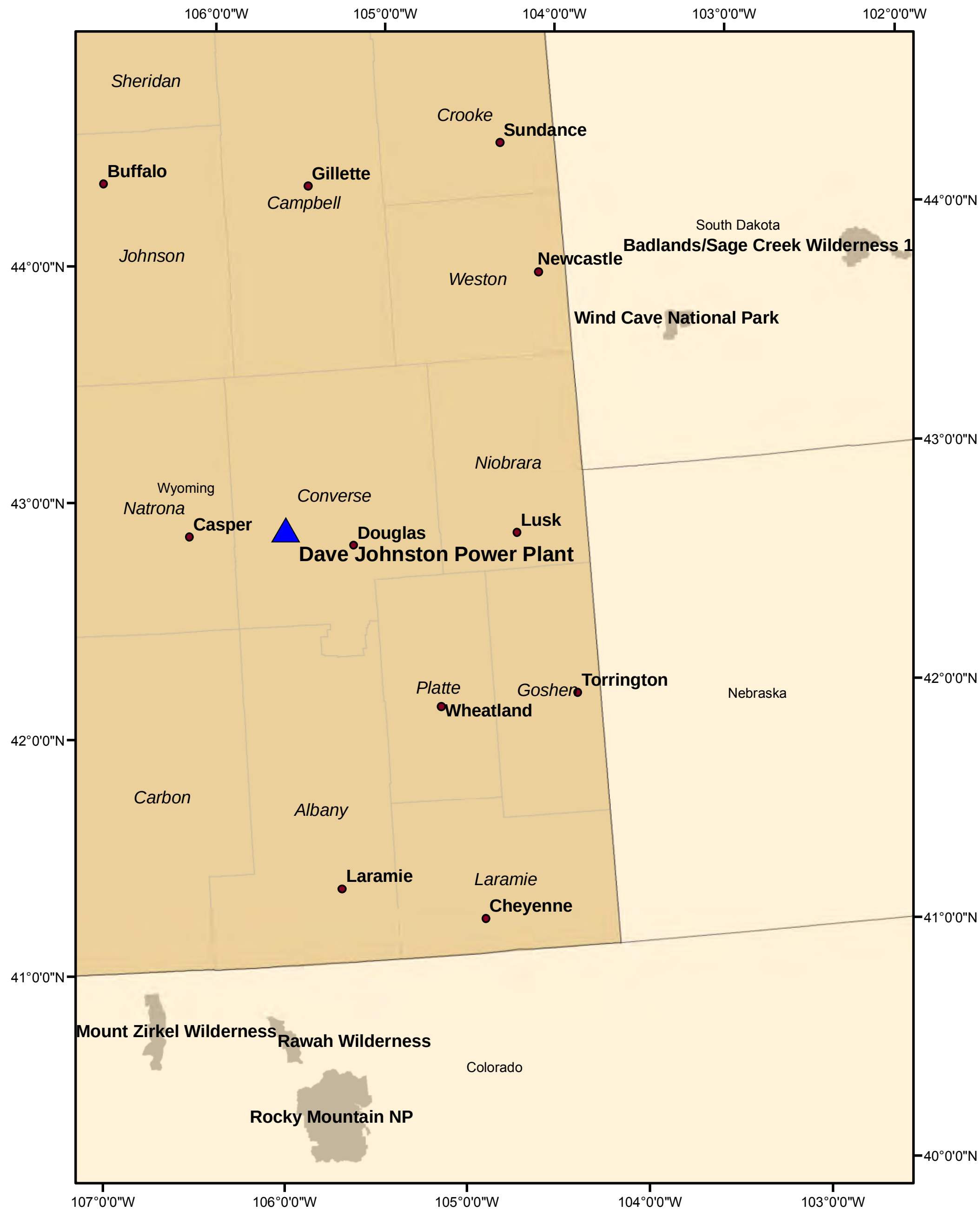
Wind Cave and Badlands National Parks (NP) in South Dakota are Class I areas located to the northeast of the plant at a distance of approximately 200 kilometers (km) and 290 km, respectively. Toward the south in Colorado, Rawah Wilderness Area (WA) and Mount Zirkel WA are both located approximately 220 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 98th 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 98th percentile impact equal to or greater than 0.5 Δdv from a given source indicates that the source contributes to visibility impairment, and therefore is subject to BART. The results of the screening modeling are shown in the table below.

Table 20: Results of the Class I Area Screening Modeling

Class I Area	Maximum Modeled Value (Δdv)	98th 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

Meteorological Data Processing (CALMET)

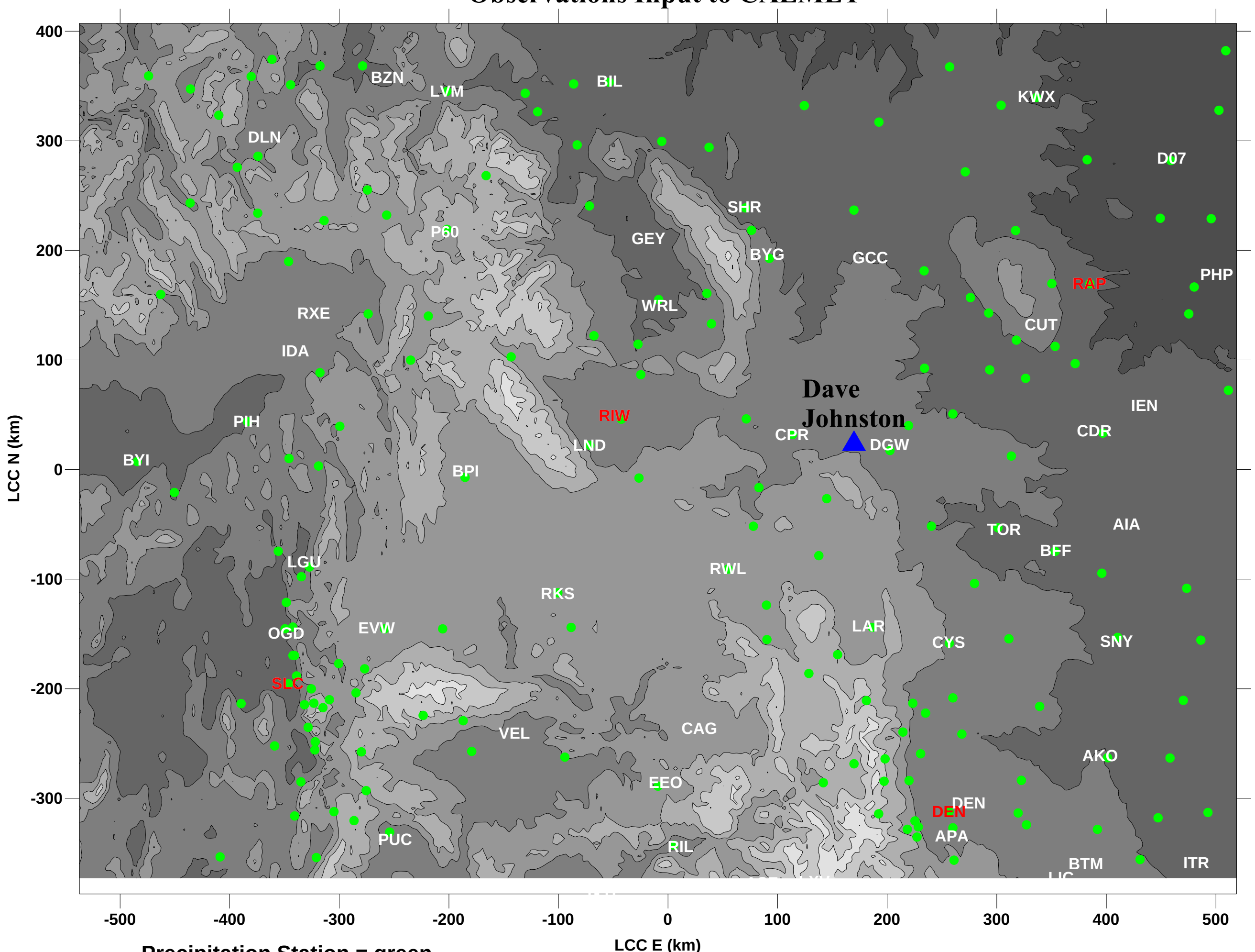
As required by the Division‟s modeling protocol, the CALMET model was used to construct an initial three-dimensional windfield using data from the MM5 model. Surface and upper-air observations were input to CALMET to adjust the initial windfield, but because of the relative scarcity of wind observations 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

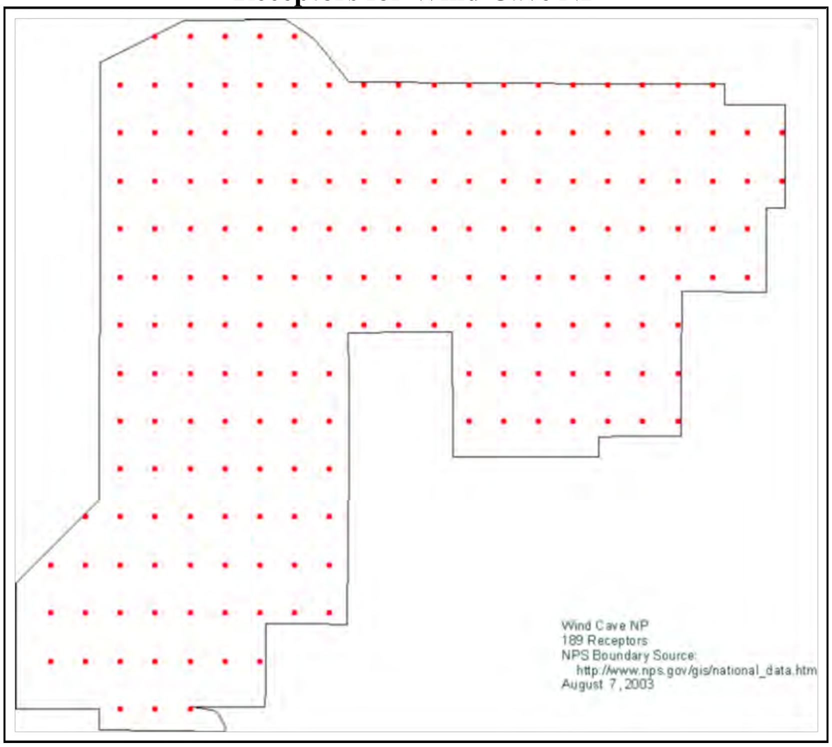


Figure 4
Receptors for Badlands NP

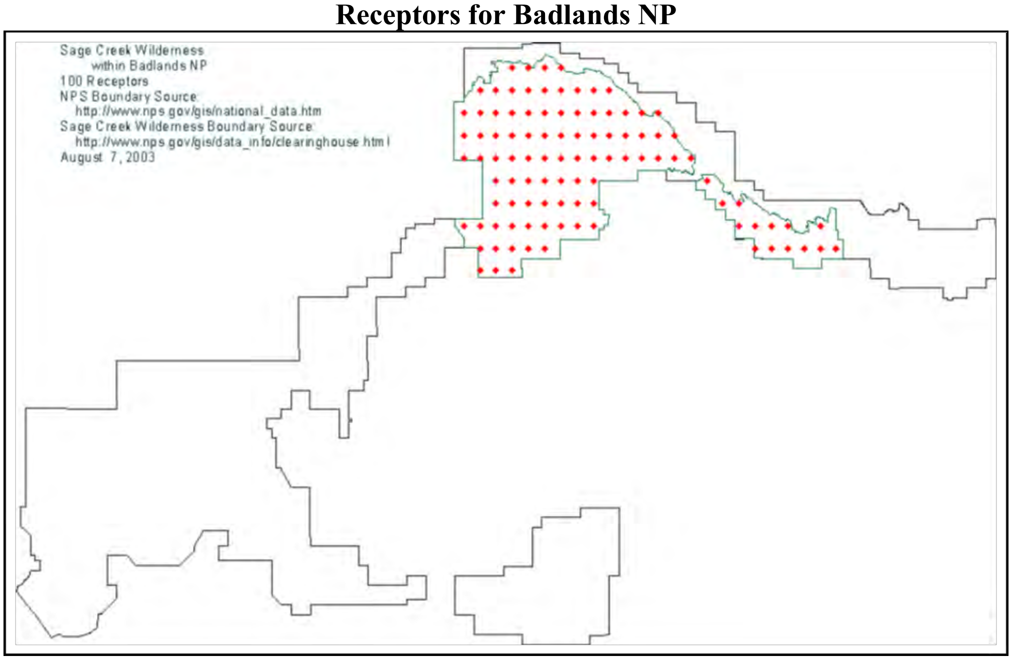


Figure 5
Receptors for Rawah WA

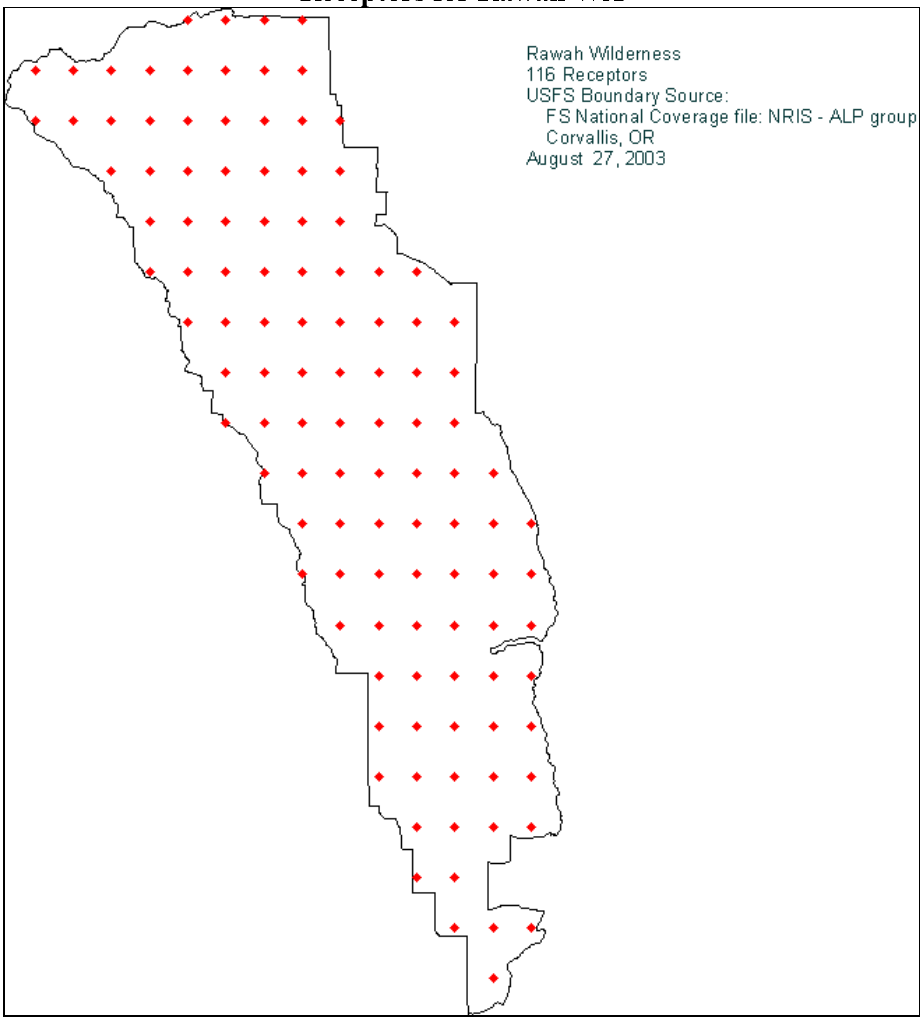
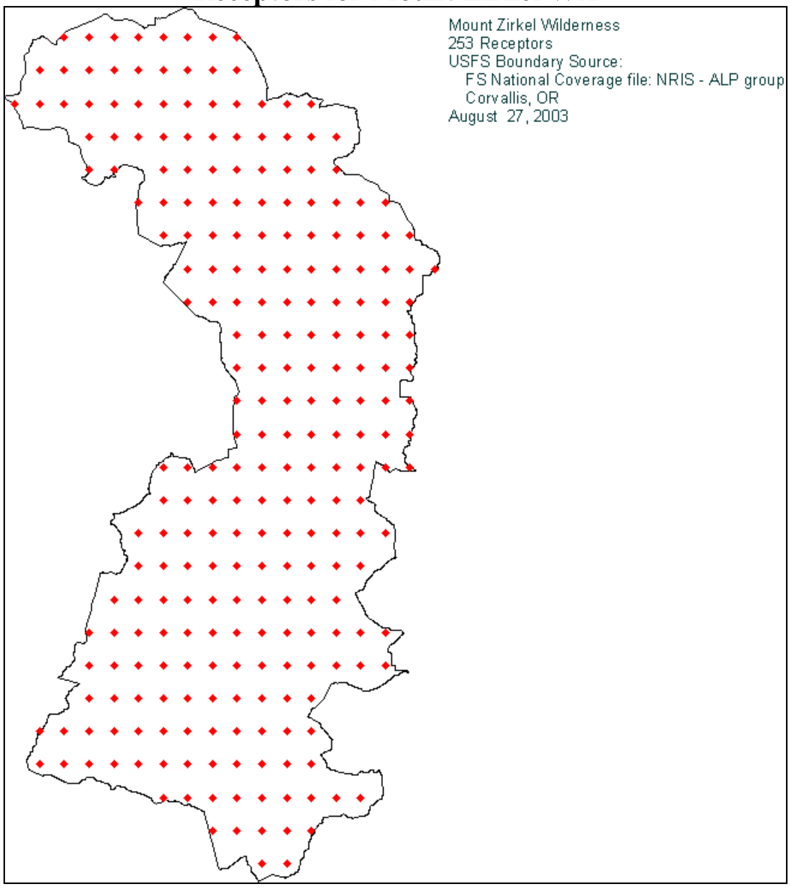


Figure 6
Receptors for Mount Zirkel WA



<u>CALPUFF Inputs – Baseline and Control Options</u>

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).

Visibility Post-Processing (CALPOST)

The changes in visibility were modeled using Method 6 within the CALPOST post-processor. Method 6 requires input of monthly relative humidity factors [f(RH)] for each Class I area. Monthly f(RH) factors that were used for 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 98th Percentile Value (Δdv)	2001 No. of Days > 0.5 Δdv	2002 98th Percentile Value (Δdv)	2002 No. of Days > 0.5 Δdv	2003 98th Percentile Value (Δdv)	2003 No. of Days > 0.5 Δdv	3-Year Average 98th Percentile Value (Δdv)	3-Year Average No. of Days > 0.5 Δdv
Baseline – 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)

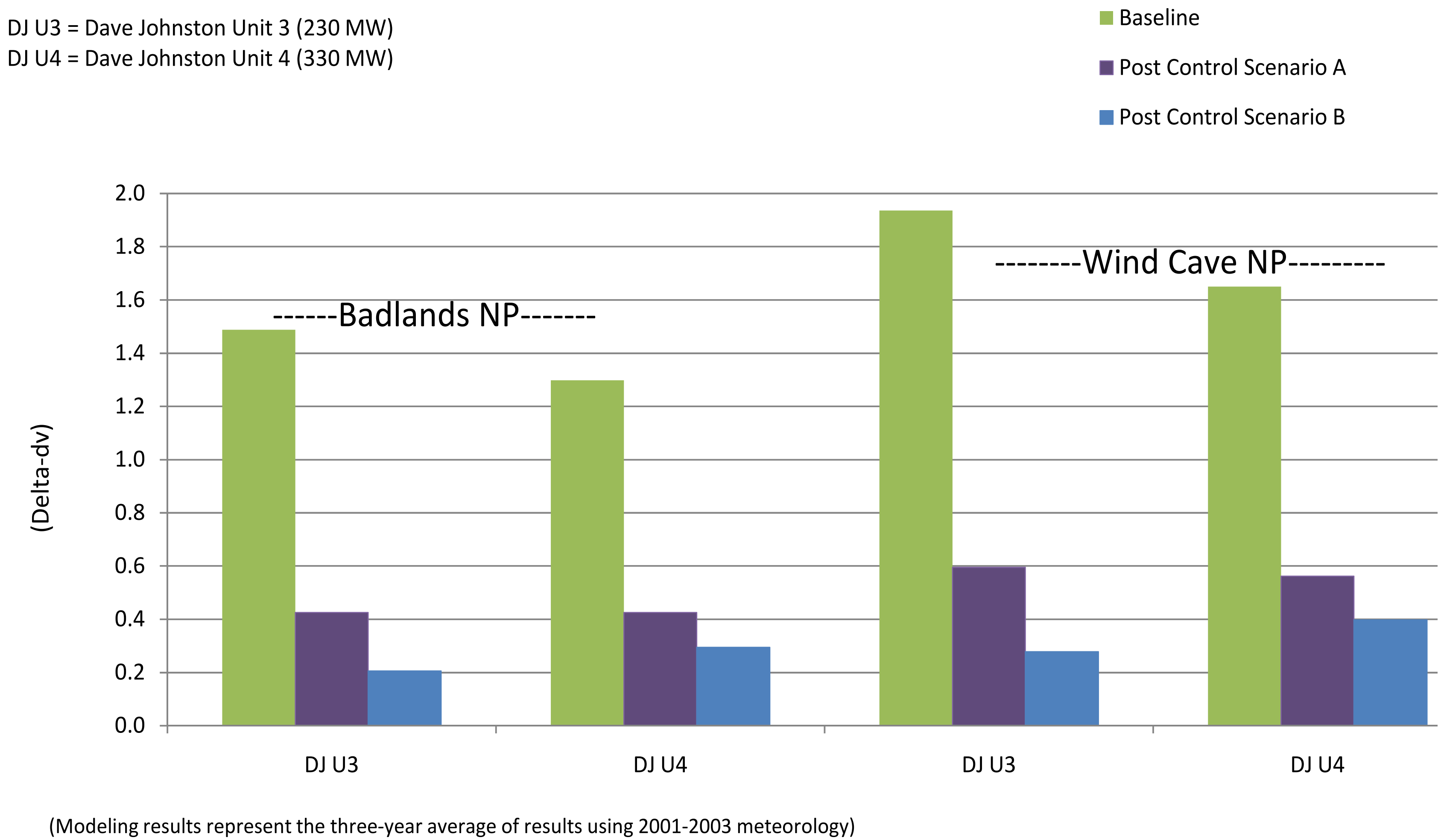


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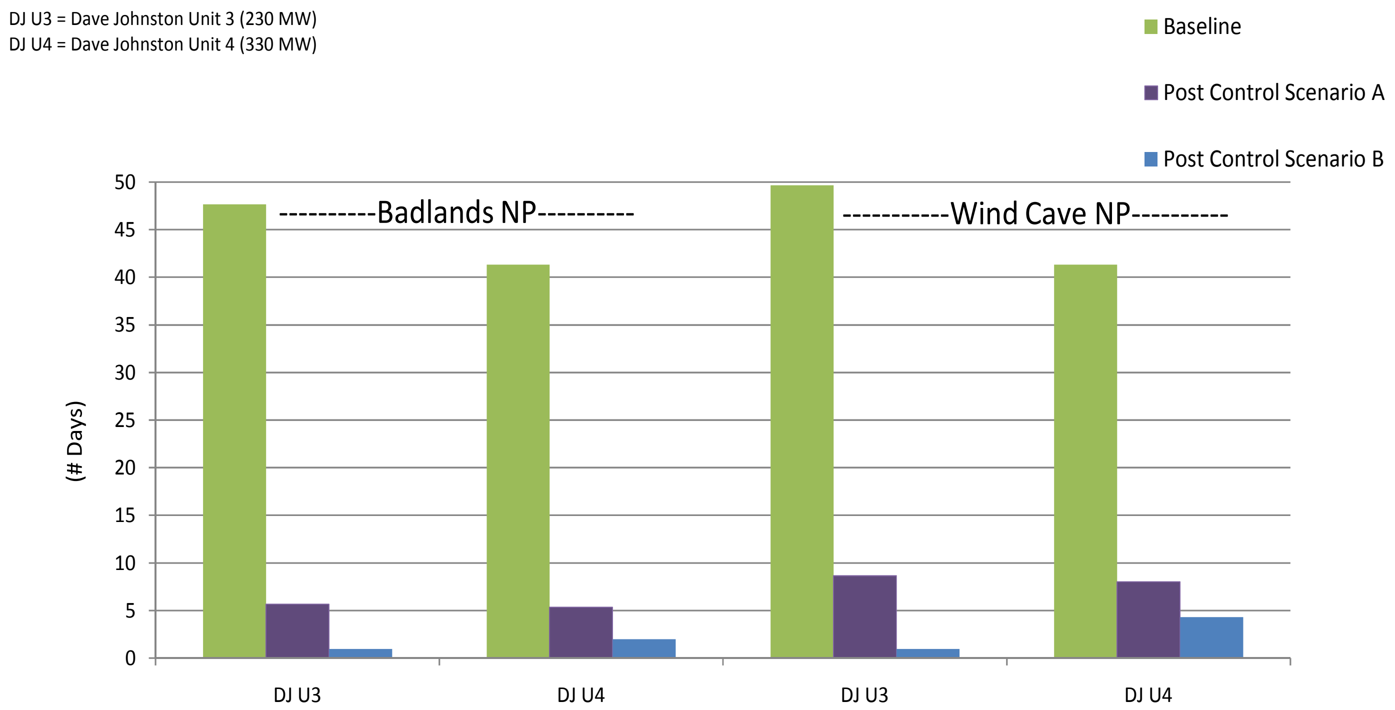
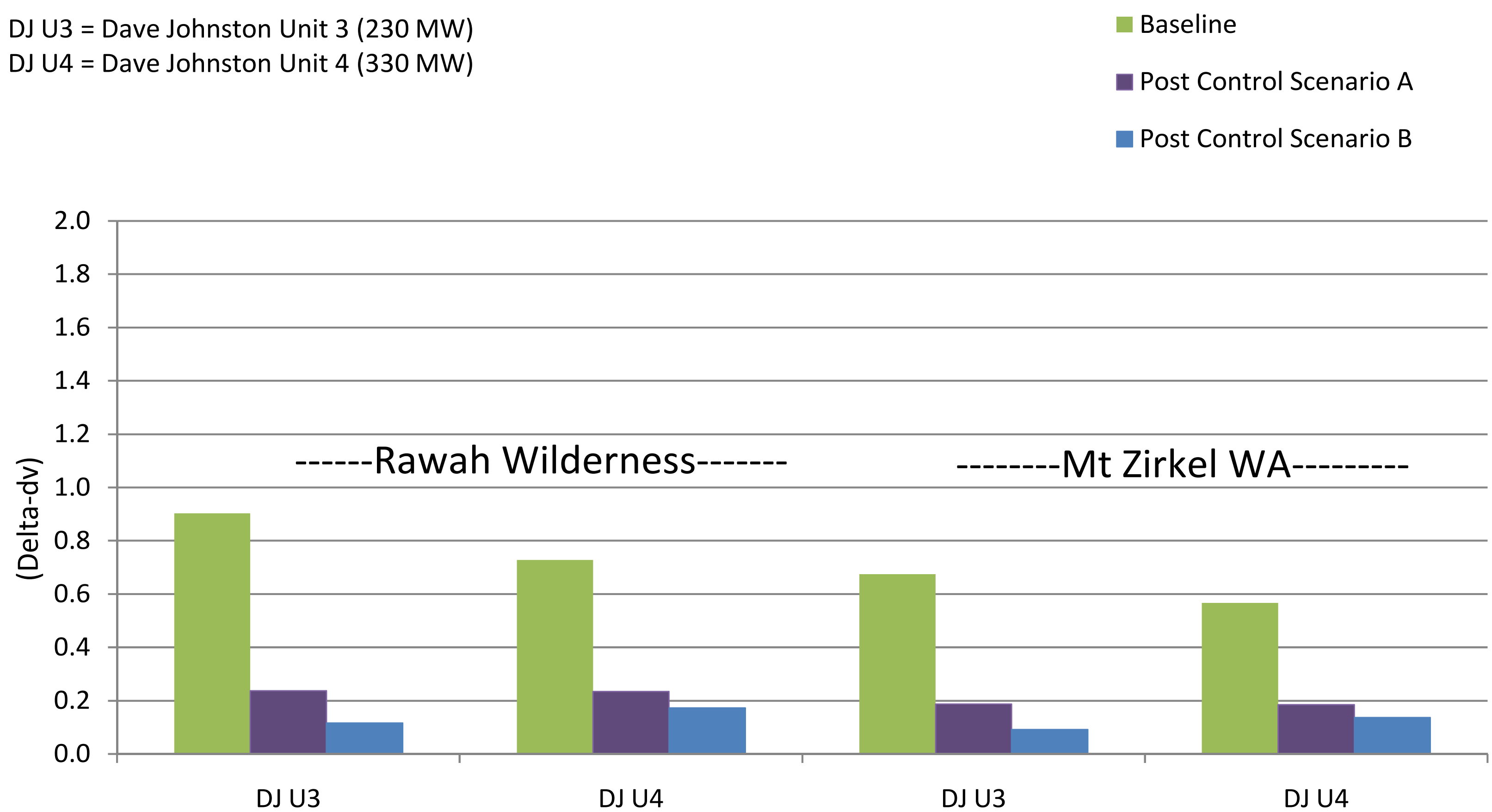
Figure 8
Modeled BART Impacts at South Dakota Class I Areas: Number of Days > 0.5 delta-dv



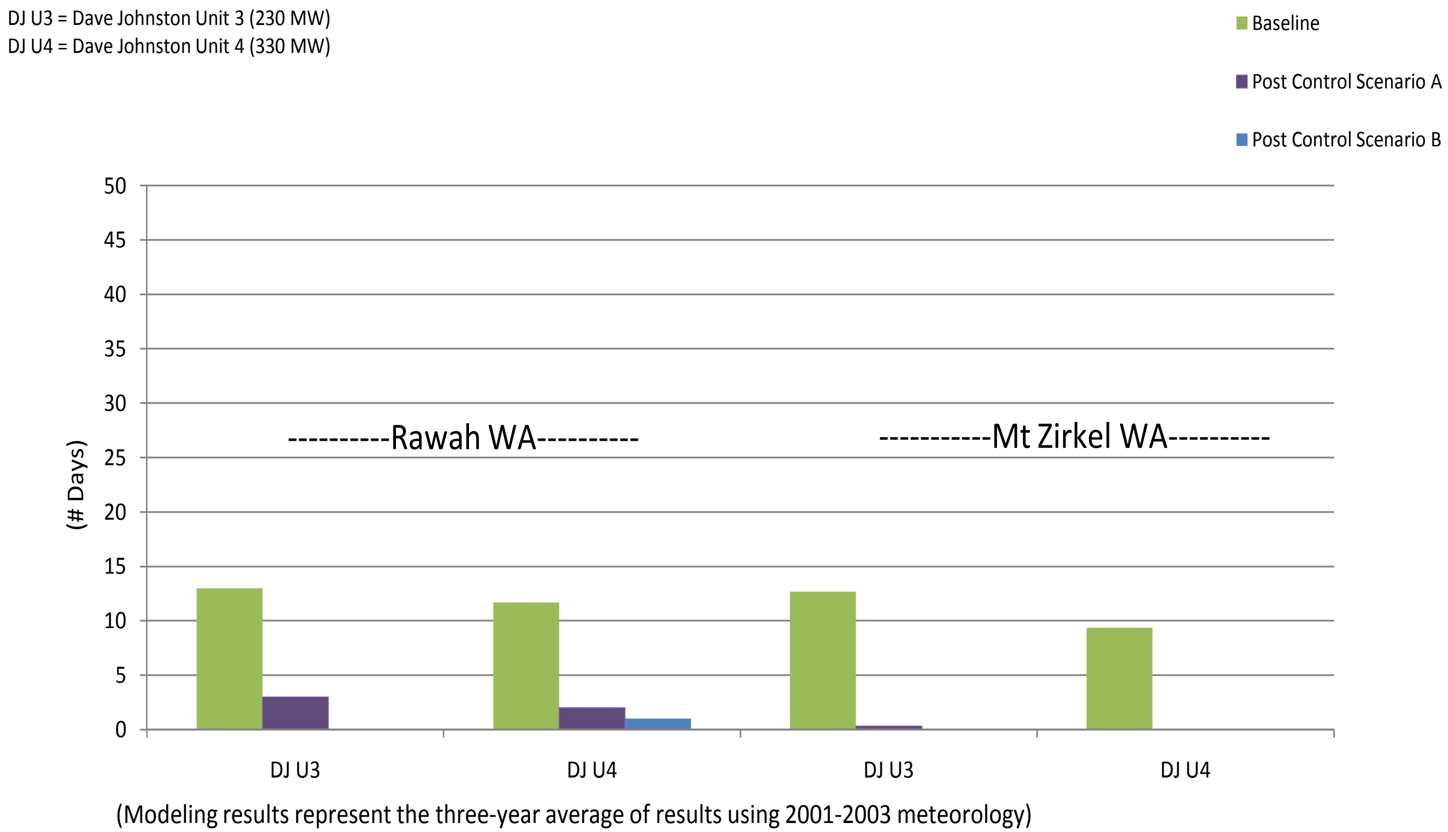
(Modeling results represent the three-year average of results using 2001-2003 meteorology)

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



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:

Dave Johnston Unit 3: 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.

Dave Johnston Unit 4: 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.

PM/PM_{10}

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:

Dave Johnston Unit 3: 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

DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

BART Application Analysis
AP-6043

May 28, 2009

NAME OF FIRM:	PacifiCorp
NAME OF FACILITY:	Wyodak Plant
FACILITY LOCATION:	Section 27, T50N, R71W UTM Zone: 13, NAD 27 Easting: 469,410 m, Northing: 4,903,708 m Campbell County, Wyoming
TYPE OF OPERATION:	Coal-Fired Electric Generating Plant
RESPONSIBLE OFFICIAL:	Gary L. Harris
MAILING ADDRESS:	48 Wyodak Road - Garner Lake Route Gillette, WY 82718
TELEPHONE NUMBER:	(307) 687-4230
REVIEWERS:	Cole Anderson, Air Quality Engineer Josh Nall, Air Quality Modeler

PURPOSE OF APPLICATION:

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

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

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

On February 5, 2007, in accordance with the requirements of WAQSR Chapter 6 Section 9(e)(i), the Division received a BART application for the existing coal-fired boiler at the PacifiCorp Wyodak Power Plant. A map showing Wyodak"s location is attached as Appendix A.

On June 5, 2007, PacifiCorp submitted additional copies of the February application for the existing unit at Wyodak subject to BART.

On October 16, 2007, PacifiCorp submitted an updated application for the single unit subject to BART at Wyodak. Additional modeling performed after the February 5, 2007 submittal and revised visibility control effectiveness calculations were included.

On December 5, 2007, PacifiCorp submitted a revised application incorporating changes to the post-processing of the visibility model runs for Wyodak Unit 1.

On March 31, 2008, PacifiCorp submitted an addendum to the BART application for Wyodak Unit 1. Revised cost estimates and updated visibility modeling for two (2) NO_x control scenarios were included in the addendum.

BART ELIGIBILITY DETERMINATION:

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

The next step for the Division was to identify BART-eligible sources that may emit any air pollutant which may reasonably be anticipated to cause or contribute to impairment of Class I area visibility. Three pollutants are identified by 40 CFR part 51, Appendix Y as visibility impairing pollutants. They are sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM). Particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) was used as an indicator of PM. In order to determine visibility impairment of each source, a screening analysis was performed using CALPUFF. Sources that emitted over 40 tons of SO_2 or NO_x or 15 tons of PM_{10} were included in the screening analysis. Using three years of meteorological data, the screening analysis calculated visibility impacts from sources at nearby Class I areas. Sources whose modeled 98th percentile 24-hour impact or 8th highest modeled impact, by year, was equal to or greater than 0.5 deciviews (dv) above natural background conditions (Δdv) were determined to be subject to BART. For additional information on the Division‟s screening analysis see the Visibility Improvement Determination: Screening Modeling section of this analysis. The single existing coal-fired boiler at PacifiCorp‟s Wyodak Power Plant, Unit 1, was 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 Wyodak Power Plant is comprised of one (1) coal-fired boiler burning pulverized sub-bituminous Powder River Basin coal for a total net generating capacity of a nominal 335 megawatts (MW). Wyodak‟s pulverized coal-fired boiler commenced service in 1978. It was manufactured by Babcock & Wilcox and equipped with wall-fired burners. NO_x emissions from the boiler are currently controlled with first generation low NO_x burners. Particulate matter (PM) emissions from the unit are controlled using a Babcock & Wilcox Rothemuhle weighted wire electrostatic precipitator (ESP). SO_2 emissions from Wyodak Unit 1 are controlled using a Joy Niro, three-tower lime-based spray dryer installed in 1986.

Table 1: Wyodak Unit 1 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)
Unit 1	4,100 [(b)]	LNB, ESP, & dry FGD	0.70 (3-hour fixed) 0.31 (annual) [(c)]	0.5 (3-hour fixed)	0.10

[(a)] Emissions taken from Operating Permit 3-1-101-1.
[(b)] Boiler heat input reported based on historical monthly coal data.
[(c)] Annual emission limit established under 40 CFR part 76.

On April 24, 2007, WAQSR Chapter 6, Section 3 Operating Permit 3-1-101-1, was issued to PacifiCorp for Wyodak Unit 1. NO_x and PM emission limits did not change from the previous Operating Permit 30-101-1. SO_2 emission limit established under the Acid Rain Program (40 CFR 76.11) for the baseline period were 0.31 lb/MMBtu, annual average.

The reported maximum firing rate of the boiler stated in Operating Permit 3-1-101-1 is based on monthly coal data. The maximum firing rate of the boiler, as measured by the existing continuous emission monitoring system (CEM), is 4,700 MMBtu/hr. PacifiCorp based emissions calculations for the BART analysis on the highest firing rate of 4,700 MMBtu/hr.

PacifiCorp recently received an Air Quality permit to modify Wyodak Unit 1. The first generation LNB on Unit 1 will be replaced with Alstom TFS 2000™ LNB with overfire air. The existing ESP will be replaced with a new full-scale fabric filter baghouse. Table 2 lists the new emission limits for Unit 1. They become effective after the corresponding controls are installed and the applicable initial performance tests are completed.

Table 2: New Emission Limits for Wyodak Unit 1 [(a)]

Source	Permitted Controls	NO_x	SO_2	PM/PM_{10} [(b)]
Unit 1	New LNB with advanced OFA, Dry FGD, Fabric Filter Baghouse	0.23 lb/MMBtu (30-day rolling) 1,081.0 lb/hr (30-day rolling)	0.16 lb/MMBtu (30-day rolling) 0.5 lb/MMBtu (3-hr block) 2,115.0 lb/hr (3-hr block)	0.015 lb/MMBtu 71.0 lb/hr 308.8 tpy

[(a)] Emissions limits taken from recent New Source Review construction permit for Wyodak Unit 1.
[(b)] Averaging period is determined by the appropriate test method.

PacifiCorp provided a construction schedule for the installation of the new LNB with advanced OFA and a new full-scale fabric filter baghouse in the permit application. Construction activities for the pollution control upgrades on Unit 1 are anticipated to begin March 5, 2011 during the scheduled outage and end approximately April 16, 2011.

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

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

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

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

[1] 40 CFR Part 51 Appendix Y: Guidelines for BART Determinations under the Regional Haze Rule (70 Federal Register 39163).
[2] Footnote 12 of 40 CFR 51 Appendix Y defines the intended use of „all" by stating "…you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies."

The Division acknowledges that BART is intended to identify retrofit technology for existing sources and is not the same as a top down analysis required for new sources under the Prevention of Significant Deterioration (PSD) rules known as Best Available Control Technology (BACT). Although BART is not the same as BACT, it is possible that BART may be equivalent to BACT on a case-by-case basis. The Division applied all five steps to each visibility impairing pollutant emitted from Wyodak Unit 1 thereby conducting a comprehensive BART analysis for NO_x, SO_2 and PM/PM_{10}.

PRESUMPTIVE LIMITS FOR SO_2 AND NO_X FROM UTILITY BOILERS

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

EPA"s presumptive BART SO_2 limits analysis considered coal-fired units with existing SO_2 controls and units without existing control. Four key elements of the analysis were: "…(1) identification of all potentially BART-eligible EGUs [electric generating units], and (2) technical analyses and industry research to determine applicable and appropriate SO_2 control options, (3) economic analysis to determine cost effectiveness for each potentially BART-eligible EGU, and (4) evaluation of historical emissions and forecast emission reduction for each potentially BART-eligible EGU."[3] 491 BART-eligible coal-fired units were identified and included in the presumptive BART analysis for SO_2. Based on removal efficiencies of 90% for spray dry lime dry flue gas desulfurization systems and 95% for limestone forced oxidation wet flue gas desulfurization systems, EPA calculated projected SO_2 emission reductions and cost effectiveness for each unit. Based on the results of this analysis, EPA concluded that the majority of identified BART-eligible units greater than 200 MW without existing SO_2 control can meet the presumptive limits at a cost of $400 to $2,000 per ton of SO_2 removed.

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

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

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 Wyodak Power Plant generates nominal 335 MW from the single unit. A three-tower lime-based spray dryer currently controls SO_2 emissions. The unit does not have NO_x post-combustion controls. Presumptive SO_2 limit of 95% reduction or 0.15 lb/MMBtu and presumptive NO_x limit of 0.23 lb/MMBtu, based on unit type and coal type, do not apply to Unit 1 since the cumulative generating capacity of the facility is less than 750 MW. Before making a BART determination for Unit 1, the Division analyzed potential retrofit controls for NO_x, SO_2, and PM/PM_{10}, taking into consideration all five statutory factors. The analysis is presented below.

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 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.

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

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 Wyodak unit and to collect data from boiler vendors. Based on results from the study, PacifiCorp indicates that new LNB with advanced OFA on Wyodak Unit 1 would result in a NO_x emission rate of 0.23 lb/MMBtu. On page 3-4 of the December 2007 submittal PacifiCorp states: "PacifiCorp has indicated that this rate [0.23 lb/MMBtu] corresponds to a vendor guarantee plus an added operating margin, not a vendor prediction, and they believe that this emission rate can be sustained as an average between overhauls."

PacifiCorp worked with Mobotec to conduct an analysis of retrofitting the existing boiler at the Wyodak 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 0.18 lb/MMBtu was achievable on Unit 1 using ROFA technology. PacifiCorp added an additional operating margin of 0.02 lb/MMBtu to Unit 1 to account for site specific issues, such as feed coal variance, for total proposed emission rate of 0.20 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 0.23 lb/MMBtu on Unit 1, S&L concluded that SNCR can reduce emissions by 20% resulting in projected NO_x emission rate of 0.18 lb/MMBtu. PacifiCorp noted in the analysis that the economics of SNCR are greatly impacted by reagent utilization. When SNCR is used to achieve high levels of NO_x reduction, lower reagent utilization can result in significantly higher operating cost. PacifiCorp did not model visibility improvement from installing SNCR on Unit 1 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 Wyodak Unit 1. 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 Unit 1 can achieve a NO_x emission rate of 0.07 lb/MMBtu.

Table 3: Wyodak Unit 1 Boiler NO_x Emission Rates

Control Technology	Resulting NO_x Emission Rate (lb/MMBtu)
Existing LNB	0.31 [a]
New LNB with advanced OFA	0.23
Existing burners with ROFA	0.20
New LNB with advanced OFA and SNCR	0.18
New LNB with advanced OFA and SCR	0.07

[a] Operating Permit 3-1-101-1 annual averaged NO_x emissions established through 40 CFR part 76.

NO_x: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impacts associated with installing each of the proposed control technologies. Replacing the existing LNB with new LNB with advanced OFA will not significantly impact the boiler efficiency or forced draft fan power usage, two common boiler features for adverse energy impact often affected by changes in boiler combustion.

Installing the Mobotec ROFA system has a significant energy impact on Wyodak. One 7,000 horsepower (hp) ROFA fan on Unit 1 is required to induct a sufficient volume of air into the boiler to cause rotation of the combustion air throughout the boiler. The annual energy impact from operating the proposed ROFA fan is 41,200 Mega Watt-hour (MW-hr).

PacifiCorp determined the SNCR system would require 340 kilo Watt (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 1 would be approximately 2.4 MW.

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

PacifiCorp anticipates operating Wyodak Unit 1 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 Wyodak Unit 1 are summarized in the following tables.

Table 4: Wyodak Unit 1 Economic Costs

Cost	Existing LNB	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	$13,100,000	$15,252,149	$19,495,654	$171,900,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$1,246,203	$1,450,937	$1,854,622	$16,352,847
Annual O&M Costs	$0	$60,000	$2,147,685	$452,106	$2,557,934
Annual Cost of Control	$0	$1,306,203	$3,598,622	$2,306,728	$18,910,781

Table 5: Wyodak Unit 1 Environmental Costs

	Existing LNB	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)	0.31	0.23	0.20	0.18	0.07
Annual NO_x Emission (tpy) [(a)]	5,744	4,261	3,706	3,335	1,297
Annual NO_x Reduction (tpy)	N/A	1,483	2,038	2,409	4,447
Annual Cost of Control	$0	$1,306,203	$3,598,622	$2,306,728	$18,910,781
Cost per ton of Reduction	N/A	$881	$1,766	$958	$4,252
Incremental Cost per ton of Reduction	N/A	$881	$4,130	-$3,482 [(b)]	$8,147

[(a)] Annual emissions based on unit heat input rate of 4,700 MMBtu/hr and 7,884 hours of operation per year.
[(b)] 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. PacifiCorp modeled the range of anticipated visibility improvement from the company-proposed BART controls for Unit 1 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 Wyodak Unit 1, 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 15 on page 28 lists the modeled control scenarios and associated emission rates.

PM_{10}: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Wyodak Unit 1 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/PM_{10} from the flue gas stream by creating a strong electro-magnetic field in which fly ash particles gain electric charge. While the current PM_{10} emission limit for Unit 1 is 0.10 lb/MMBtu, PacifiCorp states that the existing ESP is achieving controlled PM/PM_{10} emissions of 0.030 lb/MMBtu. PacifiCorp analyzed three technologies for additional PM control: 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 the existing ESP with a polishing fabric filter or installing a new full-scale fabric filter to control PM/PM_{10} emissions as technically infeasible. However, PacifiCorp did not further analyze the use of FGC or installing a new full-scale fabric filter. According to PacifiCorp, the existing ESP on Unit 1 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. Installing a new full-scale fabric filter is cost-prohibitive in comparison to installing a polishing fabric filter on the existing ESP, which can achieve the same PM/PM_{10} emission rate.

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 1 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 unit is already capable of controlling PM_{10} emissions from Unit 1 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 the existing ESP on Unit 1 can reduce emissions an additional 50% resulting in a PM_{10} emission rate of 0.015 lb/MMBtu. PacifiCorp did not further evaluate the installation on a new full-scale fabric filter on Unit 1 since there is a substantial capital cost associated with the control and no anticipated benefit when compared to COHPAC.

Table 6: Wyodak Unit 1 Boiler PM_{10} Emission Rates

Source	Existing ESP PM_{10} Emission (lb/MMBtu)	Existing ESP With Polishing Fabric Filter PM_{10} Emission (lb/MMBtu)
Unit 1	0.030	0.015

PM_{10}: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impact of installing COHPAC on Unit 1. The pressure drop created by the fabric filter and associated ductwork requires additional energy from the existing draft fan, which will have to be upgraded. PacifiCorp calculated the additional energy costs based on a 90 percent annual plant capacity factor. The installation of a COHPAC fabric filter would require approximately 2.1 MW of power, equating to an annual power usage of approximately 16,200 MW-hr.

PacifiCorp evaluated the environmental impacts from the proposed installation of COHPAC on Unit 1 and did not anticipate negative environmental impacts from the addition of this PM control technology.

PacifiCorp anticipates operating Wyodak Unit 1 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 the proposed PM/PM_{10} emission control. Economic and environmental costs for additional PM/PM_{10} control on Wyodak Unit 1 are summarized in the following tables.

Table 7: Wyodak Unit 1 Economic Costs

Cost	Existing ESP	Existing ESP with New Polishing Fabric Filter
Control Equipment Capital Cost	$0	$32,630,832
Capital Recovery Factor	N/A	0.09513
Annual Capital Recovery Costs	$0	$3,104,171
Annual O&M Costs	$0	$1,120,709
Annual Cost of Control	$0	$4,224,880

Table 8: Wyodak Unit 1 Environmental Costs

	Existing ESP	Exiting ESP with New Polishing Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.030	0.015
Annual PM_{10} Emission (tpy) [(a)]	556	278
Annual PM_{10} Reduction (tpy)	N/A	278
Annual Cost of Control	$0	$4,224,880
Cost per ton of Reduction	N/A	$15,197
Incremental Cost per ton of Reduction	N/A	$15,197

[(a)] Annual emissions based on unit heat input rate of 4,700 MMBtu/hr and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of applying a new polishing fabric filter to Unit 1 are not reasonable. However, the control was included in the final step in the PM/PM_{10} BART determination process for Wyodak Unit 1, 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 15 on page 28 lists 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 Wyodak Unit 1. 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 Wyodak Unit 1.

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 dry 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 determined that Wyodak Unit 1 has an uncontrolled SO_2 emission rate of 1.61 lb/MMBtu, based on an average coal sulfur content of 0.65% by weight. The existing three column dry scrubber currently reduces SO_2 emissions by approximately 69% to achieve the SO_2 emission limit of 0.50 lb/MMBtu. Upgrading the existing dry FGD system by eliminating bypass flue gas flow, placing new static mixers to redistribute the flue gas flow prior to the ESP, increasing the reagent feed ratio, and increasing the recycle ratio is projected to reduce SO_2 emissions by 80% from uncontrolled levels, based on an average sulfur content in the feed coal of 0.65% by weight. The resulting SO_2 emission rate would be 0.32 lb/MMBtu.

If the existing ESP is replaced with a new full-scale fabric filter downstream of the lime spray dryer, the dry FGD system is projected to achieve 90% SO_2 removal after the aforementioned upgrades are applied to the dry scrubber. Based on an average sulfur content of 0.65% by weight, the resulting SO_2 emission rate is 0.16 lb/MMBtu.

PacifiCorp evaluated the application of wet FGD on Wyodak Unit 1. A new wet FGD would likely use lime/limestone forced oxidation scrubbing, which is available in several variations from vendors. Wet lime/limestone scrubbing is projected to achieve a SO_2 removal rate of 95% resulting in an outlet SO_2 emission rate of 0.08 lb/MMBtu, based on a sulfur content of 0.65% by weight in the feed coal. PacifiCorp‟s proposed emission rates for each SO_2 emission reduction technology applied to Wyodak Unit 1 are shown in Table 9.

Table 9: Wyodak Unit 1 SO_2 Emission Rates

Control Technology	SO_2 Emission Rate (lb/MMBtu)
Existing Dry FGD	0.50
Upgraded Dry FGD with existing ESP	0.32
Upgraded Dry FGD with full-scale Fabric Filter	0.16
Wet Lime FGD with existing ESP	0.08

SO_2: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impacts of upgrading the existing dry FGD system with the existing ESP on Wyodak Unit 1. Dry FGD requires less electric power than a wet FGD system. Upgrading the current dry FGD system with the existing ESP at Wyodak would require approximately 0.1 MW of additional power. Upgrading the existing dry FGD and installing a new polishing fabric filter would require 0.2 MW, while a new wet FGD would require approximately 1.8 MW. Using a 90% annual plant capacity factor, upgrading the existing dry FGD and installing a full-scale fabric filter equates to an annual power savings of approximately 12,600 MW-hr as opposed to installing and operating a new wet FGD system.

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 analysis for SO_2 controls on Wyodak Unit 1 and listed below.

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

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

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

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

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

PacifiCorp anticipates operating Wyodak Unit 1 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 Wyodak Unit 1 are summarized in the following tables.

Table 10: Wyodak Unit 1 Economic Costs

Cost	Existing Dry FGD with existing ESP	Upgraded Dry FGD with existing ESP	Upgraded Dry FGD with new full-scale Fabric Filter	New Wet FGD
Control Equipment Capital Cost	$0	$26,759,011	$66,777,531	$95,136,483
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$2,545,585	$6,352,547	$9,050,334
Annual O&M Costs	$0	$1,346,423	$1,471,432	$2,798,979
Annual Cost of Control	$0	$3,892,008	$7,823,979	$11,849,313

Table 11: Wyodak Unit 1 Environmental Costs

	Existing Dry FGD with existing ESP	Upgraded Dry FGD with existing ESP	Upgraded Dry FGD with new full-scale Fabric Filter	New Wet FGD
SO_2 Emission Rate (lb/MMBtu)	0.5	0.32	0.16	0.08
Annual SO_2 Emission (tpy) [a]	9,264	5,929	2,964	1,482
Annual SO_2 Reduction (tpy)	N/A	3,335	6,300	7,782
Annual Cost of Control	$0	$3,892,008	$7,823,979	$11,849,313
Cost per ton of Reduction	N/A	$1,167	$1,242	$1,523
Incremental Cost per ton of Reduction	N/A	$1,167	$1,326	$2,716

[a] Annual emissions based on unit heat input rate of 4,700 MMBtu/hr and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of the proposed wet FGD and dry FGD controls for Unit 1 are reasonable. The final step in the SO_2 BART determination process for Wyodak Unit 1, 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 15 on page 28 lists 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 Wyodak 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 that was conducted using current (baseline) emissions from the facility. The screening modeling, as well as more refined modeling conducted by the applicant, is described in detail below.

Wind Cave and Badlands National Parks (NP) in South Dakota are the closest Class I areas to the Wyodak plant, as shown in Figure 1 below. Wind Cave NP is located approximately 168 kilometers (km) east-southeast of the plant and Badlands NP is located approximately 240 km east-southeast of the plant.

Only those Class I areas most likely to be impacted by the Wyodak sources were modeled, as determined by source/Class I area locations, distances to each Class I area, and professional judgment considering meteorological and terrain factors. It can be reasonably assumed that areas at greater distances and in directions of less frequent plume transport will experience lower impacts than those predicted for the two modeled areas.

SCREENING MODELING

To determine if the Wyodak plant would be subject to BART, the Division conducted CALPUFF visibility modeling 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 coal-fired boiler at the Wyodak plant were input to the model.

Results of the modeling showed that the 98th percentile value for the change in visibility (in units of delta deciview [Δdv]) was above 0.5 Δdv for Badlands NP and Wind Cave NP. As defined in EPA‟s final BART rule, a predicted 98th percentile impact equal to or greater than 0.5 Δdv from a given source indicates that the source contributes to visibility impairment, and therefore is subject to BART. The results of the screening modeling are shown in Table 12.

Figure 1
Wyodak Power Plant and Class I Areas

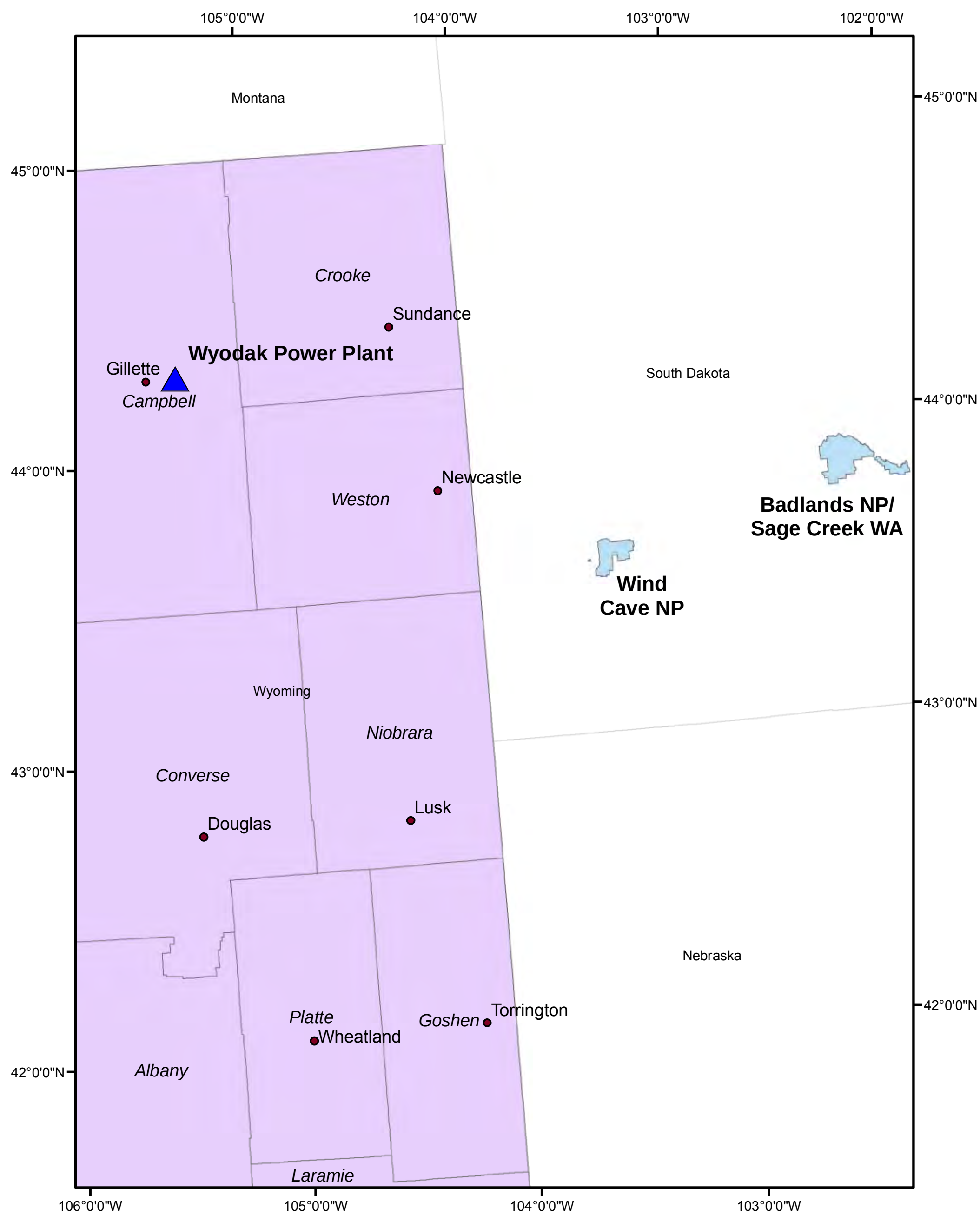


Table 12: Results of the Class I Area Screening Modeling

Class I Area	Maximum Modeled Value (Δdv)	98th Percentile Value (Δdv)
2001		
Badlands NP	1.155	0.842
Wind Cave NP	1.671	1.007
2002		
Badlands NP	2.160	1.246
Wind Cave NP	2.490	1.213
2003		
Badlands NP	2.484	1.097
Wind Cave NP	3.685	1.657

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).

CALPUFF System

Predicted visibility impacts from the Wyodak plant 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 13: 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 14: 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

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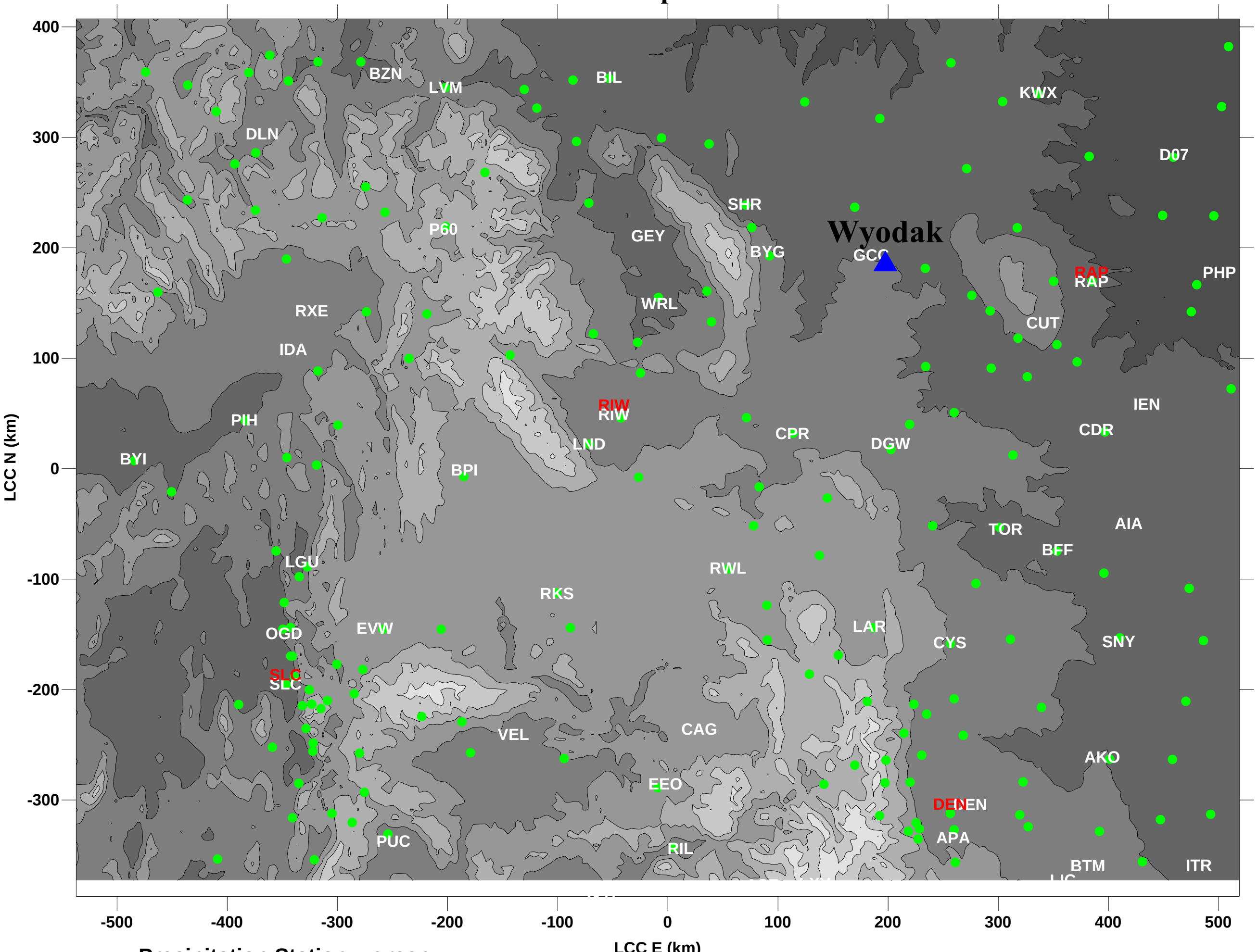
Figure 2
Observations Input to CALMET



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 through 4 show the receptor configurations that were used for Badlands NP and Wind Cave NP. Receptor spacing within Wind Cave NP is approximately 0.7 km in the east-west direction and approximately 0.9 km in the north-south direction. For 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.

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Figure 3
Receptors for Wind Cave NP

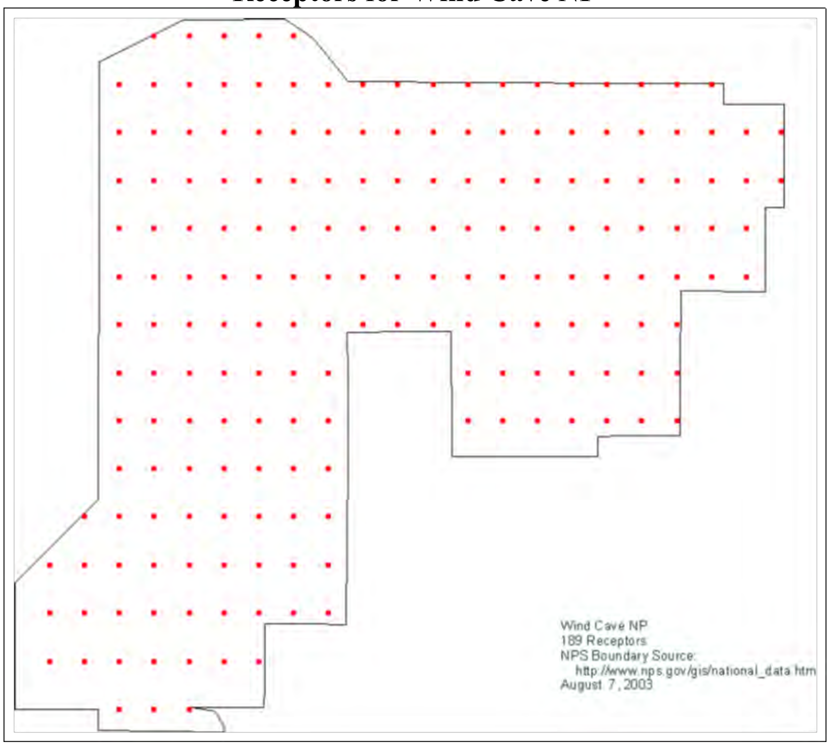
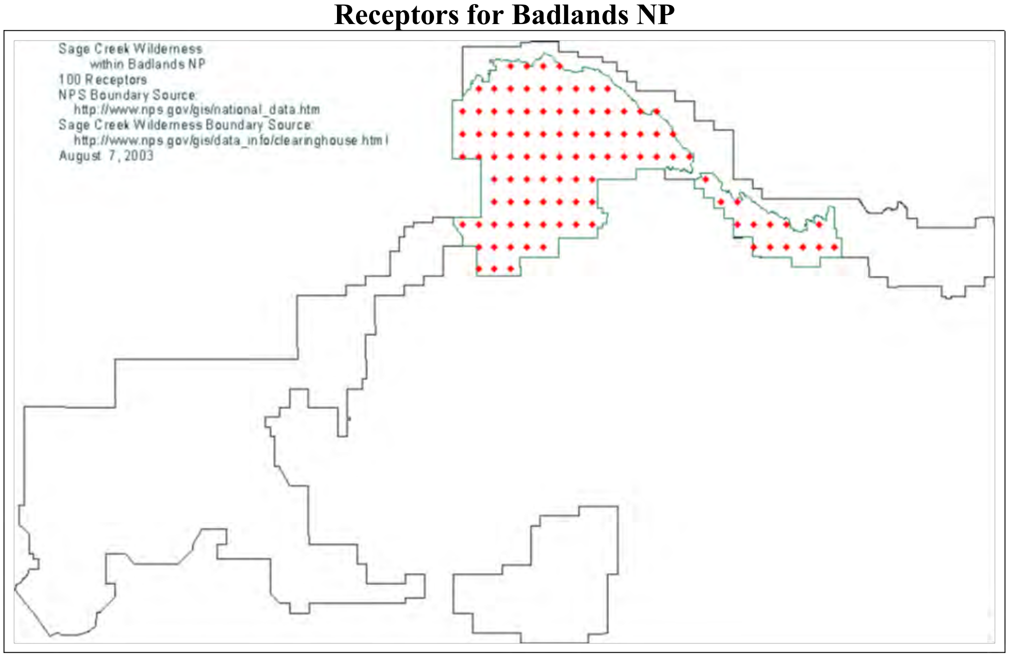


Figure 4
Receptors for Badlands NP



CALPUFF Inputs – Baseline and Control Options

Source release parameters and emissions for baseline and control options for the Wyodak plant are shown in the table below.

Table 15: CALPUFF Inputs for Wyodak Unit 1

Wyodak Unit 1	Baseline	Post-Control Scenario 1	Post-Control Scenario 2	Post-Control Scenario 3	Post-Control Scenario 4	Post-Control Scenario A	Post-Control Scenario B
Model Input Data	Current Operation with Dry FGD and ESP	LNB with advanced OFA, Dry FGD, ESP	LNB with advanced OFA, Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Wet FGD, ESP	Committed Controls: LNB with advanced OFA, Dry FGD, New Fabric Filter	Committed Controls and SCR
Hourly Heat Input (mmBtu/hour)	4,700	4,700	4,700	4,700	4,700	4,700	4,700
Sulfur Dioxide (SO_2) (lb/mmBtu)	0.50	0.32	0.16	0.16	0.08	0.16	0.16
Sulfur Dioxide (SO_2) (lb/hr)	2,350	1,518	759	759	380	759	759
Nitrogen Oxide (NO_x) (lb/mmBtu)	0.31	0.23	0.23	0.07	0.07	0.23	0.07
Nitrogen Oxide (NO_x) (lb/hr)	1,457	1,081	1,081	329	329	1,081	329
PM_{10} (lb/mmBtu)	0.030	0.030	0.015	0.015	0.030	0.015	0.015
PM_{10} (lb/hr)	141.0	141.0	70.5	70.5	141.0	70.5	70.5
Coarse Particulate ($PM_{2.5}$ <diameter < PM_{10}) (lb/hr)[a]	60.6	60.6	40.2	40.2	60.6	40.2	40.2
Fine Particulate (diameter < $PM_{2.5}$) (lb/hr)[b]	80.4	80.4	30.3	30.3	80.4	30.3	30.3
Sulfuric Acid (H_2SO_4) (lb/hr)	5.6	5.6	5.6	9.4	105.0	5.6	9.4
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	--	1.1	5.5	--	1.1
$(NH_4)HSO_4$ (lb/hr)	--	--	--	1.9	9.5	--	1.9
H_2SO_4 as Sulfate (SO_4) (lb/hr)	5.5	5.5	5.5	9.2	103.0	5.5	9.2
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	--	--	--	0.8	4.0	--	0.8
$(NH_4)HSO_4$ as SO_4 (lb/hr)	--	--	--	1.6	8.0	--	1.6
Total Sulfate (SO_4) (lb/hr)[c]	5.5	5.5	5.5	11.6	114.9	5.5	11.6
Stack Conditions							
Stack Height (meters)	122	122	122	122	122	122	122
Stack Exit Diameter (meters)	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Stack Exit Temperature (Kelvin)	358	353	350	350	322	350	350
Stack Exit Velocity (meters per second)	23.5	23.5	23.5	23.5	23.5	23.5	23.5

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.

Visibility Post-Processing (CALPOST)

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

Table 16: Relative Humidity Factors for CALPOST

Month	Badlands NP & Wind Cave NP
January	2.65
February	2.65
March	2.65
April	2.55
May	2.70
June	2.60
July	2.30
August	2.30
September	2.20
October	2.25
November	2.75
December	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 17 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 17: 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 two Class I areas in question are listed in the table below.

Table 18: Natural Background Aerosol Concentrations (μg/m^3)

Aerosol Component	Wind Cave NP & Badlands NP
Ammonium Sulfate	0.047
Ammonium Nitrate	0.040
Organic Carbon	0.186
Elemental Carbon	0.008
Soil	0.198
Coarse Mass	1.191

Visibility Post-Processing Results

The results of the visibility modeling for the Wyodak facility for the baseline and control scenarios are shown in the tables below. For each scenario, the 98th percentile Δdv results are reported along with the total number of days for which the predicted impacts exceeded 0.5 dv. Following the tables are figures that present the results graphically for baseline, the BART configuration proposed by PacifiCorp, and for the proposed BART configuration with the addition of SCR.

Table 19: CALPUFF Visibility Modeling Results for Wyodak Unit 1

Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Dry FGD, ESP								
Badlands NP	0.841	27	1.140	34	1.070	31	1.017	31
Wind Cave NP	1.153	41	1.323	38	1.530	37	1.335	39
Post-Control Scenario 1 – LNB w/ advanced OFA, Dry FGD, ESP								
Badlands NP	0.595	12	0.829	18	0.739	20	0.721	17
Wind Cave NP	0.817	19	0.940	26	1.114	28	0.957	24
Post-Control Scenario 2 – LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Badlands NP	0.472	6	0.624	14	0.583	13	0.560	11
Wind Cave NP	0.671	11	0.788	17	0.929	17	0.796	15
Post-Control Scenario 3 – LNB w/ advanced OFA and SCR, Dry FGD, Fabric Filter								
Badlands NP	0.254	1	0.331	2	0.314	2	0.300	2
Wind Cave NP	0.333	2	0.383	5	0.457	6	0.391	4
Post-Control Scenario 4 – LNB w/ advanced OFA and SCR, Wet FGD, ESP								
Badlands NP	0.294	1	0.405	3	0.340	3	0.346	2
Wind Cave NP	0.396	2	0.519	9	0.684	10	0.533	7
Post-Control Scenario A – Committed Controls: LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Badlands NP	0.473	6	0.624	14	0.583	13	0.560	11
Wind Cave NP	0.671	11	0.788	17	0.929	17	0.796	15
Post-Control Scenario B – Committed Controls + SCR								
Badlands NP	0.254	1	0.331	2	0.314	2	0.300	2
Wind Cave NP	0.333	2	0.383	5	0.457	6	0.391	4

Figure 5
Modeled BART Impacts: 98th Percentile (delta-dv)

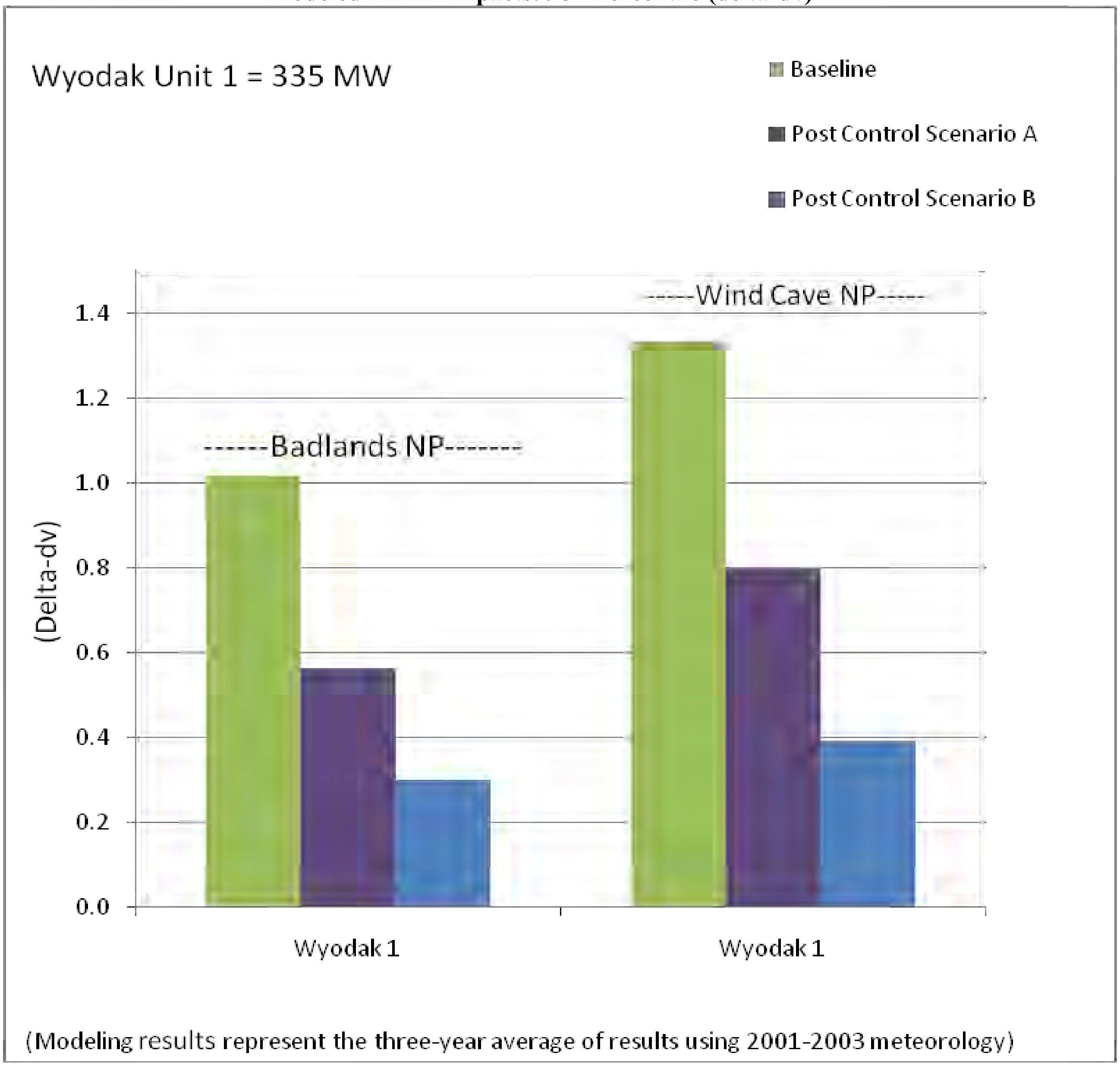
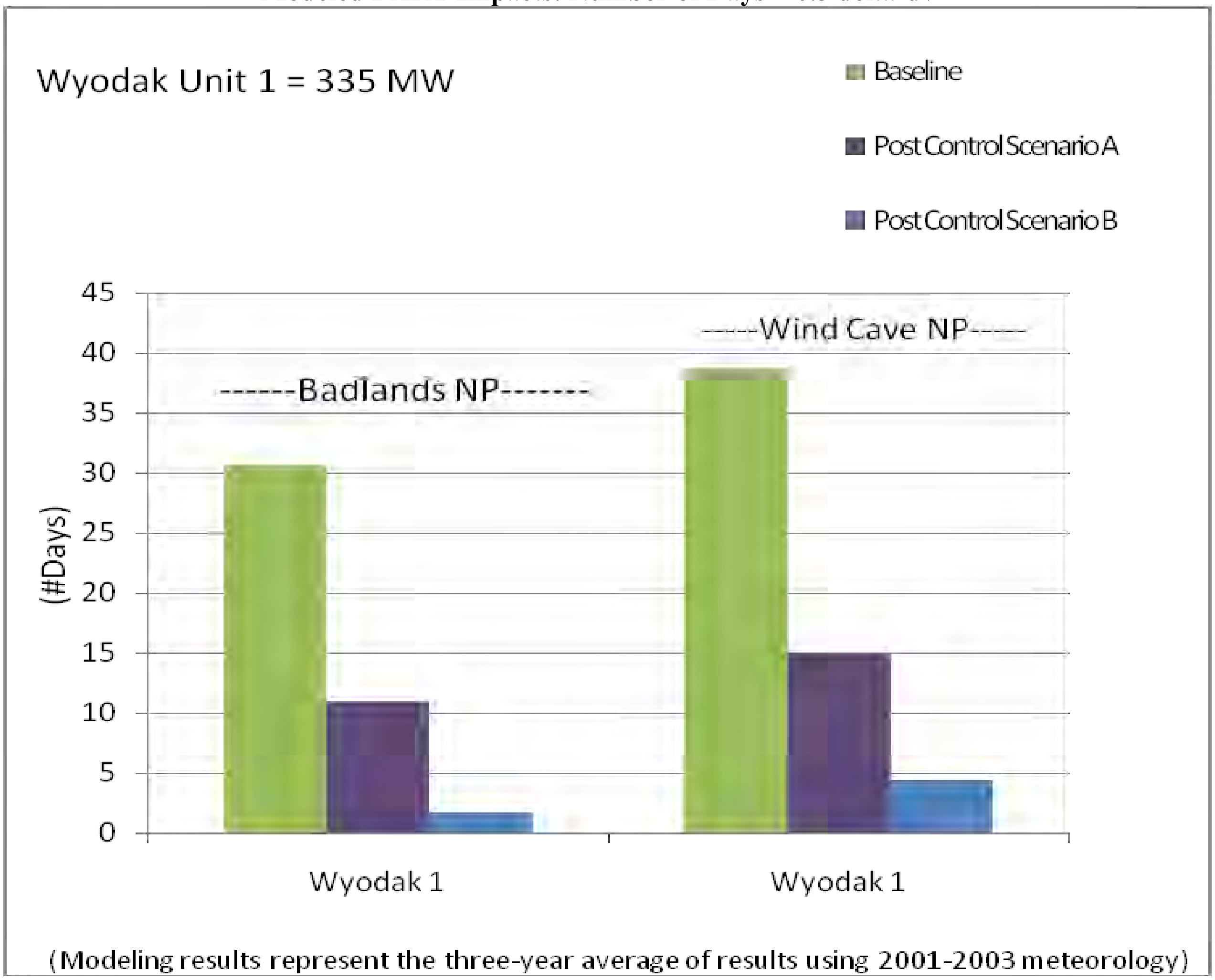


Figure 6
Modeled BART Impacts: Number of Days > 0.5 delta-dv



BART CONCLUSIONS:

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

NO_x

LNB with advanced OFA is determined to be BART for Unit 1 for NO_x based, in part, on the following conclusions:

1. LNB with advanced OFA on Unit 1 was cost effective with a capital cost of $13,100,000. The average cost effectiveness, over a twenty year operational life, is $881 per ton of NO_x removed.

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 0.23 lb/MMBtu on a 30-day rolling average, equal to EPA‟s presumptive limit of 0.23 lb/MMBtu for wall-fired boilers burning sub-bituminous coal, though it is not applicable, is justified for Unit 1.

4. Visibility impacts were addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants and associated control options. The cumulative 3-year averaged 98^{th} percentile visibility improvement from the baseline summed across both Class I areas achieved with LNB with advanced OFA, upgrading the existing dry FGD, and a new full-scale fabric filter, Post-Control Scenario A for Unit 1, was 0.996 Δdv.

5. Annual NO_x emission reduction from baseline achieved by applying LNB with advanced OFA on Unit 1 is 1,483 tons.

LNB with advanced OFA and SCR was not determined to be BART for Unit 1 for NO_x based, in part, on the following conclusions:

1. The cost of compliance for installing SCR on the unit is significantly higher than LNB with advanced OFA. Capital cost for SCR on Unit 1 is $171,900,000. Annual SCR O&M costs for Unit 1 are $2,557,934.

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 2.4 MW from Unit 1.

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 both Class I areas achieved with Post-Control Scenario B was 0.665 Δdv.

The Division considers the installation and operation of the BART-determined NO_x control, new LNB with advanced OFA on Unit 1 to meet corresponding emission limits on a continuous basis, to meet the statutory requirements of BART.

Unit-by-unit NO_x BART determinations:

Wyodak Unit 1:	Installing new LNB with advanced OFA and meeting NO_x emission limits of 0.23 lb/MMBtu (30-day rolling average), 1,081.0 lb/hr (30-day rolling average), and 4,735 tpy as BART for NO_x.

PM/PM_{10}

A new full-scale fabric filter is determined to be BART for Unit 1 for PM/PM_{10} based, in part, on the following conclusions:

1. While the Division considers the cost of compliance for a full-scale fabric filter on Unit 1 not reasonable, PacifiCorp is committed to installing this control device and has permitted the installation of a full-scale fabric filter on Unit 1 in a recently issued New Source Review construction permit. A full-scale fabric filter is the most stringent PM/PM_{10} control technology and therefore the Division will accept it as BART.

The Division considers the installation and operation of the BART-determined PM/PM_{10} control, new full-scale fabric filter on Unit 1 to meet corresponding emission limits on a continuous basis, to meet the statutory requirements of BART.

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

Wyodak Unit 1:	Installing a new full-scale fabric filter and meeting PM/PM_{10} emission limits of 0.015 lb/MMBtu, 71.0 lb/hr, and 309 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 0.16 lb/MMBtu or lower from the coal-fired boilers. PacifiCorp proposed upgrading the existing dry FGD and installing a full-scale fabric filter as SO_2 BART controls on Wyodak Unit 1.

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 20.

Table 20: 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 21 to underscore the improvements associated with SO_2 reductions.

Table 21: 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 22. 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 22: 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 application for Wyodak Unit 1, 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 Wyodak 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 Wyodak Unit 1.

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 Wyodak Unit 1.

CHAPTER 6, SECTION 3 – OPERATING PERMIT:

The Wyodak Power Plant is a major source under Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations. The most recent Operating Permit, 3-2-101, was issued for the facility on February 18, 2009. In accordance with Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations, 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 Wyodak 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 Unit 1.

PROPOSED PERMIT CONDITIONS:

The Division proposes to issue an Air Quality Permit to PacifiCorp for the modification of the Wyodak 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, 1866 South Sheridan Avenue, Sheridan, WY 82801.

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 Wyodak Unit 1 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 the flue gas desulfurization system on Unit 1 reaches a temperature of 275°F and three (3) coal pulverizers have been placed in service.

Pollutant	lb/MMBtu	lb/hr	tpy
NO_x	0.23 (30-day rolling)	1,081.0 (30-day rolling)	4,735
PM/PM_{10}[(a)]	0.015	71.0	309

[(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 Boiler (Wyodak Unit 1):

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 boiler (Wyodak Unit 1) shall be determined with data from the continuous monitoring system 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 boiler (Wyodak Unit 1) 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 and a new full-scale fabric filter on Unit 1, in accordance with the Division‟s BART determination, and conduct the initial performance tests required in Condition 6 no later than December 31, 2011.

Appendix A
Facility Location

Sierra Club/502
Cross Exhibit ______________/1
PUBLIC VERSION

Market Extra

Burlington Northern slowed by empty coal cars

July 18, 2012 | Sue Chang, MarketWatch

An earlier version of this story misspelled the name of Burlington Northern Santa Fe. The story has been corrected.

SAN FRANCISCO (MarketWatch) — Burlington Northern Santa Fe hauls a lot of coal. In fact, electricity flowing to one out of every 10 homes in the United States is generated using coal hauled by Berkshire Hathaway Inc.'s Burlington Northern Santa Fe.

And as power plant demand for coal drops in favor of cheaper natural gas, Burlington Northern is seeing a decline in loadings which in turn could drag down Berkshire Hathaway's results.

BNSF accounted for roughly 19% of Berkshire Hathaway's (US:BRK.A) (US:BRK.B) pretax earnings in 2009 and about 11% of the holding company's revenue, according to analysts at Barclays Capital.

"I think it's a moderate headwind," said Meyer Shields, an analyst at Stifel Nicolaus who covers Berkshire Hathaway.

Berkshire Hathaway is scheduled to release its quarterly earnings on Aug. 3.

More than 90% of coal transported by BNSF comes from the Powder River Basin in eastern Wyoming and Montana. The price of Powder River Basin coal has fallen to $8.50 a ton as of July 6 from $12.90 a ton on Jan. 6.

"Warren Buffett said in an interview recently that housing is picking up and everything else is flat. What that means, I guess, is that growth in freight is flat," said Bill Smead, chief executive officer of Smead Capital Management.

Buffett told CNBC last week that freight car loadings were down moderately in the eastern region due mostly to less coal being hauled.

The railroad declined to comment on its coal revenue but if it is like other railroad companies, its earnings are expected to reflect the impact of utility coal's fall from grace.

CSX Corp. (US:CSX) reported after the bell that its second-quarter profit rose to 49 cents a share from 46 cents a share in the same period a year earlier despite weakness in its utility coal business.

Kansas City Southern (US:KSU) on Tuesday also reported its second-quarter profit jumped to $1.09 a share from 64 cents a share in the year-ago period on revenue of $545.3 million. The company credited the slight rise in revenue to a 4% increase in carloads which helped to offset a lower-than-anticipated coal traffic.

The slump in demand for coal was underscored by data from the Energy Information Administration last week that showed that for the first time ever, gas-fired power plants generated as much electricity as coal-fired plants in April. Read more on how coal is no longer king.

The preference for natural gas and a warm winter has led to a glut of coal at many utilities, said Timna Tanners, a research analyst at Bank of America Merrill Lynch.

"We remain cautious on U.S. thermal coal, and expect further updates on curtailment plans and elevated costs in Q2 earnings results and conference calls," said Tanners in a report.

Indeed, the best hope for coal's recovery is for natural gas price to rebound, she said.

Natural-gas futures for August delivery (US:NGQ12) lost 0.5 cent, or 0.2%, to $2.80 per million British thermal units on Tuesday.

BNSF freight train passing northwest of Shallowater, Texas.

Sierra Club/502
Cross Exhibit ______________/2
PUBLIC VERSION

MidAmerican Energy Co., a utility company that serves the Midwest, is another Berkshire Hathaway company that has a lot of exposure to coal.

Its generation portfolio includes 45% coal, 17% natural gas, 31% wind, and around 7% nuclear, said Ann Thelen, director of communications at MidAmerican Energy Holdings Co. She declined to comment on whether the company plans to lower its reliance on coal.

MidAmerican contributed 11% to Berkshire Hathaway's 2009 pretax earnings and 9% to its revenue, the Barclays analysts said.

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Related Keywords

Gas

BEFORE THE ENVIRONMENTAL QUALITY COUNCIL
STATE OF WYOMING

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

RESPONSE TO BASIN ELECTRIC'S MOTION FOR SUMMARY JUDGMENT

Basin Electric's Initial Submittal, dated 2/28/07

EXHIBIT 2

**BASIN ELECTRIC
POWER COOPERATIVE**

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D.E.
File: 6047

MAR 2007
RECEIVED
AIR QUALITY
DIVISION

February 28, 2007

David A. Finley
Wyoming Department of Environmental Quality
Division of Air Quality
122 West 25th Street
Cheyenne, WY 82002

Dear Mr. Finley,

The Department of Environmental Quality (DEQ) notified Basin Electric in June 2006 that the Laramie River Station (LRS) was a Best Available Retrofit Technology (BART) applicable source which required a BART engineering and modeling analysis for reducing visibility impacts in accordance with the Environmental Protection Agency's Guidelines for BART Determinations under the Regional Haze Rules (40 CFR Part 51). Visibility impacts for LRS were evaluated at two Federal Class I areas; Badlands National Park and Wind Cave National Park.

A BART review was required to identify the best control technology for the reduction of nitrogen oxides (NOx), sulfur dioxide (SO_2), and particulate matter (PM) emissions from Laramie River Station Units 1, 2 and 3. Basin Electric contracted Black & Veatch to conduct a BART analysis to identify technically feasible and cost-effective technologies following the BART Guidelines. A modeling analysis was completed to evaluate the impact on visibility in the two identified Class I areas. A summary of their findings is attached.

As a result of Black & Veatch's studies, Basin Electric commits to meet an equivalent to the presumptive level of 0.23 lb/mmBtu NOx on a plant-wide 30-day rolling average based on a pound per hour limitation of 4,471 pounds per hour for LRS.

Basin Electric will participate in the Western Regional Air Partnership (WRAP) SO_2 emissions trading program. Should the WRAP trading program not be implemented, Basin Electric will commit to meeting an equivalent to the presumptive level of 0.15 lb/mmBtu on a plant-wide 30-day rolling average based on a pound per hour limitation of 2,916 pounds per hour for LRS.

Our existing electrostatic precipitators are already state-of-the-art particulate control and are considered BART technology; therefore, no additional technology or further reductions of PM are necessary.

The Laramie River Station will meet all BART emission levels no later than five years following EPA's approval of the Wyoming State Implementation Plan.

If you have any questions, please contact me at 701-355-5654. Thank you.

Sincerely,

Robert L. Eriksen, P.E.
Environmental Compliance Administrator

/gmj
Enclosures
cc: Ken Rairigh, DEQ
Roosevelt Huggins, Black & Veatch
Kyle Lucas, Black & Veatch
Dallas Wade
Terry Archbold
Tom Spaulding

BLACK & VEATCH

MEMORANDUM

Basin Electric Power Cooperative
Laramie River Station BART Analysis
BART 5-Step process

B&V Project 145423
B&V File 15.1300
February 28, 2007

The Wyoming Department of Environmental Quality (DEQ) identified Basin Electric Power Cooperative's (BEPC) Laramie River Station's (LRS) Unit 1, 2 and 3 as Best Available Retrofit Technology (BART) applicable sources which required a BART engineering and modeling analysis for reducing visibility impacts in accordance with the Environmental Protection Agency's (EPA's) Guidelines for BART Determinations under the Regional Haze Rules (40 CFR Part 51). Visibility impacts for LRS were evaluated at two Federal Class I areas; Badlands National Park and Wind Cave National Park.

A BART review was required to identify the best control technology for the reduction of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter (PM) emissions from Laramie River Station Units 1, 2 and 3. However, it should be noted that for those large BART sources greater than 200 MW in size located at power plants greater than 750 MW, EPA has defined presumptive limits for NO_x and SO_2 which have been determined to be generally highly-cost effective, but may prove not to be for certain sources. SO_2 presumptive limit emission rate of 0.15 lb/mmBtu was established for coal-fired units that do not have existing post-combustion SO_2 controls. The NO_x presumptive limits differ based on the type of coal burned and the boiler design. In the case of the Laramie River Station, the NO_x presumptive limits for a dry-bottom wall fired, sub-bituminous coal burning unit is 0.23 lb/mmBtu. There are no presumptive limits for PM. A BART source, meeting the applicable criteria, can complete the BART engineering analysis and determine those technologies able to reach the presumptive limits are the preferred control strategy for each unit.

The units at LRS are currently operating with existing air quality control equipment in place. For NO_x emissions reduction, all three units utilizes good combustion practices and Low NO_x Burners (LNB) to achieve permit levels of NO_x. LRS Units 1 and 2 are also equipped with high-efficiency Electrostatic Precipitator (ESP) and a high-efficiency Wet Flue Gas Desulfurization (FGD) system. LRS Unit 3 is equipped with a dry scrubber FGD system with a high-efficiency ESP. Unlike many other BART applicable sources, LRS employs two of the three air quality control devices that can achieve the most visible improvement.

Wyoming DEQ identified that based upon the state's overall goals in achieving the federal requirements for visibility improvement, that acceptance of the BART presumptive limits would preclude the requirements of the exhaustive 5-step engineering analysis. This was also identified based upon the fact that LRS station already has significant controls with good operation history. The guideline allows for units with existing controls to focus on enhancement or operating modifications to the existing control equipment in lieu of complete replacement of air quality retrofit changes.

The BART review performed for LRS Units 1, 2 and 3 utilized EPA's five step process for determination of the BART selected technologies. In Step 1 of the BART methodology, available retrofit emissions control technologies that may be practically implemented at the Laramie River Station site are identified for NO_x, SO_2 and PM. The technology considered can be a method, system, or a combination for control of a pollutant. Technologies that have been successfully applied in commercial scale at similar sources or sources with similar gas characteristics are considered to be available. From this list of available technologies, technically feasible control technologies are identified in Step 2. A control technology is technically feasible if it is determined to have been successfully implemented at a similar facility and/or is available commercially.

In Step 3, characteristics and features of the technically feasible control technologies are determined and the estimated control effectiveness of the technology as applied to Laramie River Station was determined. Also evaluated in this step are the retrofit requirements for the control technology at the existing plant site; these are determined by considering the current configuration of the equipment and the situation at the plant site. Control effectiveness is a measure of the emissions reduction expected after the implementation of the control technology.

For Step 4 of the BART review process, cost-effectiveness and other impacts are evaluated. Impact analysis for each technically feasible control technology was performed for this purpose. The impact analysis considers such issues as the cost of compliance, energy impacts, non-air quality impact, and the remaining useful life. Upon completion of the impact analysis for each control technology, the cost-effectiveness can be calculated. The two types of cost-effectiveness are average cost-effectiveness and incremental cost-effectiveness. Also performed in this step is the identification of the most cost-effective control technologies; these are determined by plotting the total annual cost to implement each technology versus the expected emissions reduction which results in a "least-cost envelope". The "least-cost envelope", identifies the most cost-effective control technologies for each pollutant.

The control effectiveness information was then used as one of the factors for consideration along with the cost effectiveness, existing plant conditions, retrofit difficulty of the control technology, and operational impacts of the new control technologies to determine the control technology for each BART unit. Therefore, to meet the presumptive level of emissions, the most cost effective control technologies were selected as the recommended BART control scenario.

In Step 5 of the BART review process, visibility demonstration using CALPUFF, was performed. To satisfy DEQ requirements, only two CALPUFF model runs were required – Scenario one represents the existing emissions case (Baseline Scenario) and Scenario two represents the preferred control strategy selected for PM and the strategy selected to achieve the presumptive emission levels for NO_x and SO_2. The visibility modeling was performed based on a modeling protocol that was approved by the Wyoming DEQ, dated September 2006. The preferred control strategy for each pollutant was modeled using meteorological data for years 2001 to 2003. Visibility data was analyzed for the 98th percentile modeled visibility impact and the number of days per year that the 0.5 deciview (dv) extinction criteria in each of the Federal Class I area modeled is exceeded. The CALPUFF modeling to determine visibility improvements with the addition of the preferred BART control technologies resulted in improvements to visibility from 0.2 dv to 0.24 dv. This corresponds to the number of days exceeding the 0.5 dv extinction criteria ranging from 34 to 45 days. These visibility improvements are limited due to the LRS units already having existing control technology that is considered for BART technology and operating at corresponding controlled emission level for NO_x, SO_2 and PM.

At the conclusion of the BART process, it was determined that presumptive emissions level for NO_x at 0.23 lb/mmBtu and SO_2 at 0.15 lb/mmBtu will be achieved at Laramie River Station on a plant-wide basis on a 30-day rolling average. The preferred control strategy to achieve these presumptive emissions levels includes potentially installing overfired air (OFA) systems for one or more units. Additionally, possible DBA addition into the Units 1 and 2 wet FGD system and potential modifications to the Unit 3 dry scrubber is preferred to improve SO_2 removal to meet the required emissions level. It was also determined that the performance of the existing ESPs meets the requirements for controlling visibility impacts.

WYOMING STATE IMPLEMENTATION PLAN

Regional Haze

Addressing Regional Haze Visibility Protection For The Mandatory Federal Class I Areas Required Under 40 CFR 51.309

December 2, 2003 (Original Submittal)
Revised May 22, 2008
Revised January 7, 2011

Table of Contents

Title **Page**

STATE IMPLEMENTATION PLAN REQUIREMENTS

Section A. Projection of Visibility Improvement

1. Projection of Visibility Improvement Anticipated From Long-Term Strategy

(a) Applicable Class I areas. This projection of visibility improvement covers the 16 Class I areas of the Colorado Plateau, as defined in 40 CFR 51.309(b)(1).

(b) Projected visibility improvement. Pursuant to 40 CFR 51.309(d)(2), Table 1 below compares the monitored 2000-04 baseline visibility conditions in deciviews for the 20% Best and 20% Worst days to the projected visibility improvement resulting from the 2018 Base Case (Base 18b) and 2018 Preliminary Reasonable Progress (PRP18) modeling scenarios completed to date. These 2018 modeling scenarios are defined as follows:

- Base Case (Base 18b) = growth plus all controls "on the books" as of December 2004, no BART or SO_2 milestones assumptions;

- Preliminary Reasonable Progress Case (PRP18) = refined growth estimates plus all controls "on the books" as of May 2007, includes presumptive limit or known SO_2 BART on EGUs; and

- [*future*] Final Reasonable Progress Case (FRP18) = all controls "on the books" as of 2007, will include all BART controls in the WRAP region and limits defined in the SO_2 milestone "better-than-BART" program.

When SO_2 and NOx controls for all BART sources have been adopted in the WRAP region, and the 309 states re-adopt the SO_2 milestone program, a 2018 Final Reasonable Progress (FRP18) modeling scenario will then be analyzed and the remaining cells completed in the table below. The data in the table below satisfy 40 CFR 51.309(d)(2) of the Regional Haze Rule.

All 16 Colorado Plateau Class I areas show a projected visibility improvement for 2018 using the monthly averages on the 20% Worst average visibility days, and no degradation on the 20% Best average visibility days for each monitoring site. The monthly average method for projecting visibility improvement is an allowed variation of EPA guidance, and the method description is found at: http://www.wrapair.org/forums/taf/meetings/070226c/Applying_Monitoring_Metrics_for_Regional_Haze_Planning_%20February_23_2007_finalreviewdraft.pdf. The monthly averaging method was chosen because it was the shortest averaging period for making the future visibility projections, while avoiding the use of the EPA specific days method that only assesses improvements on the Worst and Best days observed during one year (2002) of the 2000-04 baseline monitoring period. The methodology and current data showing projected visibility improvement in 2018 are now available through the WRAP TSS (http://vista.cira.colostate.edu/tss).

Table 1. Visibility Impairment in Deciviews*

Colorado Plateau Class I areas under §309(d)(2)	State	20% Worst Visibility Days: 2000-04 Regional Haze Rule Baseline Monitoring Data	20% Worst Visibility Days: Projected Visibility (*Monthly Average Method*): 2018 Base Case (Base18b)	20% Worst Visibility Days: Projected Visibility (*Monthly Average Method*): 2018 Preliminary Reasonable Progress Case (PRP18)	20% Worst Visibility Days: Projected Visibility (*Monthly Average Method*): 2018 Final Reasonable Progress Case (FRP18)	20% Best Visibility Days: 2000-04 Regional Haze Rule Baseline Monitoring Data	20% Best Visibility Days: Projected Visibility (*Monthly Average Method*): 2018 Base Case (Base18b)	20% Best Visibility Days: Projected Visibility (*Monthly Average Method*): 2018 Preliminary Reasonable Progress Case (PRP18)	20% Best Visibility Days: Projected Visibility (*Monthly Average Method*): 2018 Final Reasonable Progress Case (FRP18)
Grand Canyon National Park	AZ	11.7	11.4	11.3		2.2	2.2	2.1	
Mount Baldy Wilderness	AZ	11.9	11.5	11.4		3.0	2.9	2.8	
Petrified Forest National Park	AZ	13.2	12.9	12.9		5.0	4.9	4.8	
Sycamore Canyon Wilderness	AZ	15.3	15.1	15.1		5.6	5.6	5.6	
Black Canyon of the Gunnison National Park Wilderness	CO	10.3	10.1	9.9		3.1	2.9	2.9	
Flat Tops Wilderness	CO	9.6	9.2	9.0		0.7	0.6	0.5	
Maroon Bells Wilderness	CO	9.6	9.2	9.0		0.7	0.6	0.5	
Mesa Verde National Park	CO	13.0	12.8	12.6		4.3	4.1	4.0	
Weminuche Wilderness	CO	10.3	10.1	9.9		3.1	2.9	2.9	
West Elk Wilderness	CO	9.6	9.2	9.0		0.7	0.6	0.5	
San Pedro Parks Wilderness	NM	10.2	10.0	9.8		1.5	1.3	1.2	
Arches National Park	UT	11.2	11.0	10.9		3.8	3.6	3.5	
Bryce Canyon National Park	UT	11.6	11.3	11.2		2.8	2.7	2.6	
Canyonlands National Park	UT	11.2	11.0	10.9		3.8	3.6	3.5	
Capitol Reef National Park	UT	10.9	10.6	10.5		4.1	4.0	3.9	
Zion National Park	UT	13.2	13.0	13.0		5.0	4.7	4.7	

* Data are from: http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx --> Modeling --> Visibility Projections

2. Applicable WRAP Reports and Documents

Appendix B is found in the WRAP TSD. The methodology and current data showing projected visibility improvement in 2018 are now available through the WRAP TSS (http://vista.cira.colostate.edu/tss).

Section B. Clean Air Corridors

Note: No revisions were made to this section.

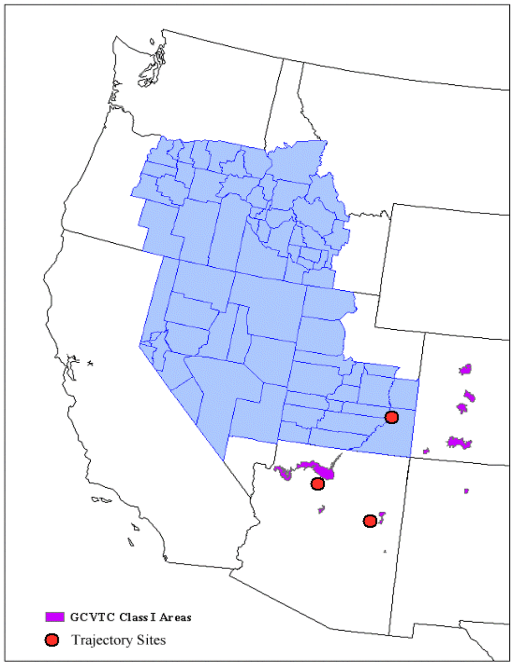
1. Long-Term Strategy for the Clean Air Corridor

See the Wyoming TSD for further details that summarize the *WRAP Policy Paper on Clean Air Corridors* and supports parts *b, c, d, and f below.*

(a) Comprehensive emissions tracking program. Pursuant to 40 CFR 51.309(d)(3), a comprehensive emissions tracking system has been established to track emissions within portions of Oregon, Idaho, Nevada and Utah, that have been identified as part of the Clean Air Corridor, as specified in *(b)* below, to ensure that visibility is not degraded on the least-impaired days in any of the 16 Class I areas of the Colorado Plateau. This comprehensive emissions tracking system was developed by the WRAP to assist the above states in meeting this requirement. The Wyoming TSD describes the comprehensive emissions tracking system, and the process by which the WRAP will summarize annual emission trends in order to identify any significant emissions growth that could lead to visibility degradation in the 16 Class I areas. Included in this summary will be an assessment of whether any significant emissions growth has occurred within the Clean Air Corridor, in accordance with *(c)* below.

(b) Identification of Clean Air Corridors. Pursuant to 40 CFR 51.309(d)(3)(i), the State of Wyoming has identified a Clean Air Corridor, as indicated in the map provided below. This Clean Air Corridor was identified using studies conducted by the Meteorological Subcommittee of the Grand Canyon Visibility Transport Commission, and then updated by the WRAP based on an assessment described in the *WRAP Policy Paper on Clean Air Corridors*, and related technical analysis conducted by the WRAP.

Figure 1. Map of the Clean Air Corridor in the Transport Region



(c) Patterns of growth within the Clean Air Corridor. Pursuant to 40 CFR 51.309(d)(3)(ii), the State of Wyoming has determined, based on the *WRAP Policy Paper on Clean Air Corridors* and technical analysis conducted by the WRAP, that inside the Clean Air Corridor identified in *(b)* there is no significant emissions growth occurring at this time that is causing visibility impairment in the 16 Class I areas of the Colorado Plateau. Future emissions growth will be tracked in accordance with the comprehensive emissions tracking system in *(a)* above. The WRAP will summarize annual emission trends within the corridor and make an assessment of whether any significant emissions growth has occurred within the corridor.

(d) Patterns of growth outside the Clean Air Corridor. Pursuant to 40 CFR 51.309(d)(3)(iii), the State of Wyoming has determined, based on the *WRAP Policy Paper on Clean Air Corridors* and technical analysis conducted by the WRAP, that outside the Clean Air Corridor identified in *(b)* there is no emissions growth occurring at this time that is impairing air quality within the Clean Air Corridor sufficient to cause any visibility impairment in any of the 16 Class I areas of the Colorado Plateau. As part of the WRAP's annual summary of emission trends within the corridor, an assessment will be made of emission and monitoring data trends outside the Clean Air Corridor, in order to determine if significant emissions growth is occurring outside the corridor that could be impairing air quality within the corridor, and resulting in visibility impairment in the 16 Class I areas. See Chapter 3 of the WRAP Technical Support Document for additional details on this assessment process.

(e) Actions if impairment inside or outside the Clean Air Corridor occurs. The State of Wyoming, in coordination with other transport region states and tribes, will review the WRAP's annual summary of emission trends within the Clean Air Corridor and whether any significant

emissions growth was identified within the corridor in accordance with *(c)* above, or was identified outside the corridor, in accordance with *(d)* above. If significant emissions growth was identified, the State of Wyoming in coordination with other transport region states and tribes, will conduct or seek WRAP assistance in conducting an analysis of the effects of this emissions growth in terms of possible impact on air quality within the corridor and possible degradation of the least-impaired days in any of the 16 Class I areas of the Colorado Plateau. Pursuant to 40 CFR 51.309(d)(3)(iv), if this analysis finds that this growth is causing visibility impairment in the 16 Class I areas, the State of Wyoming in coordination with other transport states and tribes will evaluate the need for additional emission reduction measures, and identify an implementation schedule for such measures, if needed. The implementation of any additional emission measures shall be coordinated with all appropriate transport region states and tribes, on a mutually agreed upon timetable, and reported to EPA in accordance with the periodic progress reports required under 40 CFR 51.309(d)(10)(i).

(f) Other Clean Air Corridors. Pursuant to 40 CFR 51.309(d)(3)(v), the State of Wyoming has concluded that no other Clean Air Corridors can be identified at this time. This finding is based on the review of work conducted by the Meteorological Subcommittee of the Grand Canyon Visibility Transport Commission on Clean Air Corridors, as described in the *WRAP Policy Paper on Clean Air Corridors*. Although no formal update on this finding is required, the State of Wyoming recognizes that future modeling or monitoring data may indicate other possible Clean Air Corridors exist. The State of Wyoming will notify EPA if there is evidence to support such a finding in the future, and take appropriate action pursuant to this requirement.

2. Applicable WRAP Reports and Documents

See Chapter 3 of the TSD Development Plan for the technical work conducted in support of the *WRAP Policy Paper on Clean Air Corridors*, summary provided in the Wyoming TSD.

Section C. Stationary Sources

1. Long-Term Strategy for Stationary Sources

The definitions associated with this section are provided in Appendix A of this document. A demonstration of how the Backstop Trading Program is better than applying BART to stationary sources is included in Appendix E of this document.

Part A—Milestones and Determination of Program Trigger

A1 Regional SO_2 Milestones

A1.1 Milestone Values

The regional sulfur dioxide milestones for the years 2003 through 2018 are provided in Table 1. The milestones shall be adjusted annually as described in paragraph A1.2 of this Stationary Sources section.

Table 1. Sulfur Dioxide Emissions Milestones

Column 1	Column 2	Column 3
For the year	the regional sulfur dioxide milestone is	and the annual SO_2 emissions for these years will determine whether emissions are greater than or less than the milestone
2008	269,083 tons SO_2	Average of 2006, 2007 and 2008
2009	234,903 tons SO_2	Average of 2007, 2008 and 2009
2010	200,722 tons SO_2	Average of 2008, 2009 and 2010
2011	200,722 tons SO_2	Average of 2009, 2010 and 2011
2012	200,722 tons SO_2	Average of 2010, 2011 and 2012
2013	185,795 tons SO_2	Average of 2011, 2012 and 2013
2014	170,868 tons SO_2	Average of 2012, 2013 and 2014
2015	155,940 tons SO_2	Average of 2013, 2014 and 2015
2016	155,940 tons SO_2	Average of 2014, 2015 and 2016
2017	155,940 tons SO_2	Average of 2015, 2016 and 2017
2018	141,849 tons SO_2	Year 2018 only
2019 forward, until replaced by an approved SIP	141,849 tons SO_2	Annual; no multiyear averaging

A1.2 Milestone Adjustments

(a) All milestone adjustments shall require a SIP revision. Section A3.3 of this Plan outlines adjustments to be made to the emissions inventory to ensure a consistent comparison to the milestones. These adjustments shall be incorporated into the milestones every five years as part of the periodic Implementation Plan revisions required by 40 CFR 51.309(d)(10).

Adjustments to the milestones shall be tracked in the annual emissions report pursuant to Section A3.3.

(b) Within ninety days of the periodic Implementation Plan revision incorporating adjustments based on Section A3.3, the State of Wyoming shall provide the date of the SIP revision reflecting the milestone adjustment to sources whose records were used as the basis for the milestone adjustment and state that the source needs to retain the record at least five years from the date of the SIP revision, or ten years from the date of establishing the record, whichever is longer.

(c) Opt-in Provisions for States and Tribes. The regional milestones in Table 1 were developed for a 3-state region: New Mexico, Utah, and Wyoming. Other western states and tribes may choose to join this backstop trading program in the future. The addition of a state or tribe to the program will require SIP/TIP revision for all participating states and tribes to adjust the regional milestones, and will not occur automatically. Any state or tribe that wishes to opt in to the program will propose milestone adjustments to the participating states and tribes using the same methodology that was used to develop the milestones in Table 1. A new participant must agree to develop a SIP and backstop trading rule that is consistent with those adopted by the other participating states and tribes.

A2 Regional Program Administration

A2.1 Pre-trigger Tracking of Regional SO_2 Emissions

The Wyoming Department of Environmental Quality shall work cooperatively with the states and tribes that are participating in the SO_2 Milestones and Backstop Trading Program to ensure that an emission tracking system for the regional SO_2 inventory is developed and maintained. The Department is responsible for all regional program administration functions as described in this Plan. The Department will perform these functions through the WRAP, with the WRAP functioning as the Department's agent. The Western Regional Air Partnership (WRAP) compiled the SO_2 emission inventories that were used during the development of the Western Emissions Backstop Trading Program and subsequent SIP revisions, and the WRAP continues to refine and improve the overall tracking system for regional haze. The WRAP shall maintain the pre-trigger emissions tracking functions outlined in this Plan for the foreseeable future. If the WRAP is no longer able to fulfill this function, then the Department shall ensure that other arrangements are made, either through a different regional organization or through a contractor to maintain the SO_2 tracking system that is described in this Plan. The WRAP shall have no authority to make regulatory determinations. The WRAP has limited authority under this Plan to perform tracking and accounting functions, prepare reports, and perform other administrative functions as directed by the Department. The Department shall work expeditiously to correct any problems if the WRAP fails to perform any of the functions described in the SIP in a timely manner.

A2.2 Designation of the Tracking System Administrator

If the backstop trading program is triggered due to an exceedance of the SO_2 milestones as outlined in Part A3 of this section, the Department shall work cooperatively with the other participating states and tribes to designate one Tracking System Administrator (TSA). The TSA shall be designated as expeditiously as possible, but no later than six months after the program trigger date. In addition, before the TSA is designated, the Department shall have entered into a binding contract with the TSA that shall require the TSA to perform all TSA functions described in this Plan. In addition, the State of Wyoming must obtain sufficient authority to ensure the functions in the Implementation Plan are carried out by the TSA.

A2.3 Information Provided by Other States and Tribes

The Department shall accept the emission inventory and permitting information provided by the other participating states and tribes in order to determine the milestone value and program trigger if such other states and tribes have provided proper documentation and followed the public notification process outlined in Parts A3.6 through A3.8 of this section.

A3 Determination of Program Trigger

A3.1 Until the program has been triggered and source compliance is required, the Department shall submit an annual emissions report for Wyoming sources to the WRAP and all participating states and tribes by September 30 of each year. The report shall document actual sulfur dioxide emissions during the previous calendar year for all sources subject to the sulfur dioxide milestone inventory requirement of Chapter 14, Section 3. The first report for calendar year 2003 shall be submitted by September 30, 2004. The Department shall prepare the supporting documentation that is included with the annual emissions report as noted in provisions A3.2 and A3.3 below.

A3.2 The annual emissions report for Wyoming shall include a source emissions change report that contains the following information:

(a) identification of any new sources that were not contained in the previous calendar year's emissions report, and an explanation of why the source is now included in the program;

(b) identification of any sources that were included in the previous year's report and are no longer included in the program, and an explanation of why this change has occurred; and

(c) an explanation for emissions variations at any applicable source that exceeds +/- 20 percent from the previous year.

A3.3 The annual emissions report for Wyoming shall include a proposed emissions adjustment as described in (a) and (b) to ensure a consistent comparison to the milestones.

(a) Changes in emission monitoring or calculation methods. Actual emission inventories for sources that change the method of monitoring or calculating their emissions shall be adjusted to be comparable to the emission monitoring or calculation method that was used in the 2006 base year inventory.

(b) Changes due to enforcement actions.

1. Adjustments due to enforcement actions arising from settlements. Adjustments to the milestones shall be made, as specified in Part A3.3(b)3 and 4 of this section, if:

(A) an agreement to settle an action, arising from allegations of a failure of an owner or operator of an emissions unit at a source in the program to comply with applicable regulations which were in effect during the base year, is reached between the parties to the action;

(B) the alleged failure to comply with applicable regulations affects the assumptions that were used in calculating the source's base year and forecasted sulfur dioxide emissions; and

(C) the settlement includes or recommends an adjustment to the milestones.

2. Adjustments due to enforcement actions arising from administrative or judicial orders. Adjustments shall be made to the milestones as directed by any final administrative or judicial order, as specified in Part A3.3(c)3 and 4 of this section. Where the final administrative or judicial order does not include a reforecast of the source's baseline, the state or tribe shall evaluate whether a reforecast of the source's baseline emissions is appropriate.

3. Adjustments method and effective dates. Based on Part A3.3(c)3 and 4 of this section, the milestone must be decreased by an appropriate amount based on a reforecast of the source's decreased sulfur dioxide emissions. The adjustments to the milestone do not become effective until after the source has reduced its sulfur dioxide emissions as required in the settlement agreement, or administrative or judicial order. All adjustments based upon enforcement actions must be made in the form of an implementation plan revision that complies with the procedural requirements of 40 CFR 51.102 and 51.103.

4. Documentation of adjustments for enforcement actions. In the periodic plan revision required under 40 CFR 51.309(d)(10), the state or tribe shall include the following documentation of any adjustment due to an enforcement action:

(A) identification of each source under the state or tribe's jurisdiction which has reduced sulfur dioxide emissions pursuant to a settlement agreement, or an administrative or judicial order;

(B) for each source identified, a statement indicating whether the milestones were adjusted in response to the enforcement action;

(C) discussion of the rationale for the state or tribe's decision to adjust or not to adjust the milestones; and

(D) if SO_2 emissions reductions over and above those reductions needed for compliance with the applicable regulations were part of an agreement to settle an action, a statement indicating whether such reductions resulted in any adjustment to the milestones or allowance allocations, and a discussion of the rationale for the state or tribe's decision on any such adjustment.

A3.4 The annual sulfur dioxide milestone and emissions report for Wyoming shall document any adjustments that should be made to the milestone for the previous year as described below:

(a) The Department will document the submittal date of this Implementation Plan to implement the regional Sulfur Dioxide Milestones and Backstop Trading Program, and the approval date by the EPA Administrator, if applicable.

(b) Changes due to enforcement actions.

1. *Adjustments due to settlements arising from enforcement actions*. Adjustments to the milestones will be made, as specified in subsection (3.) below, if:

(i) an agreement to settle an action, arising from allegations of a failure of an owner or operator of an emissions unit at a source in the program to comply with applicable regulations which were in effect during the base year, is reached between the parties to the action;

(ii) the alleged failure to comply with applicable regulations affects the assumptions that were used in calculating the source's base year and forecasted sulfur dioxide emissions; and

(iii) the settlement includes or recommends an adjustment to the milestones.

2. *Adjustments due to administrative or judicial orders*. Adjustments to the milestones will be made as directed by any final administrative or judicial order, as specified in (3.) below. Where the final administrative or judicial order does not include a reforecast of the source's baseline, the Department will evaluate whether a reforecast of the source's baseline emissions is appropriate.

3. *Adjustments method and effective dates*. The milestone will be decreased by an appropriate amount based on a reforecast of the source's decreased sulfur dioxide emissions. The adjustments will not be made to the milestone until after the source has reduced its sulfur dioxide emissions as required in the settlement agreement, or administrative or judicial order.

4. *Documentation of adjustments for enforcement actions*. The report will include the following documentation of any adjustment due to an enforcement action or a settlement agreement:

(i) identification of each source in Wyoming that has reduced sulfur dioxide emissions pursuant to a settlement agreement or an administrative or judicial order;

(ii) for each source identified, a statement indicating whether the milestones were adjusted in response to the enforcement action;

(iii) discussion of the rationale for the Department's decision to adjust or not to adjust the milestones; and

(iv) if SO_2 emissions reductions over and above those reductions needed for compliance with the applicable regulations were part of an agreement to settle an action, a statement indicating whether such reductions resulted in any adjustment to the milestones or allowance allocations, and a discussion of the rationale for the Department's decision on any such adjustment.

5. The State of Wyoming will include all accumulated milestone adjustments due to enforcement actions or settlement agreements in the periodic SIP revisions required under 40 CFR 51.309(d)(10).

A3.5 Compilation of Reports

(a) The WRAP shall compile the annual emissions reports submitted by all participating states and tribes into a draft regional emission report for sulfur dioxide. The WRAP shall follow additional quality assurance procedures developed by states and tribes to identify possible errors in the emissions data, including screening for missing or added sources, name changes, and significant changes in reported emissions. Any questions or anomalies regarding Wyoming's report shall be referred back to the Department for resolution prior to the submission of the draft regional emission report.

(b) By December 31 of each year, the WRAP shall submit the draft regional emission and milestone report to the Department and shall post the draft report on the WRAP website for public review. The report shall include the following information:

1. Actual regional sulfur dioxide emissions (tons/year).
2. Adjustments to account for:
    (i) changes in emission monitoring or calculation methods, or
    (ii) enforcement actions or settlement agreements as a result of enforcement actions.
3. Average adjusted emissions for the last three years (if applicable) for comparison to the regional milestone.

A3.6 The Department shall evaluate the draft regional emissions report and shall propose a draft determination that the sulfur dioxide milestone has either been met in the region, or has been exceeded. In the event that the WRAP has not submitted to the Department a draft regional emissions and milestone report by the December 31 deadline for any year, the Department shall prepare its own report for that year based upon the annual emissions reports submitted by all participating states and tribes pursuant to Part A3.5 of this section for that year. The Department shall modify the data in these annual emissions reports, or use data where such report(s) have not been submitted, based upon direction received from the Environmental Protection Agency.

A3.7 The Department will publish a notice of the final determination in newspapers of general circulation throughout the State of Wyoming. This notice will include the milestone and the final annual regional sulfur dioxide emissions for that year. If the milestone has been exceeded, the notice will specify the program trigger date and the first year that WEB sources must be in compliance with the WEB Trading Program provisions as outlined in Chapter 14, Section 2. The Department shall submit the draft determination to EPA for review and comment.

A3.8 The Department shall review any comments received during the comment period, and shall submit a copy of all comments to the WRAP and to all participating states and tribes along with a response to address the comments.

A3.9 The WRAP shall compile the comments and responses from all participating states and tribes and prepare a draft final regional emissions report. The report shall be submitted to the states and tribes that are participating in the program and, if necessary, the report shall propose a common program trigger date.

A3.10 The Department shall review and approve the final regional emissions report. The Department shall then submit this report to the Environmental Protection Agency along with a final determination that the milestone has either been met in the region, or that the milestone has been exceeded and the WEB Trading Program has been triggered in Wyoming. This final determination shall be submitted to the Environmental Protection Agency by the end of March fifteen months following the milestone year. The first final determination shall be due March 31, 2005 for the 2003 milestone. If the milestone has been exceeded, the common trigger date proposed in the regional report shall become the program trigger date for purposes of implementing the WEB Trading Program. In the event that the program trigger date must be established by the Department in the absence of a regional emissions and milestone report prepared by the WRAP, the date shall be March 31 of the applicable year.

A3.11 The Department shall notify the public of the final determination. This notice shall include the final calculation of the milestone and the final annual regional emissions. If the milestone has been exceeded, the notice shall include the program trigger date and the first year that WEB sources must be in compliance with the WEB Trading Program provisions outlined in Section 2(c)(ii) of Chapter 14. Wyoming will publish the final annual emissions report in a statewide newspaper’s legal section.

A4 Year 2013 Assessment

A4.1 Initial Assessment in 2013 Periodic SIP/TIP Review

(a) The Department shall work cooperatively with the WRAP and other participating states and tribes to develop a projected emission inventory for SO_2 through the year 2018, using the 2010 regional inventory as a baseline. This projected inventory shall be included in the 2010 annual emission and milestone report that shall be completed in March 2012 as outlined in Part A3 of this section.

(b) The Department shall evaluate the projected inventory, and based upon this information make an assessment of the likelihood of meeting the regional milestone for the year 2018. The Department shall include this assessment as part of Wyoming's progress report that must be submitted by December 31, 2013, as required by 40 CFR 51.309(d)(10).

A4.2 Regional Emissions Report for 2012

(a) The Department shall prepare an SO_2 emission report for the year 2012 by September 30, 2013 as described in Part A3.1 of this section. The Department shall include a list of all known projects in Wyoming that are anticipated to affect SO_2 emissions in 2018. This may include permitted projects, projects that are still in the planning stage, or projections from the affected sources of anticipated emissions in 2018. The status of these projects shall be described to provide a better understanding of the degree of certainty that individual projects will be completed by 2018.

(b) The WRAP shall compile the information from all participating states and tribes, prepare draft SO_2 inventory projections for the year 2018, and estimate the effect of known future projects on SO_2 emissions. Projected 2018 emissions will be compared to the 2018 milestone. This information shall be included in the draft regional emissions report that shall be submitted to the Department by December 31, 2013, as part of the report for the year 2012, as outlined in Part A3.5 of this section.

A4.3 Consensus Decision

The Department commits to meet with the participating states and tribes in March 2014 to discuss any comments received on the 2018 emission projections in the draft report. The participating states and tribes shall decide, through a consensus process, whether an early trigger of the WEB Trading Program is necessary to meet the SO_2 emission reduction goals in 2018.

A4.4 Official Trigger

If the participating states and tribes unanimously decide under Part A4.3 of this section that an early trigger of the backstop trading program is necessary, the Department shall trigger the WEB Trading Program and the timing of various program elements shall be adjusted as follows to ensure that the WEB Trading Program is in place in 2018. The date of the consensus decision by the participating states and tribes to voluntarily trigger the WEB trading program shall become the program trigger date.

(a) Allowances for 2018 shall be distributed to WEB sources by January 1, 2015.

(b) The first control period shall be the year 2018. WEB sources will need to demonstrate at the end of the first control period that they have enough allowances to cover their SO_2 emissions in 2018.

A4.5 Public Notification

The Department shall notify the public of the decision. The Department will publish notice of the decision in newspapers of general circulation throughout Wyoming. If applicable, the notice will include a statement that the WEB Trading Program is in effect and will specify the program trigger date.

A5 Special Penalty Provisions for the 2018 Milestone

If the WEB Trading Program is triggered as outlined in Part A.3 of Section C of this Implementation Plan, and the first control period will not occur until after the year 2018, a special penalty shall be assessed for the exceedance of the 2018 milestone.

Details on the penalty provisions for violation of the 2018 milestone can be found in Section 2(l) of Chapter 14. In general, the penalty involves an assessment of the minimum $5,000 per ton of SO_2 emissions in excess of the WEB source's allowance limitation. The source can resolve its excess emissions violation by agreeing to a streamline settlement approach outlined in Section 2(l)(i)(E)(I) of Chapter 14.

The amount of the minimum monetary penalty in Section 2(l) of Chapter 14 shall be evaluated at each five-year SIP review, and adjusted to ensure that penalties per ton substantially exceeds the expected cost of allowances to ensure that this remains a stringent penalty.

The 2018 special penalty provisions shall continue to be applied each year after 2018 until the 2018 milestone has been achieved.

Part B—Pre-Trigger Emissions Tracking Requirements

B1 SO_2 Emission Inventory

WDEQ is in the process of developing Chapter 14, Section 3 to satisfy the SO_2 emission inventory requirements described below. That rule will be processed parallel with this SIP.

(a) Applicability. To insure compliance with the emission inventory requirements for pre-trigger tracking compliance with the sulfur dioxide milestones set forth under 40 CFR 51.309, the following changes will be incorporated into Chapter 14, Section 3. All stationary sources with actual emissions of one hundred (100) tons per year or more of sulfur dioxide in the year 2000, or in any subsequent year, must submit an annual inventory of sulfur dioxide emissions, beginning with the 2003 emission inventory. A source that meets these criteria that then emits less than 100 tons per year in a later year must still submit a sulfur dioxide inventory for tracking compliance with the regional sulfur dioxide milestones until the WEB Trading Program has been fully implemented and emission tracking has occurred under Section 2(h) of Chapter 14.

(b) All stationary sources will be required to comply with the following federally enforceable provisions:

(1) submit an annual inventory of SO_2 emissions;

(2) document the emissions monitoring/estimation methodology used, and demonstrate that the selected methodology is acceptable under the inventory program;

(3) include emissions from startup, shut down, and upset conditions in the annual total inventory;

(4) use 40 CFR part 75 methodology for reporting emissions for all sources subject to the federal acid rain program;

(5) smelters must submit an annual report of sulfur input, in tons/year;

(6) maintain all records used in the calculation of the emissions, including but not limited to the following:

(i) amount of fuel consumed,
(ii) percent sulfur content of fuel and how the content was determined,
(iii) quantity of product produced,
(iv) emissions monitoring data,
(v) operating data, and
(vi) how the emissions are calculated;

(7) maintain records of any physical changes to facility operations or equipment, or any other changes (e.g., raw material or feed) that may affect the emissions projections, and retain records for a minimum of ten years from the date of establishment, or if the record was the basis for an adjustment to the milestone, 5 years after the date of an implementation plan revision, whichever is longer.

(8) retain records for a minimum of ten years from the date of establishment, or if the record was the basis for an adjustment to the milestone, 5 years after the date of an implementation plan revision, whichever is longer.

(c) The State of Wyoming shall retain 2006 emission inventory records for non-utilities until the year 2018 to ensure that changes in emissions monitoring techniques can be tracked.

B2 Development of Emission Tracking System

The Department shall work cooperatively with the states and tribes that are participating in the WEB Trading Program to ensure that an emission tracking system for the regional SO_2 inventory is developed and maintained.

B3 Periodic Audit of Pre-Trigger Emission Tracking Database

During the pre-trigger phase when the Department is tracking compliance with the regional SO_2 milestones, the Department shall work cooperatively with the participating states and tribes to ensure that an independent audit of the tracking database is conducted to ensure that the WRAP is accurately compiling the regional emissions report. The first audit shall occur during the year 2006 and shall review data collected during the first two years of the program. Subsequent audits shall occur in 2011 (which shall cover emissions years 2005-2009) and 2016 (which shall cover emissions years 2010-2014).

The primary focus of the audit will be the process that is used to compile the regional inventory from the data provided by each state and tribe, and the tracking of accumulated changes during the period between SIP revisions. The audit shall also review the accuracy and integrity of the regional reports that are used by the Department to determine compliance with the milestones.

The audit is not intended to be a full review of the Department's process for compiling and reporting SO_2 emissions, but shall include a broad review of the Department inventory management and quality assurance systems (i.e., presence and exercise of systems to assure data quality and integrity).

The audit shall discuss the uncertainty of emissions calculations, and whether this uncertainty is likely to affect the annual determination of whether the milestone is exceeded. The audit shall identify any recommended changes to emissions monitoring or calculation methods or data quality assurance systems. The audit shall also review and recommend any changes to improve the administrative process of collecting the annual emissions data at the state and tribal level, compiling a regional emission inventory, and making the annual determination of whether the WEB Trading Program has been triggered.

Changes to the WEB trading program, including any changes to the milestones, due to the results of these periodic audits shall be submitted to EPA as a SIP revision as part of the five-year SIP review required by 40 CFR 51.309(d)(10).

The Department shall provide an opportunity for public review and comment on the draft audit report following each Department procedure. The Department shall respond to comments and provide notice of the final availability of the report. The Department shall submit the final audit report to the EPA regional office.

Part C—WEB Trading Program Requirements

C1 Allowance Allocations

C1.1 Initial Allocation of SO_2 Allowances

(a) Draft Allocation Report. Within six months of the program trigger date, as outlined in Part A3.11 of this section, the Department will submit a draft allocation report to all participating states and tribes and to the TSA. This report will contain the following information:

1. A list of all WEB sources in Wyoming as defined in Chapter 14, Section 2 that groups the sources into two categories:

(i) Category 1: WEB sources that commenced operation prior to January 1, 2008. These sources will receive a floor allocation and will be eligible for the reducible portion of the allocation.

(ii) Category 2: WEB sources that commenced operation on January 1, 2008 or a later date. These sources will receive a floor allocation, but will not be eligible for the reducible allocation. The floor allocation for Category 2 sources will be deducted from the new source set-aside.

WEB sources that have received a retired source exemption under Chapter 14, Section 2(c)(iv) will be included in the allocation process in the same manner as WEB sources that are currently operating. However, sources that were permanently shut down prior to the program trigger date are not considered WEB sources under Chapter 14, Section 2(c)(i) and would therefore not be included in the allocation process.

2. The floor allocation for all WEB sources in Wyoming.

(i) For non-utility Category 1 WEB sources, the floor allocation shall be as established in the E.H. Pechan Report, "Market Trading Forum Non-Utility Sector Allocation Final Report from the Allocations Working Group" (November 2002). If any additional Category 1 sources are identified, the Department shall calculate a floor allocation using the methodology outlined in the E.H. Pechan Report.

(ii) For utility Category 1 WEB sources, the floor will be calculated by first assigning a "clean unit" emission rate to each unit. The clean unit emission rate will then be multiplied by an annual heat input (MMBtu) that represents a realistic upper bound for the unit.

Note: The floor level approach described above is designed to address equity issues regarding the allocation process for utilities. The State of Wyoming is participating in ongoing discussions with the other participating states, tribes and regional stakeholders to ensure that all equity issues have been addressed. Wyoming will work with the other participating states and tribes to ensure that the floor allocation is calculated in a consistent manner for all participants. As outlined further in this allocation methodology, the floor for both utilities and non-utilities is limited by the utility/non-utility split in Table 2. The floor allocation methodology will ensure that credits are available for early reduction allocations. In addition, the regional number of allowances allocated for each year cannot exceed the milestone for that year under any circumstances.

Principles

- Each unit will have enough allowances to operate as a clean source and at an operating rate (capacity factor) that is a realistic upper bound for the unit.
- There will not be significant winners and losers in this process.
- The focus is on a fair approach that is applied equally to all sources rather than on state and tribal budgets.
- The allocation process will use data that reflect current conditions, including current monitoring methodologies.

Equity Issues

- Sources that are currently burning very low sulfur coal may see changes in their supply in the future. Historic actual emissions may not reflect future operations.
- Sources that are currently operating at a low utilization may not reach full capacity in the future. Assumptions about growth that are realistic on the regional level may provide a windfall to some sources, and not provide adequate allowances for other sources.
- There are some utility units in the region that are not BART-eligible and are operating at a low level of control for SO_2. The relative responsibility of BART-eligible vs. non-BART-eligible is a consideration in the process.
- Sources that are operating at a high level of control are already bearing the cost of control and this affects their ability to compete in the market.
- Sources that have no SO_2 controls are facing a large expense that could affect their ability to continue to operate.
- Emission rate disparities exist throughout the region.

(iii) For Category 2 WEB sources the floor allocation shall be the lower of the permitted SO_2 annual emissions for the WEB source, or SO_2 annual emissions calculated based on a level of control equivalent to BACT and assuming 100% utilization of the WEB source.

3. A list of certified early reductions, expressed as tons of SO_2. Early reductions will be calculated and certified as follows:

(i) Any WEB source that installs control technology and accepts new permit emissions limits that are, for a non-utility source, below its floor as established in this section, or, for a utility source, below BACT, may apply for an early reduction credit as outlined in Chapter 14, Section 2(f)(v). The credit will be available for reductions that occur between 2008 and the program trigger year. The application must show that the floor was calculated in a manner that is consistent with the monitoring requirements of Chapter 14, Section 2(h)(i)(A) and (i)(C) and the new permit must contain monitoring requirements that are consistent with Chapter 14, Section 2(h). Emission units that are monitored using the less stringent monitoring requirements of Chapter 14, Section 2(h)(i)(B) are not eligible for early reduction credits. The credits accumulate from the time the new controls come on line until the program trigger date and will be allocated to the WEB source over a 10-year period. The use of early reduction credits in any control period is limited to no more than five percent, systemwide, of the existing available allowances, as provided in Part C1.1(b)5 of this section.

(ii) The Department will review the application and will certify early reductions for each full year between 2008 and the program trigger year that meet the requirements of Chapter 14, Section 2(f)(v) and this Plan.

(iii) A source's certified early reductions for all years will be added together to obtain the total certified early reductions for that source.

4. Historical SO_2 emissions data for all Category 1 sources for the purposes of calculating the reducible allocation.

(i) For utilities, the annual SO_2 emissions for the year 2006. Another time period may be used for individual emission units, if needed, to be representative of normal operating conditions.

(ii) For non-utilities, the annual SO_2 emissions for the year 2006.

5. Changes due to enforcement actions or settlement agreements as a result of enforcement actions. The adjustment shall be determined in accordance with Part A3.3(c) of this section. The difference between the WEB source's allocations prior to enforcement and after the enforcement action shall be removed from the allocation pool.

(b) Compiled Allocation Report

The TSA will compile the information provided by all participating states and tribes into a draft regional allocation report, and will submit this draft regional report to the Department and all participating states and tribes for review and comment thirty days after receiving the preliminary allocation reports. The draft regional allocation report will include a proposed budget for each state and tribe and the proposed allocation for each WEB source in Wyoming.

The State of Wyoming will work closely with the other participating states and tribes to ensure that the regional allocation is distributed consistently and fairly and to address any change in status that may affect this process.

The following methodology distributes the allowances available under the milestone in the following order: tribal set-aside, new source set-aside, floor, early reduction credit, reducible allocation. The allocation process is limited by the number of allowances available under the milestone. It is not possible under this methodology to distribute more allowances than are available under the milestone. Wyoming expects that there will be allowances available for all of the categories listed above. However, if at any time in the process there are not enough allowances available to fully cover a particular category, then the sources eligible for that category will receive a pro-rated allowance, and the process will stop. For example, if the early reduction credit allocation is greater than the remaining available allowances under the milestone, then each of the early reduction sources would receive a reduced early reduction credit allocation, and there would be no reducible allocation.

1. Table 2 shows the major categories that will be used to allocate allowances under the milestone. The methodology to calculate the available allocation for existing sources is described below. The milestone for the 3-state region is the starting point.

Table 2. Utility/Non-utility Split.

	Milestone from Table 1	Tribal Set-aside	New Source Set-aside	Remaining Allocation	Utility Portion	Non-utility Portion
2008	269,083	2,500	6,143	260,440	10,480	49,961
2009	234,903	2,500	6,143	226,260	176,299	49,961
2010	200,722	2,500	6,143	192,079	142,119	49,961
2011	200,722	2,500	6,143	192,079	142,119	49,961
2012	200,722	2,500	6,143	192,079	142,119	49,961
2013	185,795	2,500	12,286	171,009	121,048	49,961
2014	170,868	2,500	12,286	156,082	106,121	49,961
2015	155,940	2,500	12,286	141,154	91,194	49,961
2016	155,940	2,500	12,286	141,154	91,194	49,961
2017	155,940	2,500	12,286	141,154	91,194	49,961
2018	141,849	2,500	12,286	127,063	80,402	46,661

2. Subtract the floor allocation for all WEB sources in the region that were identified as Category 2 from the new source set-aside to determine the available allocation for new sources that begin operation after the program trigger date.

This allocation methodology treats all Category 2 sources as existing sources because these sources will be operating on the program trigger date. However, the allowances for all Category 2 sources are actually drawn from the new source set-aside. If new source growth exceeds the projections used to develop this Plan, it is possible that the above calculation will result in a negative number. Therefore, to address this problem, Category 2 sources will be ranked based on the date the permit is issued for each source. Sources will then be removed from the list of Category 2 sources, starting with the most recent permit, until the new source set-aside is no longer depleted. The last source on the list will receive a partial allocation. The sources that were removed from the list will be considered new sources as described in Section C1.3 of this Plan. These sources will need to purchase allowances to cover their emissions because the new source set-aside for sources that begin operation after the program trigger date will be calculated as zero until it is replenished in the next 5-year period. The allocation process for these new sources is described in Section C1.3 of this Plan.

Example calculation of the new source set-aside.

The example uses the following assumptions:
(i) Emissions exceed the milestones based on an average of the years 2004-2006.
(ii) The program trigger date is March 31, 2008.
(iii) The first 5 years of the program are 2012-2016.
(iv) New sources that commenced operation between January 1, 2008 and the program trigger date have a total floor allocation of 600.

	2012	**2013**	**2014**	**2015**	**2016**
New Source Set-Aside	6,143	12,286	12,286	12,286	12,286
Floor for Category 2 Sources	600	600	600	600	600
Remaining New Source Set-aside	5,543	11,686	11,686	11,686	11,686

3. The remaining allocation shown in Table 2 is available for distribution to Category 1 sources. The final two columns in Table 2 split this remaining allocation into a utility allocation and a non-utility allocation.

4. Subtract the floor allocations for all Category 1 utility and non-utility sources in the region from the utility allocation or the non-utility allocation.

In the unlikely event that the total floor allocation for either utility or non-utility sources submitted by the participating states and tribes exceeds the total allocation available for that category, the TSA will notify the participating states and tribes of the discrepancy. Wyoming commits to work with the participating states and tribes through a consensus process to ensure that the floor allocation has been calculated in a consistent manner for all participants and to ensure that the floor allocation does not exceed the total allocation available for that category. The total number of allowances distributed cannot exceed the milestone for any given year.

5. Calculate the early reduction allocation.

> (i) Divide the number of certified early reduction credits for all WEB sources in the region by ten.
>
> (ii) Add the utility allocation for 2018 to the non-utility allocation for 2018 and then multiply this total by 0.05.
>
> (iii) If the product of paragraph (i) is no more than the product of paragraph (ii), the product of paragraph (i) is the early reduction allocation, and each source is allocated ten percent of its early reduction credits.
>
> (iv) If the product of paragraph (i) is more than the product of paragraph (ii), the early reduction allocation for the region is the product of paragraph (ii). To determine a source's allocation, divide the product of paragraph (ii) by 0.10 times the total number of early reduction credits and apply that ratio to the early reduction credits claimed by the source.
>
> (v) Split the regional early reduction allocation based on the ratio of utility to non-utility allocations in 2018 and subtract the early reduction allocation from the utility and non-utility allocation totals.
>
> (vi) The early reduction allocation will be calculated in a similar manner for the second five-year allocation period under this program, and will then be discontinued for any future allocation periods.

6. Any remaining allowances in the utility allocation or the non-utility allocation after subtraction of the early reduction allocation is considered the reducible allocation and will be assigned to Category 1 sources.

> (i) For non-utility sources, add together the historic SO_2 emissions in accordance with Part C1.1(a)5 of this section for all Category 1 non-utility sources in the region to determine an historic emission total. Determine a percent contribution of SO_2 emissions for each WEB source to the historic

emission total. Multiply the non-utility reducible allocation calculated in paragraph (7.) by the percent contribution for each WEB source to determine a reducible allocation for each WEB source.

(ii) For utility sources, the reducible allocation will be distributed to sources that emitted above their floor in the baseline period (2006) based on their percentage of total floor emissions for sources emitting above the floor times the number of reducible allowances available for the first five years of the WEB Trading Program. The number of allowances for any source receiving a reducible allocation shall not exceed a recent historic emission rate times a heat input that represents a realistic upper bound for the unit.

Note: The approach for distributing the reducible utility allocation described above is designed to address equity issues regarding the allocation process for utilities. The State of Wyoming is participating in ongoing discussions with the other participating states, tribes and regional stakeholders to ensure that all equity issues have been addressed. The principles and equity issues that are under discussion are listed in Part C1.1(a)2 of this section.

7. Add together the floor allocation, early reduction allocation, and reducible allocation for each WEB source to determine the proposed allocations for the first five years of the WEB Trading Program.

8. Add together the proposed allocations for all of the WEB sources in the jurisdiction of each participating state and tribe to determine a draft SO_2 allowance budget for each state and tribe.

(c) Public Comment Period

The Department will publish notice of availability of the draft regional allocation report in newspapers of general circulation throughout Wyoming. A 30-day public comment period will be established, and a hearing will be held during the comment period. The Department will consider the comments, and will revise the draft report if the recommended changes are consistent with the allocation process outlined in this Plan. The Department will prepare a written response that explains why each comment has either been accepted or has been determined to be inconsistent with the allocation process outlined in this Plan.

(d) Proposed Changes Submitted to Tracking System Administrator

The Department will submit a copy of all comments received, the response to those comments, and any proposed changes to the budget and source allocations to the TSA within sixty days of receipt of the draft regional allocation report.

(e) Compilation of Changes

The TSA will compile the comments, responses, and proposed changes to the report and will submit a final draft regional allocation report that is consistent with the allocation methodology outlined in this Plan to the Department within 90 days of the receipt of the draft regional allocation report.

(f) Final Regional Allocation Report

The Department will review the final regional allocation report and will determine the budget for Wyoming and allocations for WEB sources within Wyoming in accordance with the allocation methodology outlined in this Plan within 30 days of receipt of the final draft allocation report. The Department will submit the budget and allocations for all WEB sources in Wyoming to EPA, and will notify the TSA that the WEB source allocations should be recorded in the allowance tracking system.

(g) Notification

The Department will notify all WEB sources within Wyoming of the number of allowances that have been recorded in their compliance account. The notice will include a warning to the WEB sources that reported annual sulfur dioxide emissions may change due to the implementation of new monitoring methods as required by Chapter 14, Section 2(h). Allocations for the first five years of the program will not be adjusted to account for changes due to the new monitoring method. However, allocations during the next five-year distribution will be adjusted as needed to account for paper changes in emissions due to changes in monitoring methodology.

C1.2 Distribution of Allowances for Future Control Periods

By December 1 of the year five years after the initial allocation, the Department will follow the process outlined in Part C1.1 of this section to distribute allowances for the next five-year period. This process will continue every five years until allowances have been allocated through the year 2018.

C1.3 Distribution of the New Source Allocation

(a) The new source set-aside will be available for two categories of sources.

1. New WEB sources are eligible to receive an annual floor allocation equal to the lower of the annual permitted sulfur dioxide emissions for the source, or sulfur dioxide annual emissions calculated based on a level of control equivalent to BACT and assuming 100% utilization of the WEB source, beginning with the first full calendar year of operation and in accordance with the provisions of Chapter 14, Section 2(f)(vi).

2. Existing sources that increase production are eligible to receive allowances from the new source set-aside equal to:

(i) the permitted annual sulfur dioxide emission limit for a new unit; or

(ii) the permitted annual SO_2 emission increase for the WEB source due to the replacement of an existing unit with a new unit or the modification of an existing unit that increased the production capacity of the WEB source.

Permitted emission increases due to fuel switching or other process changes that are not directly related to increased production capacity are not eligible for allocations from the new source set-aside. The allocation from the new source set-aside in the first year of operation will be adjusted to account for the number of days that the source is operating in that first year.

EXAMPLE. A new unit with a nameplate capacity of 400 MW is constructed at a power plant with two existing units with nameplate capacities of 400 MW and 300 MW. The two existing units install SO_2 controls and reduce emissions to meet PSD requirements for the construction of the new unit. In this example, the source would continue to receive a floor and a reducible allocation for each of the existing units, and would also be eligible to receive an allocation from the new source set-aside for the new unit. Even though total SO_2 emissions will decrease at this plant due to the construction of the new unit, the allowances allocated to the source will increase to reflect the increase in production capacity of 400 MW of electricity. If the new unit comes on line on July 1 the allocation for the first year will be reduced by 50 percent because the unit was operational for half of the year.

(b) Allocations from the new source set-aside will remain constant for the applicable WEB source and will be made on an annual basis by March 31 of each year for the current control period. When the next five-year allocation block is distributed as outlined in Part C1.2 of this section, all sources with an allocation under the new source set-aside will receive a five-year allocation block from the new source set-aside, and will continue to receive this allocation in future five-year allocation blocks.

(c) Owners or operators of new WEB sources or modified WEB sources that meet the eligibility requirements of (1) may apply for an allocation from the new source set-aside by submitting a written request to the Department as outlined in Chapter 14, Section 2(f)(vi).

(d) The Department will review the application for an allocation for accuracy and completeness, and will notify the source of intent to distribute allocations from the regional new source set-aside pending verification that allowances are available in the new source set-aside account. The Department will then forward the request to the TSA.

(e) The TSA will document the date that the request is received by the TSA. Requests for allocation of allowances from the new source set-aside will be processed in the order received. The TSA will deduct the number of allowances requested from the regional new source set-aside that was established by the participating states and tribes, and will then record an equal number of allowances in the source's compliance account for each remaining year of the five-year period. The TSA will then send written notification to the source and to the Department that the allowances have been recorded in the source's compliance account.

(f) If there are insufficient allowances remaining in the new source set-aside to fulfill the request, the source must ~~to~~ purchase the allowances required to demonstrate compliance. Any eligible WEB source that does not receive an allocation from the new source set-aside because the set-aside was depleted will be first in line to receive an allocation when the new source set-aside is increased in the next five-year period as outlined in Section C1.1(b)3 of this Plan. If there is more than one such source, their allocation requests will be processed in the order they were received by the TSA.

(g) A source that has received a retired source exemption and continues to receive an allocation as a retired WEB source is not eligible to receive an allocation from the new source set-aside.

C1.4 Regional Tribal Set-aside

(a) Each year after the program is triggered for which allowances are allocated, 2,500 allowances will exist as a tribal set-aside.

(b) The tribal caucus of the WRAP has stated its intent to determine the means for distributing the allowances among the tribes by one year after the program trigger date. The Department understands that there will be a process that shall meet the tracking and data security requirements of the allowance tracking system by which a tribe shall move its set-aside allowances into the trading program for the purposes of trading.

(c) The State recognizes that the tribal set-aside allowances are bonus allowances for the tribes and as such, are separate and additional to any allowances included in a tribal budget or the new source set-aside as outlined in the allocation report in Part C1.1(b)(1) of this section.

C1.5. Opt in Sources. The State of Wyoming is deferring inclusion of provisions for opt-in sources until a future SIP revision to allow time to thoroughly consider how to provide the flexibility and potential benefits to the market by expanding the program while also ensuring that the SO_2 emission reductions goals are maintained.

C2 WEB Emissions and Allowance Tracking System (WEB EATS)

The Department will provide a centralized system for the tracking of allowances and emissions within the framework of the SIP. The centralized system will be referred to as the WEB

Emissions and Allowance Tracking System (WEB EATS). The WEB EATS must provide that all necessary information regarding emissions, allowances, and transactions is publicly available in a secure, centralized database. The EATS must ensure that each allowance is uniquely identified, allow for frequent updates, and include enforceable procedures for recording data.

The Department shall work cooperatively with other states and tribes participating in the WEB Trading Program to designate this system. The Department shall be responsible for ensuring that all the EATS provisions are completed as described in this Plan.

The EATS will not exist unless the program is triggered. Prior to the implementation of the WEB Trading Program, a separate emissions tracking database will be employed to track the ongoing emissions of sources emitting SO_2 at amounts equal to or greater than 100 tons per year. The emissions tracking database, used to track and measure SO_2 emissions against the milestones, will still exist once the WEB Trading Program is triggered; however, it shall become incorporated into the SO_2 Emissions and Allowance Tracking System. Both the emissions tracking database and the EATS shall be centralized systems with data posted in a format, including an electronic, Web-based program, and available to all persons.

The participating states and tribes shall contract with a common Tracking System Administrator to service and maintain the WEB EATS. It is envisioned that the EATS will require the use of a contracted consultant or database design engineer to create a secure, efficient and transparent tracking system. Because the EATS shall be utilized by all states and tribes participating in the program, the design will require a uniform approach and level of security that will satisfy regional needs and concerns as well as meet the electronic, Web-based, access needs and security provisions. Due to the dynamic needs of the marketplace, the EATS will require a database that will reflect the current status of allowances and allowance transactions. The EATS shall be operational within one year after the program trigger date.

Specifications of the WEB EATS such as emissions tracking, the recording of allowance transactions, account management, system integrity and transparency are outlined in the WEB Emissions and Allowance Tracking System (EATS) Analysis. The EATS Analysis and related sections of Chapter 14, Section 2 detail how a WEB source will register for the EATS and how the source will, through an account representative, establish accounts, transfer allowances, and track unused allowances from a previous year. The account representative will also look to the Analysis to determine the appropriate interface with the EATS.

Neither the Department nor the TSA shall adjudicate any dispute concerning the authorization of any Account Representative with regard to any representation, action, inaction, or submission of the Account Representative.

As an example of how the WEB EATS will generally function, once the WEB Trading Program is triggered a WEB source will have its allowance allocation determined. On a parallel track, the WEB source's account representative will register for the EATS under Section 2(e) of Chapter 14, and a compliance account will be established under Section 2(g) of Chapter 14. Each allowance will be assigned a serial number. The allowance serial number will be used by the WEB EATS to track allowance allocations, transfers (Section 2(i) of Chapter 14), deductions, and account for any unused allowances from a previous year (Section 2(j) of Chapter 14). The serial number will also be assigned each allowance recorded in a general account, an account for allowances that are not held to meet program compliance requirements. Furthermore, the EATS will track tribal allowance set-asides and new source allowance set-asides not yet assigned to either a compliance or general account.

It is important to note that while an effort has been made in this Plan to provide a design for and an operational understanding of the EATS, the components of the EATS will need to be examined and possibly altered upon each required SIP revision.

C3 Allowance Transfers

Allowance transfers are defined as the conveyance from one account to another account (compliance account or general account) of one or more allowances by whatever means, including but not limited to purchase, trade, or gift in accordance with the procedures established in Section 2(i) of Chapter 14. This includes transfer of allowances for the purpose of retirement. Once an allowance is retired, it is no longer available for transfer to or from any account. Allowances may be purchased by any party for the purpose of retirement.

The Tracking System Administrator shall have specific recording requirements involving transfers. These required procedures will be detailed in the service contract but are outlined here as well.

C3.1 Recording of Allowance Transfers

Within five business days of receiving an allowance transfer, except when the transfer does not meet the requirements of this section, the Tracking System Administrator shall record an allowance transfer by moving each allowance from the transferor account to the transferee account as specified by the request, provided that:

(a) The transfer is correctly submitted; and
(b) The transferor account includes each allowance identified in the transfer.

Any allowance transfer that is submitted for recording following the allowance transfer deadline and that includes any allowances allocated for a control period prior to or the same as the control period to which the allowance transfer deadline applies, shall not be recorded until after completion of the compliance account reconciliation.

Where an allowance transfer submitted for allowance transfer recording fails to meet the requirements of this section, the Tracking System Administrator shall not record such transfer.

C3.2 Notification of the Recording of Allowance Transfers

The Tracking System Administrator has specific responsibilities involving the notification of the recording of any transferred allowances, including the failure to record any transfer of allowances. Again, these required procedures will be outlined in the service contract, but will include what is outlined here.

(a) Within five business days of the recording of an allowance transfer, the Tracking System Administrator shall notify the Account Representatives of both the transferor and transferee accounts, and make the transfer information publicly available on the Internet.

(b) Within five business days of receipt of an allowance transfer that fails to meet the requirements of Section 2(i) of Chapter 14, the Tracking System Administrator shall notify the Account Representatives of both accounts of the decision not to record the transfer, and the reasons for not recording the transfer.

C4 Use of Allowances From a Previous Year

C4.1 Background

Unused allowances may be kept for use in future years in accordance with Section 2(j), Chapter 14.

Allowances kept for use in future years may be used in calendar year 2018 only to the extent that the Implementation Plan guarantees that such allowances will not interfere with the achievement of the 2018 milestone. Section 2(j)(iv), Chapter 14 addresses this requirement by prohibiting the use, after the year 2017, of allowances allocated for the years 2003 - 2017. This provision ensures that actual emissions will be less than the 2018 milestone because only allowances allocated for the year 2018 could be used to show compliance in that year. The provision also maintains flexibility by resetting the baseline to the year 2018 and then allowing sources to once again use extra allowances to show compliance in any future year. This flexibility is important for sources that have variable operations because the source may build up a reserve of unused allowances for use in a high production year.

Increased flexibility and early reduction stimulus are a benefit to allowing the WEB source to tap the previous year's unused allowances.

Because the regional haze SIP is based on reasonable progress requirements related to the remedying or prevention of any future visibility impairment, it is important to assure the use of these allowances will not interfere with attainment or maintenance of any reasonable progress goals. The safeguard employed here to mitigate this type of risk is termed, "flow control".

C4.2 Flow Control Provisions

At the end of each control period, WEB sources may transfer allowances in and out of their compliance account for a period of 60 days to ensure that the account will contain enough allowances to cover sulfur dioxide emissions during the previous year. At the end of the sixty-day transfer period, allowances shall be deducted from the compliance account of each WEB source in an amount equal to the sulfur dioxide emissions of that source during the control period.

After the deductions have been completed, the Tracking System Administrator shall perform the following calculations and prepare a report according to Part C7.1(b) of this section.

(a) Determine the total number of allowances remaining in the allowance tracking system that were allocated for the just completed control period and all previous control periods.

(b) If the number calculated in (a) exceeds 10 percent of the milestone for the next control period, then the flow control procedures in Section 2(j)(iii) of Chapter 14 shall be triggered for that next control period. These flow control provisions will discourage the excessive use of allowances that were allocated for an earlier control period without establishing an absolute limit on their use. WEB sources will maintain the option to use allowances allocated for an earlier control period, but will be required to use two allowances for each ton of SO_2 emissions. Flow control operates as follows:

1. The flow control ratio shall be calculated by multiplying one tenth multiplied by the milestone for the next control period divided by the total number of unused allowances remaining in the system.

2. To calculate the number of prior-year allowances that can be used without restriction by a source for the next control period, the TSA shall multiply them by the flow control ratio. The resulting number of allowances may be used on a one-to-one ratio to show compliance with the source's allowance limitation as outlined in Section 2(k) of Chapter 14.

3. The remaining prior-year allowances may be used on a two-to-one ratio to show compliance. Thus, WEB sources will maintain the option to use allowances allocated for an earlier control period, but will be required to use two of those allowances for each ton of SO_2 emissions.

Example: On March 1, 2010 (the compliance transfer deadline for the 2009 control period) the Tracking System Administrator deducts allowances from the compliance account for each WEB source to cover 2009 SO_2 emissions from that source. After completing these deductions, the TSA reports the following information:

Total number of allowances still in the system for the years 2003 – 2009	=	30,000
2010 milestone	=	200,722
Percent of milestone	=	14.94%

Because the number of allowances not used in previous control periods is greater than 10% of the milestone, flow control procedures are triggered. In the annual report required in Part C7.1(b) of this section the TSA will then calculate the flow control ratio for 2010:

$$0.1 \times 2010 \text{ Milestone} \div \text{prior year allowances} = \text{flow control ratio}$$
$$0.1 \times 200{,}722 \div 30{,}000 = 0.70$$

On March 1, 2011 (the compliance transfer deadline for the 2010 control period) the TSA will apply the 2010 flow control ratio before deducting allowances from each WEB source's compliance account:

WEB Source A	2010 Allowances	=	1,000
	Remaining Prior Year Allowances	=	600
	2010 Emissions	=	1,580

In this example, the TSA would multiply the prior year allowances by 0.70 to determine the number of prior year allowances that could be used without restriction, at a one-to-one ratio. This would equal 420. The remaining prior year allowances would then be used at a 2:1 ratio. 360 allowances would be needed to cover the remaining 180 tons of SO_2 emissions. The TSA would therefore deduct a total of 1,780 allowances (1,000 + 420 + 360) to cover 1,580 tons of SO_2 emissions.

C5 Monitoring and Recordkeeping

C5.1 For WEB sources subject to 40 CFR part 75, the EPA Administrator shall quality assure and finalize the data for submission to the Tracking System Administrator. For WEB sources subject to WEB Trading Monitoring Protocols in Appendix A of Chapter 14 of the Wyoming Air Quality Standards and Regulations, the Department shall quality assure and finalize the data in accordance with these provisions for submission to the Tracking System Administrator.

C5.2 The Department shall verify and submit data to the emissions tracking database as soon as reasonably feasible after annual emissions are reported by the WEB sources. *Note: these timelines will be modified, as necessary, according to the monitoring protocols.*

C5.3 *Special Reserve Compliance Accounts*. The WEB Trading Program requires most WEB sources to install continuous emission monitoring systems (CEMS) that meet the monitoring, recordkeeping and reporting requirements of 40 CFR part 75. However, there are some emission units that are not physically able to install CEMS and there are also emission units that do not emit enough sulfur dioxide to justify the expense of installing these systems (see Chapter 14, Section 2(h)(i)(B)). The WEB Trading Program allows these emission units to continue to use their pre-trigger monitoring methodology, but does not allow the WEB source to transfer any allowances that were allocated to that unit for use by another WEB source. The restriction on transferring these allowances is needed to ensure that an emission reduction of sulfur dioxide and the corresponding increase in sulfur dioxide are equal. The allowances associated with emission units that continue to use their pre-trigger monitoring methodology are placed in a special reserve compliance account, while allowances for other emission units are placed in a regular compliance account. Allowances may not be traded out of a special reserve compliance account, even for use by emission units with CEMS at the same WEB source. However, the WEB source may use allowances in the compliance account to demonstrate compliance with the WEB source's allowance limitation.

Chapter 14, Section 2(h)(i)(B)(I) allows WEB sources with any of the following emission units to apply to establish a special reserve compliance account:

(a) any smelting operation where all of the emissions from the operation are not ducted to a stack; or

(b) any flare, except to the extent such flares are used as a fuel gas combustion device at a petroleum refinery; or

(c) any other type of unit without add-on sulfur dioxide control equipment, if the unit belongs to one of the following source categories: cement kilns, pulp and paper recovery furnaces, lime kilns, or glass manufacturing.

The emission units described in (a) and (b) cannot physically be monitored using a CEM. The emission units described in (c) do not typically have add-on controls for sulfur dioxide. These units, addressed in Chapter 14, Section 2(h)(i)(B), are expected to operate within their floor-level allocation and therefore will not be affected by the market, unless they make a process change and wish to sell allowances on the market. Other sources that are meeting the more rigorous monitoring requirements of Chapter 14, Section 2(h)(i)(A) and emit sulfur dioxide above their expected allocation will either need to purchase allowances or install sulfur dioxide controls. Therefore, it is important that all emission units that participate in emissions trading have an accurate monitoring methodology that is comparable to other sources in the program to ensure that a ton of reductions is the same regardless of where the reductions originate.

The Department will review the application to monitor under Chapter 14, Section 2(h)(i)(B)(I). If the emission units meet the criteria in Chapter 14, Section 2(h)(i)(B)(I), the Department will determine the portion of the WEB source's allocation that is associated with the emission units that will be monitored under Chapter 14, Section 2(h)(i)(B)(I) and will require the TSA to record that portion of the WEB source's allocation in the special reserve compliance account. The Department will use the methodology for determining allocations described in Section C1.1 of this Plan to determine the portion of the allocation that is associated with emission units monitored under Chapter 14, Section 2(h)(i)(B)(I). The Department will notify the WEB source that the application has either been accepted or rejected, including a notification of the allowances that are to be recorded in the WEB source's regular compliance account and the special reserve compliance account.

If an emission unit that is monitored under Chapter 14, Section 2(h)(i)(B)(I) is permanently retired, the TSA will transfer the portion of allowances that were associated with that emission unit from the WEB source's special reserve compliance account to the source's compliance account. These allowances will then be available for use or sale by the WEB source. The allowances will be transferred after the compliance deduction has taken place for the last control period that the unit was in operation.

C6 Compliance and Penalties

C6.1 Compliance, Excess Emissions, and Penalties

When a WEB source exceeds its allowance limitation in Section 2(k) of Chapter 14, the Department shall require the Tracking System Administrator to deduct allowances from the following year's allocation in an amount equal to three times the WEB source's emissions of SO_2 in excess of its allowance limitation. This deduction shall be made from the WEB source's compliance account after deductions for compliance under Section 2(k) of Chapter 14. If sufficient allowances do not exist in the compliance account for the next control period to cover this amount, the Department shall require the Tracking System Administrator to deduct the required number of allowances, regardless of the control period for which they were allocated, whenever the allowances are recorded in the account.

Under the rule, sources may also be liable for penalties for each day of violations of the program's other requirements.

C7 Periodic Evaluation of the Trading Program

C7.1 Annual Report

(a) Beginning one year after compliance with the trading program is required, the Department shall obtain from the Tracking System Administrator an annual report that contains the following information:

1. The level of compliance program-wide;

2. A summary of the use and transfer of allowances, both geographically and temporally;

3. A source-by-source accounting of allocations compared to emissions;

4. A report on the use of unused allowances from a previous year in order to determine whether these emissions have or have not contributed to emissions in excess of the cap.

5. The total number of WEB sources participating in the trading program and any changes to eligible sources, such as retired sources, or sources that emit more than 100 tons of SO_2 after the program trigger date.

(b) Within 10 months after the allowance transfer deadline for each control period when compliance with the trading program is required, the Tracking System Administrator shall prepare a draft report that lists:

1. the total number of allowances deducted for the control period,

2. the total number of allowances remaining in the Allowance Tracking System allocated for that control period and any earlier control period,

3. proposed determination that flow control procedures have either been triggered or have not been triggered for the next control period, and

4. if flow control procedures have been triggered, a draft flow control ratio calculated according to Part C4.2 of this section.

(c) The Department shall evaluate the draft report, and shall propose a determination that flow control procedures have either been triggered or have not been triggered for the next control period.

(d) The Department will publish a notice of availability of the draft report in newspapers of general circulation throughout Wyoming, and will hold a 30-day public comment period.

(e) After the comment period the Department will make a final determination that the flow control procedures have either been triggered or have not been triggered for the next control period. If the flow control procedures have been triggered, the Department will notify all WEB sources in Wyoming that flow control procedures will be in effect during the next control period.

C7.2 Five-year Evaluation

(a) The Department will work cooperatively with other participating states and tribes to conduct an audit of the WEB Trading Program no later than three years following the first full year of the trading program, and at least every five years thereafter. This evaluation does not replace the Implementation Plan assessments in 2013 and 2018. The evaluation will be conducted by an independent third party and include an analysis of:

1. Whether the total actual emissions could exceed the values in Table 1 of this Implementation Plan of the WEB Trading Program even though sources comply with their allowances;

2. Whether the program achieved the overall emission milestone it was intended to reach;

3. The effectiveness of the compliance, enforcement and penalty provisions;

4. A discussion of whether states and tribes have enough resources to implement the WEB Trading Program;

5. Whether the trading program resulted in any unexpected beneficial effects, or any unintended detrimental effects;

6. Whether the actions taken to reduce sulfur dioxide have led to any unintended increases in other pollutants;

7. Whether there are any changes needed in emissions monitoring and reporting protocols, or in the administrative procedures for program administration and tracking; and,

8. The effectiveness of the provisions for interstate trading, and whether there are any procedural changes needed to make the interstate nature of the program more effective.

9. The integrity of the emissions and allowance tracking system, including whether the procedures for recording transactions are adequate, whether the procedures are being followed and in a timely manner, whether the information on sources' emissions are accurately recorded, whether the emissions and allowance tracking system has procedures in place to ensure that the transactions are valid, whether back-up systems are in place to account for problems with loss of data.

(b) The public shall have an opportunity to participate in this trading program evaluation.

(c) In the event that any audit results in recommendations for program revisions, Wyoming, in consultation with the WRAP, will make appropriate modifications to this Plan. Wyoming will revise this Plan if the program is not meeting its emission reduction goals.

(d) The Department shall submit a copy of the report to the EPA regional office.

C8 Retired Source Exemption

Section 2(c)(iv), Chapter 14 outlines the procedure that a WEB source must follow to receive a retired source exemption. The exemption would allow the source to continue to receive an allocation, but would exempt the source from monitoring and recordkeeping requirements. The Department shall notify the source of its obligation to apply for a retired source exemption upon the cancellation or relinquishment of a permit.

In order to receive a retired source exemption, the source must submit a request for the exemption to the Department. The Department shall review this request, and within sixty days of receipt of the request shall notify the source that the retired source exemption has been granted or has been rejected. If the exemption has been rejected, the notification shall contain an explanation of the reasons for rejecting the request.

The Tracking System Administrator shall record an allocation to a WEB source that has received a retired source exemption. However, the allowances shall be recorded in a general account rather than a compliance account for the source. The TSA will transfer any existing allowances in the retired source's compliance account or special reserve compliance account into the general account for the retired source, and will close the compliance accounts.

A WEB source that is permanently retired and that does not request a retired source exemption shall forfeit all abandoned allowances in that source's compliance account, as outlined in Section 2(c)(iv), Chapter 14. The forfeited allowances shall not be redistributed to other sources, and shall be permanently retired from the Allowance Tracking System, as outlined in Section 2(c)(iv)(E), Chapter 14. During the next five-year allowance distribution period the retired source shall not receive an allocation, and the allowances that would have been distributed to that source shall be added to the new source set-aside.

C9 Integration Into Permits

It is expected that all WEB sources will at least initially be subject to Wyoming's Title V permitting requirements. Under Chapter 6, Section 3, Wyoming's approved Title V permitting program, the pre- and post-trigger requirements of the market trading program fall under the definition of "applicable requirements", and will be incorporated into each source's Title V permit. Chapter 6, Section 3 requires that any source that for any reason and at any time is not required to have a permit under Chapter 6, Section 3 must obtain a New Source Review permit pursuant to Chapter 6, Section 2 et seq. that incorporates the pre- and post-trigger requirements. Both types of permits are enforceable federally and by citizens pursuant to Wyoming's SIP.

Part D— Miscellaneous Provisions for Stationary Sources

D1 Requirements of 2013 SIP Revision

In addition to the requirements of 40 CFR 51.309(d)(10), the 2013 SIP shall contain:

1. Source-specific allocations for all WEB sources under the jurisdiction of the Department for the year 2018; and

2. Either the provisions of a program designed to achieve reasonable progress for stationary sources of SO_2 beyond 2018 or a commitment to submit a SIP revision containing the provisions of such a program no later than December 31, 2016. The program will ensure that the requirements of 40 CFR 51.309 for the first planning period are achieved, including requirements that cannot be measured until after 2018, such as the determination of compliance with the 2018 milestone.

Adjustments in Allocation Calculations

This 2013 SIP revision will provide certainty to sources regarding their potential liability under the special penalty provisions for the year 2018 outlined in Part A5 of this section. The calculation of these allocations is delayed until 2013 to provide certainty about the number of sources that would qualify as WEB sources at that time; the allocations needed for new sources in the region; and early reductions that would need to be included in the allocation process. It is difficult to estimate the impact of these factors in 2003 because many things may change during the next 10 years.

If the 2018 milestone is not met, the starting point for the next planning period shall be the 2018 milestones, not actual emissions in 2018.

D2 Achievement of 13 Percent SO_2 Emission Reduction

Pursuant to 40 CFR 51.309(d)(4)(ii), the State of Wyoming has determined that a 13 percent reduction in actual stationary source SO_2 emissions has occurred between the years 1990 and 2000. Table 3 below provides a state-by-state comparison of these emissions, and shows that there has been a 25 percent reduction from 1990 to 2000 for all states (from 828,775 tons to 621,838 tons). The current emissions and modeling data and results for stationary sources in the WRAP region are now available through the WRAP TSS (http://vista.cira.colostate.edu/tss). The methodology and data for the revised SO_2 Milestone Program are available at: http://www.wrapair.org/forums/309/docs.html. Tracking pre-trigger stationary source SO_2 emissions is found in Section 4.3 of Chapter 4 of the WRAP TSD.

Table 3. State-by-State Comparison of SO_2 Emission Reductions, 1990-2000 (in tons per year)

States	1990	2000
Arizona	185,398	99,133
California	52,832	38,501
Colorado	95,534	99,161
Idaho	24,652	27,763
Nevada	52,775	53,943
New Mexico	177,994	117,344
Oregon	17,705	23,362
Utah	85,567	38,521
Wyoming	136,318	124,110
Totals	**828,775**	**621,838**

D3 Provisions for Stationary Source NO_x and PM

Assessment of need for NO_x and PM milestones. Pursuant to 40 CFR 51.309(d)(4)(v), the State of Wyoming has evaluated the need for NO_x and PM emission control strategies, the degree of visibility improvement expected, and whether such milestones are needed to avoid any net increase in these pollutants. This evaluation was made by the WRAP Market Trading Forum for all WRAP states, including the transport region states.

Several conclusions were reached based on current analyses. These include:

(a) That for the vast majority of Mandatory Federal Class I areas throughout the WRAP region stationary source NO_x and PM emissions are not a major contributor to visibility impairment;

(b) That RAVI remedies are available in cases where particular stationary sources may impact particular Class I areas;

(c) Analysis for NO_x and PM impacts in the 2007 309(g) SIP submittal has reaffirmed the position that the absolute need for milestones to support potential market-based programs is not yet established.

The initial assessment of the need for NO_x and PM long-term strategies is provided in the Wyoming TSD. The State of Wyoming will continue to work with the WRAP to improve the emission inventories and regional modeling to support future policy decisions regarding stationary source NO_x and PM emissions. The State of Wyoming has made an additional preliminary assessment on the need for long-term strategies for stationary sources of PM and NO_x in the 309(g) SIP submittal due in 2007. NO_x and PM long-term strategies are discussed in the 309(g) SIP submittal, with commitments to reassess in SIP updates for 2013 and 2018.

2. Applicable WRAP Reports and Documents

Chapter 4, Section 4.3 of the TSD Development Plan provides a summary of the method for tracking and reporting stationary source emissions covered in the backstop trading program, through the WRAP emissions data system. The current emissions and modeling data and results for stationary sources in the WRAP region are now available through the WRAP TSS (http://vista.cira.colostate.edu/tss). The methodology and data for the revised SO_2 Milestone Program are available at: http://www.wrapair.org/forums/309/docs.html.

The *Western Emissions Backstop Emissions Trading and Allowance Tracking System (EATS) Analysis* report describes how emissions, allocations, and transactions will occur if the backstop trading program is triggered. This report is described further in the Wyoming TSD.

Stationary Source NO_x and PM Emissions in the WRAP Region: An Initial Assessment of Emissions, Controls and Air Quality Impacts reviews possible emission control strategies for stationary sources of NO_x and PM, and the degree of visibility improvement that would result from such strategies. The report is described further in the Wyoming TSD.

Section D. Mobile Sources

1. Inventory and Determination of Significance of Mobile Source Emissions

(a) Inventory of Current and Projected Emissions from Mobile Sources. Pursuant to 40 CFR 51.309(d)(5)(i), the State of Wyoming, in collaboration with the WRAP, assembled a comprehensive statewide inventory of mobile source emissions. The emission inventory showed the year with the lowest level of emissions would be the end of the SIP planning period in 2018 or perhaps later instead of 2005 as anticipated by the GCVTC. The substantial reduction of projected mobile source emissions from 2003 to 2018 is due to the adoption of new on-road and non-road vehicle emission and fuel standards by EPA.

(b) Program to Assure Continuous Decline in Mobile Source Emissions. Pursuant to 40 CFR 51.309(d)(5)(i)(A), the State of Wyoming commits to monitoring the emissions from mobile sources to assure a continuous decline in VOC, NO_x, $PM_{2.5}$, EC and OC emissions as defined in 40 CFR 51.309(b)(6). The table below demonstrates Wyoming's continuous decline in mobile source emissions over the period of 2002-2018. Since a decline is demonstrated, no further action is required to address mobile source emission of these pollutants.

Table D-1. Mobile Source Inventory for 2002, 2008, 2013 and 2018

Wyoming Emissions by Source Category		Sulfur Dioxide (SOx)	Nitrogen Oxide (NOx)	Organic Carbon <2.5 Microns (OC)	Elemental Carbon <2.5 Microns (EC)	$PM_{2.5}$	Volatile Organic Carbon Gases (VOC)
Mobile Sources- On-Road	2002	2.6	105.6	0.8	1.2	2.2	39.1
	2008 w/309	0.2	68.1			1.6	23.6
	% Change (2002-2008)	-92%	-36%			-27%	-40%
	2013 w/309	0.2	42.9			1.2	17.9
	% Change (2008-2013)	0%	-37%			-25%	-24%
	2018 w/309	0.2	26.7	0.7	0.2	1.0	14.5
	% Change (2013-2018)	0%	-38%			-17%	-19%
	% Change (2002-2018)	-92%	-75%	-13%	-83%	-55%	-63%
Mobile Sources- Non-Road	2002	16.1	210.1	1.7	5.5	8.5	37.7
	2008 w/309	3.6	170.9			7.9	37.5
	% Change (2002-2008)	-78%	-19%			-7%	-0.5%
	2013 w/309	0.2	166.0			7.2	33.5
	% Change (2008-2013)	-94%	-3%			-9%	-11%
	2018 w/309	0.2	162.7	1.3	4.0	6.5	28.9
	% Change (2013-2018)	0%	-2%			-10%	-14%
	% Change (2002-2018)	-99%	-23%	-24%	-27%	-24%	-23%
TOTAL MOBILE EMISSIONS IN WYOMING	2002	18.7	315.7	2.5	6.7	10.7	76.8
	2008 w/309	3.8	239.0			9.5	61.1
	% Change (2002-2008)	-80%	-24%			-11%	-20%
	2013 w/309	0.4	208.9			8.4	51.4
	% Change (2008-2013)	-89%	-13%			-12%	-16%
	2018 w/309	0.4	189.4	2.0	4.2	7.5	43.4
	% Change (2013-2018)	0%	-9%			-11%	-16%
	% Change (2002-2018)	-98%	-40%	-20%	-37%	-30%	-43%

Notes: 1) Values are in average annual TPD; 2) Organic carbon (on-road), elemental carbon (on-road) and PM values include exhaust, brake wear and tire wear emissions. Data was available for 2002 and 2018 only for organic and elemental carbon; 3) Non-road values do not include commercial marine; 4) This information was taken from spreadsheets from ENVIRON, who developed updated on-road and off-road mobile source emissions inventories for 14 Western states for the 2002 base year and for three future years - 2008, 2013, and 2018. Emissions were estimated for an average weekday for each of the four seasons. ENVIRON surveyed state and local air quality planning agencies and also metropolitan planning organizations (MPOs) to obtain the most up-to-date mobile source activity data and control program information. On-road mobile source emissions were estimated with EPA's Draft NONROAD2004 model. Locomotive emissions were estimated based on locomotive fuel consumption. Aircraft emissions were based on aircraft landing and takeoffs and FAA EDMS emission factors. Commercial marine emissions were estimated using a variety of activity data sources and EPA emission factors.

(c) Long-Term Strategies Necessary to Reduce Emissions of SO_2 From Non-Road Mobile Sources. Pursuant to 40 CFR 51.309(d)(5)(i)(B), the State of Wyoming reviewed estimated SO_2 emissions from non-road mobile sources. For the period of 2002-2018 a 99% reduction in emissions has been calculated. This is shown in Table D-1. This reduction has been achieved through the promulgation of EPA's new rule on "Control of Emissions of Air Pollution From Non-road Diesel Engines and Fuel" (Final Rule June 29, 2004). A 99% reduction in SO_2 from non-road mobile sources is consistent with the goal of reasonable progress.

2. State of Wyoming Long-Term Strategy for Mobile Sources

Pursuant to 40 CFR 51.309(d)(9) and 40 CFR 51.309(d)(5)(iv), the State of Wyoming recognizes efforts of EPA to reduce emissions from mobile sources through the national programs for vehicle emissions and fuel standards. Actions taken by EPA have resulted, or will result, in significant mobile source emission reductions that will positively impact visibility in the 16 Colorado Plateau Class I areas and additional Mandatory Federal Class I areas. The methods for incorporating federal and state emissions control programs are detailed in a series of reports specific to point, area, mobile, fire, and dust sources. The references for these reports are now available through the WRAP TSS (http://vista.cira.colostate.edu/tss).

3. Applicable WRAP Reports and Documents

The current emissions and modeling data and results for mobile sources in the WRAP region are now available through the WRAP TSS (http://vista.cira.colostate.edu/tss).

See EPA *Revisions to the Regional Haze Rule To Correct Mobile Source Provisions in Optional Program for Nine Western States and Eligible Indian Tribes,* 68 FR 39842, July 3, 2003, and 5/6/03 WRAP letter to EPA entitled *Significance of Mobile Source Emissions for the Purpose of Section 309 of the Regional Haze Rule.* The rule eliminated the requirements in 309(d)(5)(ii) and (iii) related to determining if mobile sources are a significant contributor, and instead modified 309(d)(5)(i) to require showing a continuous decline in emissions from 2003-2018.

E. Long-Term Strategy for Fire Programs

The WRAP's effort to document and understand the incidence of fire and its effect on visibility in Mandatory Federal Class I areas has been extensive and productive. WRAP modeling shows that prescribed fire emissions will continue to affect visibility. The current emissions and modeling data and results for fire sources in the WRAP region are now available through the WRAP TSS (http://vista.cira.colostate.edu/tss). The WRAP Fire Emissions Tracking System (FETS) was implemented in 2007 to address the ongoing fire tracking requirement for §309 regional haze plans.

1. Prescribed Fire Program Evaluation

Pursuant to 40 CFR 51.309(d)(6)(i), the State of Wyoming has evaluated its existing WAQSR Chapter 10, Section 2 Open burning restrictions and all Federal, State, and private prescribed fire smoke management programs in the State, based on the potential to contribute to visibility impairment in the 16 Class I areas of the Colorado Plateau, and how visibility protection from smoke is addressed in planning and operation. The State of Wyoming relied upon the WRAP report *Assessing Status of Incorporating Smoke Effects into Fire Planning and Operation*[1] as well as EPA's *Interim Air Quality Policy on Wildland and Prescribed Fires* as guides for making this evaluation. The State of Wyoming has also evaluated whether the State's existing WAQSR Chapter 10, Section 2 and these prescribed fire smoke management programs contain the following elements: actions to minimize emissions; evaluation of smoke dispersion; alternatives to fire; public notification; air quality monitoring; surveillance and enforcement; and program evaluation.

The result of this evaluation was the determination that revisions to the existing WAQSR Chapter 10, Section 2 Open burning restrictions as well as a new Smoke Management Regulation, to be incorporated as WAQSR Chapter 10, Section 4, would be required to meet the requirements of 40 CFR 51.309(d)(6)(i). WAQSR Chapter 10, Section 4 will establish requirements for vegetative burning sources for the management of emissions and air quality impacts from smoke on public health and visibility. A companion Smoke Management Program Guidance Document will also be developed by the State of Wyoming and will address the following elements: actions to minimize emissions; evaluation of smoke dispersion; alternatives to fire; public notification; air quality monitoring; surveillance and enforcement; and program evaluation.

A comprehensive stakeholder process to develop the new Smoke Management Regulation was initiated by the State of Wyoming in 2003, and will culminate in the initiation of the rulemaking process in December of 2003. The State of Wyoming will phase-in WAQSR Chapter 10, Section 4 during a six to eight month period after it becomes State-approved in 2004. This phase-in period will consist of an extensive public education and outreach effort by the State of Wyoming to garner full participation and compliance with WAQSR Chapter 10, Section 4.

1 All WRAP and EPA documents cited in Part E are available in the Wyoming TSD Supplement.

2. Emission Inventory and Tracking System

Pursuant to 40 CFR 51.309(d)(6)(ii), a system was established in 2007 to develop a tracking system and an emissions inventory for the following pollutants: VOC, NO_x, elemental and organic carbon, and fine particulate for fire sources within the State of Wyoming. WAQSR Chapter 10, Section 4 will require burn project reporting and the State of Wyoming will record the required burn project reporting information in a tracking system. For consistency, the State of Wyoming will use the emissions tracking system developed by the WRAP as defined by the WRAP *Policy on Fire Tracking Systems.* This policy identifies a process for gathering the essential post-burn activity information necessary to consistently calculate emissions and uniformly assess fire impact on regional haze. This policy is the basis for creating a fire emissions inventory within the State of Wyoming, using an emissions calculation mechanism developed by the WRAP. In addition, fire emission inventory updates will be provided in future progress reports, as part of the periodic implementation plan revisions, pursuant to 40 CFR 51.309(d)(10). See the WRAP *Policy on Fire Tracking Systems* for further information on the emissions inventory and tracking system to be utilized in Wyoming.

3. Strategy for Use of Alternatives to Burning

The State of Wyoming is continuing to develop a process with key public and private entities to identify and remove administrative barriers to the use of alternatives to burning to prescribed fire on Federal, State, and private lands, pursuant to 40 CFR 51.309(d)(6)(iii). The process is collaborative and provides for continuing identification and removal of administrative barriers, and considers economic, safety, technical and environmental feasibility criteria, and land management objectives.

WAQSR Chapter 10, Section 4 will require the consideration and identification of alternatives to burning being planned and utilized. If alternatives to burning are not used, rationale will be required to be submitted to the State. The State of Wyoming will continually collect and assess this data to determine whether administrative barriers to the use of alternatives to burning exist. Should the State determine that an administrative barrier exists, the State will work collaboratively with the appropriate public and private entities to evaluate the administrative barrier, identify the steps necessary to remove the administrative barrier, and initiate the removal of the administrative barrier, where it is feasible to do so, as required by 40 CFR 51.309(d)(6)(iii). In addition, the process to identify and remove administrative barriers to the use of alternatives to burning will be addressed during the annual Smoke Management Program evaluation meeting.

The State of Wyoming will rely on the following documents as reference guides in the process for evaluating alternatives to burning: (1) *Nonburning Alternatives for Vegetation and Fuel Management*, and (2) *Burning Management Alternatives on Agricultural Lands in the Western United States*. These two documents were prepared by the WRAP and describe a variety of alternatives to burning and methods of assessing their potential applicability.

4. Enhanced Smoke Management Program

Pursuant to 40 CFR 51.309(d)(6)(iv), the smoke management programs that operate within the State of Wyoming shall be consistent with the WRAP *Policy on Enhanced Smoke Management Programs for Visibility*. This policy calls for programs to be based on the criteria of efficiency, economics, law, emission reduction opportunities, land management objectives, and reduction of visibility impacts. The WRAP *Policy on Enhanced Smoke Management Programs for Visibility* lists the previously identified elements under 40 CFR 51.309(d)(6)(i) as well as adding “burn authorization” and “regional coordination” elements to ensure visibility protection and meet the designation of “enhanced”.

The State of Wyoming evaluated the State’s existing WAQSR Chapter 10, Section 2 and concluded that a new Smoke Management Regulation, to be incorporated as WAQSR Chapter 10, Section 4, would be required to meet the requirements of 40 CFR 51.309(d)(6)(i) and be consistent with the WRAP *Policy on Enhanced Smoke Management Programs for Visibility*. The WAQSR Chapter 10, Section 4 and companion Smoke Management Program Guidance Document include burn authorization and regional coordination elements and are available in the Wyoming TSD Supplement.

5. Annual Emission Goal

Pursuant to 40 CFR 51.309(d)(6)(v), efforts will be made within the State of Wyoming to minimize emission increases in fire, excluding wildfire, to the maximum extent feasible, through the use of annual emission goals, in accordance with the WRAP *Policy on Annual Emission Goals for Fire*. This policy recognizes that emission reduction techniques can be used to minimize emissions from fire. The State of Wyoming will establish a collaborative mechanism for setting annual emission goals, and developing a process for tracking their attainment on a yearly basis.

The State of Wyoming intends to use this policy and quantify the emission reduction techniques that are being used within the State on a project-specific basis to reduce the total amount of emissions being generated from areas where prescribed fire is being used. The use of emission reduction techniques to meet this rule requirement is subject to economic, safety, technical and environmental feasibility, and land management objectives. The Wyoming TSD Supplement describes this process in more detail.

Section F. Paved and Unpaved Road Dust

1. Assessment of Emissions From Paved and Unpaved Road Dust

(a) Assessment of paved and unpaved road dust emissions. Pursuant to 40 CFR 51.309(d)(7), an assessment was made by the WRAP of the impact of dust emissions from paved and unpaved roads from transport region states on the 16 Class I areas of the Colorado Plateau. The current emissions data for road dust sources in the WRAP region are now available through the WRAP TSS (http://vista.cira.colostate.edu/tss). The State of Wyoming, in consultation with the WRAP, will perform further assessments of road dust impacts on visibility in the 16 Colorado Plateau Class I areas in the progress updates and status reports, and will submit implementation plan revisions as needed to make reasonable progress in the SIP amendments due in 2013 and 2018.

(b) Contribution to Visibility Impairment Finding. Pursuant to 40 CFR 51.309(d)(7) and the results of the assessment of the impact of road dust emissions described above, the State of Wyoming, in collaboration with other states through the WRAP, determined that road dust emissions are not a significant contributor at this time to regional haze visibility impairment within the Colorado Plateau 16 Class I areas. Based on these findings, no emission management strategies have been identified at this time. Wyoming will perform further assessments of road dust impact on visibility in the 16 Colorado Plateau Class I areas. The technical and policy foundation for this determination can be found in Chapter 7, Sections 7.2 and 7.3, of the WRAP TSD. The current emissions data for road dust sources in the WRAP region are now available through the WRAP TSS (http://vista.cira.colostate.edu/tss).

2. Applicable WRAP Reports and Documents

Technical reports and analysis related to the impact from paved and unpaved road dust for item (1) below are now available through the WRAP TSS (http://vista.cira.colostate.edu/tss). Information for items (2) through (4) enumerated below can be found in Sections 7.2 and 7.3 of Chapter 7 of the TSD. (1) a summary of 1996 and 2018 emission inventories for re-entrained road dust from paved and unpaved roads; (2) a description of the definition of significance for road dust in the 16 Class I areas; (3) road dust modeling results – regional versus localized impacts; and (4) discussion of finding of no significance.

Section G. Pollution Prevention

1. Description of Existing Pollution Prevention Programs in Wyoming

Pursuant to 40 CFR 51.309(d)(8)(i), Table G-1 summarizes all pollution prevention and renewable energy programs currently in place in Wyoming.

Table G-1. Summary of Renewable Energy Programs Currently in Place in Wyoming.

Policy Program Title	Statutory/Regulatory Citation	Program Description
Ethanol Production Tax Credit	Wyo. Stat.§ 39-17-109(d)	The Wyoming Ethanol Production Tax Credit, previously set to expire on July 1, 2003, was extended under HB 0005 in March of 2003. Under the tax credit, any person who has a tax liability for the sale of ethanol-based motor fuel or gasoline sold for the purpose of blending into an ethanol-based motor fuel may redeem a credit of \$0.40 per gallon, valid with the Wyoming Department of Transportation (DOT). Under the 2003 provisions, an ethanol producer must purchase at least 25% (previously \$1,000,000) of Wyoming origin products during the year the tax credits were earned. The total tax credits redeemed per ethanol producer must not exceed \$2,000,000 per year (\$4,000,000 for all tax credits). An ethanol producer constructing a new ethanol plant after July 1, 2003, may receive tax credits for a maximum of 15 years. Producers qualifying for the tax credit on or before July 1, 2003 may only receive the tax credit until June 30, 2009, unless there is an expansion in production of at least 25%, which may increase the amount of time a tax credit may be received.
Renewable Energy Sales Tax Exemption	Wyo. Stat. § 39-15-105(a)(viii)(N)	In 2003, under HB 188, the Wyoming legislature added sales of equipment used to generate electricity from renewable sources to the list of types of sales or leases which are exempt from the state excise tax. Renewable resources include wind generation, solar, biomass, landfill gas, hydro, hydrogen, and geothermal energy.

Policy Program Title	Statutory/Regulatory Citation	Program Description
		Equipment eligible for the exemption includes wind turbines, generating equipment, control and monitoring systems, power lines, substation equipment, lighting, fencing, pipes and other equipment for locating power lines and poles. Equipment not eligible for the exemption includes tools and other equipment used in the construction of a new facility, contracted services required for construction and routine maintenance activities, and equipment utilized or acquired after the project is operational. This exemption will be repealed on June 30, 2008.
Net Metering	Wyo. Stat. § 37-16-101 through § 37-16-104	House Bill 195 was passed by the House and Senate of the Wyoming legislature, and signed by the Governor on February 22, 2001. As a result, net metering took effect July 1, 2001. The rule applies to investor-owned utilities and rural electric cooperatives, and with passage of Senate File 106 in 2003, to municipal utilities. Eligible technologies under 2001 legislation include solar, wind, and hydro systems up to 25kW, with the addition of biomass in 2003. Excess generation is credited to the following month. When an annual period ends, the utility purchases unused credits at avoided cost. Systems must meet IEEE and UL standards and cannot be subject to additional interconnection requirements, although system owners must install a manual, lockable external disconnect.
Interconnection Standards	WY code 37-16-101 et. seq.	Wyoming's net metering law included basic interconnection requirements for systems generating up to 25kW of solar, wind, or hydropower, but the Wyoming Public Service Commission has not established separate interconnection rules, per se. There is no limit on overall enrollment specified within the law. Systems must comply with the National

Policy Program Title	**Statutory/Regulatory Citation**	**Program Description**
		Electric Code (NEC), Institute of Electrical and Electronic Engineers (IEEE), and Underwriters Laboratories (UL) safety and equipment standards. Customers must install an external disconnect switch at their own expense. Wyoming's Public Service Commission may make additional control and testing requirements. Additional liability insurance is not required. PacifiCorp (Pacific Power and Light) has developed a two-page interconnection agreement for net metering customers. Wyoming's Public Service Commission staff is discussing the development of standard interconnection rules for larger distributed generation systems.
Photovoltaic Grant Program	Wyoming Business Council through DOE formula grant funding	Wyoming's photovoltaic grant program offers grants of $3000 or 50%, whichever is less, to residents who install photovoltaic or phototaic hybrid systems on their homes. Approximately 70 grants have been provided over the course of the program, which began in July 1996. Funding for the program comes from DOE formula grant money (renewed July 1 annually) and is administered by the Energy, Minerals, and Transportation Division of the Wyoming Business Council. Both grid-connected and off grid systems are eligible. Program requirements include an application, a copy of the equipment invoice, pictures of the installation, and quarterly reports on the system during the first year of installation.
Pacific Power – Blue Sky	PacifiCorp	PacifiCorp's green pricing tariff program, named Blue Sky, began accepting participants in April 2000. The program allows customers to voluntarily pay a premium for renewable energy generated from new wind turbines. Pacific Power (serving Oregon, Washington, and Wyoming) and Utah Power (serving Utah) customers can subscribe to the Blue Sky program by paying $1.95/month for a 100kWh block. There is no limit to the

Policy Program Title	**Statutory/Regulatory Citation**	**Program Description**
		number of blocks available for purchase. As of March 2003, over 10,600 customers are participating in the Blue Sky program. Business customers have an extra incentive to participate. All businesses that commit to purchase a minimum of 4 blocks per month for one year will be featured in press releases, advertisements, and general marketing material. The program is certified by renew 2000. Marketing has included bill inserts, direct mail, telemarketing, mass media, and outreach using relationships with local environmental organizations.
Photovoltaic Leasing Program	Carbon Power and Light, Inc.	Carbon Power and Light Offers its customers a leasing program for photovoltaic systems, with an option to purchase equipment. Most solar systems are used to operate livestock watering installations. The utility provides all of the PV equipment, handles installation, and conducts routine maintenance of the systems. CP&L will cover all of the construction costs below the electric facilities allowance (EFA) cap of $2,500. The EFA is a standard line extension cost determined by the typical customer's average bill over a set number of years. The leasing period can extend for either five years or ten years. If a customer wishes to discontinue the lease, he or she can transfer the contract to another individual or purchase the system by paying off both the remaining balance of the line extension charges and the remainder of the monthly minimum amounts per the applicable rate tariff.

2. Inventory of All Renewable Energy Generation Capacity and Production in Wyoming

Pursuant to 40 CFR 51.309(d)(8)(i), Table G-2 summarizes all renewable energy generation capacity and production in use as of 2003 (expressed in kW).

Table G-2. Summary of Renewable Energy Generation Capacity and Production

Technology	Owner	Plant Name	Capacity (kW)
Hydro	Bureau of Reclamation	Alcova	36,000
Hydro	Bureau of Reclamation	Boysen	15,000
Hydro	City of Buffalo	Buffalo	245
Hydro	Bureau of Reclamation	Buffalo Bill	18,000
Hydro	Bureau of Reclamation	Fontenelle	10,000
Hydro	Bureau of Reclamation	Fremont Canyon	66,800
Hydro	Shoshone Irrigation District	Garland Canal	2,610
Hydro	Bureau of Reclamation	Glendo	38,000
Hydro	Bureau of Reclamation	Guernsey	6,400
Hydro	Bureau of Reclamation	Heart Mountain	5,000
Hydro	Goodman, Charles	Kinky Creek	12
Hydro	Bureau of Reclamation	Kortes	36,000
Hydro	Bureau of Reclamation	Pilot Butte	1,600
Hydro	Pinedale Power & Light Co.	Pinedale	100
Hydro	Bureau of Reclamation	Seminoe	51,000
Hydro	Bureau of Reclamation	Shoshone	3,000
Hydro	Bureau of Reclamation	Spirit Mountain	4,500
Hydro	Lower Valley Power & Light Inc.	Strawberry Creek	1,500
Hydro	Lower valley Power & Light Inc.	Swift creek	800
Hydro	PacifiCorp	Viva Naughton	750
Photovoltaic	University of Wyoming	University	10
Photovoltaic	University of Wyoming	University	1
Photovoltaic	University of Wyoming	Univ. Parking	35
Wind	Seawest Windpower Inc./Cinergy Global Power Inc.	Foote Creek IV	16,800
Wind	PacifiCorp/Eugene Water & Electric Board	Foote Creek	41,400
Wind	Bonneville Power Admin.	Foote Creek II	1,800
Wind	PSC of Colorado	Foote Creek III	24,750
Wind	Platte River Power Authority	Medicine Bow II	1,320
Wind	Shell Renewables	Rock River I	50,000
Wind	Platte River Power Authority	Medicine Bow I	3,300
Wind	Tera Moya Aqua/Global Wind Energy Systems	Simpson Ridge	10,000
TOTAL			**446,733**

Office of Energy Efficiency and Renewable Energy – US DOE

Total energy generation capacity for 1999 is summarized in Table G-3.

Table G-3. Summary of Wyoming's Total Energy Generation Capacity and Production

WYOMING'S TOP 10 ELECTRIC GENERATING FACILITIES					
BY SUMMER MEGAWATT CAPACITY					
Rank	**Operator**	**Plant Name**	**Fuel**	**MW**	**Percent**
1	PacifiCorp	Jim Bridger	Petroleum, Coal	2,110	19.2%
2	Basin Electric Power Coop	Laramie River Station	Petroleum, Coal	1,667	11.6%
3	PacifiCorp	Dave Johnston	Petroleum, Coal	772	6.7%
4	PacifiCorp	Naughton	Gas, Coal	700	5.4%
5	PacifiCorp	Wyodak	Petroleum, Coal	335	5.4%
6	Black Hills Corp	Neil Simpson II	Petroleum, Coal	80	5.1%
7	Bureau of Reclamation	Fremont Canyon	Water	67	4.1%
8	Bureau of Reclamation	Seminoe	Water	52	3.9%
9	BP Amoco Exploration	Anschutz Ranch East	Gas	43	3.2%
10	Bureau of Reclamation	Glendo	Water	38	3.2%
Total, Top 10 Plants				5,864	76%
Balance of State				246	
Wyoming Total				**6,110**	**MW**
Sources					
Energy Information Administration – DOE					

3. Summary of Anticipated Renewable Energy Contribution

Anticipated renewable energy contribution is not certain at this time. The contribution is dependent upon a review of certification of low impact hydropower. The State of Wyoming supports renewable energy goals.

4. Incentive Programs

Pursuant to 40 CFR 51.309(d)(8)(ii), Table G-4 below identifies incentive programs in the State of Wyoming that reward efforts to go beyond compliance and/or achieve early compliance with air pollution related requirements.

Table G-4. Summary of Wyoming's Incentive Programs

Program Title	Program Description
Market Trading	Wyoming has opted into the Section 309 regional SO_2 "cap-and-trade program".
Western Backstop SO_2 Trading Program Early Reduction Credits	As further described in Section C1.1 of the stationary source provisions of this Plan, industrial sources of SO_2 subject to the trading program which, upon verification by the State, reduce emissions to levels below their floor amount prior to the program trigger date shall receive additional emission allowances. Such allowances may be used by the source for compliance purposes or may be sold to other parties, hence, providing an incentive for sources to go beyond compliance (i.e., their floor) or to achieve early compliance (i.e., reductions prior to the program trigger date).
Western Backstop SO_2 Trading Program Renewable Energy Credits	As further described in Section C1.1 of the stationary source provisions of this Plan, allowances shall be provided to the owners of renewable energy facilities installed since October 1, 2000. Such allowances will hold a market value and therefore provide an incentive for power suppliers to invest in renewable energy facilities with zero or very low air pollutant emissions.

5. Programs to Preserve and Expand Energy Conservation Efforts

Pursuant to 40 CFR 51.309(d)(8)(iii), Table G-5 identifies programs in Wyoming that preserve and expand energy conservation efforts.

Table G-5. Programs that Preserve and Expand Energy Conservation in Wyoming

Program Title	Program Description
Energy Exchange Program	PacifiCorp offers the Energy Exchange Program, an internet based, voluntary demand reduction program. PacifiCorp posts a price for each hour that a load reduction is needed, and customers may respond by pledging to curtail a specific load. Participants are paid for each hour of curtailment based on a measured load reduction. Eligibility is limited to customers who have exceeded 1 MW within the last year.
Energy Finanswer Large Commercial and Industrial Program	PacifiCorp's Energy Finanswer Large Commercial and Industrial Program provides rebates for energy efficient equipment, including lighting, motors, and HVAC. The program also incorporates a variety of energy-efficiency services, such as facility energy analysis, detailed design assistance, competitive financing, commissioning, and post installation savings verification.

Program Title	Program Description
Business Enhancement Program	Black Hills Power offers a Business Enhancement Program to assist customers in the use of energy efficient electro-technologies such as energy storage and lighting. The following incentives are available: Lighting - Existing commercial customers who retrofit indoor lighting systems are eligible for up to a $5,000 incentive if they sign a three-year electric power service contract. Without a contract the maximum incentive is $500. Incentives are based on $0.12 per watt saved for hard wire installations and $0.04 per watt saved for compact florescent lamps. Power Factor Correction – Reduced demand charges are the primary incentive for commercial and industrial customers to improve their power factor. BHP provides an account analysis, rate savings calculations, and project financing. BHP requires the customer to sign a three-year electric power service contract for certain projects. Custom Packages – Other electro-technologies may qualify for an economic development incentive including closed loop heat pumps, geothermal loop fields, heating or air conditioning systems, water heating systems, power-quality equipment, and energy management systems. Financing, project design assistance, or an economic development rate may be other options to consider. These economic development incentives would be negotiated on a case-by-case basis and BHP would expect the customer to sign at least a three-year contract extension or, if a smaller customer, sign a five-year all requirements contract for electric service. Economic development rates would require a negotiated contract of up to seven years.
Rebuild America	Rebuild America is a U.S. Department of Energy (DOE) resource network that provides practical solutions and practices for a community's energy related needs. It is a voluntary partnership program that assists individuals, organizations, or companies looking for opportunities to save money by cutting energy use in commercial, institutional, or multifamily buildings. It provides links to a network of technical tools and business experts. By participating in a Rebuild America Partnership, a community can save money, create jobs, promote community growth, and protect the environment through smart energy use.
NICE 3	The National Industrial Competitiveness through Energy, Environment, and Economics (NICE3) is a U.S. Department of Energy (DOE) Office of Industrial Technologies (OIT) program that funds the initial commercial demonstration of technologies to improve energy efficiency or reduce pollution associated with product manufacturing. State energy offices work with organizations to secure funding from NICE3 for qualifying projects. The company receiving the grant is the primary beneficiary of the program because it helps them reduce pollution, reduce energy costs, and reduce operating expenses. The Program focuses on industries identified as dominant energy users and waste generators, including agriculture, aluminum, chemicals, forest products, glass, metal casting, mining, petroleum, and steel.
BestPractices	BestPractices is an initiative of the Office of Industrial Technologies (OIT) industries of the future strategy, which offers tools to improve a plant's energy efficiency, enhance its environmental performance, and increase its productivity. BestPractices focuses on plant systems where significant efficiency improvements and savings can be achieved. Industry gains easy access to near-term and long-term solutions for

Program Title	Program Description
	improving the performance of motors, steam, compressed air, combined heat and power, and process heat systems.
Motor Challenge	The Motor Challenge Program is a voluntary industry/government partnership of the U.S. Department of Energy's Industrial BestPractices Strategy. Motor Challenge is designed to help industry capture significant electricity savings by providing the technical expertise and knowledge necessary to manage motor systems and purchasing more efficient motors. 79% of energy used in industry is used by motors.
Energy Star	Customer Education on Purchasing Decisions WDEQ is an ENERGY STAR® partner. This DOE/EPA program establishes stricter efficiency criteria for new products. As a partner, WDEQ has been able to not only increase awareness of ENERGY STAR, but also to provide information for customers so that they can make informed purchase decisions.
Energy Efficiency Audits	*Energy audits for residential customers are provided by local power and gas suppliers.*
Low Income Weatheriza-tion	The Wyoming Department of Family Services (DFS) administers the DOE-funded Weatherization Assistance program for the State of Wyoming. DFS sets the eligibility requirements and oversees local agencies that provide weatherization services in the field. This program, through its 13 local service providers, provided weatherization assistance to 232 homes in 2001.
Special Project Grants	The Energy Office administers the State Energy Project – Special Project Grants. Each year states submit proposals in response to a DOE solicitation identifying how specific technologies could be implemented in their region of the country. DOE then selects the projects that best meet national energy goals. The Wyoming Energy Office was awarded $65,388 in 2001 to develop information on the performance of insulated foundations in coordination with the Building Science Consortium, a Building America team. The State will collect performance data, estimate investment and life cycle costs, and develop an action plan for deploying most advantageous crawl space, slab, and/or basement insulation configurations.
Federal Energy Management Program	Goal: reduce the cost and environmental impact of the federal government by advancing energy efficiency and water conservation, promoting the use of distributed and renewable energy, and improving utility management decisions at federal sites. Funds are occasionally available to the Wyoming Energy Office to partner with Indian communities and military bases or other federally-owned facilities.
State Energy Program	Working with the Department of Administration and Information, the Energy Office is utilizing DOE funding to implement the State energy plan, improve the State building energy codes, and provide public education and information.
Laramie County School District 1-Energy Efficiency	Laramie County School District 1 has implemented an energy efficiency program. The program has one full-time staff position and has been active for six years.

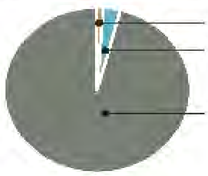
Program Title	Program Description
Rebuild America	U.S. D.O.E. Program supported by the Wyoming Energy Office to help businesses and communities reduce energy use in buildings.
Green Buildings	Green buildings are using design and construction practices that significantly reduce or eliminate the negative impact of buildings on the environment. The concept includes: Sustainable site planning Safeguarding water and water efficiency Energy efficiency and renewable energy Conservation of materials and resources Indoor environmental quality
National Industries of the Future/ MAMTC	Administered by Department of Energy – Office of Industrial Technologies Nine industries targeted that together supply 90% of the materials vital to U.S. economy. The 9 industries are: agriculture, aluminum, chemicals, forest products, glass, metal casting, mining, petroleum, and steel. Goal: Promote energy efficiency and manage waste streams.
Industrial Assessment Centers	Administered by DOE, OIT Enables eligible small and medium-sized manufacturers to have comprehensive industrial assessments performed at no cost to the manufacturers. Teams of engineering faculty and students from the center located at 26 universities around the country, conduct energy audits, or industrial assessment and provide recommendations to manufacturers to help them identify opportunities to improve productivity, reduce waste, and save energy.
Building America	Building America is a private/public partnership that provides energy solutions for production housing.

6. Potential for Renewable Energy

Pursuant to 40 CFR 51.309(d)(8)(iv), the State of Wyoming has utilized data assembled by the National Renewable Energy Laboratory assessing areas where there is the potential for renewable energy to supply power in a cost-effective manner. This section summarizes the potential for renewable energy development in Wyoming. Figure G-1 is a summary of current renewable resources in the state. Geographic distribution of renewable energy potential is contained in Figures G-2 through G-4. Figures G-5 and G-6 illustrate the load growth patterns in the region and infrastructure restrictions to renewable source future development. Figure G-7 illustrates projected cost of energy from renewable energy technology.

Wyoming Renewable Energy Resources

Existing Generation Mix



Data source: Energy Information Administration 1999

Wyoming has one of the best wind resources in the country and is already a large exporter of wind power to Colorado, Oregon and Utah. Wyoming also has good solar and biomass resources. Despite the presence of these renewable resources, however, Wyoming's electricity generation remains dominated by non-renewable resources.

Renewable Energy Installed Renewable Capacity[1]

Resource Type	Installed Capacity
Wind	140.64 MW
Solar (PV)	0.05 MW
Solar (Thermal)	0 MW
Geothermal	0 MW
Biomass	0 MW
Total	**141 MW**

[1]*Source: REPIS database, plus known installations*

Renewable Energy Policies

NM Net Metering
Maximum capacity – 50 kW

GP Green Power Programs

Data source: Database of State Incentives for Renewable Energy (www.dsireusa.org)

Annual Electricity Consumption (1999)

12 million MWh

Economic Development at Foote Creek Rim

Foote Creek Rim Wind Farm

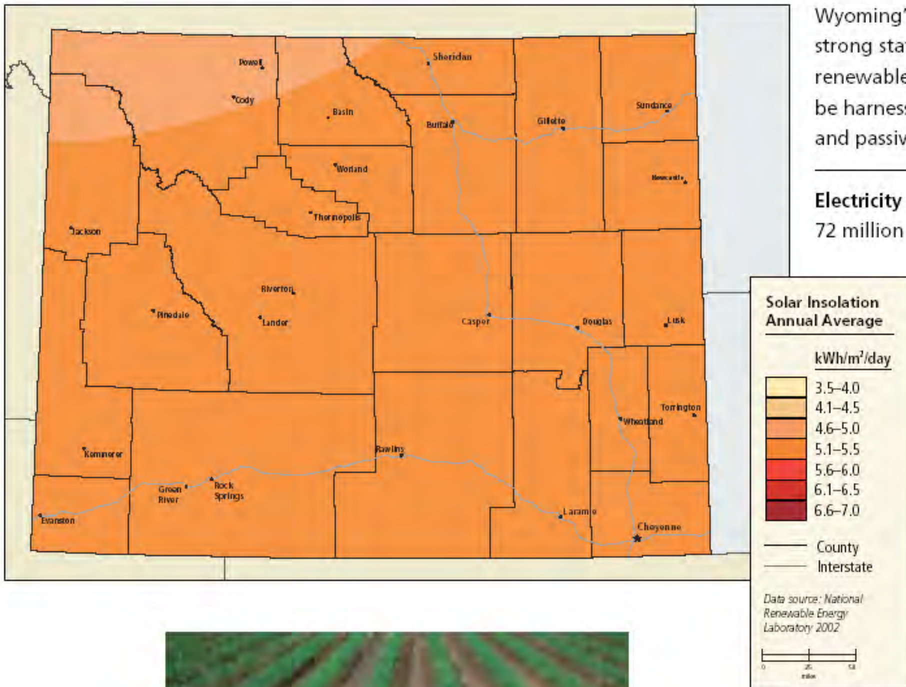
Photo: Tom Hall, DOE

Developing large-scale wind farms not only harnesses the vast potential energy found in the wind but also provides economic benefits for local landowners and residents. The Foote Creek Rim Wind Farm began operations in 1999 and has since grown to include 133 large-scale wind turbines, with a rated capacity of nearly 85 MW. Foote Creek Rim, the first commercial wind farm to go on line in Wyoming, is built on one of the windiest sites in the country. The facility was developed by SeaWest WindPower Inc. in three separate phases, and produces power for PacifiCorp, Eugene (OR) Water and Electric Board, the Bonneville Power Administration and Xcel Energy. Located in Carbon County, Wyoming (population 16,000), the wind farm is a significant contributor to the local economy. This facility will contribute over $9 million in property taxes, nearly $4 million in sales taxes and over $5 million in royalty payments to landowners over its 20-year life span.

Figure G-1

Figure G-2

Solar



Wyoming's solar resource is strong statewide. This clean, renewable energy source can be harnessed through active and passive solar applications.

Electricity Generation Potential: 72 million MWh/yr.

Farmer Using Photovoltaics

In parts of rural Wyoming, solar-powered control mechanisms can be used for irrigation systems, such as this PV-powered switch.

Photo: Siemens Solar Industries

Wind

Wyoming has long been recognized for its outstanding wind resource and has already attracted the attention of several wind energy companies that have successfully developed projects in the state. The state is estimated to have over 14 million acres of windy land. Many utilities throughout the Western US buy their "green power" from Wyoming to meet their customers' demand for a cleaner energy portfolio.

Electricity Generation Potential: 883 million MWh/yr.

Wind Power at 50 Meters

Wind Power Density

Class	W/m²
1 Poor	0–200
2 Marginal	200–300
3 Fair	300–400
4 Good	400–500
5 Excellent	500–600
6 Outstanding	600–800
7 Superb	> 800

County
Interstate
Transmission Line
Substation

Data source: TrueWind/NWSEED 2002; POWERmap, powermap.platts.com ©2002 Platts, A Division of The McGraw-Hill Companies

0 25 50
miles

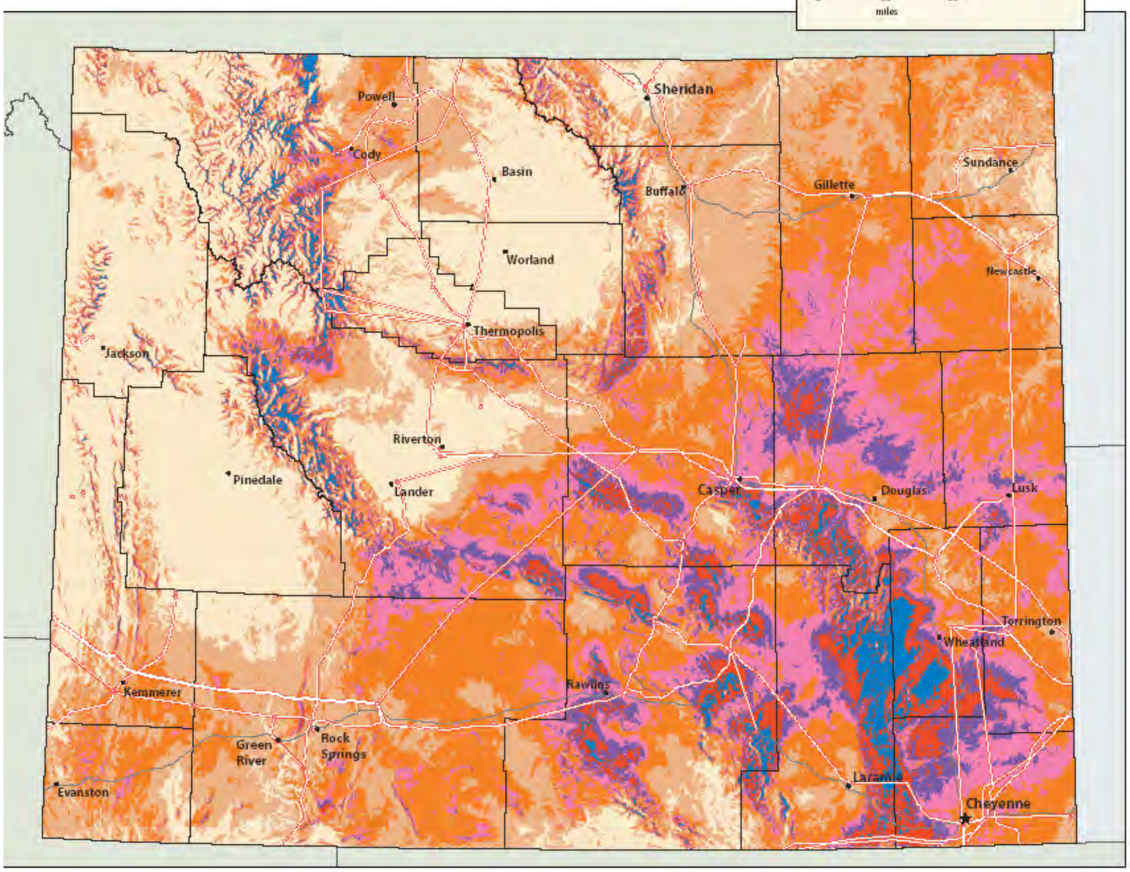
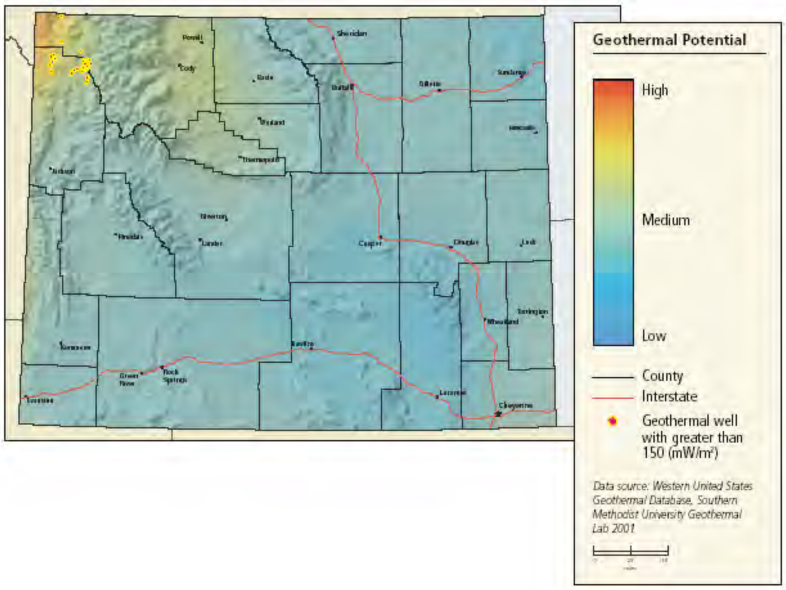


Figure G-3

Figure G-4

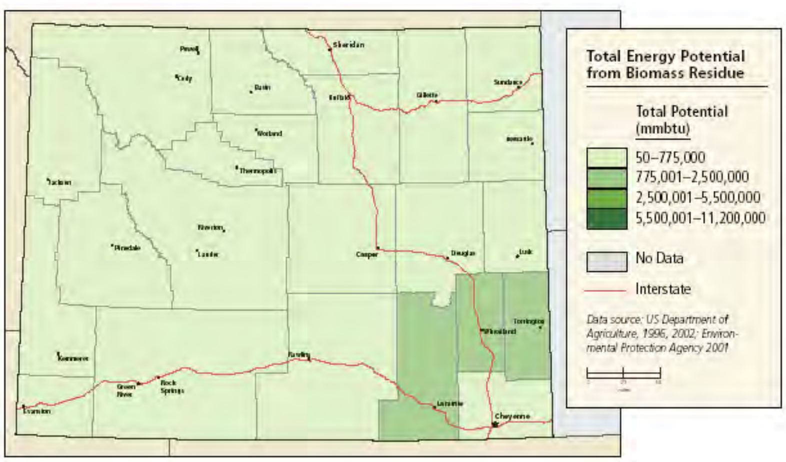
Geothermal



Wyoming's geothermal resources are concentrated in the northwest corner of the state, site of some of America's most famous natural wonders: the geysers and hot springs of Yellowstone National Park. High-temperature geothermal hotspots outside of sensitive environmental areas could prove suitable for electricity generation, while direct heating and cooling may be viable across the state.

Electricity Generation Potential:
N/A

Biomass



There are currently no electricity-producing biomass facilities in Wyoming, although there is limited potential to harness biomass resources in the state.

Electricity Generation Potential:
0 million MWh/yr.

Figure G-5

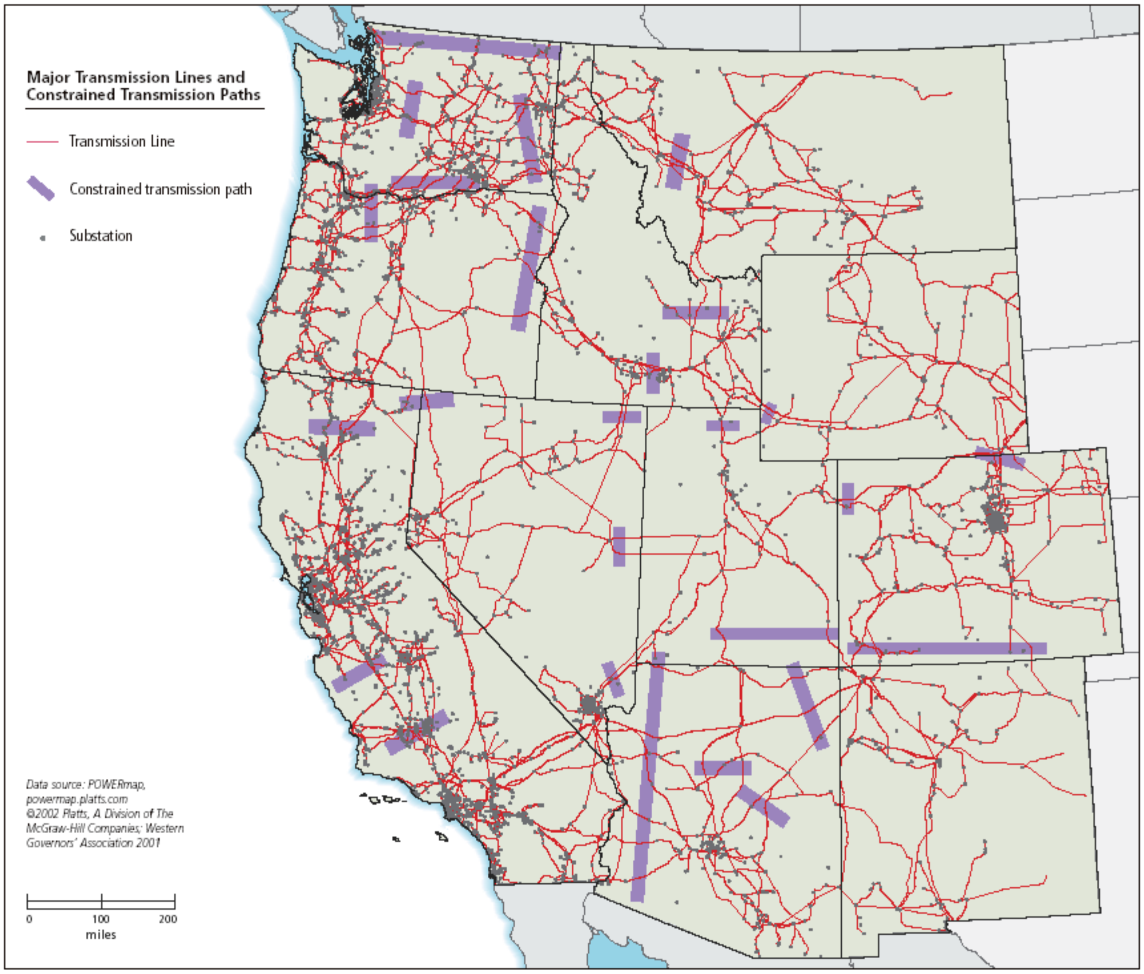

Major Transmission Lines and Constrained Transmission Paths
Transmission Line
Constrained transmission path
Substation
Data source: POWERmap, powermap.platts.com ©2002 Platts, A Division of The McGraw-Hill Companies; Western Governors' Association 2001
0
100
200
miles

Figure G-6

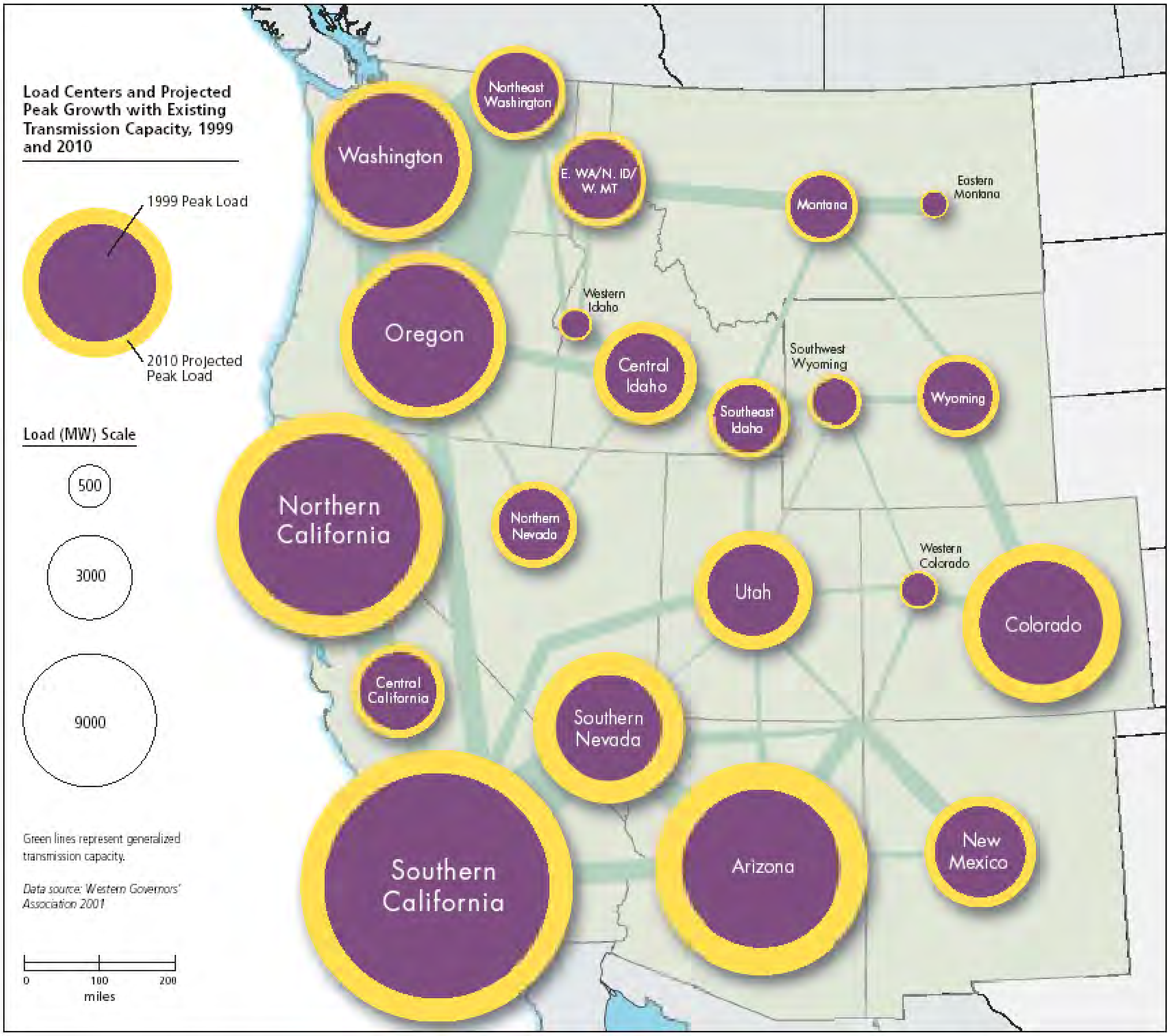
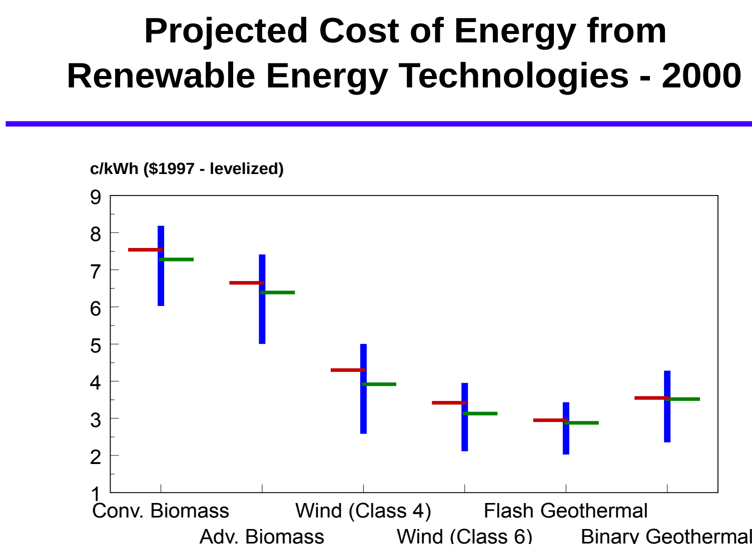

Load Centers and Projected Peak Growth with Existing Transmission Capacity, 1999 and 2010
1999 Peak Load
2010 Projected Peak Load
Load (MW) Scale
500
3000
9000
Green lines represent generalized transmission capacity.
Data source: Western Governors' Association 2001
0
100
200
miles
Northeast Washington
Washington
E. WA/N. ID/ W. MT
Montana
Eastern Montana
Oregon
Western Idaho
Central Idaho
Southeast Idaho
Southwest Wyoming
Wyoming
Northern California
Northern Nevada
Utah
Western Colorado
Colorado
Central California
Southern Nevada
Southern California
Arizona
New Mexico

Figure G-7



Technologies

Source: WRAP AP2 Renewables, "Recommendations of the Air Pollution Prevention Forum to Increase Generation of Electricity from Renewable Energy Resources," p. I-13.

7. Projections of Renewable Energy Goals, Energy Efficiency, and Pollution Prevention Activities

Pursuant to 40 CFR 51.309(d)(8)(v), projections have been made by the WRAP of the short and long-term emissions reductions, visibility improvements, cost savings, and secondary benefits associated with "renewable energy goals, energy efficiency and pollution prevention activities". A complete description of these projections is provided in the *Economic Assessment of Implementing the 10/20 Goals and Energy Efficiency Recommendations.* Projections of visibility improvements for the 16 Class I areas on the Colorado Plateau are provided in Section A. These projections include the combined effects of all measures in this SIP, including air pollution prevention programs. Although emission reductions and visibility improvements from air pollution prevention programs are expected at some level, they were not explicitly calculated because the resolution of the regional air quality modeling system is not currently sufficient to show any significant visibility changes resulting from the marginal nitrogen oxide emission reduction described above for air pollution prevention programs. Details of the modeling methodology are contained in the WRAP TSD in Chapter 8 entitled, "Assessment of Pollution Prevention."

8. Programs to Achieve GCVTC Renewable Energy Goal

Pursuant to 40 CFR 51.309(d)(8)(vi), the programs relied upon by the State of Wyoming to demonstrate progress in achieving the renewable energy goal of the GCVTC that renewable energy comprise 10 percent of the regional power needs by 2005 and 20 percent by 2015 are the environmental portfolio standard, and the utility customer funding or system benefit charge funding for renewables in addition to the other programs that are listed in Table G-1.

9. Future Progress Reports

Pursuant to 40 CFR 51.309(d)(8)(vi), the State of Wyoming shall submit progress reports in 2013 and 2018, describing the state's contribution toward meeting the GCVTC renewable energy goals. This description shall be consistent with Section G.7, above. To the extent that it is not feasible for the state to meet its contribution to these goals, the state shall identify what measures were implemented to achieve its contribution, and explain why meeting its contribution was not feasible.

10. Applicable WRAP Reports and Documents

Chapter 8 of the TSD Development Plan contains a regional modeling analysis related to the GCVTC 10/20 goals.

The WRAP *Policy on Renewable Energy and Energy Efficiency As Pollution Prevention Strategies For Regional Haze* summarizes three years of stakeholder and consensus-based recommendations from the AP2. The policy reaffirms the findings of the GCVTC – that energy efficiency measures and renewable energy goals could result in emissions reductions, improvements in visibility, energy costs savings, and secondary environmental and economic benefits. The WRAP policy provides a menu of individual policies and programs, various combinations of which would achieve the 10/20 renewable energy and energy efficiency goals, especially if implemented in a coordinated fashion among states and tribes. Specifically, ten recommendations are provided to promote renewable energy generation, and eight more are provided specifically for consideration by tribes. Similarly, seven recommendations are provided to promote energy efficiency, and eleven more are provided specifically for consideration by tribes. This policy will help states identify policies and programs within their state that are consistent with these recommendations, and that may be implemented or expanded to meet the 10/20 goals for regional renewable energy and energy efficiency.

Other reports from the WRAP Air Pollution Prevention Forum:

1. *Determining a State's Contribution to the GCVTC Regional Renewable Energy Goals.* A discussion paper describing an approach for establishing a state's contribution by using the total electricity consumption within each state multiplied by the RE percentage target to yield each state's contribution in terms of MWh. This method bases a state's contribution on its share of overall regional electricity demand. This would be consistent with the principle that energy production, hence visibility degradation is driven by demand. States with higher demand and

consumption, due to higher population, would have a greater share of contribution toward the RE goals. The discussion goes on to suggest an approach for crediting each state's programs against its contribution. Here, a program that induces increased RE production is counted, if the RE production occurs anywhere within the region.

2. *Recommendations of the Air Pollution Prevention Forum to Increase the Generation of Electricity from Renewable Resources* presents a comprehensive state-by-state review of current energy production, consumption and existing RE policies, definition of Renewable Energy, a menu of potential additional RE projects and a recommended portfolio of projects states are required to include in their SIPs. The report provides detailed recommendations for state and federal programs to encourage increased RE production to displace potential new conventional energy production. Conclusions regarding most cost effective RE production projects, financial analysis, and types of RE inducement policies are also included.

3. *Economic Assessment of Implementing the 10/20 Goals and Energy Efficiency Recommendations* is a report prepared by ICF Consultants for the AP2 Forum which analyzes cost, emissions and regional economic impacts of meeting the 10-20 goals and implementing the energy efficiency recommendations. The report projects that with no additional efforts to promote renewable energy, (business as usual) the high technology costs for RE will not change significantly and that significant new additions to RE capacity will not occur. The report goes on to say that load reductions from energy efficiencies will continue. The economic impacts will not occur uniformly across the region. Some states will gain, some will not. Meeting the 10/20 goals and EE will likely increase annual region-wide electricity production costs by 1%-5%, and will mostly affect new gas generating capacity, rather than existing coal and oil power production. Some emission reductions should occur, mostly CO_2 and NOx. The overall effect on the regional economy is very limited and may produce some gains in employment and income.

4. *Pollution Prevention Workshop for the Preparation of Section 309 SIPs and TIPs: May 20-21, 2003, Portland, OR-Session Notes* summarizes discussions among 309 states as to common understandings of the P2 requirements of Section 309, developing a baseline of the minimum information necessary for an adequate filing and how each 309 state is proposing to approach this issue. A number of agreements among the participating states were reached, as well as some specific language in this SIP. The group noted that, at a minimum, a state's Section 309 filing could center on energy/electricity. However, if a state has information on P2 programs beyond this scope, it can be included for a broader P2 filing. A paragraph-by-paragraph summary of discussions and conclusions is presented.

Section H. Additional Recommendations

Note: No revisions were made to this section.

1. Other GTVTC Recommendations

(a) Evaluation of additional Grand Canyon Visibility Transport Commission recommendations. Pursuant to 40 CFR 51.309(d)(9), the State of Wyoming has evaluated the “additional” recommendations of the Grand Canyon Visibility Transport Commission, to determine if any of these recommendations can be practicably included in this Implementation Plan. The State of Wyoming reviewed the Commissions’ 1996 report, “Recommendations for Improving Western Vistas”, to identify those recommendations that were not incorporated into Section 309 of the Regional Haze Rule. This evaluation is described in the Wyoming TSD.

(b) Implementation of Additional Recommendations. Based on the evaluation made by the State of Wyoming, as described in the Wyoming TSD, no additional measures have been identified as being practicable or necessary to demonstrate reasonable progress at this time.

2. Applicable WRAP Reports and Documents

All of the GCVTC original recommendations are contained in the 1996 report *Recommendations for Improving Western Vistas.*

Section I. Periodic Implementation Plan Revisions

1. Periodic Implementation Plan Revisions

(a) Periodic Progress Reports for demonstrating Reasonable Progress. Pursuant to 40 CFR 51.309(d)(10)(i), the State of Wyoming shall submit to EPA, as a SIP revision, periodic progress reports for the years 2013 and 2018 for the purpose of demonstrating reasonable progress in Mandatory Federal Class I areas within Wyoming, and Mandatory Federal Class I areas outside Wyoming that are affected by emissions from Wyoming. This demonstration may be conducted by the WRAP, with assistance from Wyoming, and shall address the elements listed under 40 CFR 51.309(d)(10)(i)(A) through (G), as summarized below:

(1) Implementation status of 2003 SIP measures;
(2) Summary of emissions reductions;
(3) Assessment of most/least impaired days;
(4) Analysis of emission reductions by pollutant;
(5) Significant changes in anthropogenic emissions;
(6) Assessment of 2003 SIP sufficiency; and
(7) Assessment of visibility monitoring strategy.

(b) Actions to be taken concurrent with Periodic Progress Reports. Pursuant to 40 CFR 51.309(d)(10)(ii), the State of Wyoming shall take one of the following actions based upon information contained in each periodic progress report:

(1) Provide a negative declaration statement to EPA saying that no implementation plan revision is needed if reasonable progress is being made, in accordance with section *(a)* above;

(2) If the state finds that the Implementation Plan is inadequate to ensure reasonable progress due to emissions from outside the state, Wyoming shall notify EPA and the other contributing state(s), and initiate efforts through a regional planning process to address the emissions in question. The State of Wyoming shall identify in the next progress report the outcome of this regional planning effort, including any additional strategies that were developed to address the Plan's deficiencies;

(3) If the state finds that the Implementation Plan is inadequate to ensure reasonable progress due to emissions from another country, Wyoming shall notify EPA and provide information on the impairment being caused by these emissions; or

(4) If the state finds that the Implementation Plan is inadequate to ensure reasonable progress due to emissions from within Wyoming, Wyoming shall develop additional strategies to address the Plan deficiencies and revise the Implementation Plan no later than one year from the date that the progress report was due.

2. Applicable WRAP Reports and Documents

None.

Section J. State Planning/Interstate Coordination and Tribal Implementation

Note: No revisions were made to this section.

1. State Planning/Interstate Coordination and Tribal Implementation

(a) Participation in Regional Planning and Coordination. Pursuant to 40 CFR 51.309(d)(11), the State of Wyoming has participated in regional planning and coordination with other states in developing its emission reduction strategies under 40 CFR 51.309, related to protecting the 16 Class I areas of the Colorado Plateau. This participation was through the Western Regional Air Partnership. A chart in Appendix D of this Implementation Plan illustrates the State of Wyoming's participation in regional planning and interstate coordination.

(b) Applicability to Tribal Lands. Pursuant to 40 CFR 51.309(d)(12), and in accordance with the Tribal Authority Rule, the Tribe whose lands are surrounded by the State of Wyoming have the option to develop a regional haze TIP for their lands to assure reasonable progress in the 16 Class I areas of the Colorado Plateau. As such, no provisions of this chapter of the Implementation Plan shall be construed as being applicable to Indian Country.

2. Applicable WRAP Reports and Documents

The *WRAP Charter* sets forth the basic operating goals, principles and procedures.

Section K. Geographic Enhancements

1. Geographic Enhancement Program

The requirements for geographic enhancement are discussed on page 35757 in the Preamble to the 1999 regional haze rule. Geographic enhancement is a voluntary approach for addressing reasonably attributable visibility impairment (RAVI) for stationary sources, under the provisions of 40 CFR 51.302(c). RAVI is different from regional haze in that it addresses “hot spots” or situations where visibility impairment in a Class I area is reasonably attributable to a single source or small group of sources in relatively close proximity to the Class I area. The geographic enhancement approach would allow states or tribes to use the efficiencies and reduced cost provided by the market trading program to accommodate situations where RAVI needs to be addressed. Additional information is contained in the WESTAR report, *Recommendations for Making Attribution Determinations in the Context of Reasonably Attributable BART*.

Procedure for addressing Reasonably Attributable Visibility Impairment under the Regional Haze Rule. If the Federal Land Manager certifies impairment, the State of Wyoming will fulfill its obligations to determine attribution and if necessary determine BART for the applicable source or group of sources in accordance with Wyoming’s SIP for reasonably attributable visibility protection approved by EPA on February 15, 1989 through a notice in the Federal Register. The Wyoming SIP for reasonably attributable visibility became effective on April 17, 1989.

2. Applicable WRAP Reports and Documents

See WESTAR report *Recommendations for Making Attribution Determinations in the Context of Reasonably Attributable BART*. This report recommends approaches for determining if visibility impairment is reasonably attributable to a source or group of sources, often known as reasonably attributable visibility impairment (RAVI). The report was prepared by the WESTAR Council under contract to the WRAP, and has been reviewed by the Market Trading Forum and made available for public comment on May 22, 2003.

Section L. Reasonable Progress for Additional Mandatory Federal Class I Areas

1. Reasonable Progress for Additional Mandatory Federal Class I Areas

(a) Declaration for other Mandatory Federal Class I areas. Pursuant to 40 CFR 51.309(g)(1), the State of Wyoming declares it will follow Section 309(g)(2) and (g)(3) in supplementing this regional haze Implementation Plan for the seven Mandatory Federal Class I areas not on the Colorado Plateau in the State of Wyoming. These Mandatory Federal Class I areas are as follows:

Yellowstone National Park
Grand Teton National Park
North Absaroka Wilderness
Washakie Wilderness
Teton Wilderness
Bridger Wilderness
Fitzpatrick Wilderness

2. Applicable WRAP Reports and Documents

None.

APPENDICES

Appendix A: Definitions in the Regional Haze SIP

Applicable definitions from 40 CFR 51.301:

1. ***BART-eligible source*** means an existing stationary facility as defined in this section.

2. ***Best Available Retrofit Technology (BART)*** means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence 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.

3. ***Deciview*** means a measurement of visibility impairment. A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired. The deciview haze index is calculated based on the following equation (for the purposes of calculating deciview, the atmospheric light extinction coefficient must be calculated from aerosol measurements):

   Deciview haze index = 10 $1n_e$ $(b_{ext}/10\ Mm^{-1})$.
   Where b_{ext} = the atmospheric light extinction coefficient, expressed in inverse megameters (Mm^{-1}).

4. ***Department*** means the Wyoming Department of Environmental Quality.

5. ***Existing stationary facility*** means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted.

   Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input,
   Coal cleaning plants (thermal dryers),
   Kraft pulp mills,
   Portland cement plants,
   Primary zinc smelters,
   Iron and steel mill plants,
   Primary aluminum ore reduction plants,
   Primary copper smelters,
   Municipal incinerators capable of charging more than 250 tons of refuse per day,
   Hydrofluoric, sulfuric, and nitric acid plants,
   Petroleum refineries,

Lime plants,
Phosphate rock processing plants,
Coke oven batteries,
Sulfur recovery plants,
Carbon black plants (furnace process),
Primary lead smelters,
Fuel conversion plants,
Sintering plants,
Secondary metal production facilities,
Chemical process plants,
Fossil-fuel boilers of more than 250 million British thermal units per hour heat input,
Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
Taconite ore processing facilities,
Glass fiber processing plants, and
Charcoal production facilities.

6. ***Federal Class I area*** means any Federal land that is classified or reclassified Class I.

7. ***Federal Land Manager*** means the Secretary of the department with authority over the Federal Class I area (or the Secretary's designee) or, with respect to Roosevelt-Campobello International Park, the Chairman of the Roosevelt-Campobello International Park Commission.

8. ***Federally enforceable*** means all limitations and conditions which are enforceable by the Administrator under the Clean Air Act including those requirements developed pursuant to parts 60 and 61 of this title, requirements within any applicable State Implementation Plan, and any permit requirements established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51, 52, or 60.

9. ***Implementation plan*** means, for the purposes of this part, any State Implementation Plan, Federal Implementation Plan, or Tribal Implementation Plan.

10. ***Indian tribe or tribe*** means any Indian tribe, band, nation, or other organized group or community, including any Alaska Native village, which is federally recognized as eligible for the special programs and services provided by the United States to Indians because of their status as Indians.

11. ***In existence*** means that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time.

12. ***Least impaired days*** means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the lowest amount of visibility impairment.

13. ***Major stationary source and major modification*** mean major stationary source and major modification, respectively, as defined in 40 CFR 51.166.

14. ***Mandatory Class I Federal Area*** means any area identified in part 81, subpart D of this title.

15. ***Most impaired days*** means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the highest amount of visibility impairment.

16. ***Natural conditions*** includes naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration.

17. ***Potential to emit*** means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

18. ***Reasonably attributable*** means attributable by visual observation or any other technique the State deems appropriate.

19. ***Reasonably attributable visibility impairment*** means visibility impairment that is caused by the emission of air pollutants from one, or a small number of sources.

20. ***Regional haze*** means visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources.

21. ***State*** means “State” as defined in section 302(d) of the CAA.

22. ***Stationary Source*** means any building, structure, facility, or installation which emits or may emit any air pollutant.

23. ***Visibility impairment*** means any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions.

Definitions from 40 CFR 51.309:

1. ***16 Class I areas*** means the following mandatory Class I Federal areas on the Colorado Plateau: Grand Canyon National Park, Sycamore Canyon Wilderness, Petrified Forest National Park, Mount Baldy Wilderness, San Pedro Parks Wilderness, Mesa Verde National Park, Weminuche Wilderness, Black Canyon of the Gunnison Wilderness, West Elk Wilderness, Maroon Bells Wilderness, Flat Tops Wilderness, Arches National Park, Canyonlands National Park, Capitol Reef National Park, Bryce Canyon National Park, and Zion National Park.

2. ***Transport Region State*** means one of the States that is included within the Transport Region addressed by the Grand Canyon Visibility Transport Commission (Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming).

3. ***Commission Report*** means the report of the Grand Canyon Visibility Transport Commission entitled "Recommendations for Improving Western Vistas," dated June 10, 1996.

4. ***Fire*** means wildfire, wildland fire (including prescribed natural fire), prescribed fire, and agricultural burning conducted and occurring on Federal, State, and private wildlands and farmlands.

5. ***Milestone*** means the maximum level of annual regional sulfur dioxide emissions for a given year, assessed annually consistent with paragraph (h)(2) of this section beginning in the year 2003.

6. ***Mobile Source Emission Budget*** means the lowest level of VOC, NOx, SO_2, elemental and organic carbon, and fine particles which are projected to occur in any area within the transport region from which mobile source emissions are determined to contribute significantly to visibility impairment in any of the 16 Class I areas.

7. ***Geographic enhancement*** means a method, procedure, or process to allow a broad regional strategy, such as a milestone or backstop market trading program designed to achieve greater reasonable progress than BART for regional haze, to accommodate BART for reasonably attributable impairment.

Definitions for the SO2 Milestones and Backstop Trading Program, Section C

1. ***Account Certificate of Representation*** means for a WEB Source the completed and signed submission required to designate an Account Representative for a WEB source who is authorized to represent the owners and operators of the WEB source with regard to matters under the WEB Trading Program and for a general account, the individual who is authorized to represent the persons having an ownership interest with respect to allowances in the general account with regard to matters concerning the general account.

2. ***Account Representative*** means the individual who is authorized through an Account Certificate of Representation to represent owners and operators of the WEB source with

regard to matters under the WEB Trading Program (including, for example, to transfer and otherwise manage allowances and certify all submissions to the Allowance Tracking System and the emissions tracking database for the purposes of the Rule) or, for a general account, who is authorized through an Account Certificate of Representation to represent the persons having an ownership interest in allowances in the general account with regard to matters concerning the general account.

3. ***Act*** means the Clean Air Act, as amended, 42 U.S.C. 7401, *et seq*.

4. ***Actual emissions*** means, for the purpose of this Implementation Plan, total annual SO_2 emissions as reported to EPA, and revised as necessary by, state, tribes, or EPA, under 40 CFR part 75 or to the authorized permitting agency in accordance with the requirements of the Rule or Title V of the Clean Air Act, as applicable.

5. ***Allocate*** means to assign allowances to a WEB source through Part C1 of Section C of this Implementation Plan.

6. ***Allowance*** means the limited authorization under the WEB Trading Program to emit one ton of SO_2 during a specified control period or any control period thereafter subject to the terms and conditions for use of unused allowances as established by the Rule.

7. ***Allowance limitation*** means the tonnage of SO_2 emissions authorized by the allowances available for compliance deduction for a WEB source for a control period under Section 2(k)(i) of Chapter 14 on the allowance transfer deadline for that control period.

8. ***Allowance Tracking System*** means the system developed by Wyoming where allowances under the WEB Trading Program are recorded, held, transferred and deducted.

9. ***Allowance Tracking System account*** means an account in the Allowance Tracking System established for purposes of recording, holding, transferring, and deducting allowances.

10. ***Compliance account*** means an account established in the Allowance Tracking System under Section 2(g)(i) of Chapter 14 for the purpose of recording allowances that a WEB source might hold to demonstrate compliance with its allowance limitation.

11. ***Control period*** means the period beginning January 1 of each year and ending on December 31 of the same year, inclusive.

12. ***Emissions tracking database*** means the central database where SO_2 emissions for WEB sources as recorded and reported in accordance with Chapter 14 are tracked to determine compliance with allowance limitations.

13. ***EPA Administrator*** means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

14. ***Existing source*** means a stationary source that commenced operation before the program trigger date.

15. ***Floor allocation*** means the amount of allowances set by Wyoming in accordance with this Plan that represents the minimum necessary for a source to operate under stringent control assumptions.

16. ***General account*** means an account established in the Allowance Tracking System under Section 2(g)(i) of Chapter 14 for the purpose of recording allowances held by a person that are not to be used to show compliance with an allowance limitation.

17. ***Milestone*** means the maximum level of stationary source regional sulfur dioxide emissions for each year from 2003 to 2018, established according to the procedures in Part A of Section C of this Implementation Plan.

18. ***New WEB Source*** means a WEB source that commenced operation on or after the program trigger date.

19. ***New Source Set-aside*** means a pool of allowances that are available for allocation to new sources in accordance with the provisions of Part C1.3 of Section C of this Implementation Plan.

20. ***Opt-in*** means to choose to participate in the WEB Trading Program by following the procedures in Section 2(c) of Chapter 14 and to comply with the terms and conditions of Chapter 14.

21. ***Program trigger date*** means the date that Wyoming determines that the WEB Trading Program has been triggered in accordance with the provisions of Part A2 of Section C of this Implementation Plan.

22. ***Reducible allocation*** means the amount of allowances set by Wyoming in accordance with Part C1.1(b)(9) of Section C of this Plan that represents, for each source, emissions in excess of the floor allocation that shall be reduced over time as the regional milestone is decreased.

23. ***Retired source*** means a WEB source that has received a retired source exemption as provided in Section 2(c) of Chapter 14.

24. ***Special Reserve Compliance Account*** means an account established in the allowance tracking system under Chapter 14, Section 2(g)(i) for the purpose of recording allowances that a WEB source might hold to demonstrate compliance with its allowance limitation for emission units that are monitored for sulfur dioxide in accordance with Chapter 14, Section 2(h)(i)(B).

25. ***Stationary source*** means any building, structure, facility or installation that emits or may emit any air pollutant subject to regulation under the Clean Air Act.

26. ***Ton*** means 2,000 pounds and, for any control period, any fraction of a ton equaling 1,000 pounds or more shall be treated as one ton and any fraction of a ton equaling less than 1,000 pounds shall be treated as zero tons.

27. ***Tracking System Administrator*** means the person designated by Wyoming as the administrator of the WEB Allowance Tracking System and the emission tracking database.

28. ***Tribal Set-Aside*** means a 2,500-ton SO_2 WEB allowance allocated to tribes on an annual basis. The tribes will decide how to distribute the allowances in the set-aside among tribes in the region. The set-aside is intended to ensure equitable treatment for tribal economies and to prevent barriers to economic development.

29. ***Trigger*** refers to the activation of the WEB Trading Program for SO_2 in accordance with Part A of Section C of this Implementation Plan.

30. ***Unit*** means a stationary boiler, combustion turbine or combined cycle system.

31. ***WEB source*** means a stationary source that meets the applicability requirements of Chapter 14, Section 2.

32. ***Western Backstop SO_2 Trading Program ("WEB Trading Program")*** refers to the Rule that shall be triggered as a backstop in accordance with the provisions in Part A of Section C of this Implementation Plan to ensure that regional SO_2 emissions are reduced.

33. ***Western Regional Air Partnership (WRAP)*** means the collaborative effort of tribal governments, state governments, and federal agencies to promote and monitor implementation of recommendations from the Grand Canyon Visibility Transport Commission authorized under Section 169B(f) of the Act, and to address other common Western regional air quality issues.

Appendix B: Stationary Sources

WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
STANDARDS AND REGULATIONS
CHAPTER 14
EMISSION TRADING PROGRAM REGULATIONS

Section 2. Western backstop sulfur dioxide trading program.

(a) Definitions.

The following additional definitions apply to Chapter 14, Section 2.

"Account Representative" means the individual who is authorized through a Certificate to represent owners and operators of the WEB source with regard to matters under the WEB Trading Program or, for a general account, who is authorized through a Certificate to represent the persons having an ownership interest in allowances in the general account with regard to matters concerning the general account.

"Act" means the federal Clean Air Act, as amended 42 U.S.C. 7401, *et seq*.

"Actual Emissions" means total annual sulfur dioxide emissions determined in accordance with Section 2(h) of this Chapter or determined in accordance with Section 3 of this Chapter for sources that are not subject to Section 2(h) of this Chapter.

"Allocate" means to assign allowances to a WEB source in accordance with Part C1 of Section C of the Wyoming Regional Haze SIP (WYRHSIP).

"Allowance" means the limited authorization under the WEB Trading Program to emit one ton of sulfur dioxide during a specified control period or any control period thereafter subject to the terms and conditions for use of unused allowances as established by Section 2 of this Chapter.

"Allowance limitation" means the tonnage of sulfur dioxide emissions authorized by the allowances available for compliance deduction for a WEB source under Section 2(k) of this Chapter on the allowance transfer deadline for each control period.

"Allowance Tracking System" means the system where allowances under the WEB Trading Program are recorded, held, transferred and deducted.

"Allowance Tracking System account" means an account in the Allowance Tracking System established for purposes of recording, holding, transferring, and deducting allowances.

"Allowance transfer deadline" means the deadline established in Section 2(i)(ii) of this Chapter when allowances must be submitted for recording in a WEB source's compliance account in order to demonstrate compliance for that control period.

"Best Available Retrofit Technology (BART)" means that emission reduction control device, facility, method, or system, used to achieve the best continuous emission reduction for each pollutant emitted by an existing stationary facility. The emission limitation shall be established on a case-by-case basis taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence 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.

"Certificate" means the completed and signed submission required to designate an account representative for a WEB source or an account representative for a general account.

"Compliance account" means an account established in the Allowance Tracking System under Section 2(g)(i) of this Chapter for the purpose of recording allowances that a WEB source might hold to demonstrate compliance with its allowance limitation.

"Compliance certification" means a submission to the Department by the account representative as required under Section 2(k)(ii) of this Chapter to report a WEB source's compliance or noncompliance with Chapter 14, Section 2.

"Control period" means the period beginning January 1 of each year and ending on December 31 of the same year, inclusive.

"Emissions tracking database" means the central database where sulfur dioxide emissions for WEB sources as recorded and reported in accordance with Section 2 of this Chapter are tracked to determine compliance with allowance limitations.

"Emission unit" means any part of a stationary source that emits or would have the potential to emit any pollutant subject to regulations under the Clean Air Act.

"Existing source" means a stationary source that commenced operation before the program trigger date.

"General account" means an account established in the Allowance Tracking System under Section 2(g) of this Chapter for the purpose of recording allowances held by a person that are not to be used to show compliance with an allowance limitation.

"Milestone" means the maximum level of stationary source regional sulfur dioxide emissions for each year from 2003 to 2018, established according to the procedures in Part A1 of Section C of the WYRHSIP.

"New WEB Source" means a WEB source that commenced operation on or after the program trigger date.

"New Source Set-aside" means a pool of allowances that are available for allocation to new sources in accordance with the provisions of Part C1.3 of Section C of the WYRHSIP.

"Owner or Operator" means any person who is an owner or who operates, controls or supervises a WEB source, and includes but is not limited to any holding company, utility system or plant manager.

"Potential to emit" means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is enforceable by the EPA Administrator.

"Program trigger date" means the date that the Department determines that the WEB Trading Program has been triggered in accordance with the provisions of Part A3 of Section C of the WYRHSIP.

"Program trigger years" means the years shown in Part A1 of Section C of the WYRHSIP, Table 1, column 3 for the applicable milestone if the WEB Trading Program is triggered as described in Part A3 of Section C of the WYRHSIP.

"Renewable Energy Resource" means a resource that generates electricity by non-nuclear and non-fossil technologies that results in low or no air emissions. The term includes electricity generated by wind energy technologies; solar photovoltaic and solar thermal technologies; geothermal technologies; technologies based on landfill gas and biomass sources, and new low-impact hydropower that meets the Low-Impact Hydropower Institute criteria. Biomass includes agricultural, food and wood wastes. The term does not include pumped storage or biomass from municipal solid waste, black liquor, or treated wood.

"Retired source" means a WEB source that has received a retired source exemption as provided in Section 2(c)(iv) of this Chapter. Any retired source resuming operations under Section 2(c)(iv) of this Chapter, must submit its exemption as part of its registration materials.

"Serial number" means, when referring to allowances, the unique identification number assigned to each allowance by the TSA, in accordance with Section 2(f)(ii) of this Chapter.

"Special Reserve Compliance Account" means an account established in the allowance tracking system under Section 2(g)(i) for the purpose of recording allowances that a WEB source might hold to demonstrate compliance with its allowance limitation for emission units that are monitored for SO_2 in accordance with Section 2(h)(i)(B).

"Stationary source" means any building, structure, facility or installation that emits or may emit any air pollutant subject to regulation under the Clean Air Act.

"Submit" means sent to the appropriate authority under the signature of the account representative. For purposes of determining when something is submitted, an official U.S. Postal Service postmark, or equivalent electronic time stamp, shall establish the date of submittal.

"Sulfur dioxide emitting unit" means any equipment that is located at a WEB source and that emits sulfur dioxide.

"Ton" means 2000 pounds and any fraction of a ton equaling 1000 pounds or more shall be treated as one ton and any fraction of a ton equaling less than 1000 pounds shall be treated as zero tons.

"Tracking System Administrator (TSA)" means the person designated by the Department as the administrator of the Allowance Tracking System and the emission tracking database.

"WEB source" means a stationary Western Backstop (WEB) source that meets the applicability requirements of Section 2(c) of this Chapter.

"WEB Trading Program" means Section 2 of this Chapter, triggered as a backstop in accordance with the provisions in Part A3 of Section C of the WYRHSIP, if necessary, to ensure that regional sulfur dioxide emissions are reduced.

"WYRHSIP" means the Wyoming Regional Haze State Implementation Plan.

(b) WEB Trading Program Trigger.

(i) Except as provided in (ii), the provisions of Section 2 of this Chapter shall apply on the program trigger date that is established in accordance with the procedures in Part A3 of Section C of the WYRHSIP.

(ii) Special Penalty Provisions for 2018 Milestone, Section 2(l) of this Chapter, shall apply on January 1, 2018 and shall remain effective until the provisions of Section 2(l) of this Chapter have been fully implemented.

(c) WEB Trading Program Applicability.

(i) General Applicability. Section 2 of this Chapter applies to any stationary source or group of stationary sources that are located on one or more contiguous or adjacent properties and which are under the control of the same person or persons under common control, belonging to the same industrial grouping, and that are described in paragraphs (A) and (B) of this subsection. A stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group (i.e., all have the same two-digit code) as described in the Standard Industrial Classification Manual, 1987.

(A) All stationary sources that have actual sulfur dioxide emissions of 100 tons or more per year in the Program Trigger Years or any subsequent year. The fugitive emissions of a stationary source shall not be considered in determining whether it is subject to Section 2 of this Chapter unless the source belongs to one of the following categories of stationary source:

(I) Coal cleaning plants (with thermal dryers);

(II) Kraft pulp mills;

(III) Portland cement plants;

(IV) Primary zinc smelters;

(V) Iron and steel mills;

(VI) Primary aluminum ore reduction plants;

(VII) Primary copper smelters;

(VIII) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(IX) Hydrofluoric, sulfuric, or nitric acid plants;

(X) Petroleum refineries;

(XI) Lime plants;

(XII) Phosphate rock processing plants;

(XIII) Coke oven batteries;

(XIV) Sulfur recovery plants;

(XV) Carbon black plants (furnace process);

(XVI) Primary lead smelters;

(XVII) Fuel conversion plants;

(XVIII) Sintering plants;

(XIX) Secondary metal production plants;

(XX) Chemical process plants;

(XXI) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(XXII) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(XXIII) Taconite ore processing plants;

(XXIV) Glass fiber processing plants;

(XXV) Charcoal production plants;

(XXVI) Fossil-fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input; or

(XXVII) Any other stationary source category, which as of August 7, 1980 is being regulated under Section 111 or 112 of the Clean Air Act.

(B) A new source that begins operation after the program trigger date and has the potential to emit 100 tons or more of sulfur dioxide per year.

(ii) The Department may determine on a case-by-case basis, with concurrence from the EPA Administrator, that a stationary source defined in 2(c)(i)(A) above that has not previously met the applicability requirements of (i) is not subject to Chapter 14, Section 2 if the stationary source had actual sulfur dioxide emissions of 100 tons or more in a single year and in each of the previous five years had actual sulfur dioxide emissions of less than 100 tons per year, and:

(A) (I) The emissions increase was due to a temporary emission increase that was caused by a sudden, infrequent failure of air pollution control equipment, or process equipment, or a failure to operate in a normal or usual manner, and

(II) The stationary source has corrected the failure of air pollution equipment, process equipment, or process by the time of the Department's determination; or

(B) The stationary source had to switch fuels or feedstocks on a temporary basis and as a result of an emergency situation or unique and unusual circumstances besides the cost of such fuels or feedstocks.

(iii) Duration of Applicability. Except as provided for in Section 2(c)(iv) of this Chapter, once a stationary source is subject to Section 2 of this Chapter, it will remain subject to Chapter 14, Section 2 every year thereafter.

(iv) Retired Source Exemption.

(A) Application. Any WEB source that is permanently retired shall apply for a retired source exemption. The WEB source may only be considered permanently retired if all sulfur dioxide emitting units at the source are permanently retired. The application shall contain the following information:

(I) Identification of the WEB source, including plant name and an appropriate identification code in a format specified by the Department.

(II) Name of Account Representative.

(III) Description of the status of the WEB source, including the date that the WEB source was permanently retired.

(IV) Signed certification that the WEB source is permanently retired and will comply with the requirements of Section 2(c)(iv) of this-Chapter.

(V) Verification that the WEB source has a general account where any unused allowances or future allocations will be recorded.

(B) Notice. The retired source exemption becomes effective when the Department notifies the WEB source that the retired source exemption has been granted.

(C) Responsibilities of Retired Sources.

(I) A retired source shall be exempt from Section 2(h) and Section 2(k) of this Chapter, except as provided below.

(II) A retired source shall not emit any sulfur dioxide after the date the retired source exemption is issued.

(III) A WEB source shall submit sulfur dioxide emissions reports, as required by Section 2(h)(viii) of this Chapter for any time period the source was operating prior to the effective date of the retired source exemption. The retired source shall be subject to the compliance provisions of Section 2(k) of this Chapter, including the requirement to hold allowances in the source's compliance account to cover all sulfur dioxide emissions prior to the date the source was permanently retired.

(IV) A retired source that is still in existence but no longer emitting sulfur dioxide shall, for a period of five years from the date the records are created, retain records demonstrating the effective date of the retired source exemption for purposes of Chapter 14, Section 2.

(D) Resumption of Operations.

(I) Should a retired source desire to resume operation, the retired source must submit registration materials as follows:

(1.) If the source is required to obtain a construction permit under Chapter 6, Section 2 or an operating permit under Chapter 6, Section 3 prior to resuming operation, then registration information as described in Section 2(e)(i) of this Chapter and a copy of the retired source exemption must be submitted with the notice of intent under Chapter 6, Section 2 or the operating permit application required under Chapter 6, Section 3;

(2.) If the source does not meet the criteria of (1.), then registration information as described in Section 2(e)(i) of this Chapter and a copy of the retired source exemption must be submitted to the Department at least ninety (90) days prior to resumption of operation.

(II) The retired source exemption shall automatically expire on the day the retired source resumes operation.

(E) Loss of Future Allowances. A WEB source that is permanently retired and that does not apply to the Department for a retired source exemption within ninety (90) days of the date that the source is permanently retired shall forfeit any unused and future allowances. The abandoned allowances shall be retired directly by the TSA.

(d) Account Representative for WEB Sources.

(i) Each WEB source must identify one account representative and may also identify an alternate account representative who may act on behalf of the account representative. Any representation, action, inaction or submission by the alternate account representative will be deemed to be a representation, action, inaction or submission by the account representative.

(ii) Identification and Certification of an Account Representative.

(A) The account representative and any alternate account representative shall be appointed by an agreement that makes the representations, actions, inactions or submissions of the account representative and any alternate binding on the owners and operators of the WEB source.

(B) The account representative shall submit to the Department and the TSA a signed and dated Certificate that contains the following elements:

(I) Identification of the WEB source by plant name, state and an appropriate identification code in a format specified by the Department;

(II) The name, address, e-mail (if available), telephone and facsimile number of the account representative and any alternate;

(III) A list of owners and operators of the WEB source;

(IV) Information to be part of the emission tracking system database in accordance with Part A2.1 of Section C of the WYRHSIP. The specific data elements shall be as specified by the State of Wyoming to be consistent with the data system structure, and may include basic facility information that may appear in other reports and notices submitted by the WEB source, such as county location, industrial classification codes, and similar general facility information.

(V) The following certification statement: "I certify that I was selected as the account representative or alternate account representative, as applicable, by an agreement binding on the owners and operators of the WEB source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the WEB Trading Program on behalf of the owners and operators of the WEB source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Department regarding the WEB Trading Program."

(C) Upon receipt by the Department of the complete Certificate, the account representative and any alternate account representative represents and, by his or her representations, actions, inactions, or submissions, legally binds each owner and operator of the WEB source in all matters pertaining to the WEB Trading Program. The owners and operators shall be bound by any decision or order issued by the Department regarding the WEB Trading Program.

(D) No WEB Allowance Tracking System account shall be established for the WEB source until the TSA has received a complete Certificate. Once the account is established, the account representative shall make all submissions concerning the account, including the deduction or transfer of allowances.

(iii) Responsibilities.

(A) The responsibilities of the account representative include, but are not limited to, the transferring of allowances and the submission of monitoring plans, registrations, certification applications, sulfur dioxide emissions data and compliance reports as required by Section 2 of this Chapter, and representing the source in all matters pertaining to the WEB Trading Program.

(B) Each submission under this program shall be signed and certified by the account representative for the WEB source. Each submission shall include the following truth and accuracy certification statement by the account representative:

(I) "I am authorized to make this submission on behalf of the owners and operators of the WEB source for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iv) Changing the Account Representative or Owners and Operators.

(A) Changes to the Account Representative or the alternate Account Representative.

The account representative or alternate account representative may be changed at any time by sending a complete superseding Certificate to the Department and the TSA under Section 2(d)(ii) of this Chapter, with the change taking effect upon receipt of such Certificate by the TSA. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous account representative or alternate prior to the time and date when the TSA receives the superseding Certificate shall be binding on the new account representative and the owners and operators of the WEB source.

(B) Changes in Owners and Operators.

(I) Within thirty (30) days of any change in the owners and operators of the WEB source, including the addition of a new owner or operator, the account representative shall submit a revised Certificate amending the list of owners and operators to include such change.

(II) In the event a new owner or operator of a WEB source is not included in the list of owners and operators submitted in the Certificate, such new owner or operator shall be deemed to be subject to and bound by the Certificate, the representations, actions, inactions, and submissions of the account representative of the WEB source, and the decisions, orders, actions, and inactions of the Department as if the new owner or operator were included in such list.

(e) Registration.

(i) Deadlines.

(A) Each source that is a WEB source on or before the program trigger date shall register by submitting the initial Certificate required in Section 2(d)(ii) of this Chapter to the Department no later than 180 days after the program trigger date.

(B) Any existing source that becomes a WEB source after the program trigger date shall register by submitting the initial Certificate required in Section 2(d)(ii) of this Chapter to the Department by September 30 of the year following the inventory year in which the source exceeded the emission threshold.

(C) Any new WEB source shall register by submitting the initial Certificate required in Section 2(d)(ii) of this Chapter to the Department prior to the commencement of operation.

(ii) Integration Into Permits.

(A) Any allocation, transfer or deduction of allowance to or from the compliance account of a WEB source shall not require revision of the WEB source's operating permit under Chapter 6, Section 3.

(B) Any WEB source that is not required to have a permit under Chapter 6, Section 2 at any time after Chapter 14 becomes effective must at all times possess a permit that includes the requirements of Chapter 14. If it does not possess a Title V permit under Chapter 6, Section 3, it may do so by obtaining or modifying a permit under Chapter 6, Section 2 to incorporate the requirements of Chapter 14. The source must at all times possess a permit that includes these requirements.

(f) Allowance Allocations.

(i) The TSA will record the allowances for each WEB source in the compliance account for the WEB source once the allowances are allocated by the Department under Part C1 of Section C of the WYRHSIP. If applicable, the TSA will record a portion of the sulfur dioxide allowances for a WEB source in a special reserve compliance account to account for any allowances to be held in accordance with Section 2(h)(i)(B) of this Chapter.

(ii) The TSA will assign a serial number to each allowance in accordance with Part C2 of Section C of the WYRHSIP.

(iii) All allowances shall be allocated, recorded, transferred, or used as whole allowances. To determine the number of whole allowances, the number of allowances shall be rounded down for decimals less than 0.50 and rounded up for decimals of 0.50 or greater.

(iv) An allowance is not a property right, and is a limited authorization to emit one ton of sulfur dioxide valid only for the purpose of meeting the requirements of Section 2 of this Chapter. No provision of the WEB Trading Program or other law should be construed to limit the authority of the Department to terminate or limit such authorization.

(v) Early Reduction Bonus Allocation. Any non-utility WEB source that installs new control technology and that reduces its permitted annual sulfur dioxide emissions to a level that is below the floor level allocation established for that source in Part C1 of Section C of the WYRHSIP or any utility that reduces its permitted annual sulfur dioxide emissions to a level that is below best available control technology may apply to the Department for an early reduction bonus allocation. The bonus allocation shall be available for reductions that occur between 2008 and the program trigger year. The application must be submitted no later than ninety (90) days after the program trigger date. Any WEB source that applies and receives early reduction bonus allocations must retain the records referenced below for a minimum of five (5) years after the early reduction bonus allowance is certified in accordance with Part C1.1(a)(3) of Section C of the WYRHSIP. The application for an early reduction bonus allocation must contain the following information:

(A) Copies of all construction permits, operating permits or other enforceable documents that include annual sulfur dioxide emissions limits for the WEB source during the period the WEB source qualifies for an early reduction credit. Such permits or enforceable documents must require monitoring for sulfur dioxide emissions that meet the requirements in Section 2(h) of this Chapter.

(B) Demonstration that the floor level established for the source in accordance with Part C1.1(a)(2) of Section C of the WYRHSIP for non-utilities or best available control technology for utilities was calculated using data that are consistent with monitoring methods specified in Section 2(h)(i)(A) of this Chapter. If needed, the demonstration shall include a new floor level calculation that is consistent with the monitoring methodology in Section 2(h) of this Chapter.

(vi) Request for allowances for new WEB sources or modified WEB Sources.

(A) A new WEB source may apply to the Department for an allocation from the new source set-aside, as outlined in Part C1.3 of Section C of the WYRHSIP.

(I) A new WEB source is eligible for an annual floor allocation equal to the lower of the permitted annual sulfur dioxide emission limit for that source, or sulfur dioxide annual emissions calculated based on a level of control equivalent to best available control technology (BACT) and assuming 100 percent utilization of the WEB source, beginning with the first full calendar year of operation.

(B) An existing WEB source that has increased production capacity through a new construction permit issued under Chapter 6, Section 2 may apply to the Department for an allocation from the new source set-aside, as outlined in Part C1.3 of Section C of the WYRHSIP. An existing WEB source is eligible for an annual allocation equal to:

(I) The permitted annual sulfur dioxide emission limit for a new unit; or

(II) The permitted annual sulfur dioxide emission increase for the WEB source due to the replacement of an existing unit with a new unit or the modification of an existing unit that increased production capacity of the WEB source.

(C) A source that has received a retired source exemption under Chapter 14, Section 2(c)(iv) is not eligible for an allocation from the new source set-aside.

(D) The application for an allocation from the new source set-aside must contain the following:

(I) For existing WEB sources under Section 2(f)(vi)(B)(II) of this Chapter, documentation of the production capacity of the source before and after the new permit;

(II) For new WEB sources or a new unit under Section 2(f)(vi)(B)(I), documentation of the actual date of the commencement of operation and a copy of the permit issued under Chapter 6, Section 2.

(g) Establishment of Accounts.

(i) Allowance Tracking System Accounts. All WEB sources are required to open a compliance account. In addition, if a WEB source conducts monitoring under Section 2(h)(i)(B) of this Chapter, the WEB source shall open a special reserve compliance account for allowances associated with units monitored under those provisions. The WEB source and account representative shall have no rights to transfer allowances in or out of such special reserve compliance account. The State of Wyoming shall allocate allowances to the account in accordance with Section 2(h)(i)(B)(V) of this Chapter and all such allowances for each control period shall be retired each year for compliance in accordance with Section 2(k) of this Chapter. Any person may open a general account for holding and transferring allowances. To open either type of account, an application that contains the following information shall be submitted:

(A) The name, mailing address, e-mail address, telephone number and facsimile number of the account representative. For a compliance account, include a copy of the Certificate for the account representative and any alternate as required in Section 2(d)(ii)(B) of this Chapter. For a general account, include the Certificate for the account representative and any alternate as required in (iii)(B).

(B) The WEB source or organization name;

(C) The type of account to be opened; and

(D) A signed certification of truth and accuracy by the account representative according to Section 2(d)(iii)(B) of this Chapter for compliance accounts and for general accounts, certification of truth and accuracy by the account representative according to (iv).

(ii) Account Representative for General Accounts. For a general account, one account representative must be identified and an alternate account representative may be identified and may act on behalf of the account representative. Any representation, action, inaction or submission by the alternate account representative will be deemed to be a representation, action, inaction or submission by the account representative.

(iii) Identification and Certification of an Account Representative for General Accounts.

(A) The account representative shall be appointed by an agreement that makes the representations, actions, inactions or submissions of the account representative binding on all persons who have an ownership interest with respect to allowances held in the general account.

(B) The account representative shall submit to the Department and the TSA a signed and dated Certificate that contains the following elements:

(I) The name, address, e-mail (if available), telephone and facsimile number of the account representative and any alternate;

(II) The organization name;

(III) The following certification statement:

"I certify that I was selected as the account representative or alternate account representative, as applicable, by an agreement binding on all persons who have an ownership interest in allowances in the general account with regard to matters concerning the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the WEB Trading Program on behalf of said persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions."

(C) Upon receipt by the Department of the complete Certificate, the account representative represents and, by his or her representations, actions, inactions, or submissions, legally binds each person who has an ownership interest in allowances held in the general account with regard in all matters concerning the general account. Such persons shall be bound by any decision or order issued by the Department.

(D) No WEB Allowance Tracking System general account shall be established until the TSA has received a complete Certificate. Once the account is established, the account representative shall make all submissions concerning the account, including the deduction or transfer of allowances.

(iv) Requirements and Responsibilities. Each submission for the general account shall be signed and certified by the account representative for the general account. Each submission shall include the following truth and accuracy certification statement by the account representative:

(A) "I am authorized to make this submission on behalf of all persons who have an ownership interest in allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(v) Changing the Account Representative. The account representative or alternate account representative may be changed at any time by sending a complete superseding Certificate to the Department and the TSA under (iii)(B), with the change taking effect upon receipt of such Certificate by the Department. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous account representative or alternate prior to the time and date when the Department receives the superseding Certificate shall be binding on the new account representative and all persons having ownership interest with respect to allowances held in the general account.

(vi) Changes to the Account. Any change to the information required in the application for an existing account under (i) shall require a revision of the application.

(h) Monitoring, Recordkeeping and Reporting.

(i) General Requirements on Monitoring Methods.

(A) For each sulfur dioxide emitting unit at a WEB source the WEB source shall comply with the following, as applicable, to monitor and record sulfur dioxide mass emissions:

(I) If a unit is subject to 40 CFR part 75 under a requirement separate from the WEB Trading Program, the unit shall meet the requirements contained in part 75 with respect to monitoring, recording and reporting sulfur dioxide mass emissions.

(II) If a unit is not subject to 40 CFR part 75 under a requirement separate from the WEB Trading Program, a unit shall use one of the following monitoring methods, as applicable:

(1.) A continuous emission monitoring system (CEMS) for sulfur dioxide and flow that complies with all applicable monitoring provisions in 40 CFR part 75;

(2.) If the unit is a gas- or oil-fired combustion device, the excepted monitoring methodology in Appendix D to 40 CFR part 75, or, if applicable, the low mass emissions (LME) provisions (with respect to sulfur dioxide mass emissions only) of section 75.19 of 40 CFR part 75;

(3.) One of the optional WEB protocols, if applicable, in Appendix A to Chapter 14; or

(4.) A petition for site-specific monitoring that the source submits for approval by the State of Wyoming and approval by the U.S. Environmental Protection Agency in accordance with Section 2(h)(ix) of this Chapter (relating to petitions).

(III) A permanently retired unit shall not be required to monitor under this Section if such unit was permanently retired and had no emissions for the entire period and the account representative certifies in accordance with Section 2(k)(ii) of this Chapter that these conditions were met. In the event that a permanently retired unit recommences operation, the WEB source shall meet the requirements of this Section 2(h) in the same manner as if the unit was a new unit.

(B) Notwithstanding paragraph (A) of this Section, the WEB source with a unit that meets one of the conditions of paragraph (B)(I) may submit a request to the Department to have the provisions of this paragraph (B) apply to that unit.

(I) Any of the following units may implement this paragraph (B):

(1.) Any smelting operation where all of the emissions from the operation are not ducted to a stack;

(2.) Any flare, except to the extent such flares are used as a fuel gas combustion device at a petroleum refinery; or

(3.) Any other type of unit without add-on sulfur dioxide control equipment if the unit belongs to one of the following source categories: cement kilns, pulp and paper recovery furnaces, lime kilns, or glass manufacturing.

(II) For each unit covered by this paragraph (B), the account representative shall submit a notice to request that this paragraph (B) apply to one or more sulfur dioxide emitting units at a WEB source. The notice shall be submitted in accordance with the compliance dates specified in Section 2(h)(vi)(A) of this Chapter, and shall include the following information in a format specified by the State of Wyoming with such additional, related information as may be requested:

(1.) A list of all units at the WEB source that identifies which of the units are to be covered by this paragraph (B); and

(2.) An identification of any such units that are permanently retired.

(III) For each new unit at an existing WEB source for which the WEB source seeks to comply with this paragraph (B) and for which the account representative applies for an allocation under the new source set-aside provisions of Section 2(f)(vi) of this Chapter, the account representative shall submit a modified notice under paragraph (B)(II) that includes such new sulfur dioxide emitting unit(s). The modified request shall be submitted in accordance with the compliance dates in Section 2(h)(vi)(A) of this Chapter, but no later than the date on which a request is submitted under Section 2(f)(vi) of this Chapter for allocations from the set-aside.

(IV) The account representative for a WEB source shall submit an annual emissions statement for each unit under this paragraph (B) in accordance with Section 2(h)(viii) of this Chapter. The WEB source shall maintain operating records sufficient to estimate annual emissions in a manner consistent with emission inventory submitted by the source for calendar year 1998. In addition, if the estimated emissions from all such units at the WEB source are greater than the allowances for the current control year held in the special reserve compliance account for the WEB source, the account representative shall report the excess amount as part of the annual report for the WEB source under Section 2(k) of this Chapter and be required to use other allowances in the standard compliance account for the WEB source to account for such emissions, in accordance with Section 2(k) of this Chapter.

(V) Section 2(h) shall not apply to units covered by this paragraph except where otherwise noted.

(VI) A WEB source may opt to modify the monitoring for a sulfur dioxide emitting unit to use monitoring under Section 2(h)(i)(A) of this Chapter, but any such monitoring change must take effect on January 1 of the next compliance year. In addition, the account representative must submit an initial monitoring plan at least 180 days prior to the date on which the new monitoring will take effect and a detailed monitoring plan in accordance with Section 2(h)(ii) of this Chapter. The account representative shall also submit a revised notice under paragraph (B)(II) at the same time that the initial monitoring plan is submitted.

(C) For any monitoring that the WEB source uses under this Section (including paragraph (B)), the WEB source (and, as applicable, the account representative) shall implement, certify, and use such monitoring in accordance with this Section, and record and report the data from such monitoring as required in this Section. In addition, the WEB source (and, as applicable, the account representative) may not:

(I) Except for an alternative approved by the U.S. EPA Administrator for a WEB source that implements monitoring under Section 2(h)(i)(A)(I), use an alternative monitoring system, alternative reference method or another alternative for the required monitoring method without having obtained prior written approval in accordance with Section 2(h)(ix) of this Chapter (relating to petitions);

(II) Operate a sulfur dioxide emitting unit so as to discharge, or allow to be discharged, sulfur dioxide emissions to the atmosphere without accounting for these emissions in accordance with the applicable provisions of this Section;

(III) Disrupt the approved monitoring method or any portion thereof, and thereby avoid monitoring and recording sulfur dioxide mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing or maintenance is performed in accordance with the applicable provisions of this Section; or

(IV) Retire or permanently discontinue use of an approved monitoring method, except under one of the following circumstances:

(1.) During a period when the unit is exempt from the requirements of this Section, including retirement of a unit as addressed in Section 2(h)(i)(A)(III);

(2.) The WEB source is monitoring emissions from the unit with another certified monitoring method approved under this Section for use at the unit that provides data for the same parameter as the retired or discontinued monitoring method; or

(3.) The account representative submits notification of the date of certification testing of a replacement monitoring system in accordance with this Section, and the WEB source recertifies thereafter a replacement monitoring system in accordance with the applicable provisions of this Section.

(ii) Monitoring Plan.

(A) General Provisions. A WEB source with a sulfur dioxide emitting unit that uses a monitoring method under Section 2(h)(i)(A)(II) of this Chapter shall meet the following requirements:

(I) Prepare and submit to the State of Wyoming an initial monitoring plan for each monitoring method that the WEB source uses to comply with this Section. In accordance with paragraph 2(h)(ii)(C) of this Chapter, the plan shall contain sufficient information on the units involved, the applicable method, and the use of data derived from that method to demonstrate that all unit sulfur dioxide emissions are monitored and reported. The plan shall be submitted in accordance with the compliance deadlines specified in Section 2(h)(vi) of this Chapter.

(II) Prepare, maintain and submit to the State of Wyoming a detailed monitoring plan prior to the first day of certification testing in accordance with the compliance deadline specified in Section 2(h)(vi) of this Chapter. The plan will contain the applicable information required by Section 2(h)(ii)(D) of this Chapter. The State of Wyoming may require that the monitoring plan (or portions thereof) be submitted electronically. The State of Wyoming also may require that the plan be submitted on an ongoing basis in electronic format as part of the quarterly report submitted under Section 2(h)(viii)(A) of this Chapter or resubmitted separately after any change is made to the plan in accordance with the following paragraph (A)(III).

(III) Whenever the WEB source makes a replacement, modification, or change in one of the systems or methodologies provided for in Section 2(h)(i)(A)(II) of this Chapter, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to serial number for a component of a monitoring system), then the WEB source shall update the monitoring plan in accordance with the compliance deadline specified in Section 2(h)(vi) of this Chapter.

(B) A WEB source with a sulfur dioxide emitting unit that uses a method under Section 2(h)(i)(A)(I) of this Chapter (a unit subject to 40 CFR part 75 under a program other than this WEB Trading Program) shall meet the requirements of Section 2(h)(ii)(A)-(F) by preparing, maintaining and submitting a monitoring plan in accordance with the requirements of 40 CFR part 75. If requested, the WEB source also shall submit the entire monitoring plan to the State of Wyoming.

(C) Initial Monitoring Plan. The account representative shall submit an initial monitoring plan for each sulfur dioxide emitting unit (or group of units sharing a common methodology) that, except as otherwise specified in an applicable provision in Appendix A, contains the following information:

(I) For all sulfur dioxide emitting units:

(1.) Plant name and location;

(2.) Plant and unit identification numbers assigned by the State of Wyoming;

(3.) Type of unit (or units for a group of units using a common monitoring methodology);

(4.) Identification of all stacks or pipes associated with the monitoring plan;

(5.) Types of fuel(s) fired (or sulfur containing process materials used in the sulfur dioxide emitting unit), and the fuel classification of the unit if combusting more than one type of fuel and using a 40 CFR part 75 methodology;

(6.) Type(s) of emissions controls for sulfur dioxide installed or to be installed, including specifications of whether such controls are pre-combustion, post-combustion, or integral to the combustion process;

(7.) Maximum hourly heat input capacity, or process throughput capacity, if applicable;

(8.) Identification of all units using a common stack; and

(9.) Indicator of whether any stack identified in the plan is a bypass stack.

(II) For each unit and parameter required to be monitored, identification of monitoring methodology information, consisting of monitoring methodology, monitor locations, substitute data approach for the methodology, and general identification of quality assurance procedures. If the proposed methodology is a site-specific methodology submitted pursuant to Section 2(h)(i)(A)(II)(4.) of this Chapter, the description under this paragraph shall describe fully all aspects of the monitoring equipment, installation locations, operating characteristics, certification testing, ongoing quality assurance and maintenance procedures, and substitute data procedures.

(III) If the WEB source intends to petition for a change to any specific monitoring requirement otherwise required under this Section, such petition may be submitted as part of the initial monitoring plan.

(IV) The State of Wyoming may issue a notice of approval or disapproval of the initial monitoring plan based on the compliance of the proposed methodology with the requirements for monitoring in this Section.

(D) Detailed Monitoring Plan. The account representative shall submit a detailed monitoring plan that, except as otherwise specified in an applicable provision in Appendix A, shall contain the following information:

(I) Identification and description of each monitoring component (including each monitor and its identifiable components, such as analyzer or probe) in a CEMS (e.g., sulfur dioxide pollutant concentration monitor, flow monitor, moisture monitor), a 40 CFR part 75, Appendix D monitoring system (e.g., fuel flowmeter, data acquisition and handling system), or a protocol in Appendix A, including:

(1.) Manufacturer, model number and serial number;

(2.) Component or system identification code assigned by the facility to each identifiable monitoring component, such as the analyzer or probe;

(3.) Designation of the component type and method of sample acquisition or operation (e.g., in situ pollutant concentration monitor or thermal flow monitor);

(4.) Designation of the system as a primary or backup system;

(5.) First and last dates the system reported data;

(6.) Status of the monitoring component; and

(7.) Parameter monitored.

(II) Identification and description of all major hardware and software components of the automated data acquisition and handling system, including:

(1.) Hardware components that perform emission calculations or store data for quarterly reporting purposes (provide the manufacturer and model number); and

(2.) Software components (provide the identification of the provider and model or version number).

(III) Explicit formulas for each measured emissions parameter, using component or system identification codes for the monitoring system used to measure the parameter that links the system observations with the reported concentrations and mass emissions. The formulas must contain all constants and factors required to derive mass emissions from component or system code observations and an indication of whether the formula is being added, corrected, deleted, or is unchanged. The WEB source with a low mass emissions unit for which the WEB source is using the optional low mass emissions excepted methodology in section 75.19(c) of 40 CFR part 75 is not required to report such formulas.

(IV) Inside cross-sectional area (ft^2) at flow monitoring location (for units with flow monitors only).

(V) If using CEMS for sulfur dioxide and flow, for each parameter monitored: scale, maximum potential concentration (and method of calculation), maximum expected concentration (if applicable) (and method of calculation), maximum potential flow rate (and method of calculations), span value, full-scale range, daily calibration units of measure, span effective date and hour, span inactivation date and hour, indication of whether dual spans are required, default high range value, flow rate span, and flow rate span value and full scale value (in standard cubic feet per hour) for each unit or stack using sulfur dioxide or flow component monitors.

(VI) If the monitoring system or excepted methodology provides for use of a constant, assumed, or default value for a parameter under specific circumstances, then include the following information for each value of such parameter:

(1.) Identification of the parameter;

(2.) Default, maximum, minimum, or constant value, and units of measure for the value;

(3.) Purpose of the value;

(4.) Indicator of use during controlled or uncontrolled hours;

(5.) Types of fuel;

(6.) Source of the value;

(7.) Value effective date and hour;

(8.) Date and hour value is no longer effective (if applicable); and

(9.) For units using the excepted methodology under section 75.19 of 40 CFR part 75, the applicable sulfur dioxide emission factor.

(VII) Unless otherwise specified in section 6.5.2.1 of Appendix A to 40 CFR part 75, for each unit or common stack on which hardware CEMS are installed:

(1.) The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of Appendix A to 40 CFR part 75), or thousand of pounds per hour (lb/hr) of steam, or feet per second (ft/sec) (as applicable);

(2.) The load or operating level(s) designated as normal in section 6.5.2.1 of Appendix A to 40 CFR part 75, or thousands of lb/hr of steam, or ft/sec (as applicable);

(3.) The two load or operating levels (i.e., low, mid, or high) identified in section 6.5.2.1 of Appendix A to 40 CFR part 75 as the most frequently used;

(4.) The date of the data analysis used to determine the normal load (or operating) level(s) and the two most frequently-used load (or operating) levels; and

(5.) Activation and deactivation dates when the normal load or operating level(s) change and are updated.

(VIII) For each unit that is complying with 40 CFR part 75 for which the optional fuel flow-to-load test in section 2.1.7 of Appendix D to 40 CFR part 75 is used:

(1.) The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of Appendix A to 40 CFR part 75), expressed in thousands of lb/hr of steam;

(2.) The load level designated as normal, pursuant to section 6.5.2.1 of Appendix A to 40 CFR part 75, expressed in thousands of lb/hr of steam; and

(3.) The date of the load analysis used to determine the normal load level.

(IX) Information related to quality assurance testing, including (as applicable): identification of the test strategy; protocol for the relative accuracy test audit; other relevant test information; calibration gas levels (percent of span) for the calibration error test and linearity check; calculations for determining maximum potential concentration, maximum expected concentration (if applicable), maximum potential flow rate, and span;

(X) If applicable, apportionment strategies under sections 75.10 through 75.18 of 40 CFR part 75.

(XI) Description of site locations for each monitoring component in a monitoring system, including schematic diagrams and engineering drawings and any other documentation that demonstrates each monitor location meets the appropriate siting criteria. For units monitored by a continuous emission monitoring system, diagrams shall include:

(1.) A schematic diagram identifying entire gas handling system from unit to stack for all units, using identification numbers for units, monitor components, and stacks corresponding to the identification numbers provided in the initial monitoring plan and paragraphs (D)(I) and (III). The schematic diagram must depict the height of any monitor locations. Comprehensive or separate schematic diagrams shall be used to describe groups of units using a common stack.

(2.) Stack and duct engineering diagrams showing the dimensions and locations of fans, turning vanes, air preheaters, monitor components, probes, reference method sampling ports, and other equipment that affects the monitoring system location, performance, or quality control checks.

(XII) A data flow diagram denoting the complete information handling path from output signals of CEMS components to final reports.

(E) In addition to supplying the information in paragraphs (C) and (D) above, the WEB source with a sulfur dioxide emitting unit using either of the methodologies in paragraph (h)(i)(A)(II)(2.) of this Section shall include the following information in its monitoring plan for the specific situations described:

(I) For each gas-fired or oil-fired sulfur dioxide emitting unit for which the WEB source uses the optional protocol in Appendix D to 40 CFR part 75 for sulfur dioxide mass emissions, the WEB source shall include the following information in the monitoring plan:

(1.) Parameter monitored;

(2.) Type of fuel measured, maximum fuel flow rate, units of measure, and basis of maximum fuel flow rate (i.e., upper range value or unit maximum) for each fuel flowmeter;

(3.) Test method used to check the accuracy of each fuel flowmeter;

(4.) Submission status of the data;

(5.) Monitoring system identification code;

(6.) The method used to demonstrate that the unit qualifies for monthly gross calorific value (GCV) sampling or for daily or annual fuel sampling for sulfur content, as applicable;

(7.) A schematic diagram identifying the relationship between the unit, all fuel supply lines, the fuel flowmeter(s), and the stack(s). The schematic diagram must depict the installation location of each fuel flowmeter and the fuel sampling location(s). Comprehensive or separate schematic diagrams shall be used to describe groups of units using a common pipe;

(8.) For units using the optional default sulfur dioxide emission rate for "pipeline natural gas" or "natural gas" in Appendix D to 40 CFR part 75, the information on the sulfur content of the gaseous fuel used to demonstrate compliance with either section 2.3.1.4 or 2.3.2.4 of appendix D to 40 CFR part 75;

(9.) For units using the 720 hour test under section 2.3.6 of Appendix D to 40 CFR part 75 to determine the required sulfur sampling requirements, report the procedures and results of the test; and

(10.) For units using the 720 hour test under section 2.3.5 of Appendix D to 40 CFR part 75 to determine the appropriate fuel GCV sampling frequency, report the procedures used and the results of the test.

(II) For each sulfur dioxide emitting unit for which the WEB source uses the low mass emission excepted methodology of section 75.19 to 40 CFR part 75, the WEB source shall include the following information in the monitoring plan that accompanies the initial certification application:

(1.) The results of the analysis performed to qualify as a low mass emissions unit under section 75.19(c) to 40 CFR part 75. This report will include either the previous three years actual or projected emissions. The following items should be included:

a. Current calendar year of application;

b. Type of qualification;

c. Years one, two, and three;

d. Annual measured, estimated or projected sulfur dioxide mass emissions for years one, two, and three; and

e. Annual operating hours for years one, two, and three.

(2.) A schematic diagram identifying the relationship between the unit, all fuel supply lines and tanks, any fuel flowmeter(s), and the stack(s). Comprehensive or separate schematic diagrams shall be used to describe groups of units using a common pipe;

(3.) For units which use the long-term fuel flow methodology under section 75.19(c)(3) to 40 CFR part 75, a diagram of the fuel flow to each unit or group of units and a detailed description of the procedures used to determine the long-term fuel flow for a unit or group of units for each fuel combusted by the unit or group of units;

(4.) A statement that the unit burns only gaseous fuel(s) or fuel oil and a list of the fuels that are burned or a statement that the unit is projected to burn only gaseous fuel(s) or fuel oil and a list of the fuels that are projected to be burned;

(5.) A statement that the unit meets the applicability requirements in sections 75.19(a) and (b) to 40 CFR part 75 with respect to sulfur dioxide emissions; and

(6.) Any unit historical actual, estimated and projected sulfur dioxide emissions data and calculated sulfur dioxide emissions data demonstrating that the unit qualifies as a low mass emissions unit under sections 75.19(a) and (b) to 40 CFR part 75.

(III) For each gas-fired unit the WEB source shall include the following in the monitoring plan: current calendar year, fuel usage data as specified in the definition of gas-fired in section 72.2 of 40 CFR part 72, and an indication of whether the data are actual or projected data.

(F) The specific elements of a monitoring plan under this Section 2(h)(ii) shall not be part of an operating permit for a WEB source issued in accordance with Title V of the Clean Air Act, and modifications to the elements of the plan shall not require a permit modification.

(iii) Certification and Recertification.

(A) All monitoring systems are subject to initial certification and recertification testing as specified in 40 CFR part 75 or Appendix A to Chapter 14, as applicable. Certification or recertification of a monitoring system by the U.S. Environmental Protection Agency for a WEB source that is subject to 40 CFR part 75 under a requirement separate from this Rule shall constitute certification under the WEB Trading Program.

(B) The WEB source with a sulfur dioxide emitting unit not otherwise subject to 40 CFR part 75 that monitors sulfur dioxide mass emissions in accordance with 40 CFR part 75 to satisfy the requirements of this Section shall perform all of the tests required by that regulation and shall submit the following:

(I) A test notice, not later than 21 days before the certification testing of the monitoring system, provided that the State of Wyoming may establish additional requirements for adjusting test dates after this notice as part of the approval of the initial monitoring plan under Section 2(h)(ii)(C) of this Chapter; and

(II) An initial certification application within 45 days after testing is complete.

(C) A monitoring system will be considered provisionally certified while the application is pending, and the system shall be deemed certified if the State of Wyoming does not approve or disapprove the system within six months after the date on which the application is submitted.

(D) Whenever an audit of any monitoring certified under this Rule, and a review of the initial certification or recertification application, reveal that any system or component should not have been certified or recertified because it did not meet a particular performance specification or other requirement of Chapter 14, both at the time of the initial certification or recertification application submission and at the time of the audit, the State of Wyoming will issue a notice of disapproval of the certification status of such system or component. For the purposes of this paragraph, an audit shall be either a field audit of the facility or an audit of any information submitted to the State of Wyoming regarding the facility. By issuing the notice of disapproval, the certification status is revoked prospectively, and the data measured and recorded shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the WEB source completes subsequently approved initial certification or recertification tests in accordance with the procedures in this Section 2(h)(iii). The WEB source shall apply the substitute data procedures in Section 2(h)(v)(B) of this Chapter to replace, prospectively, all of the invalid, non-quality-assured data for each disapproved system or component.

(iv) Ongoing Quality Assurance and Quality Control.

The WEB source shall satisfy the applicable quality assurance and quality control requirements of part 75 or, if the WEB source is subject to a WEB protocol in Appendix A, the applicable quality assurance and quality control requirements in Appendix A on and after the date that certification testing commences.

(v) Substitute Data Procedures.

(A) For any period after certification testing is complete in which quality assured, valid data are not being recorded by a monitoring system certified and operating in accordance with Chapter 14, missing or invalid data shall be replaced with substitute data in accordance with 40 CFR part 75 or, if the WEB source is subject to a WEB protocol in Appendix A, with substitute data in accordance with Appendix A.

(B) For a sulfur dioxide emitting unit that does not have a certified (or provisionally certified) monitoring system in place as of the beginning of the first control period for which the unit is subject to the WEB Trading Program, the WEB source shall:

(I) If the WEB source will use a CEMS to comply with this Section, substitute the maximum potential concentration of sulfur dioxide for the unit and the maximum potential flow rate, as determined in accordance with 40 CFR part 75. The procedures for conditional data validation under section 75.20(b)(3) may be used for any monitoring system under Chapter 14 that uses these 40 CFR part 75 procedures, as applicable;

(II) If the WEB source will use the 40 CFR part 75 Appendix D methodology, substitute the maximum potential sulfur content, density or gross calorific value for the fuel and the maximum potential fuel flow rate, in accordance with section 2.4 of Appendix D to 40 CFR part 75;

(III) If the WEB source will use the 40 CFR part 75 methodology for low mass emissions units, substitute the sulfur dioxide emission factor required for the unit as specified in 40 CFR 75.19 and the maximum rated hourly heat input, as defined in 40 CFR 72.2; or

(IV) If using a protocol in Appendix A to Chapter 14, follow the procedures in the applicable protocol.

(vi) Compliance Deadlines.

(A) The initial monitoring plan shall be submitted by the following dates:

(I) For each source that is a WEB source on or before the program trigger date, the monitoring plan shall be submitted 180 days after such program trigger date.

(II) For any existing source that becomes a WEB source after the program trigger date, the monitoring plan shall be submitted by September 30 of the year following the inventory year in which the source exceeded the emissions threshold.

(III) For any new WEB source, the monitoring plan shall be included with the permit application for a Chapter 6, Section 2 permit.

(B) A detailed monitoring plan under Section 2(h)(ii)(B) shall be submitted no later than 45 days prior to commencing certification testing in accordance with the following paragraph (C). Modifications to monitoring plans shall be submitted within 90 days of implementing revised monitoring plans.

(C) Emission monitoring systems shall be installed, operational and shall have met all of the certification testing requirements of this Section 2(h) (including any referenced in Appendix A) by the following dates:

(I) For each source that is a WEB source on or before the program trigger date, two years prior to the start of the first control period as described in Section 2(k) of this Chapter.

(II) For any existing source that becomes a WEB source after the program trigger date, one year after the due date for the monitoring plan under Section 2(h)(vi)(A)(II) of this Chapter.

(III) For any new WEB source (or any new unit at a WEB source under paragraphs (C)(I) or (C)(2)), the earlier of 90 unit operating days or 180 calendar days after the date the new source commences operation.

(D) The WEB source shall submit test notices and certification applications in accordance with the deadlines set forth in Section 2(h)(iv)(B).

(E) For each applicable control period, the WEB source shall submit each quarterly report under Section 2(h)(viii) by no later than 30 days after the end of each calendar quarter and shall submit the annual report under Section 2(h)(viii) no later than 60 days after the end of each calendar year.

(vii) Recordkeeping.

(A) The WEB source shall keep copies of all reports, registration materials, compliance certifications, sulfur dioxide emissions data, quality assurance data, and other submissions under Chapter 14 for a period of five years. In addition, the WEB source shall keep a copy of all Certificates for the duration of this program. Unless otherwise requested by the WEB source and approved by the State of Wyoming, the copies shall be kept on site.

(B) The WEB source shall keep records of all operating hours, quality assurance activities, fuel sampling measurements, hourly averages for sulfur dioxide, stack flow, fuel flow, or other continuous measurements, as applicable, and any other applicable data elements specified in this Section or in Appendix A to Chapter 14. The WEB source shall maintain the applicable records specified in 40 CFR part 75 for any sulfur dioxide emitting unit that uses a part 75 monitoring method to meet the requirements of this Section.

(viii) Reporting.

(A) Quarterly Reports. For each sulfur dioxide emitting unit, the account representative shall submit a quarterly report within thirty (30) days after the end of each calendar quarter. The report shall be in a format specified by the State of Wyoming to include hourly and quality assurance activity information and shall be submitted in a manner compatible with the emissions tracking database designed for the WEB Trading Program. If the WEB source submits a quarterly report under 40 CFR part 75 to the U.S. EPA Administrator, no additional report under this paragraph (A) shall be required. The State of Wyoming will require that a copy of that report (or a separate statement of quarterly and cumulative annual sulfur dioxide mass emissions) be submitted separately to the State of Wyoming.

(B) Annual Report. Based on the quarterly reports, each WEB source shall submit an annual statement of total annual sulfur dioxide emissions for all sulfur dioxide emitting units at the source. The annual report shall identify total emissions for all units monitored in accordance with Section 2(h)(i)(A) of this Chapter and the total emissions for all units with emissions estimated in accordance with Section 2(h)(i)(B) of this Chapter. The annual report shall be submitted within 60 days after the end of a control period.

(C) If the State of Wyoming so directs, any monitoring plan, report, certification, recertification, or emissions data required to be submitted under this Section shall be submitted to the TSA.

(D) The State of Wyoming may review and reject any report submitted under this Section 2(h)(viii) that contains errors or fails to satisfy the requirements of this Section, and the account representative shall resubmit the report to correct any deficiencies.

(ix) Petitions.

(A) A WEB source may petition for an alternative to any requirement specified in Section 2(h)(i)(A)(II). The petition shall require approval of the State of Wyoming and the U.S. EPA Administrator. Any petition submitted under this paragraph shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(I) Identification of the WEB source and applicable sulfur dioxide emitting unit(s);

(II) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(III) A description and diagram of any equipment and procedures used in the proposed alternative, if applicable;

(IV) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed, is consistent with the purposes of Chapter 14 and that any adverse effect of approving such alternative will be *de minimis*; and

(V) Any other relevant information that the State of Wyoming may require.

***(x) Consistency of Identifying Information*.**

For any monitoring plans, reports, or other information submitted under Section 2(h) of this Chapter, the WEB source shall ensure that, where applicable, identifying information is consistent with the identifying information provided in the most recent Certificate for the WEB source submitted under Section 2(d) of this Chapter.

(i) Allowance Transfers.

(i) Procedure. To transfer allowances, the account representative shall submit the following information to the TSA:

(A) The transfer account number(s) identifying the transferor account;

(B) The transfer account number(s) identifying the transferee account;

(C) The serial number of each allowance to be transferred; and

(D) The transferor's account representative's name and signature and date of submission.

(ii) Allowance Transfer Deadline. The allowance transfer deadline is midnight Pacific Standard Time on March 1 of each year (or if this date is not a business day, midnight of the first business day thereafter) following the end of the control period. By this time, the transfer of the allowances into the WEB source's compliance account must be correctly submitted to the TSA in order to demonstrate compliance under Section 2(k) of this Chapter for that control period.

(iii) Retirement of Allowances. To permanently retire allowances, the account representative shall submit the following information to the TSA:

(A) The transfer account number(s) identifying the transferor account;

(B) The serial number of each allowance to be retired; and

(C) The transferor's account representative's name and signature and date of submission accompanied by a signed statement acknowledging that each retired allowance is no longer available for future transfers from or to any account.

(j) Use of Allowances from a Previous Year.

(i) Any allowance that is held in a compliance account or general account will remain in such an account unless and until the allowance is deducted in conjunction with the compliance process, or transferred to another account.

(ii) In order to demonstrate compliance under Section 2(k)(i) of this Chapter for a control period, WEB sources shall only use allowances allocated for that current control period or any previous year. Because all allowances held in a special reserve compliance account for a WEB source that monitors certain units in accordance with Section 2(h)(i)(B) of this Chapter will be deducted for compliance for each control period, no banking of such allowances for use in a subsequent year is permitted by Chapter 14.

(iii) If flow control procedures for the current control period have been triggered as outlined in Part C4.2 of Section C of the WYRHSIP, then the use of allowances that were allocated for any previous year will be limited as follows:

(A) The number of allowances that are held in each compliance account and general account as of the allowance transfer deadline for the immediately previous year and that were allocated for any previous year will be determined.

(B) The number determined in (A) will be multiplied by the flow control ratio established in accordance with Part C4.2(b)(1) of Section C of the WYRHSIP to determine the number of allowances that were allocated for a previous year that can be used without restriction for the current control period.

(C) Allowances that were allocated for a previous year in excess of the number determined in (B) may also be used for the current control period. If such allowances are used to make a deduction, two allowances must be deducted for each deduction of one allowance required under Section 2(k) of this Chapter.

(iv) Special provisions for the year 2018. After compliance with the 2017 allowance limitation has been determined in accordance with Section 2(k)(i) of this Chapter, allowances allocated for any year prior to 2018 shall not be used for determining compliance with the 2018 allowance limitation or any future allowance limitation.

(k) Compliance.

(i) Compliance with Allowance Limitations.

(A) The WEB source must hold allowances, in accordance with Section 2(k)(i)(B) and (C) below and Section 2(j) of this Chapter, as of the allowance transfer deadline in the WEB source's compliance account (together with any current control year allowances held in the WEB source's special reserve compliance account under Section 2(h)(i)(B) of this Chapter) in an amount not less than the total sulfur dioxide emissions for the control period from the WEB source, as determined under the monitoring and reporting requirements of Section 2(h) of this Chapter.

(I) For each source that is a WEB source on or before the program trigger date, the first control period is the calendar year that is six (6) years following the calendar year for which sulfur dioxide emissions exceeded the milestone in accordance with procedures in Part A3 of Section C of the WYRHSIP.

(II) For any existing source that becomes a WEB source after the program trigger date, the first control period is the calendar year that is four (4) years following the inventory year in which the source exceeded the sulfur dioxide emissions threshold.

(III) For any new WEB source after the program trigger date the first control period is the first full calendar year that the source is in operation.

(IV) If the WEB Trading Program is triggered in accordance with the 2013 review procedures in Part A4 of Section C of the WYRHSIP, the first control period for each source that is a WEB source on or before the program trigger date is the year 2018.

(B) Allowance transfer deadline. An allowance may only be deducted from the WEB source's compliance account if:

(I) The allowance was allocated for the current control period or meets the requirements in Section 2(j) of this Chapter for use of allowances from a previous control period, and

(II) The allowance was held in the WEB source's compliance account as of the allowance transfer deadline for the current control period, or was transferred into the compliance account by an allowance transfer correctly submitted for recording by the allowance transfer deadline for the current control period.

(C) Compliance with allowance limitations shall be determined as follows:

(I) The total annual sulfur dioxide emissions for all sulfur dioxide emitting units at the source that are monitored under Section 2(h)(i)(B) of this Chapter, as reported by the source in Section 2(h)(viii)(B) or (D) of this Chapter, and recorded in the emissions tracking database shall be compared to the allowances held in the source's special reserve compliance account as of the allowance transfer deadline for the current control period, adjusted in accordance with Section 2(j) of this Chapter. If the emissions are equal to or less than the allowances in such account, all such allowances shall be retired to satisfy the obligation to hold allowances for such emissions. If the total emissions from such units exceed the allowances in such special reserve account, the WEB source shall account for such excess emissions in the following paragraph (II).

(II) The total annual sulfur dioxide emissions for all sulfur dioxide emitting units at the source that are monitored under Section 2(h)(i)(A) of this Chapter, as reported by the source in Section 2(h)(viii)(B) or (D) of this Chapter, and recorded in the emissions tracking database, together with any excess emissions as calculated in the preceding paragraph (I), shall be compared to the allowances held in the source's compliance account as of the allowance transfer deadline for the current control period, adjusted in accordance with Section 2(j) of this Chapter.

(III) If the comparison in Section 2(k)(i)(C)(II) results in emissions that exceed the allowances held in the source's compliance account, the source has exceeded its allowance limitation and the excess emissions are subject to the allowance deduction penalty in Section 2(k)(iii).

(D) Other than allowances in a special reserve compliance account for units monitored under Section 2(h)(i)(B) of this Chapter, to the extent consistent with Section 2(j) of this Chapter, allowances shall be deducted for a WEB source for compliance with the allowance limitation as directed by the WEB source's account representative. Deduction of any other allowances as necessary for compliance with the allowance limitation shall be on a first-in, first-out accounting basis in the order of the date and time of their recording in the WEB source's compliance account, beginning with the allowances allocated to the WEB source and continuing with the allowances transferred to the WEB source's compliance account from another compliance account or general account. The allowances held in a special reserve compliance account pursuant to Section 2(h)(i)(B) of this Chapter shall be deducted as specified in paragraph (C)(I) of this Section 2(k).

(ii) Certification of Compliance.

(A) For each control period in which a WEB source is subject to the allowance limitation, the account representative of the source shall submit to the Department a compliance certification report for the source.

(B) The compliance certification report shall be submitted no later than the allowance transfer deadline of each control period, and shall contain the following:

(I) Identification of each WEB source;

(II) At the account representative's option, the serial numbers of the allowances that are to be deducted from a source's compliance account for compliance with the allowance limitation; and

(III) The compliance certification report according to subpart (C) of this section.

(C) In the compliance certification report, the account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the WEB source in compliance with the WEB Trading Program, whether the WEB source for which the compliance certification is submitted was operated during the control period covered by the report in compliance with the requirements of the WEB Trading Program applicable to the source including:

(I) Whether the WEB source operated in compliance with the sulfur dioxide allowance limitation;

(II) Whether sulfur dioxide emissions data has been submitted to the Department in accordance with Section 2(h)(viii) of this Chapter and other applicable guidance, for review, revision as necessary, and finalization for forwarding to the sulfur dioxide Allowance Tracking System for recording;

(III) Whether the monitoring plan that governs the WEB source has been maintained to reflect the actual operation and monitoring of the source, and contains all information necessary to attribute sulfur dioxide emissions to the source, in accordance with Section 2(h)(i) of this Chapter;

(IV) Whether all the sulfur dioxide emissions from the WEB source if applicable, were monitored or accounted for either through the applicable monitoring or through application of the appropriate missing data procedures;

(V) If applicable, whether any sulfur dioxide emitting unit for which the WEB source is not required to monitor in accordance with Section 2(h)(i)(A)(III) of this Chapter remained permanently retired and had no emissions for the entire applicable period; and

(VI) Whether there were any changes in the method of operating or monitoring the WEB source that required monitor recertification. If there were any such changes, the report must specify the nature, reason, and date of the change, the method to determine compliance status subsequent to the change, and specifically, the method to determine sulfur dioxide emissions.

(iii) Penalties for any WEB source exceeding its allowance limitations.

(A) Allowance deduction penalty.

(I) If emissions from a WEB source exceed the allowance limitation for a control period, as determined in accordance with Section 2(k)(i) of this Chapter, the source's allowances held in its compliance account will be reduced by an amount equal to three times the source's tons of excess emissions. If the compliance account does not have sufficient allowances allocated for that control period, the required number of allowances will be deducted from the WEB source's compliance account regardless of the control period for which they were allocated, once allowances are recorded in the account.

(II) Any allowance deduction required under Section 2(k)(i)(C) of this Chapter shall not affect the liability of the owners and operators of the WEB source for any fine, penalty or assessment or their obligation to comply with any other remedy, for the same violation, as ordered under the Clean Air Act, implementing regulations or Wyoming Statute 35-11-901. Accordingly, a violation can be assessed each day of the control period for each ton of sulfur dioxide emissions in excess of its allowance limitation, or for each other violation of Section 2 of this Chapter.

(iv) Liability.

(A) WEB Source liability for non-compliance. Separate and regardless of any allowance deduction penalty, a WEB source that violates any requirement of Chapter 14 is subject to civil and criminal penalties under Wyoming Statute 35-11-901. Each day of the control period is a separate violation, and each ton of sulfur dioxide emissions in excess of a source's allowance limitation is a separate violation.

(B) General liability.

(I) Any provision of the WEB Trading Program that applies to a source or an account representative shall apply also to the owners and operators of such source.

(II) Any person who violates any requirement or prohibition of the WEB Trading Program will be subject to enforcement pursuant to Wyoming Statute 35-11-901.

(III) Any person who knowingly makes a false material statement in any record, submission, or report under this WEB Trading Program shall be subject to criminal enforcement pursuant to Wyoming Statute 35-11-901.

(l) Special Penalty Provisions for the 2018 Milestone.

(i) If the WEB Trading Program is triggered as outlined in Part A3 of Section C of the WYRHSIP, and the first control period will not occur until after the year 2018, the following provisions shall apply for the 2018 emissions year.

(A) All WEB sources shall register, and open a compliance account within 180 days after the program trigger date, in accordance with Section 2(e)(i) and Section 2(g) of this Chapter.

(B) The TSA will record the allowances for the 2018 control period for each WEB source in the source's compliance account once the Department allocates the 2018 allowances under Part A4.4 of Section C of the WYRHSIP.

(C) The allowance transfer deadline is midnight Pacific Standard Time on May 31, 2021 (or if this date is not a business day, midnight of the first business day thereafter). WEB sources may transfer allowances as provided in Section 2(i)(i) of this Chapter until the allowance transfer deadline.

(D) A WEB source must hold allowances allocated for 2018, including those transferred into the compliance account by an allowance transfer correctly submitted by the allowance transfer deadline, in an amount not less than the WEB source's total sulfur dioxide emissions for 2018. Emissions are determined using the pre-trigger monitoring provisions in Part A2.1 of Section C of the WYRHSIP, and Chapter 14, Section 3.

(E) In accordance with Section 2(j)(iv) and 2(l)(i)(D), Wyoming shall seek at least the minimum financial penalty of $5,000 per ton of SO_2 emissions in excess of the WEB source's allowance limitation.

(I) Any source may resolve its excess emissions violation by agreeing to a streamline settlement approach where the source pays a penalty of $5,000 per ton or partial ton of excess emissions, and payment is received within 90 calendar days after the issuance of a notice of violation.

(II) Any source that does not resolve its excess emissions violation in accordance with the streamlined settlement approach in Section 2(l)(i)(E)(I) will be subject to civil enforcement action, in which the Department shall seek a financial penalty for the excess emissions based on the State's statutory maximum civil penalties.

(F) Each ton of SO_2 emissions in excess of a source's allowance limitation is a separate violation and each day of a control period is a separate violation.

(ii) The provisions in Section 2(l) of Chapter 14 shall continue to apply for each year after the 2018 emission year until:

(A) The first control period under the WEB trading program under Section 2(k)(i)(A)(I); or

(B) The Department determines, in accordance with Part A3 of Section C of the WYRHSIP, that the 2018 sulfur dioxide milestone has been met.

(iii) Special penalty provisions for the 2018 milestone for 2019 control period and each control period thereafter as provided under Section 2(l)(ii) include the following:

(A) For the 2019 control period, the allowance transfer deadline is midnight Pacific Standard Time on May 31, 2021 (or if this date is not a business day, midnight of the first business day thereafter). WEB sources may transfer allowances as provided in Section 2(i)(i) of this Rule until the allowance transfer deadline.

(B) A WEB source must hold allowances allocated for the 2019 control period, including those transferred into the compliance account by an allowance transfer correctly submitted by the allowance transfer deadline, in an amount not less than the WEB source's total SO_2 emissions for the 2019 control period. Emissions are determined using the pre-trigger monitoring provisions in Part A2.1 of Section C of the WYRHSIP, and Chapter 14, Section 3.

(C) In accordance with Section 2(j)(iv) and 2(i)(i)(D), Wyoming shall seek at least the minimum financial penalty of $5,000 per ton of SO_2 emissions in excess of the WEB source's allowance limitation.

(I) Any source may resolve its excess emissions violation by agreeing to a streamline settlement approach where the source pays a penalty of $5,000 per ton or partial ton of excess emissions, and payment is received within 90 calendar days after the issuance of a notice of violation.

(II) Any source that does not resolve its excess emissions violation in accordance with the streamlined settlement approach in Section 2(l)(i)(E)(I) will be subject to civil enforcement action, in which the Department shall seek a financial penalty for the excess emissions based on the State's statutory maximum civil penalties.

(D) Each ton of SO_2 emissions in excess of a source's allowance limitation is a separate violation and each day of a control period is a separate violation.

(E) For each control period after 2019 that the special penalty is assessed, the dates and deadlines in 2(l)(iii)(A)-(D) above will be adjusted forward by one year.

(m) Integration Into Permits.

Any WEB source that is not subject to Chapter 6, Section 3 at any time after Chapter 14 becomes effective must obtain a permit under Chapter 6, Section 2 or modify an existing permit issued under Chapter 6, Section 2 that incorporates the requirements of Section 2 of this Chapter.

Section 3. Sulfur dioxide milestone inventory.

(a) Applicability.

(i) Section 3 of this Chapter applies to all stationary sources with actual emissions of 100 tons per year or more of sulfur dioxide in calendar year 2000 or any subsequent year.

(ii) Except as provided in (iii) and (iv), any source that meets the criteria of (i) that emits less than 100 tons per year in any subsequent year shall remain subject to the requirements of Section 3 of this Chapter until 2018 or until the first control period under the Western Backstop Sulfur Dioxide Trading Program as established in Section 2 of this Chapter, whichever is earlier.

(iii) A stationary source that meets the requirements of (i) that has permanently ceased operation is exempt from the requirements of Chapter 14.

(b) Annual Sulfur Dioxide Emission Report.

(i) Except as provided in (ii), each source subject to Chapter 14 shall report sulfur dioxide emissions by April 15th of each calendar year, in accordance with the schedule cited in Section 3(b)(iii), below.

(ii) Each source subject to Chapter 14 that is also subject to 40 CFR part 75 reporting requirements, shall submit a summary report of annual sulfur dioxide emissions that were reported to the Environmental Protection Agency under 40 CFR part 75.

(iii) Each source subject to Chapter 14 shall report emissions for the year 2003 by April 15, 2004, and annually thereafter. The inventory shall be submitted in the format specified by the Division of Air Quality.

(iv) For the reports cited in (i) and (ii) of this section, each source subject to Chapter 14 shall document the emissions monitoring/estimation methodology used to calculate their sulfur dioxide emissions, and demonstrate that the selected methodology is acceptable under the inventory program.

(v) For the reports cited in (i) and (ii) of this section, each source subject to Chapter 14 shall include emissions from start up, shut down, and upset conditions in the annual total inventory.

(vi) For the reports cited in (i) and (ii) of this section, each source subject to Chapter 14 shall use 40 CFR part 75 methodology for reporting emissions for all sources subject to the federal acid rain program.

(vii) For the reports cited in (i) and (ii) of this section, each source subject to Chapter 14 shall maintain all records used in the calculation of the emissions, including but not limited to the following:

(A) amount of fuel consumed;

(B) percent sulfur content of fuel and how the content was determined;

(C) quantity of product produced;

(D) emissions monitoring data;

(E) operating data; and

(F) how the emissions are calculated

(viii) For the reports cited in (i) and (ii) of this section, each source subject to Chapter 14 shall maintain records of any physical changes to facility operations or equipment, or any other changes (e.g., raw material or feed) that may affect the emissions projections.

(ix) For the reports cited in (i) and (ii) of this section, each source subject to Chapter 14 shall retain records for a minimum of ten years from the date of establishment, or if the record was the basis for an adjustment to the milestone, 5 years after the date of an implementation plan revision, whichever is longer.

(c) Changes in Emission Measurement Techniques.

(i) Each source subject to Chapter 14 that is also subject to 40 CFR part 75 and that uses 40 CFR part 60, Appendix A, Test Methods 2F, 2G, or 2H to measure stack flow rate shall adjust reported sulfur dioxide emissions to ensure that the reported sulfur dioxide emissions are comparable to 1999 emissions. The adjustment may be calculated using the methods in (A) through (C). The calculations that are used to make this adjustment shall be included with the annual emission report under Section 3(b) of this Chapter.

(A) Directly determine the difference in flow rate through a side-by-side comparison of data collected with the new and old flow reference methods required during a RATA test under 40 CFR part 75.

(B) Compare the annual average heat rate using heat input data from the federal acid rain program (MMBtu) and total generation (MWHrs) as reported to the federal Energy Information Administration. The flow adjustment will be calculated by using the following ratio: (Heat input/MW for first full year of data using new flow rate method) divided by (Heat input/MW for last full year of data using old flow rate method).

(C) Compare the CFM per Megawatt (MW) before and after the new flow reference method based on continuous emission monitoring data submitted in the federal acid rain program, using the following equation: (SCF/unit of generation for first full year of data using new flow rate method) divided by (SCF/unit of generation for last full year of data using old flow rate method).

(ii) Each source subject to this Rule that uses a different emission monitoring or calculation method than was used to report their sulfur dioxide emissions in 1998 under Chapter 14, Section 3 shall adjust their reported emissions to be comparable to the emission monitoring or calculation method that was used in 1998. The calculations that are used to make this adjustment shall be included with the annual emission report under Section 3(b) of this Chapter.

Section 5. Incorporation by reference.

(a) Code of Federal Regulations (CFR). All Code of Federal Regulations (CFRs), including their Appendices, cited in this Chapter, revised and published as of July 1, 2006, not including any later amendments, unless portions of said CFRs are specifically excluded in citation, are incorporated by reference. Copies of the Code of Federal Regulations are available for public inspection and copies can be obtained at cost from the Department of Environmental Quality, Division of Air Quality, 122 W. 25th Street, Cheyenne, Wyoming 82002. Copies of the CFRs can also be obtained at cost from Government Institutes, 15200 NBN Way, Building B, Blue Ridge Summit, PA 17214.

APPENDIX A: WEB CHAPTER 14, SECTION 2 MONITORING PROTOCOLS

Protocol WEB-1: SO_2 Monitoring of Fuel Gas Combustion Devices

1. Applicability

(a) The provisions of this protocol are applicable to fuel gas combustion devices at petroleum refineries.

(b) Fuel gas combustion devices include boilers, process heaters, and flares used to burn fuel gas generated at a petroleum refinery.

(c) Fuel gas means any gas which is generated and combusted at a petroleum refinery. Fuel gas does not include: (1) natural gas, unless combined with other gases generated at a petroleum refinery, (2) gases generated by a catalytic cracking unit catalyst regenerator, (3) gases generated by fluid coking burners, (4) gases combusted to produce sulfur or sulfuric acid, or (5) process upset gases generated due to startup, shutdown, or malfunctions.

2. Monitoring Requirements

(a) Except as provided in paragraphs (b) and (c) of this Section 2, fuel gas combustion devices shall use a continuous fuel gas monitoring system (CFGMS) to determine the total sulfur content (reported as H_2S) of the fuel gas mixture prior to combustion, and continuous fuel flow meters to determine the amount of fuel gas burned.

(1) Fuel gas combustion devices having a common source of fuel gas may be monitored for sulfur content at one location, if monitoring at that location is representative of the sulfur content of the fuel gas being burned in any fuel gas combustion device.

(2) The CFGMS shall meet the performance requirements in Performance Specification 2 in Appendix B to 40 CFR part 60, and the following:

(i) Continuously monitor and record the concentration by volume of total sulfur compounds in the gaseous fuel reported as ppmv H_2S.

(ii) Have the span value set so that the majority of readings fall between 10 and 95% of the range.

(iii) Record negative values of zero drift.

(iv) Calibration drift shall be 5.0% of the span.

(v) Methods 15A, 16, or approved alternatives for total sulfur, are the reference methods for the relative accuracy test. The relative accuracy test shall include a bias test in accordance with paragraph 4(c) of this section.

(3) All continuous fuel flow meters shall comply with the applicable provisions of Appendix D to 40 CFR part 75.

(4) The hourly mass SO_2 emissions shall be calculated using the following equation:

$$E = (C_S)(Q_f)(K)$$

where:

E = SO_2 emissions in lbs/hr
C_S = Sulfur content of the fuel gas as H_2S(ppmv)
Q_f = Fuel gas flow rate (scfh)
$K = 1.660 \times 10^{-7}$ (lb/scf)/ppmv

(b) In place of a CFGMS in paragraph (a) of this Section 2, fuel gas combustion devices having a common source of fuel gas may be monitored with an SO_2 CEMS and flow CEMS at only one location, if the CEMS monitoring at that location is representative of the SO_2 emission rate (lb SO_2/scf fuel gas burned) of all applicable fuel gas combustion devices. Continuous fuel flow meters shall be used in accordance with paragraph (b), and the fuel gas combustion device monitored by a CEMS shall have separate fuel metering.

(1) Each CEMS for SO_2 and flow shall comply with the operating requirements, performance specifications, and quality assurance requirements of 40 CFR part 75.

(2) All continuous fuel flow meters shall comply with the applicable provisions of Appendix D to 40 CFR part 75.

(3) The SO_2 mass emissions for all the fuel gas combustion devices monitored by this approach shall be determined by the ratio of the amount of fuel gas burned by the CEMS-monitored fuel gas combustion device to the total fuel gas burned by all applicable fuel gas combustion devices using the following equation:

$$E_t = (E_m)(Q_t)/(Q_m)$$

where: E_t = Total SO_2 emissions in lbs/hr from applicable fuel gas combustion devices.
E_m = SO_2 emissions in lbs/hr from the CEMS-monitored fuel gas combustion device.
Q_t = Fuel gas flow rate (scfh) from applicable fuel gas combustion devices.
Q_m = Fuel gas flow rate (scfh) from the CEMS-monitored fuel gas combustion device.

(c) In place of a CFGMS in paragraph (a) of this section, fuel gas combustion devices having a common source of fuel gas may be monitored with an SO_2 - diluent CEMS at only one location, if the CEMS monitoring at that location is representative of the SO_2 emission rate (lb SO_2/mmBtu) of all applicable fuel gas combustion devices. If this option is selected, the owner or operator shall conduct fuel gas sampling and analysis for gross calorific value (GCV), and shall use continuous fuel flow metering in accordance with paragraph (a) of this Section 2, with separate fuel metering for the CEMS-monitored fuel gas combustion device.

(1) Each SO_2-diluent CEMS shall comply with the applicable provisions for SO_2 monitors and diluent monitors in 40 CFR part 75, and shall use the procedures in section 3 of Appendix F to part 75 for determining SO_2 emission rate (lb/mmBtu) by substituting the term SO_2 for NO_x in that section.

(2) All continuous fuel flow meters and fuel gas sampling and analysis for GCV to determine the heat input rate from the fuel gas shall comply with the applicable provisions of Appendix D to 40 CFR part 75.

(3) The SO_2 mass emissions for all the fuel gas combustion devices monitored by this approach shall be determined by the ratio of the fuel gas heat input to the CEMS-monitored fuel gas combustion device to the total fuel gas heat input to all applicable fuel gas combustion devices using the following equation:

$$E_t = (E_m)(H_t)/(H_m)$$

where: E_t = Total SO_2 emissions in lbs/hr from applicable fuel gas combustion devices.
E_m = SO_2 emissions in lb/mmBtu from the CEMS - monitored fuel gas combustion device.
H_t = Fuel gas heat input (mmBtu/hr) from applicable fuel gas combustion devices.
H_m = Fuel gas heat input (mmBtu/hr) from the CEMS - monitored fuel gas combustion device.

3. Certification/Recertification Requirements

All monitoring systems are subject to initial certification and recertification testing as follows:

(a) The owner or operator shall comply with the initial testing and calibration requirements in Performance Specification 2 in Appendix B of 40 CFR part 60 and paragraph 2 (a)(2) of this section for each CFGMS.

(b) Each CEMS for SO_2 and flow or each SO_2-diluent CEMS shall comply with the testing and calibration requirements specified in 40 CFR part 75, section 75.20 and Appendices A and B, except that each SO_2-diluent CEMS shall meet the relative accuracy requirements for a NO_x-diluent CEMS (lb/mmBtu).

(c) A continuous fuel flow meter shall comply with the testing and calibration requirements in 40 CFR part 75, Appendix D.

4. Quality Assurance/Quality Control Requirements

(a) A quality assurance/quality control (QA/QC) plan shall be developed and implemented for each CEMS for SO_2 and flow or the SO_2-diluent CEMS in compliance with Appendix B of 40 CFR part 75.

(b) A QA/QC plan shall be developed and implemented for each continuous fuel flow meter and fuel sampling and analysis in compliance with Appendix B of 40 CFR part 75.

(c) A QA/QC plan shall be developed and implemented for each CFGMS in compliance with sections 1 and 1.1 of Appendix B of 40 CFR part 75, and the following:

(1) Perform a daily calibration error test of each CFGMS at two gas concentrations, one low level and one high level. Calculate the calibration error as described in Appendix A to 40 CFR part 75. An out of control period occurs whenever the error is greater than 5.0% of the span value.

(2) In addition to the daily calibration error test, an additional calibration error test shall be performed whenever a daily calibration error test is failed, whenever a monitoring system is returned to service following repairs or corrective actions that may affect the monitor measurements, or after making manual calibration adjustments.

(3) Perform a linearity test once every operating quarter. Calculate the linearity as described in Appendix A to 40 CFR part 75. An out of control period occurs whenever the linearity error is greater than 5.0 percent of a reference value, and the absolute value of the difference between average monitor response values and a reference value is greater than 5.0 ppm.

(4) Perform a relative accuracy test audit once every four operating quarters. Calculate the relative accuracy as described in Appendix A to 40 CFR part 75. An out of control period occurs whenever the relative accuracy is greater than 20.0% of the mean value of the reference method measurements.

(5) Using the results of the relative accuracy test audit, conduct a bias test in accordance with Appendix A to 40 CFR part 75, and calculate and apply a bias adjustment factor if required.

5. Missing Data Procedures

(a) For any period in which valid data are not being recorded by an SO_2 CEMS or flow CEMS specified in this section, missing or invalid data shall be replaced with substitute data in accordance with the requirements in Subpart D of 40 CFR part 75.

(b) For any period in which valid data are not being recorded by an SO_2-diluent CEMS specified in this section, missing or invalid data shall be replaced with substitute data on a rate basis (lb/mmBtu) in accordance with the requirements for SO_2 monitors in Subpart D of 40 CFR part 75.

(c) For any period in which valid data are not being recorded by a continuous fuel flow meter or for fuel gas GCV sampling and analysis specified in this section, missing or invalid data shall be replaced with substitute data in accordance with missing data requirements in Appendix D to 40 CFR part 75.

(d) For any period in which valid data are not being recorded by the CFGMS specified in this section, hourly missing or invalid data shall be replaced with substitute data in accordance with the missing data requirements for units performing hourly gaseous fuel sulfur sampling in section 2.4 of Appendix D to 40 CFR part 75.

6. Monitoring Plan and Reporting Requirements

In addition to the general monitoring plan and reporting requirements of Section 2(h) of Chapter 14, the owner or operator shall meet the following additional requirements:

(a) The monitoring plan shall identify each group of units that are monitored by a single monitoring system under this Protocol WEB-1, and the plan shall designate an identifier for the group of units for emissions reporting purposes. For purpose of submitting emissions reports, no apportionment of emissions to the individual units within the group is required.

(b) If the provisions of paragraphs 2(b) or (c) are used, provide documentation and an explanation to demonstrate that the SO_2 emission rate from the monitored unit is representative of the rate from non-monitored units.

Protocol WEB-2: Predictive Flow Monitoring Systems for Kilns with Positive Pressure Fabric Filter

1. Applicability

The provisions of this protocol are applicable to cement kilns or lime kilns that (1) are controlled by a positive pressure fabric filter, and (2) have operating conditions upstream of the fabric filter that the WEB source documents would reasonably prevent reliable flow monitor measurements.

2. Monitoring Requirements

(a) A cement or lime kiln with a positive pressure fabric filter shall use a predictive flow monitoring system (PFMS) to determine the hourly kiln exhaust gas flow.

(b) A PFMS is the total equipment necessary for the determination of exhaust gas flow using process or control device operating parameter measurements and a conversion equation, a graph, or computer program to produce results in cubic feet per hour.

(c) The PFMS shall meet the following performance specifications:

(1) The PFMS must allow for the automatic or manual determination of failed monitors. At a minimum a daily determination must be performed.

(2) The PFMS shall have provisions to check the calibration error of each parameter that is individually measured. The owner or operator shall propose appropriate performance specifications in the initial monitoring plan for all parameters used in the PFMS comparable to the degree of accuracy required for other monitoring systems used to comply with this Rule. The parameters shall be tested at two levels, low: 0 to 20% of full scale, and high: 50 to 100% of full scale. The reference value need not be certified.

(3) The relative accuracy of the PFMS must be $\leq$ 10.0% of the reference method average value, and include a bias test in accordance with paragraph 4(c) of this section.

3. Certification Requirements

The PFMS is subject to initial certification testing as follows:

(a) Demonstrate the ability of the PFMS to identify automatically or manually a failed monitor.

(b) Provide evidence of calibration testing of all monitoring equipment. Any tests conducted within the previous 12 months of operation that are consistent with the QA/QC plan for the PFMS are acceptable for initial certification purposes.

(c) Perform an initial relative accuracy test over the normal range of operating conditions of the kiln. Using the results of the relative accuracy test audit, conduct a bias test in accordance with Appendix A to 40 CFR part 75, and calculate and apply a bias adjustment factor if required.

4. Quality Assurance/Quality Control Requirements

A QA/QC plan shall be developed and implemented for each PFMS in compliance with sections 1 and 1.1 of Appendix B of 40 CFR part 75, and the following:

(a) Perform a daily monitor failure check.

(b) Perform calibration tests of all monitors for each parameter included in the PFMS. At a minimum, calibrations shall be conducted prior to each relative accuracy test audit.

(c) Perform a relative accuracy test audit and accompanying bias test once every four operating quarters. Calculate the relative accuracy (and bias adjustment factor) as described in Appendix A to 40 CFR part 75. An out of control period occurs whenever the flow relative accuracy is greater than 10.0% of the mean value of the reference method.

5. Missing Data

For any period in which valid data are not being recorded by the PFMS specified in this section, hourly missing or invalid data shall be replaced with substitute data in accordance with the flow monitor missing data requirements for non-load based units in Subpart D of 40 CFR part 75.

6. Monitoring Plan Requirements

In addition to the general monitoring plan requirements of Section 2(h) of Chapter 14, the owner or operator shall meet the following additional requirements:

(a) The monitoring plan shall document the reasons why stack flow measurements upstream of the fabric filter are unlikely to provide reliable flow measurements over time.

(b) The initial monitoring plan shall explain the relationship of the proposed parameters and stack flow, and discuss other parameters considered and the reasons for not using those parameters in the PFMS. The State of Wyoming may require that the subsequent monitoring plan include additional explanation and documentation for the reasonableness of the proposed PFMS.

Appendix C: Fire Programs

WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
STANDARDS AND REGULATIONS
CHAPTER 10
SMOKE MANAGEMENT

Section 4. Smoke management requirements.

(a) Effective Date. The requirements of this Section are effective for planned burn projects conducted and unplanned fire events that occur on or after January 1, 2005.

(b) Definitions. The following definitions apply to Chapter 10, Section 4. Unless defined differently below, the meaning of the terms used in this section is the same as in Chapter 1, Section 3 of these regulations.

(i) "Alternatives to burning" means manual, mechanical, chemical or biological treatments designed to replace the use of fire to manage vegetation.

(ii) "Burner" means the individual, agency, organization, land manager or landowner who is responsible for conducting a planned burn project.

(iii) "Class I Area" means all mandatory Class I Federal areas established in the Clean Air Act of 1977 and include the following for the State of Wyoming: Yellowstone National Park, Grand Teton National Park, North Absaroka Wilderness, Washakie Wilderness, Teton Wilderness, Bridger Wilderness and Fitzpatrick Wilderness. Such term also includes the Savage Run Wilderness, which is not a mandatory Class I Federal area, and any future Class I area redesignated in accordance with Chapter 6, Section 4(d) of these regulations.

(iv) "Emission reduction technique" means manual, mechanical, chemical or biological treatments used in conjunction with fire to minimize emissions, including, but not limited to, methods that minimize the burn area, reduce the fuel load, or increase the efficiency of combustion.

(v) "Jurisdictional fire authority" means an agency, organization or department whose purpose is to prevent, manage, and/or suppress fires in a designated geographic area, including, but not limited to, volunteer fire departments, fire districts, municipal fire departments and federal fire staff.

(vi) "Land manager" means an individual, agency or organization that has the overall land and/or resource management responsibility.

(vii) "Monitoring" means repeated observations (i.e., visual) or measurements (i.e., instrument) to evaluate changes in smoke affecting ambient air quality and/or visibility. Monitoring can be documented, which involves collection and analysis of the observations and/or measurements.

(viii) "Nonattainment Area" means any geographic area of the United States, which has been designated as nonattainment under § 107 of the Clean Air Act and described in 40 CFR Part 81.

(ix) "Pile volume" means the quantity in cubic feet of vegetative materials that have been manually or mechanically relocated and heaped together, as calculated using pile shape and overall dimensions.

(x) "Planned burn project" means burn area(s) or pile(s) of vegetative material that are being treated or managed utilizing planned fire for the same management objectives and that are on a contiguous land area.

(xi) "Population" means all individuals, other than the burner, occupying a fixed area. Fixed areas include, but are not limited to, portions of property normally occupied as residential, recreational, institutional, commercial, or educational premises, but do not include fixed areas under control of the burner.

(xii) "Public notification" means a method that communicates information regarding planned burn projects or unplanned fire events to the public.

(xiii) "SMP" means the Smoke Management Program that specifies requirements for planned burn projects (SMP-I and SMP-II) and unplanned fire events. Irrigation district burn projects are by definition SMP-I planned burn projects.

(xiv) "Unplanned fire" means any vegetative fire ignited by natural causes such as lightning and human causes such as accidental ignitions, escaped prescribed fire or arson; irrespective of the management objectives.

(xv) "Vegetative material" means untreated unprocessed wood, including, but not limited to, trees, tree stumps, tree limbs, bark, chips, duff, grass, grass clippings, leaves, conifer needles, bushes, shrubs, weeds, clippings from bushes and shrubs, and agricultural plant residue.

(xvi) "Ventilation category" means the classification describing the potential for smoke or other pollutants to disperse from its source, and that is expressed in terms of Excellent, Very Good, Good, Fair or Poor.

(c) Applicability. The provisions of Chapter 10, Section 4 are applicable to burners who conduct, and jurisdictional fire authorities responsible for, the following:

(i) Planned burn projects of vegetative material that exceed 0.25 tons of PM_{10} emissions per day. When areas or piles are on a contiguous land area and will be burned on the same day and by the same burner for the same management objectives, the sum of these areas or piles constitutes the daily burn area or daily pile volume.

(ii) Unplanned fire events that exceed 50 acres.

(d) Materials allowed to be burned. Only vegetative material shall be burned.

(e) Compliance with requirements.

(i) The burner and responsible jurisdictional fire authority shall comply with all rules and regulations of the Wyoming Department of Environmental Quality, Division of Air Quality, and with the Wyoming Environmental Quality Act.

(ii) Authorized representatives of the Division shall be given permission by the burner or responsible jurisdictional fire authority to enter and inspect a property, premise or place on or at which a planned burn project or unplanned fire event is or was located solely for the purpose of investigating actual sources of air pollution, and for determining compliance or non-compliance with any applicable rules, regulations, standards or orders. This permission shall extend for a maximum time of ten business days after the completed reporting form is received by the Division. Site inspections during this period shall be initiated only after notification of the burner conducting the planned burn project or the jurisdictional fire authority responsible for the unplanned fire event.

(iii) Nothing in this Section shall relieve any burner or responsible jurisdictional fire authority of the responsibility to comply with all applicable local, state and federal laws, regulations and ordinances.

(iv) Nothing in this Section shall relieve any burner or responsible jurisdictional fire authority of the responsibility to comply with any lawfully issued restriction on burning.

(v) Nothing in this Section is intended to address safety issues related to the use of fire, which fall under the control of jurisdictional fire authorities.

(f) SMP-I. **For all burners whose planned burn project exceeds the thresholds in Subsection (c)(i) and is projected to generate less than two tons of PM_{10} emissions per day, all of the following shall apply.**

(i) For each planned burn project, the burner shall notify the Division prior to the ignition of the planned burn project, in accordance with the notification process approved by the Administrator of the Division. This notification shall include the burner contact information, the location of the planned burn project, and other information required by the Administrator of the Division.

(ii) The burner shall communicate burn information to the public, in accordance with the public information process approved by the Administrator of the Division, utilizing all of the following:

(A) Prior to the ignition of each planned burn project, notify the jurisdictional fire authority(ies) responsible for the geographic area in which the planned burn project is to occur.

(B) When there is a population within a 0.5-mile radius of the planned burn project, conduct public notification no sooner than 30 days and no later than two days in advance of the ignition of the planned burn project. Documentation of public notification shall be submitted on the reporting form required in Subsection (f)(v). When it can be shown that the population within a 0.5-mile radius of the planned burn project is in an area of low population density, compliance with Subsection (f)(ii)(A) shall satisfy this requirement. An average of one dwelling unit per ten acres shall be used as the definition of areas of low population density.

(iii) The burner shall only ignite a planned burn project when smoke will disperse from its source. To satisfy this requirement, the burner shall ignite the planned burn project during the daytime hours, when there is a slight breeze and there is no population within 0.5 mile of the planned burn project in the downwind trajectory. The burner may request a waiver of any part of this requirement from the Administrator of the Division. The burner shall document in writing the reasons for requesting the waiver, and must receive a waiver granted by the Administrator of the Division prior to ignition of the planned burn project. The Administrator of the Division shall consider such waiver requests on a case-by-case basis.

(iv) The burner shall attend and observe each planned burn project periodically to determine the dispersion, direction, and impacts of the smoke.

(v) For each planned burn project, the burner shall submit to the Division a completed reporting form, provided by the Division, no later than six weeks following completion of the planned burn project.

(g) SMP-II. **For all burners whose planned burn project exceeds the thresholds in Subsection (c)(i) and is projected to generate greater than or equal to two tons of PM_{10} emissions per day, all of the following shall apply.**

(i) For each planned burn project, the burner shall submit to the Division a completed registration form, provided by the Division, by January 31 or no later than two weeks prior to the ignition of the planned burn project. The completed registration form shall include documentation of all of the following:

(A) The burner shall have reviewed smoke management educational material supplied by the Division or completed a smoke management training program prior to initiating a planned burn project.

(B) The burner shall consider the use of alternatives to burning for each planned burn project, and document the consideration of such alternatives in the method approved by the Administrator of the Division.

(C) The burner shall implement a minimum of one emission reduction technique for each planned burn project. The burner may request a waiver of this requirement from the Administrator of the Division. The burner shall document in writing the reasons for requesting the waiver, and must receive a waiver granted by the Administrator of the Division prior to the ignition of the planned burn project. The Administrator of the Division shall consider such waiver requests on a case-by-case basis.

(D) The burner shall only ignite a planned burn project when smoke will disperse from its source. To satisfy this requirement, the burner shall utilize one of the following options:

(I) Ignite the planned burn project during times when the ventilation category is “Good” or better. The ventilation category shall be obtained from a source approved by the Administrator of the Division.

(II) Ignite the planned burn project during times when the ventilation category is “Fair” if there is no population within 10 miles of the planned burn project in the downwind trajectory. The ventilation category shall be obtained from a source approved by the Administrator of the Division. The burner may request a waiver of any part of this requirement from the Administrator of the Division. The burner shall document in writing the reasons for requesting the waiver, and must receive a waiver granted by the Administrator of the Division prior to ignition of the planned burn project. The Administrator of the Division shall consider such waiver requests on a case-by-case basis.

(E) The burner shall conduct monitoring utilizing all of the following:

(I) For each planned burn project, conduct and document visual monitoring, in accordance with the visual monitoring process approved by the Administrator of the Division, to determine the dispersion, direction, and impacts of the smoke. Documentation of visual monitoring shall be submitted on the reporting form required in Subsection (g)(iv).

(II) When there is a population or Nonattainment Area within 10 miles of the planned burn project in the downwind trajectory, the burner may, on a case-by-case basis, be required by the Administrator of the Division to conduct and document ambient air quality monitoring. The results and documentation of any required ambient air quality monitoring shall be submitted with the reporting form required in Subsection (g)(iv).

(III) When there is a Class I Area within 30 miles of the planned burn project in the downwind trajectory, the burner may, on a case-by-case basis, be required by the Administrator of the Division to conduct and document ambient air quality and/or visibility monitoring. The results and documentation of any required ambient air quality and/or visibility monitoring shall be submitted with the reporting form required in Subsection (g)(iv).

(ii) For each planned burn project, the burner shall notify the Division prior to the ignition of the planned burn project, in accordance with the notification process approved by the Administrator of the Division. This notification shall include the planned burn project identification information, planned burn date(s), daily burn area or daily pile volume, and other information required by the Administrator of the Division. For each planned burn project, all of the following shall apply.

(A) The burner shall not exceed the daily burn area or daily pile volume that the burner specified in the notification.

(B) The Division shall contact the burner prior to the ignition of the planned burn project, in accordance with the modification process approved by the Administrator of the Division, if a modification of the planned burn project is required. If a representative of the Division does not contact the burner, the burner may proceed with the planned burn project.

(iii) The burner shall communicate burn information to the public, in accordance with the public information process approved by the Administrator of the Division, utilizing all of the following:

(A) Prior to the ignition of each planned burn project, notify the jurisdictional fire authority(ies) responsible for the geographic area in which the planned burn project is to occur.

(B) When there is a population within a 10-mile radius of the planned burn project, conduct public notification no sooner than 30 days and no later than two days in advance of the ignition of the planned burn project. Documentation of public notification shall be submitted on the reporting form required in Subsection (g)(iv).

(iv) For each planned burn project, the burner shall submit to the Division a completed reporting form, provided by the Division, no later than six weeks following completion of the planned burn project.

(h) Long-term planning. Long-term planning shall be required for the burner and/or land manager whose total planned burn projects in a year are projected to generate greater than 100 tons of PM_{10} emissions. The burner and/or land manager shall submit a written report to the Administrator of the Division by January 31 every third year starting in 2005. The written report shall include documentation of all of the following:

(i) The long-term burn estimates for the next three years, including the location, burn area or pile volume, vegetation type, and type of burn for each planned burn project.

(ii) The alternatives to burning considered and utilized during the previous three years and planned for the next three years, including the location and area of treatment(s), the vegetation type(s), and the specific technique(s).

(i) Unplanned fire. For the jurisdictional fire authority responsible for each unplanned fire event that exceeds 50 acres, all of the following shall apply. When it can be shown that the responsible jurisdictional fire authority is a volunteer fire organization, only Subsection (i)(iii) shall apply.

(i) The responsible jurisdictional fire authority shall communicate fire information to the public, in accordance with the public information process approved by the Administrator of the Division, utilizing all of the following:

(A) For each unplanned fire event, notify the jurisdictional fire authority(ies) responsible for the geographic area in which the unplanned fire event is occurring.

(B) When there is a population within a 10-mile radius of the unplanned fire event, conduct public notification. Documentation of public notification shall be submitted on the reporting form required in Subsection (i)(iii).

(ii) The responsible jurisdictional fire authority shall conduct monitoring utilizing all of the following:

(A) For each unplanned fire event, conduct and document visual monitoring, in accordance with the visual monitoring process approved by the Administrator of the Division, to determine the dispersion, direction, and impacts of the smoke. Documentation of visual monitoring shall be submitted on the reporting form required in Subsection (i)(iii).

(B) When there is a population or Nonattainment Area within 10 miles of the unplanned fire event in the downwind trajectory, the responsible jurisdictional fire authority may, on a case-by-case basis, be required by the Administrator of the Division to conduct and document ambient air quality monitoring. The results and documentation of any required ambient air quality and/or visibility monitoring shall be submitted with the reporting form required in Subsection (i)(iii).

(C) When there is a Class I Area within 30 miles of the unplanned fire event in the downwind trajectory, the responsible jurisdictional fire authority may, on a case-by-case basis, be required by the Administrator of the Division to conduct and document ambient air quality and/or visibility monitoring. The results and documentation of any required ambient air quality and/or visibility monitoring shall be submitted with the reporting form required in Subsection (i)(iii).

(iii) For each unplanned fire event, the responsible jurisdictional fire authority shall annually submit to the Division a completed reporting form, provided by the Division, no later than December 31.

(iv) When an unplanned fire event is managed to accomplish specific pre-stated management objectives in a predefined geographic area, all of the following shall also apply.

(A) The responsible jurisdictional fire authority shall review smoke management educational material supplied by the Division or complete a smoke management training program.

(B) The Division shall contact the responsible jurisdictional fire authority, in accordance with the modification process approved by the Administrator of the Division, if a modification of the management strategy for the unplanned fire event is necessary to mitigate smoke impacts. If a representative of the Division does not contact the responsible jurisdictional fire authority, the responsible jurisdictional fire authority may proceed with the management strategy.

(j) The following are not subject to subsections 4(e)(ii), 4(f)(i), 4(f)(ii)(B), and 4(f)(v) of Chapter 10, Section 4:

(i) Planned burning of vegetative materials incident to:

(A) Weeds along fence lines;

(B) Weed growth in and along ditch banks incident to clearing ditches for irrigation purposes;

(C) Vegetative materials related to agricultural croplands.

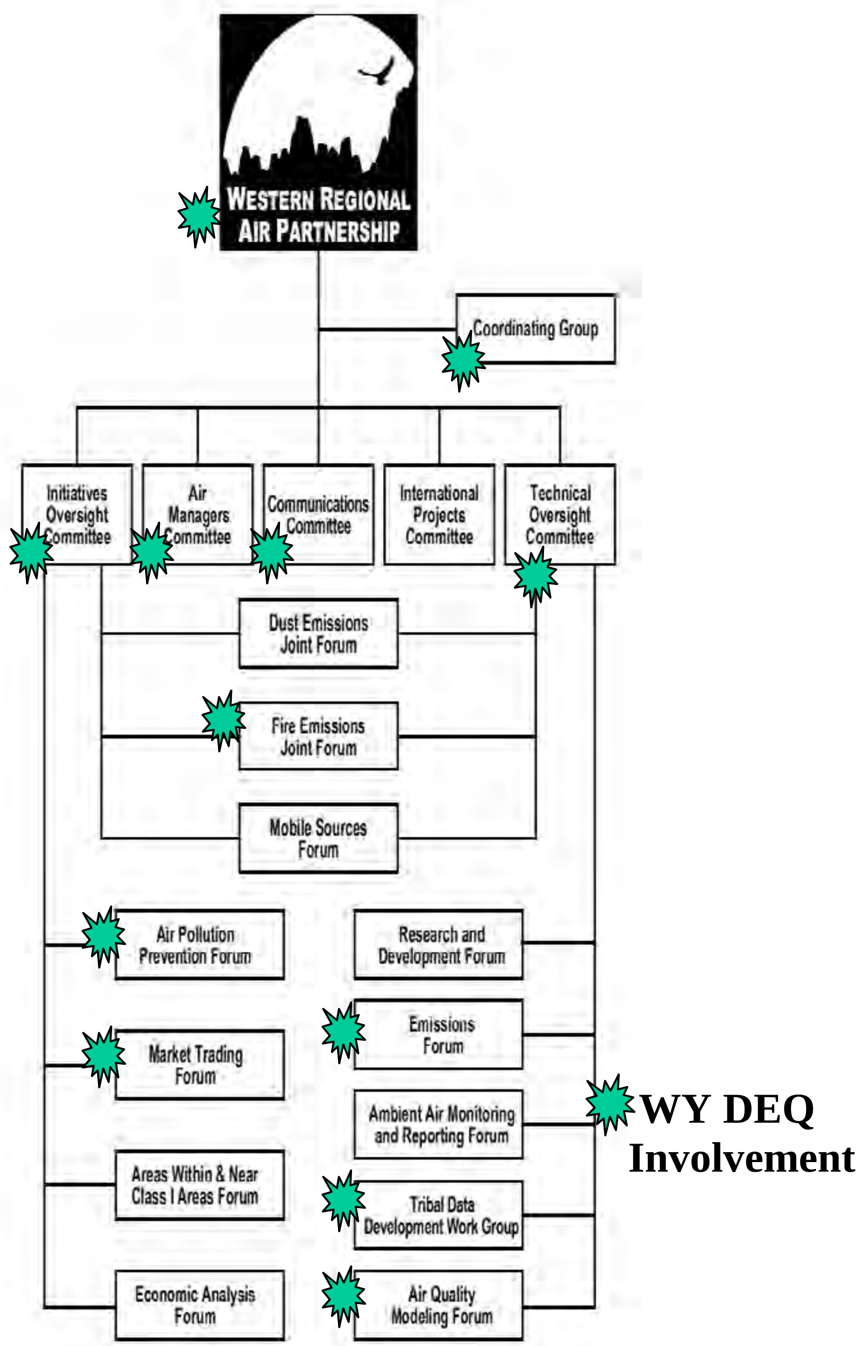
(D) Vegetative materials related to rangeland and/or pasturelands, if the project area is less than 68 acres.

(ii) The following planned burn projects do not fall under this exemption:

(A) Vegetative materials related to rangeland and/or pasture lands, unless exempted by 4(j)(i)(D).

(iii) The burner not subject to regulation under Section (j)(i) shall provide vegetative burn data requested by the Administrator in a periodic survey of agricultural burning practices.

Appendix D: Interstate and Regional Coordination



Appendix E: Demonstration that the SO_2 Milestones Provide Greater Reasonable Progress than BART

Demonstration that the SO_2 Milestones Provide Greater Reasonable Progress than BART

A. Background

In 1996 the Grand Canyon Visibility Transport Commission (GCVTC) submitted recommendations to EPA to improve visibility in the 16 Class I areas on the Colorado Plateau. The GCVTC concluded that a broad-based approach that addressed multiple pollutants and source categories was necessary to reduce regional haze. The report recommended a series of strategies to address stationary sources, mobile sources, fire, pollution prevention, fugitive dust, and clean air corridors.

On July 1, 1999 the Environmental Protection Agency (EPA) published regulations to address regional haze visibility impairment. The regulations required States to address Best Available Retrofit Technology (BART) requirements for regional haze visibility impairment, and allowed nine western states to develop plans that were based on the GCVTC recommendations for stationary sources in lieu of BART.

In 2000, the Western Regional Air Partnership (WRAP) submitted an Annex to the GCVTC recommendations that provided more details regarding the Regional SO_2 Milestones and Backstop Trading Program that had been recommended in the GCVTC Report, and included a demonstration that the milestones achieved greater reasonable progress than would have been achieved by the application of BART in the region. The Annex was approved by EPA in 2003, but this approval was later vacated by the DC Circuit Court of Appeals in 2005 due to problems with the methodology that was required in the regional haze rule for demonstrating greater reasonable progress than BART.[2]

On July 6, 2005 EPA revised the regional haze rule in response to the judicial challenges to the BART requirements. On October 13, 2006 EPA published additional revisions to address alternatives to source-specific BART determinations.

Five western states (Arizona, New Mexico, Oregon, Utah, and Wyoming) and the City of Albuquerque had submitted State Implementation Plans (SIPs) in 2003 under 40 CFR §51.309. Three of those states (New Mexico, Utah, and Wyoming) and the City of Albuquerque plan to update their SIPs to include new milestones that are based on more recent emission inventories as well as the revised BART requirements in the Regional Haze Rule. Arizona and Oregon are no longer participating in the program. This demonstration shows that the SO_2 milestones will achieve greater reasonable progress than would have been achieved from the installation and operation of BART at all sources subject to BART in the participating states in accordance with the revised Regional Haze Rule.

2 *Center for Energy and Economic Development v. EPA*, February 18, 2005; *American Corn Growers Association v. EPA*, May 24, 2002.

B. RH Rule Requirements

40 CFR 51.309(d)(4) states, "The milestones must be shown to provide for greater reasonable progress than would be achieved by application of BART pursuant to §51.308(e)(2)."

> 40 CFR 51.308(e)
> …(2) A State may opt 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 BART. Such an emissions trading program or other alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART. For all such emission trading programs or other alternative measures, the State must submit an implementation plan containing the following plan elements and include documentation for all required analyses:
>
> (i) A demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the State and covered by the alternative program. This demonstration must be based on the following:
>
> (A) A list of all BART-eligible sources within the State.
>
> (B) A list of all BART-eligible sources and all BART source categories covered by the alternative program. The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program, but each BART-eligible source in the State must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with section 302(c) or paragraph (e)(1) of this section, or otherwise addressed under paragraphs (e)(1) or (e)(4)of this section.
>
> (C) An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.
>
> (D) An analysis of the projected emissions reductions achievable through the trading program or other alternative measure.
>
> (E) A determination under paragraph (e)(3) of this section or otherwise based on the clear weight of evidence that the trading program or other alternative measure achieves greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources.

C. Identification of BART-Eligible Sources and Sources Subject to BART.

Establishing BART emission limitations under 40 CFR 51.308(e)(1) is a three-step process (70 FR 39106):

- States identify sources which meet the definition of BART eligible
- States determine which BART eligible sources are "subject to BART"
- For each source subject to BART the State identifies the appropriate control technology.

1. BART-Eligible Sources.

Pursuant to 40 CFR 51.308(e)(2)(i), States submitting §309 SIPs are required to list all BART-eligible sources covered by the alternative program. BART-eligible sources are identified as those sources that fall within one of 26 specific source categories, were built between 1962 and 1977, and have potential emissions of at least 250 tons per year of any visibility impairing air pollutant (40 CFR 51.301). The BART-eligible sources identified by the three §309 States are shown in Table 1.

2. Subject to BART Determination.

Pursuant to 40 CFR 51.308(e)(2)(i)(B) and (e)(1)(ii), States are required to determine which BART-eligible sources are "subject to BART." BART-eligible sources are subject to BART if they emit any air pollutant that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I federal area. §309 States have conducted individual source modeling to determine if a BART-eligible source causes or contributes to visibility impairment.

Two of the §309 States (New Mexico and Utah) utilized the technical modeling services of the WRAP Regional Modeling Center (RMC). Modeling was performed according to the RMC modeling protocols (CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States). For the WRAP BART exemption screening modeling, the RMC followed the EPA BART Guidelines (EPA, 2005) and the applicable CALMET/CALPUFF modeling guidance (e.g., IWAQM, 1998; FLAG, 2000; EPA, 2003c) including EPA's March 16, 2006 memorandum: "Dispersion Coefficients for Regulatory Air Quality Modeling in CALPUFF" (Atkinson and Fox, 2006).

The basic assumptions of the WRAP BART CALMET/CALPUFF modeling protocols are as follows.

- Three years (2001, 2002 and 2003) were modeled.
- Visibility impacts due to emissions of SO_2, NO_x and primary PM emissions were calculated.
- Visibility was calculated using the original IMPROVE equation and "Annual Average Natural Conditions".
- The effective range of CALPUFF modeling was set at 300km from the sources.
- According to 40 CFR Part 51, Appendix Y (EPA BART Guidelines; EPA, 2005), a BART-eligible source is considered to "contribute" to visibility impairment in a Class I area if the modeled 98th percentile change in deciviews is equal to or greater than the "contribution threshold."

- The threshold for visibility impact, for a single source, was a 0.5 deciview change or more to "contribute" to visibility impairment. This threshold is consistent with the EPA BART Guidelines (EPA, 2005) that states, "As a general matter, any threshold that you use for determining whether a source 'contributes' to visibility impairment should not be higher than 0.5 deciviews." This threshold is also consistent with long-standing visibility modeling practices. States have the discretion to set a lower threshold, but the three participating states have not determined that a lower threshold is needed or justified.

The State of Wyoming performed modeling in-house that was also based on EPA BART Guidelines and the applicable CALMET/CALPUFF guidelines. The basic assumptions were the same as used in the RMC modeling with the following exception: meteorological data for 1995, 1996, and 2001 that were prepared for a previous modeling analysis were used for the southwest Wyoming modeling domain. Wyoming's *BART Air Modeling Protocol*, September 2006, is posted at http://deq.state.wy.us/aqd/BART.asp.

Table 1. Subject to BART Status for §309 BART-Eligible Sources

State	Plant Name	Unit	BART Eligible	Subject to BART	Modeling Entity	BART Category
NM	Amoco Empire Abo	SRU Only	Y	N	WRAP	15
NM	SWPS Cunningham Station (Xcel Energy)	One Unit	Y	N	WRAP	01
NM	Duke Energy Artesia Gas Plant	SRU Only	Y	N	WRAP	15
NM	Duke Energy Linam Ranch Gas Plant	SRU Only	Y	N	WRAP	15
NM	Dynegy Saunders	SRU Only	Y	N	WRAP	15
NM	Giant Refining San Juan Refinery	Unit #1 FCCP ESP Stack	Y	N	WRAP	11
NM	Giant Refining, Ciniza Refinery	4 B&W CO Boiler	Y	N	WRAP	11
NM	SWPS Maddox Station (Xcel Energy)	One Unit	Y	N	WRAP	01
NM	Marathon Indian Basin Gas Plant	SRU Only	Y	N	WRAP	15
NM	PNM, San Juan	Units 1-4	Y	Y	WRAP	01
NM	Rio Grande Station	One Unit	Y	N	WRAP	01
NM	Western Gas Resources San Juan River Gas Plant	SRU Only	Y	N	WRAP	15
UT	PACIFICORP – Hunter Power Plant	Units 1-2	Y	Y	WRAP	01
UT	PACIFICORP – Huntington Power Plant	Units 1-2	Y	Y	WRAP	01
WY	BASIN ELECTRIC POWER COOP – LARAMIE RIVER	Units 1-3	Y	Y	WY DEQ	01
WY	BLACK HILLS POWER & LIGHT - NEIL SIMPSON I	Unit 1	Y	N	WY DEQ	01
WY	Dyno Nobel (formerly Coastal Chemical)	9 Units	Y	N	WY DEQ	10
WY	FMC CORP – GREEN RIVER SODA ASH PLANT	3 Units	Y	Y	WY DEQ	22
WY	FMC WYOMING CORP – GRANGER SODA ASH PLANT	2 Units	Y	N	WY DEQ	22
WY	GENERAL CHEMICAL – GREEN RIVER SODA ASH PLANT	2 Units	Y	Y	WY DEQ	22
WY	P4 PRODUCTION – ROCK SPRINGS COKING PLANT	1 Unit	Y	N	WY DEQ	22
WY	PACIFICORP – DAVE JOHNSTON	Units 3-4	Y	Y	WY DEQ	01
WY	PACIFICORP – JIM BRIDGER	Units 1-4	Y	Y	WY DEQ	01
WY	PACIFICORP – NAUGHTON	Units 1-3	Y	Y	WY DEQ	01

WY	PACIFICORP –WYODAK	Unit 1 (335 MW)	Y	Y	WY DEQ	01
WY	SINCLAIR OIL CORP-SINCLAIR REFINERY	16 Units	Y	N	WY DEQ	11
WY	SINCLAIR REFINERY – CASPER	1 Unit	Y	N	WY DEQ	11

D. Baseline Inventory for 2018

The Stationary Sources Joint Forum of the WRAP coordinated the development of a baseline inventory for 2018 that was used to update the SO_2 milestones for the 3-state region. The inventory was estimated as described below.

1. Electric Generating Units (EGUs)

The methodology for projecting existing EGUs into the future involves the following steps:

a) the electricity production (MWs) for each individual unit at a plant was determined from the Energy Information Administration [EIA] (data available for 2002-05)
b) the electricity generation design maximum capacity (MWs) was determined for each individual unit from EIA data
c) an operating Capacity Factor was determined by dividing the year specific production by the design maximum capacity of the each individual plant unit
d) all individual units were assumed to be operating at 85% capacity in 2018 (unless they were already operating above this level in 2002)
e) the Growth Ratio necessary to achieve 85% capacity was determined by dividing 0.85 by the Capacity Factor for each individual plant unit (averaged over four years)
f) a Current Year Emission Factor (lb SO_2/MMBtu) was calculated for the latest year of available EIA data (2006), using the actual reported emissions (tons SO_2) for each individual plant unit divided by the actual reported annual heat generation (MMBtu)
g) the 2018 Emission Factor was assumed to be the same as the current emission factor, except for a few sources that had a new permitted emission rate
h) the 2018 Emission Rate (tons SO_2) was calculated by multiplying current year emissions by the ratio of the 2018 to current year Emission Factors
i) the Adjusted 2018 Emission Rate (tons SO_2) was "grown" to 85% capacity by multiplying the 2018 Emission Rate by the Growth Ratio from Step e) (emissions from units already operating at or higher than the 85% capacity in the 2002 data year, were not grown, but accepted at face value)

2. Permitted/Future EGUs

The PRP18b inventory is documented in the ERG Final Technical Memorandum dated October 16, 2009. The Memorandum projects the need for 61.99 billion kWh of future coal-fired electricity generation between 2002 and 2018. Of this total, 36.37 billion kWh will be met by increased utilization of existing plants, and the addition of new plants that are already under construction. The remaining 25.62 billion kWh will be met by new coal plants in the WRAP region. The §309 States estimate that 25% of that total will be constructed in the 3-state region, with an emission estimate of 2,600 tons SO_2 by 2018.

a) Growth Estimates in 2008 SIPs.

The previous SO_2 milestones were finalized by the §309 States in the spring of 2008 and were adopted into the SIPs for Albuquerque, Utah, and Wyoming later that year. The milestones included a new source growth estimate of 20,000 tons SO_2 for utilities. This new source growth estimate was drawn from the PRP18a inventory that relied on the 2007 EIA projections. As part of the technical demonstration for the SIPs, the §309 States identified projects that were under construction or had been permitted that would have consumed about 10,000 tons of the new source set-aside.

b) Changes in Underlying Assumptions.

During the last two years there have been significant changes in the EIA projections for future growth of coal-fired electricity generation. The PRP18b inventory that is documented in the ERG Final Technical Memorandum dated October 16, 2009 has scaled back the projections of growth of coal-fired utilities. EPA has indicated that this more recent information calls into question the estimates for future growth in coal-fired generation in the current milestones. In addition, the State of Arizona has elected to develop a SIP under Section 308 of the Regional Haze Rule, further reducing the new source set-aside.

c) Updated New Source Growth Estimates.

The §309 States have reviewed the new Memorandum and have determined that the new source growth estimate should be reduced from 20,000 tons SO_2 to 6,600 tons SO_2. Of this total, approximately 4,000 tons SO_2 can be attributed to new units in Wyoming that are currently operating, or have commenced construction (Wygen Units II and III, Dry Fork Station, and Two Elk Unit 1). This leaves a remaining estimate of new source growth that has not been attributed to a specific plant of 2,600 tons SO_2.

This estimate is consistent with the 2009 ERG Final Technical Memorandum. As outlined in Table 3 of that Memorandum (summarized below) an additional 61.99 billion kWh of coal-fired electricity generation will be needed between 2002 and 2018.

Future Coal-Fired Electricity Generation (billion kWh)	
258.7	2002 Electricity Generation
320.69	2018 Electricity Generation
61.99	**Needed Generation**

Future Coal-Fired Electricity Generation From Existing Sources, and Those Under Construction (billion kWh)	
16.6	Unused capacity at existing 2002 facilities
5.34	Capacity at post-2002 facilities
14.43	Estimated generation capacity of the 6 EGUs under construction
36.37	**Total**
25.62	**New Source Growth Needed in WRAP Region (billion kWh)**

As shown above, 36.37 billion kWh can be met by the combination of unused capacity from existing sources plus new sources that are in operation or under construction (including the three plants in Wyoming that are described above). This leaves a remaining 25.62 billion kWh that would be met by new coal plants in the region.

The need for new source growth beyond what is already under construction is supported by estimates of future electricity demand in the region. For example, the Integrated Resource Plan submitted by PacifiCorp to the Utah Public Service Commission in May 2009 estimates a capacity deficit of 3,520 MW by 2018. The IRP meets that deficit through a combination of new natural gas-fired plants, renewable resources, and demand side management and does not include plans for new coal-fired generation. This is a change from the 2006 IRP (submitted in 2007), that included plans for new coal generation in Utah (340 MW) and Wyoming (527 MW) by 2018. However, the 2008 IRP also increased the estimated front office transactions (power purchased on the open market), from 249 MW in the 2006 IRP to 800 MW in the 2008 IRP for the year 2018. Because future demand exceeds existing capacity as shown in Table 3 of the ERG Final Technical Memorandum, it is reasonable to assume that new plants (including potential merchant plants built by other entities) will be needed to meet this demand for purchased power in 2018.

Table 4 in the Final Technical Memorandum identifies 8,880 MW that are being permitted in the region. The Memorandum states, “However, if 39% of the new coal-fired EGU plant capacity currently in the permitting process is brought on-line, then the 2008 coal-fired EIA projection for 2018 will be met.” (see page 7). Therefore, the estimate of future coal-fired EGUs in the 12-state region is 3,463 MW. Approximately 25% of the MWs listed in Table 4 as “being permitted” are located in Utah and Wyoming, therefore it is reasonable to estimate that 900 MWs (conservative emission estimate of 2,600 tons SO_2) of future coal-fired EGUs be attributed to the §309 States.

3. Non-EGUs

The Methodology for projecting emissions from "Other Industrial Sources" is described in E.H. Pechan's October 2006 Report, *2018 SO_2 Emissions Evaluation for Non-Utility Sources- Final*. The report is posted online at http://www.wrapair.org/forums/ssjf/documents/eictts/projections.html.

a) The SO_2 emissions for 19 Natural Gas Processing Plants were updated by Environ in April 2007, with additional research into future O&G Operations. The September 2007 Final Report with results of that update is posted at http://www.wrapair.org/forums/ssjf/documents/eictts/oilgas.html.
b) The 2005 SO_2 Milestone Report had some sources which were not picked up in the Pechan Report. In those cases, the 2005 emissions were used as a placeholder for the 2018 emission values.
c) The projections do not specifically break out emissions from existing sources vs. new sources. For purposes of establishing a new source set-aside, 2006 emissions were assumed to be the baseline emissions for existing sources, and the projected increase in emissions between 2006 and 2018 is attributed to new source growth.

There have been steady SO_2 emission reductions from the non-utility sector since 1990. Several major sources were shut down, including two copper smelters (BHP San Manuel and Phelps Dodge Chino: 69,491 tons SO_2 in 1990) and a steel mill (Geneva Steel: 8,473 tons SO_2 in 1990). Kennecott Utah Copper reduced SO_2 emissions by 25,000 tons SO_2 during the mid-1990s. During this same time period, oil and gas production increased substantially in all three states requiring upgrades to processing plants and other facilities to address potential air quality problems. These upgrades have largely been completed, and it is anticipated that future emissions will reflect growing demand for natural gas in the Western US. As can be seen in Figure 1, emissions have leveled off in recent years and are likely to increase as the US emerges from a major recession in coming years. The 2006 EH Pechan Report describes in detail the methodology that was used to project future emissions for each source category.

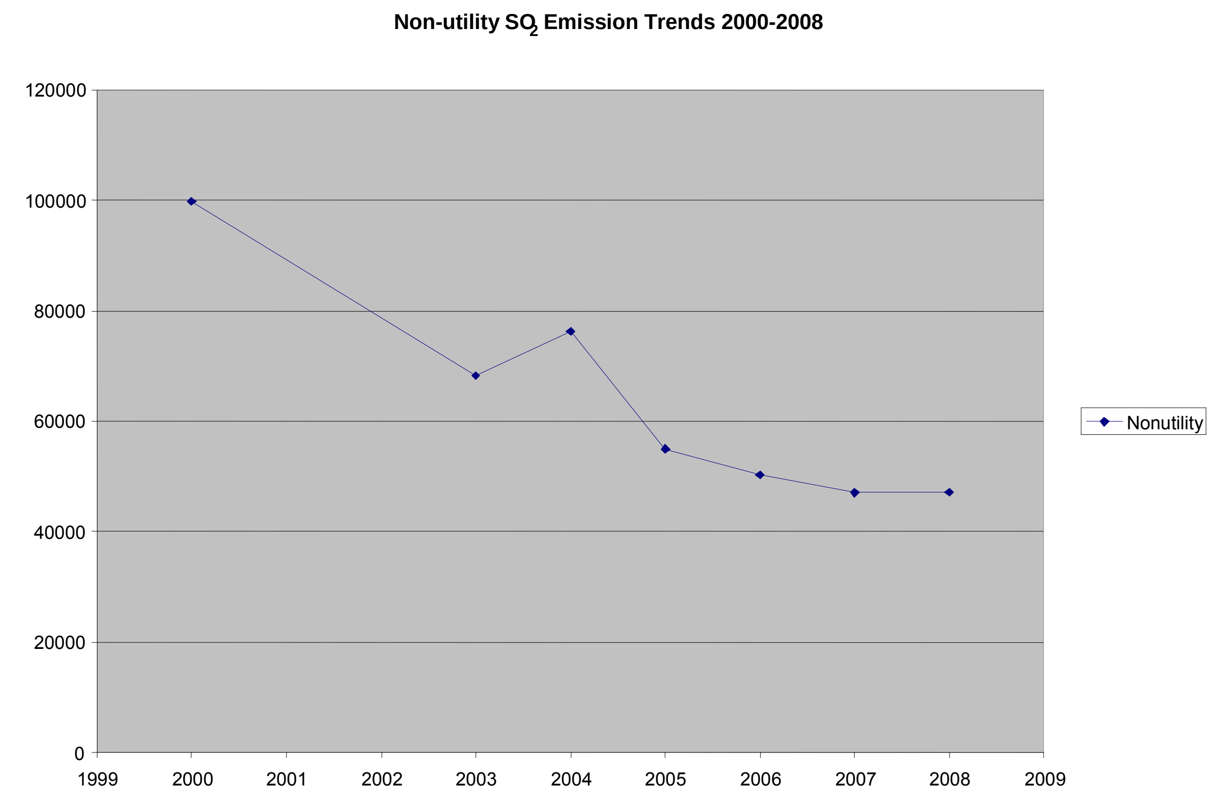


Figure 1. Non-Utility Emission Trends

Table 2 summarizes the projected 2018 baseline SO_2 emissions for the 3-state region.

Table 2. 2018 Baseline

	Projected 2018 SO_2 Emissions Baseline
Utility	128,409
Non-Utility	49,961
New Source Growth Utility	6,600
New Source Growth Non-Utility	5,686
Total 2018 Baseline	190,656

E. Estimated Emission Reductions Due to BART

The SO_2 milestones and Backstop Trading Program were designed primarily to achieve reasonable progress towards meeting the long-term visibility goal. As outlined in the Regional Haze Rule, in cases where an alternative program has been designed to meet requirements other than BART, States are not required to make BART determinations under 40 CFR 51.308(e) and may use simplifying assumptions in establishing a BART benchmark based on an analysis of what BART is likely to be for similar types of sources within a source category. Emission estimates for 2018, assuming the application of BART for SO_2 on all subject-to-BART sources in the three states, were prepared and are compiled in a spreadsheet named "10-6-10_milestone.xls" (see technical support documentation). The 2018 estimates for these sources are estimates of actual emissions and therefore reflect greater emission reductions than would be enforceable in a case-by-case BART permit. The methodology that was used to estimate these emission reductions is described below.

1. Utilities - Presumptive BART.

All utilities that were determined to be subject to BART were assumed to be operating at the presumptive emission rate established in 40 CFR Part 51, Appendix Y (0.15 lb/MMBtu). Actual emissions at this presumptive emission rate were estimated for 2018.

2. Other Sources.

The SO_2 milestones were primarily designed to achieve reasonable progress for all sources of SO_2 in the 3-state region and therefore the Regional Haze Rule allows States to use simplifying assumptions in establishing the BART benchmark. EPA has not established presumptive emission rates for non-utilities, therefore another approach was needed to estimate emission reductions from four boilers located at two trona facilities in SW Wyoming. Recent pollution control projects achieved a 63% reduction in SO_2 from two of the boilers, and represent reasonably stringent controls, considering the age and purpose of the facility. Therefore, the emission rate achieved by these projects is used as the BART benchmark for the four boilers.

I. General Chemical Soda Ash Partners, Green River Plant

C Boiler
Constructed in 1/74
Fuel Analysis for coal: 262,800 tons/year; 534 x 10e6 BTU/hr site rated capacity
Emission limit for SO_2 1.2 lb/MMBtu; 640.8 lb/hr; 2806.7 TPY

D Boiler
Constructed in 1/75
Fuel Analysis for coal: 388,000 tons/year; 880 x 10e6BTU/hr site rated capacity
Emission limit for SO_2 1.2 lb/MMBtu; 1056.0 lb/hr; 4625.3 TPY

II. FMC Wyoming Corporation Westvaco Facility

NS-1A
Constructed in 1975
Modified 8/2007 (New chevron mist eliminators installed in venturi scrubber)
Fuel Analysis coal: 380,888 tons/year; 887 x 10e6 BTU/hr site rated capacity
Emission limit for SO_2 0.54 lb/MMBtu;

NS-1B
Constructed in 1975
Modified 7/2008 (New chevron mist eliminators installed in venturi scrubber)
Fuel Analysis coal: 380,888 tons/year; 887 x 10e6 BTU/hr site rated capacity
Emission limit for SO_2 0.54 lb/MMBtu

All four boilers were originally constructed in SW Wyoming for purposes of processing trona in the mid 1970's. As process units, these four boilers are subject to greater load swings than would be experienced at electric generating units which typically come up to full operating levels and stay there. All four boilers were at one time operating under emission limits of 1.2 lb/MMBtu. All four boilers are roughly the same size with site rated capacities between 880 MMBtu/hr and 887 MMBtu/hr except for the oldest boiler, C Boiler at General Chemical at Green River rated at 534 MMBtu/hr. All four boilers burn primarily coal with oil and gas used as start up fuels. All four units have been participating in the SO_2 Backstop Trading Program, reporting inventories annually as required by Wyoming Air Quality Standards and Regulations.

Two of the four units, NS-1A and NS-1B operated by FMC, sought early SO_2 reductions in 2007 and 2008, respectively, as participants in the §309 program. These two units reduced SO_2 emissions by 55 percent or 5,126 tons collectively, from both units. New chevron mist eliminators were installed on venturi scrubbers to accomplish this reduction. Since that time, FMC has reviewed additional reductions resulting in a total reduction from the 2018 baseline of 5,827 tons or an additional 701 tons. Total reduction from the 1.2 lb/MMBtu emission rate is a 63 percent removal rate. The State of Wyoming has reviewed these additional reductions and has determined that they represent reasonably stringent controls, considering the age and purpose of the facility.

In a similar fashion, the State has reviewed potential SO_2 reductions at the General Chemical facility at Green River and has concluded that a 63 percent removal rate is also appropriate for the two boilers located at that facility. As was mentioned above, these facilities are similar in age and purpose. General Chemical boilers C and D are currently permitted at 7,432 tons of SO_2 operating at 1.2 lb/MMBtu. The State would expect that reasonably stringent controls at this facility would result in a similar 63 percent reduction from the same starting point of 1.2 lb/MMBtu. Reviewing reductions from the 2018 milestone baseline, the General Chemical boilers would be looking at reducing emissions by 2,669 tons.

While the 2018 milestone baseline level is not the same for the two companies, the State has determined that equitable treatment of like facilities would require similar reductions from the two companies prior to the §309 program. Both companies would be reducing emissions from a starting point of 1.2 lb/MMBtu down to 0.45 lb/MMBtu. In the case of FMC, who made early reductions in the program, an additional 701-ton reduction is expected to be achieved. In the case of General Chemical, 2,669 tons will be achieved. The total reduction from both facilities has been estimated at 3,370 tons. The State has determined that these are reasonably stringent controls and the resulting emissions would serve as an adequate BART benchmark.

3. Summary.

The estimated emission reductions due to the application of BART in the §309 States are summarized in Table 3.

Table 3. Emission Reduction Due to BART

	2018 Baseline SO_2	2018 SO_2 With BART	Emission Reduction Due to BART
Utilities	128,409	82,972	45,437
Non-Utilities	49,961	46,661	3,370
Total			48,807

F. 2018 BART Benchmark

2018 Baseline	190,656
Estimated BART Reductions	-48,807
Total	141,849

G. Milestones Provide Greater Reasonable Progress Than BART

The Regional SO_2 milestone of **141,849** equals the BART benchmark, but provides greater reasonable progress than BART for the reasons outlined below.

1. Early Reductions.

The GCVTC recommended that the market trading program "contain specific provisions to encourage and reward early emission reductions, including reductions achieved before 2000."[3] The GCVTC committed to achieve a 13% reduction in SO_2 emissions from stationary sources by the year 2000. The GCVTC also recognized that there was a good possibility that actual emission reductions would be greater than this 13% goal. A general plan was derived to give some early reductions credit to the region and some to the environment. The emission reductions that were greater than 13% were to be split, with ½ going to the environment (through the establishment of milestones) and the other ½ providing headroom.[4]

Sulfur dioxide emissions decreased by 25% in the 9-state GCVTC region between 1990 and 2000, and SO_2 emissions in the three §309 states 33% in that same time period.

The regional milestones have been in effect since 2003 when the original five participating states submitted regional haze SIPs, as required by Section 309 of the Regional Haze Rule. The 2003 SIP was designed to provide flexibility so that sources could find the most cost-effective way to reduce SO_2 emissions, including over-controlling some plants while opting for lower cost

[3] *Recommendations for Improving Western Vistas* at 33 (June 1996).

[4] *Id.* at 34.

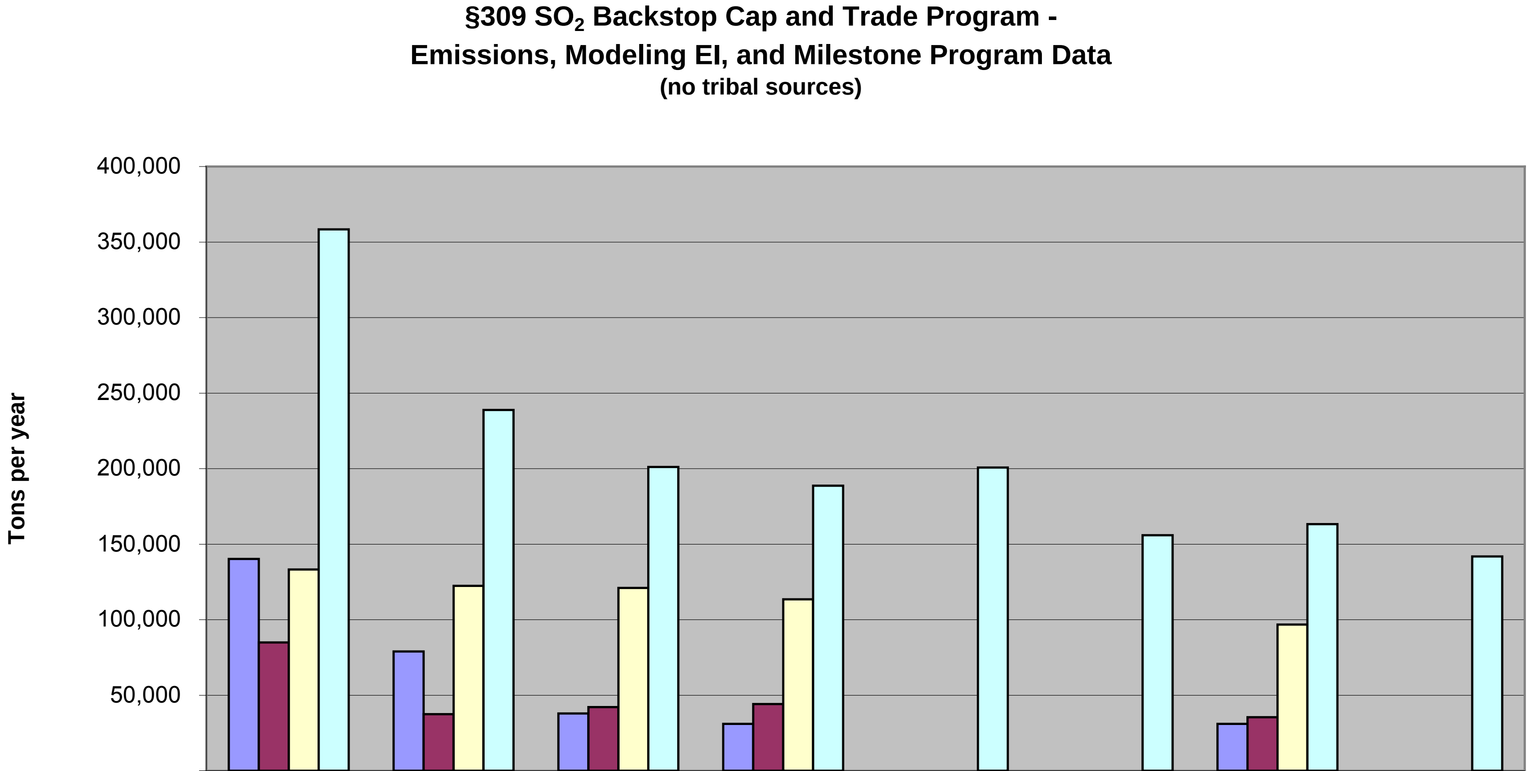
controls at other plants. The 2003 SIP was also designed to encourage early reductions by providing an extra allocation for sources that made reductions prior to the program trigger year. The 2003 SIP influenced the long-term planning for sources in the region, and utilities began upgrading plants based on the provisions of the SIP years earlier than would have been required under a case-by-case BART determination in a §308 SIP.

Emissions in the 3-state region decreased an additional 31% between 2000 and 2008.[5]
Figure 2 shows the emission reductions from 1990 baseline emissions in the §309 states that will have been achieved by 2018. This total 60% reduction from 1990 emissions is well on the way to the GCVTC goal of reducing SO_2 emissions by 50% - 70% by the year 2040.

Figure 3 shows the sulfate contribution to visibility at the long-term IMPROVE sites located on the Colorado Plateau. As can be seen from these graphs, there has been a steady decrease in the visibility impact due to sulfates. The trend is especially apparent on the 20% best days that are not affected by the variability of fire emissions in the region.

[5] *WRAP 2008 Regional Emissions and Milestone Report*, March 31, 2010.

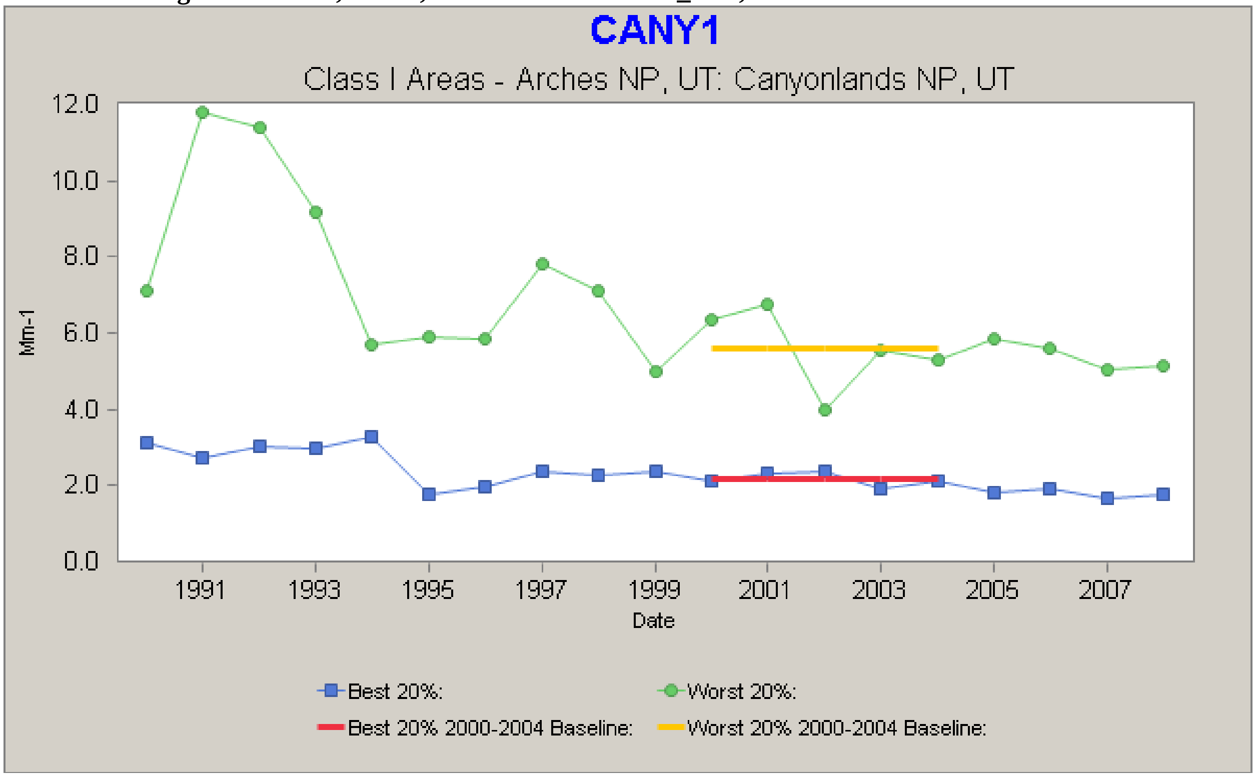
Figure 2. Emission Trends



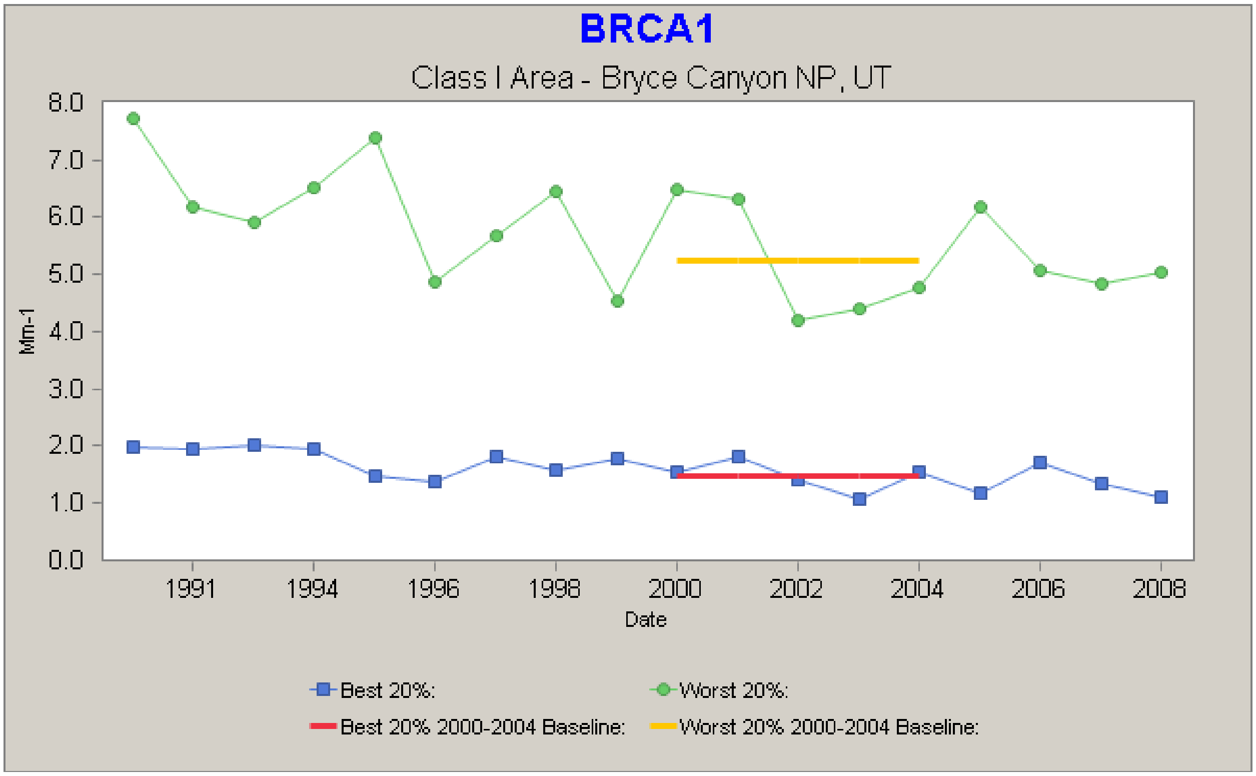
	1990	2000	2002 (Plan02d)	2006 Milestone Report	2008 Milestone	2013 Milestone	2018 (PRP18b)	2018 Milestone
NM	140,177	79,011	37,918	31,068			31,012	
UT	84,983	37,483	42,183	44,175			35,429	
WY	133,204	122,373	120,991	113,465			96,809	
3-State Total	358,364	238,867	201,092	188,708	200,722	155,940	163,250	141,849

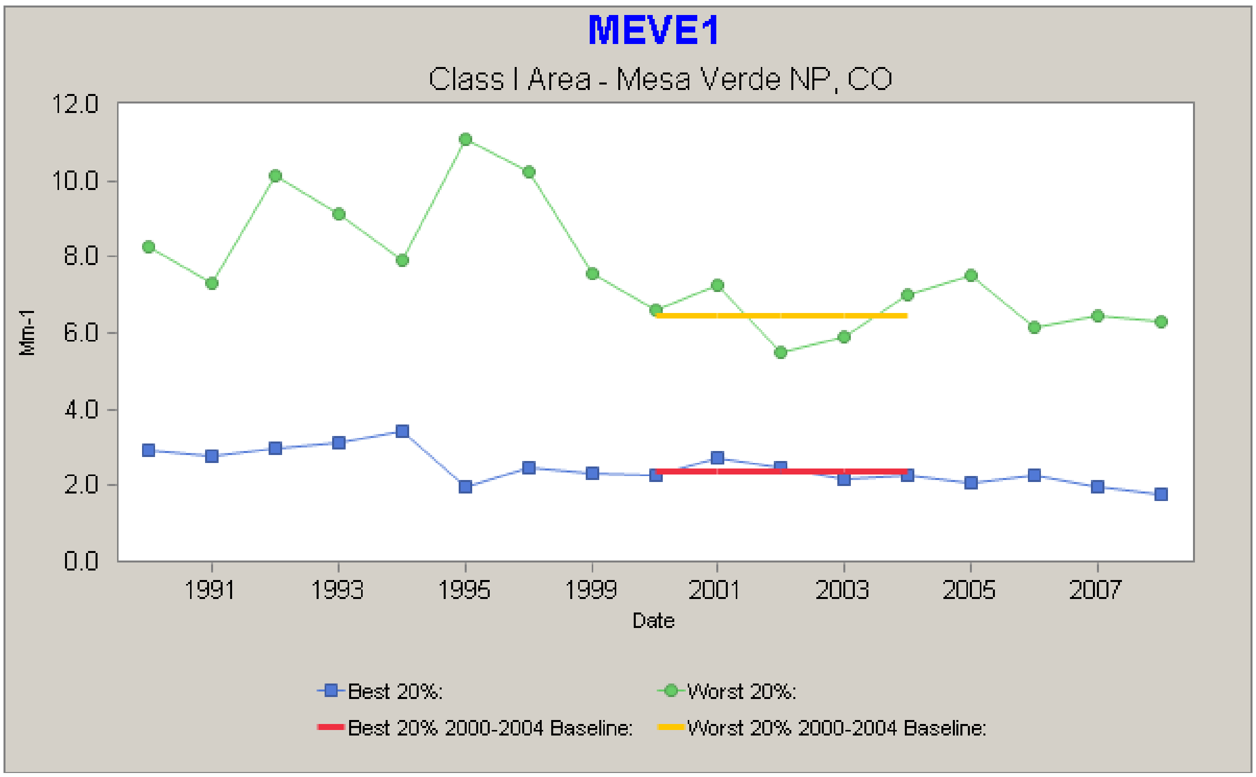
Figure 3. Sulfate Contribution to Light Extinction at Class I Areas on the Colorado Plateau.[6]

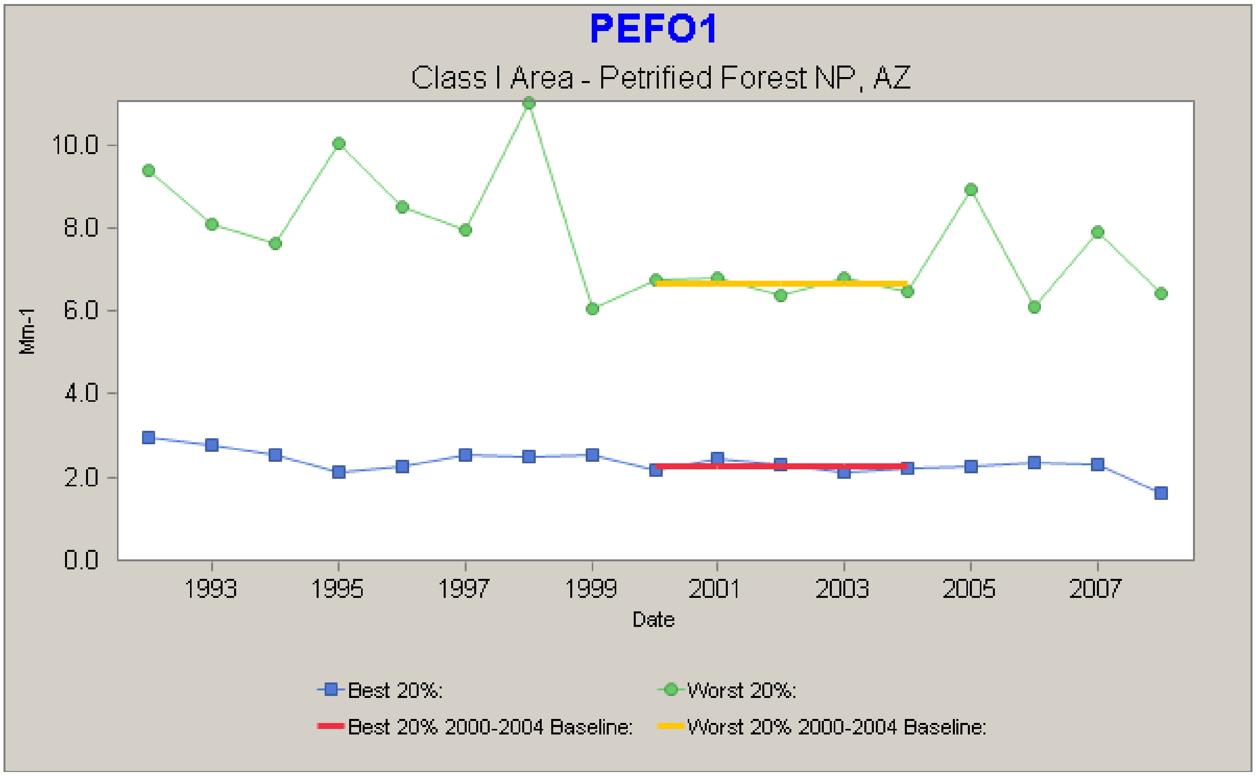
Series – Aggregation: Best 20%, Worst 20%, Best 20% 2000-2004 Baseline, Worst 20% 2000-2004 Baseline, Metadata – Program: IRHR2, Poc: 1, Parameter: ammSO4_bext, Method: RHR Dataset.

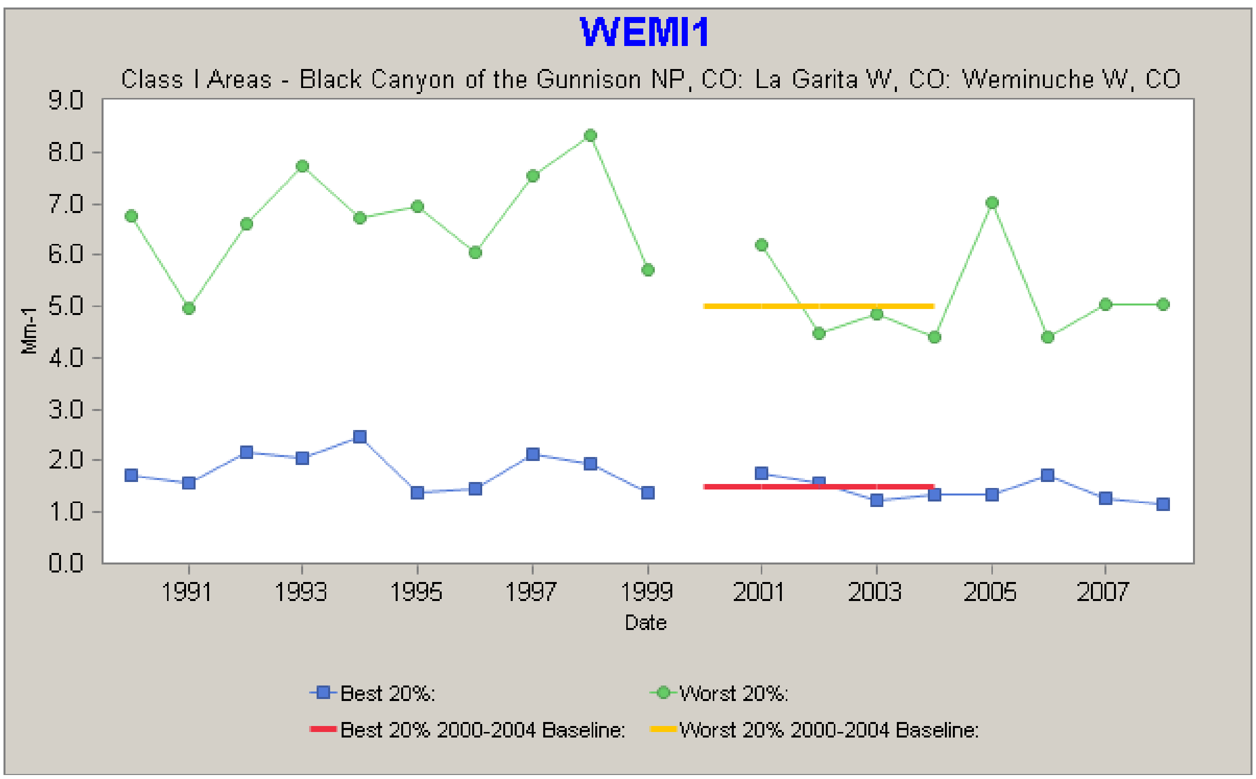


[6] Only those Class I areas on the Colorado Plateau with at least 15 years of data are included in this figure.


BRCA1
Class I Area - Bryce Canyon NP, UT
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
Mm-1
1991
1994
1996
1998
2000
2002
2004
2006
2008
Date
Best 20%:
Worst 20%:
Best 20% 2000-2004 Baseline:
Worst 20% 2000-2004 Baseline:


MEVE1
Class I Area - Mesa Verde NP, CO
12.0
10.0
8.0
6.0
4.0
2.0
0.0
Mm-1
1991
1993
1995
1999
2001
2003
2005
2007
Date
Best 20%:
Worst 20%:
Best 20% 2000-2004 Baseline:
Worst 20% 2000-2004 Baseline:


PEFO1
Class I Area - Petrified Forest NP, AZ
Mm-1
10.0
8.0
6.0
4.0
2.0
0.0
1993
1995
1997
1999
2001
2003
2005
2007
Date
Best 20%:
Worst 20%:
Best 20% 2000-2004 Baseline:
Worst 20% 2000-2004 Baseline:


WEMI1
Class I Areas - Black Canyon of the Gunnison NP, CO: La Garita W, CO: Weminuche W, CO
Mm-1
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1991
1993
1995
1997
1999
2001
2003
2005
2007
Date
Best 20%:
Worst 20%:
Best 20% 2000-2004 Baseline:
Worst 20% 2000-2004 Baseline:

2. Additional Sources Included.

The Backstop Trading Program includes all stationary sources with emissions greater than 100 tons/year of SO_2. The §309 States designed this program as part of an overall strategy to address all sources of visibility impairing pollutants, rather than focusing on a subset of stationary sources.

	Number of Sources	2006 Emissions	Percentage
Subject to BART	10	121,542	62%
Other Stationary Sources	63	73,038	38%

The inclusion of all major SO_2 sources in the program is necessary to create a viable trading program, and also serves a broader purpose to ensure that growth in emissions from sources that are not subject to BART does not undermine the progress that has been achieved. BART applied on a case-by-case basis would not affect these sources, and there would be no limitation on their future operations under their existing permit conditions. Because the milestones will cap these sources at actual emissions (which are less than current allowable emissions), the overall effect of their inclusion is to provide greater reasonable progress than would have been achieved if only sources that are subject to BART were included in the program.

3. Cap on New Source Growth.

When Congress established the visibility program in 1977 it declared as a national goal "the prevention of any future, and the remedying of any existing" anthropogenic visibility impairment in mandatory Class I federal areas.[7] BART is an emission limitation established at a specific source and is designed as a remedy to impairment at specific mandatory Class I areas. By contrast, the SO_2 milestones developed by the §309 States serve the dual purpose of remedying existing impairment and preventing future impairment by requiring regional SO_2 emissions reductions and capping emissions for stationary sources. Future impairment is prevented by capping emissions growth from sources not eligible under the BART requirements, from sources subject to BART that are expected to significantly increase utilization, and from entirely new sources in the region.

The milestones include estimates for growth, but then lock these estimates in as an enforceable emission cap. The milestone approach is consistent with the statutory goal of preventing any future visibility impairment that results from man-made air pollution. The entire region is experiencing rapid growth which could erode the progress that has been achieved in the last two decades towards improving visibility. BART applied on a case-by-case basis would have no impact on future growth, and in the long run would not achieve the regional emission reductions that are guaranteed by the program.

[7] CAA § 169A(a)(1).

4. Commission Strategies are a Total Package.

The GCVTC recommendations were developed as a comprehensive strategy includes strategies to address mobile sources, prescribed fire, pollution prevention, and Clean Air Corridors. The stationary source strategies need to be viewed as part of this overall package. Visibility impairment in the west is caused by multiple sources and pollutants, and a narrow focus on stationary sources may not achieve the same results as a broad-based program. When viewed as part of the entire SIP, the milestones achieve much greater reasonable progress than BART.

5. Mass Based Cap has Inherent Advantages Over BART

The baseline emission projections and assumed reductions due to the assumption of BART-level emission rates on all sources subject to BART are all based on actual emissions, using 2006 as the baseline. The use of actual emissions has an effect in several ways. If the BART process was applied on a case-by-case basis to individual sources, emission limitations would typically be established as an emission rate (lbs/hr or lbs/MMBtu) that would account for variations in the sulfur content of fuel and alternative operating scenarios. The difference between actual emissions and allowable emissions is particularly large when a source is permitted to burn two different fuel types, such as oil and natural gas, or when the source is part of a cyclical industry where production varies from year to year due to the changing demand for their product. A mass-based cap that is based on actual emissions is more stringent because it does not allow a source to consistently use this difference between current actual and allowable emissions.

Another difference is that mass-based limits will include excess emissions that may occur due to malfunctions or during the start-up or shut-down of emission units. A good example of this difference is the requirement in the acid rain program that emissions must be assumed to be the highest value recorded from the past year during the time period that continuous emission monitors are not functioning on a stack. These higher emissions are calculated as part of the overall tons/year, and must be accounted for under the mass-based cap for the acid rain program.

6. Tribal Set-Aside

The GCVTC recommended a market based program to address stationary source emissions of SO_2. The GCVTC recommended that the market based program include allocations to tribes that are of practical benefit.[8] This recognized the concern that "tribes, by and large, have not contributed to the visibility problem in the region" and that "[t]ribal economies are much less developed than those of states, and tribes must have the opportunity to progress to reach some degree of parity with states in this regard."[9] The tribes specifically recommended that if an emission trading strategy is adopted to achieve SO_2 reductions from stationary sources that allocations be based on considerations of equity rather than historical emissions:

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[8] *Recommendations for Improving Western Vistas* (June 1996). at 35.

[9] *Id.* at 66-67.

> Credits should not be based on historical emissions, but should be based on equitable factors, including the need to preserve opportunities for economic development on tribal lands. In general, these lands are currently lacking in economic bases and have not contributed to the visibility problems.[10]

Accordingly, the Backstop Trading Program contains a 2,500 allocation to tribes in the GCVTC region. Case-by-case BART permits would not provide this practical benefit to tribes that was an integral part of the GCVTC recommendations.

7. Other Class I Areas Also Show Improvement in Visibility

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 in each of the State §309 SIPs, but the SO_2 portion of the demonstration has been included below as Table 4 to underscore the improvements associated with §309 SO_2 reductions and further demonstrate why the §309 program is better than BART. 40 CFR 51.309(g)(2)(i) allows states to build upon the strategies implemented in a §309 program and take full credit for visibility improvement achieved through these strategies when addressing additional Class I areas. This table demonstrates achievements in visibility in these additional Class I areas (off the Colorado Plateau) in and surrounding the three states participating in the §309 program. For the most part, the table shows projected visibility improvement for 2018 with respect to SO_2 on the worst days and no degradation on the best days. There is one Class I area in New Mexico off the Colorado Plateau that is not showing improvement on the worst days. The State of New Mexico has reviewed the emissions data related to impacts in the Gila Wilderness and has determined that the visibility degradation is largely due to increasing point source emissions from Mexico.

[10] *Id.* at 71.

Table 4. 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
Great Sand Dunes NM, CO	5.3	4.9	2.0	1.8
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
Bandelier NM, NM	6.4	5.9	2.4	2.2
Bosque del Apache NWRW, NM	7.0	6.6	2.7	2.5
Gila W, NM	6.2	6.7	1.8	1.8
Salt Creek NWRW, NM	14.4	14.0	3.3	3.1
Wheeler Peak, NM (Pecos W and Wheeler Peak W)	4.7	4.4	1.1	1.0
White Mountain W, NM	8.9	8.7	1.8	1.7
Great Basin NP, NV	4.1	4.1	1.2	1.2
Jarbidge W, NV	3.8	3.4	1.3	1.2
Chiricahua, AZ (Chiricahua NM, Chiricahua W, Galiuro W)	7.4	7.4	2.2	2.1
Ike's Backbone, AZ (Mazatzal W, Pine Mountain W)	6.1	5.9	2.2	2.1
Queen Valley, AZ	7.5	7.5	3.0	3.0
Saguaro NM, AZ	7.1	6.8	2.6	2.5
Saguaro West, AZ	7.3	7.1	3.2	3.1
Sierra Ancha, AZ	6.0	5.8	2.2	2.1
Superstition, AZ	6.7	6.5	2.7	2.6
Guadalupe Mountains NP, TX (Carlsbad Caverns NP, NM and Guadalupe Mountains NP, TX)	13.7	13.6	3.3	3.2

[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.

H. Comparison of Trading vs. Command and Control BART Requirements

During the development of the Annex, the WRAP conducted modeling to determine whether the distribution of emissions under the Backstop Trading Program would differ substantially from the distribution of emissions assuming installation of BART or would disproportionately impact any Class I area due to a geographic concentration of emissions. The results of this modeling are included in Tables 2 and 3 of Attachment C to the Annex[11.] Attachment C, Section G concludes, "The results of this analysis showed that the maximum difference between the two scenarios at any of the Class I areas was only 0.1 deciviews.[12]"

11 *Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and A Backstop Market Trading Program, an Annex to the Report of the Grand Canyon Visibility Transport Commission* (September 2000) at C-15 and 16.

12 *Id*. at C-21.

March 22, 2012

2011 Review

WRAP SO2 Milestone Tracking Process Audit

The Sulfur dioxide (SO_2) milestones and backstop trading program is a major component of the regional haze control plans developed by New Mexico, Utah, Wyoming, and Albuquerque/Bernalillo County under Section 309 of the Regional Haze Rule (Section 309 States). The program requires major industrial sources of SO2 to submit an annual emissions inventory to their respective state or local air quality office. These inventories, in turn, are compiled by the Western Regional Air Partnership (WRAP) and analyzed to determine compliance with the regional SO2 milestones.

The backstop trading program also calls for an independent audit to ensure that the state inventories are accurate and efficient. According to the Section 309 SIPs, the first audit shall occur during the year 2006 and shall review the data collected during the first two years of the program. This audit was completed by E.H. Pechan & Associates, Inc. and a final report was issued in October 2007 (Pechan Report No. 07.02.002/9456.002).

Subsequent audits are scheduled to occur in 2011 and 2016. The Section 309 States have reviewed the 2006 audit report, and have determined that the 2006 report is adequate satisfy the 2011 audit requirement. The rationale for this decision is described below.

Section 309 Regional Haze SIPs were updated in 2011

The Section 309 states updated their SIPs in 2011 to incorporate new milestones. The inventory data for all major sources was updated from a 1998/1999 baseline to a 2006 baseline. In addition, more recent changes to individual sources due to new permits or federal consent decrees were included in the inventory that was the basis for the revised milestones. The 2006 audit report identified difficulties with making adjustments to utility data to address CEMs bias due to new flow rate measurements that were adopted in 1999. Because the baseline date has been changed to 2006 these adjustments are no longer required, simplifying the overall process. Arizona and Oregon are no longer participating in the program and the revised milestones reflect the smaller regional area.

Q/A Procedures have been effective

The Section 309 States are following the Q/A procedures established in the SIP. These procedures are designed to identify sources with significant changes in emissions and then follow-up to determine why the changes occurred. Utility data are compared to the acid rain database. All milestone reports are made available for public comment and review. These procedures ensure the on-going accuracy of the yearly inventories.

March 22, 2012

Current emissions are well below the milestones

Regional emissions have continued to decrease, and many of the reductions that were estimated to occur near the end of the program have occurred early. Because emissions are significantly below the milestones, it is unlikely that emission inventory discrepancies would change the determination that the SO2 milestones have been met, therefore making the audit results less critical.

Inventory procedures have not changed since 2006

The 2006 audit did not find any significant problems, and the Section 309 States have not made significant changes to their inventory procedures. For the last two years the Section 309 States have worked cooperatively to compile the inventory rather than hiring a contractor to complete this work. The WRAP has continued to assist the states with the review and public comment process. Each Section 309 state has reviewed the description of their procedures in the 2006 report and any changes are noted below.

> New Mexico: Although no changes have been made in the type of data we are collecting, the method of data collection has changed. We are now receiving EI data through a new web-based submittal tool, the Air Emissions Inventory Reporting (AEIR) tool. Facilities are still provided with a copy of their most recent EI report 90 days before the new report is due (April 1st of every year). EI data is still QA'd by NMED Air Quality staff, and if deficiencies are found, the submittal may be rejected and the facility required to update and resubmit. NM currently has about 145 Major Title V sources that are inventoried annually.
>
> Utah: The inventory process is the same as was described in the 2006 audit report. The MS Excel Workbooks have been modified to update the baseline data and emission estimation methods to 2006. As noted in the 2010 milestone report, Colleen Delaney is the current contact for Utah.
>
> Wyoming: No changes to the QA process have occurred since the final 2006 audit report was issued. There are currently 43 sources that are included in the milestone inventory. As noted in the 2010 milestone report, Brian Bohlmann is the current contact for Wyoming.
>
> Albuquerque/Bernalillo County: No changes have been made to the inventory process.

Sections of the 2006 Audit Report are no longer relevant

The 2006 Audit Report contains information regarding the inventory process in the states of Oregon and Arizona. These two states are no longer participating in the program, and this information is no longer relevant for the current milestone reports. The information regarding the inventory process in Oregon and Arizona has not been reviewed or updated. The 2006 Audit Report is intended to be used as a reference and has not been revised to reflect the 2010 inventory. This audit provided an independent review of the Section 309 State's inventory process that is still valid for the 2010 milestone report.

2016 Audit Report

The next audit report is due in 2016. The 2018 milestone is the most critical year of the program, and it will be worthwhile to review inventory procedures prior to determining compliance in that critical year. The Section 309 States intend to conduct a new independent audit in 2016.

WRAP SO_2 MILESTONE TRACKING PROCESS AUDIT

FINAL REPORT

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TABLES

ACRONYMS AND ABBREVIATIONS

ADEQ	Arizona Department of Environmental Quality
AZ	Arizona
CEMS	continuous emissions monitoring system
CLC	Chemical Lime Corporation
CO	carbon monoxide
DEP	Department of Environmental Protection
DEQ	Department of Environmental Quality
EGU	electricity generating unit
EPA	United States Environmental Protection Agency
FCC	fluid catalytic cracking
FCCU	fluid catalytic cracking unit
NEI	National Emissions Inventory
NM	New Mexico
OR	Oregon
PQA	Perrin Quarles Associates, Inc.
PSEL	Plant Site Emission Limit
RATA	Relative Accuracy Test Audit
SCC	source classification code
SIP	State Implementation Plan
SO_2	sulfur dioxide
SRU	sulfur incinerator/recovery unit
tpy	tons per year
UDAQ	Utah Department of Air Quality
UT	Utah
WEB	Western Emissions Backstop
WRAP	Western Regional Air Partnership
WY	Wyoming

INTRODUCTION

The sulfur dioxide (SO_2) milestones and backstop trading program is a major component of the regional haze control plans developed by five western states under Section 309 of the federal regional haze rule [40 CFR 51.309]. The program requires major industrial sources of SO_2 to submit an annual emissions inventory to their respective state air quality offices. These inventories, in turn, are compiled by the Western Regional Air Partnership (WRAP) and analyzed to determine compliance with the regional SO_2 milestones.

The backstop trading program also calls for an independent audit to ensure that the state inventories and regional analyses are accurate and efficient. According to the program, the first audit shall occur during the year 2006 and shall review data collected during the first two years of the program. The primary focus of the audit is on the process that is used to compute the regional inventory from the data provided by each state and tribe, and the tracking of accumulated changes during the period between SIP revisions. The audit shall also review the accuracy and integrity of the regional reports that are used by the section 309 states to determine compliance with the milestones. The purpose of this report is to describe the audit of the milestone tracking program that was conducted by Pechan during the fall of 2006.

This audit is not intended to be a full review of each state's or local agency's (Arizona [AZ], City of Albuquerque, New Mexico [NM], Oregon [OR], Utah [UT], and Wyoming [WY]) process for compiling and reporting SO_2 emissions, but is a broad review of each state's inventory management and quality assurance systems (i.e., presence and exercise of systems to assure data quality and integrity).

This audit discusses the uncertainty of emission calculations, and whether this uncertainty is likely to affect the annual determination of whether the milestone is exceeded. It also identifies and recommends changes to emissions monitoring or calculation methods or data quality assurance systems. The audit also reviews and recommends any changes to improve the administrative process of collecting the annual emissions data at the state and tribal level, compiling a regional emission inventory, and making the annual determination of whether the Western Emissions Backstop (WEB) Trading program has been triggered.

This project was performed by Pechan staff participating in teleconferences with the state emission inventory staff, WRAP support staff, and the WRAP contractor responsible for preparing the 2003, 2004, and 2005 Regional SO_2 Emissions and Milestone Reports. Pechan's role was to observe the data collection process during the fourth quarter of 2006, interview each of the participating state and local agencies and primary contractor to understand and review the point source emission inventory development process, and review the first two program years of data. In addition, each state/local agency's emission inventory development processes were documented.

The sections that follow provide summaries of the interviews with the emission inventory staff of the section 309 states plus the City of Albuquerque (Bernalillo Co., NM). Following the state-specific analyses is a summary and recommendations section.

ARIZONA - DISCUSSION WITH LATHA TOOPAL

The facilities in AZ are provided with electronic software by the State so that they can report their emissions (for SO_2 and other pollutants) using that software (which is *i*Steps). Facility data submittals are due to the AZ Department of Environmental Quality (ADEQ) by March 31st of each year for the preceding calendar year.

The State's quality control process includes reviewing the reporting performed by each facility, and includes a review of how the emissions were computed. Emissions estimation can either be continuous emissions monitoring system (CEMS), stack tests, mass balances on sulfur, or the United States Environmental Protection Agency (EPA) emission factors. CEMS are the emissions data source for electricity generating units (EGUs). The copper smelters in AZ provide monthly SO_2 emissions estimates to the ADEQ, which they review. Sources that have an SO_2 emissions performance standard are required to perform annual SO_2 emissions stack tests. For these sources, the stack test-based emission estimates are used to develop an emission factor/emission rate estimate that is then multiplied by the annual activity to estimate annual SO_2 emissions.

Independent validation and verification of SO_2 emission values is performed in a number of ways by ADEQ. One is by having an ADEQ observer at the stack tests that are performed to meet the performance standard requirement.

In their reporting to the WRAP contractor (Perrin Quarles Associates, Inc. [PQA]), ADEQ summarizes the information from their emission inventory system in the MS Excel file supplied by PQA. Then they calibrate any emission estimates that are plus or minus 20 percent from the emissions from the previous year. There is also confirmation from the facility that the SO_2 emission estimate is correct when this 20 percent threshold is exceeded.

ADEQ was asked by Pechan to provide the *as received* emission inventory data submittal for calendar year 2005 for the Chemical Lime Corporation (CLC) - Douglas plant. The purpose of this request was so that Pechan could provide an independent validation and verification of these data. The data submitted by CLC showed that all of the SO_2 emissions for this facility come from Kiln 5. The CLC submittal shows that SO_2 emissions for Kiln 5 are estimated by multiplying an emission factor by the annual fuel use to estimate annual SO_2 tons emitted. The SO_2 emission factor was 10.12 lbs per ton and the estimation method for this value is local emission factor. The annual activity was estimated as 149, 295 tons of lime manufactured. The resulting annual SO_2 emission estimate (after conversion of pounds to tons) was 755.4 tons.

The source classification code (SCC) code for this lime kiln is 30501608, which is a calcining, coal-fired rotary kiln. The standard AP-42 SO_2 emission factor for this SCC is 5.4 lbs per ton. AP-42 States that due to differences in the sulfur content of the raw material and fuel and in process operations, a mass balance on sulfur may yield a more representative emission factor for a specific facility than the SO_2 emission factors presented in Tables 11.17-5 and 11.17. Therefore, the facility specific factor is acceptable.

It is recommended that there be documentation included in the milestone reporting of the specific basis for establishing a local emission factor, such as the one used here for Kiln 5. This documentation would include the year of the stack test. If a new stack test is performed each year to determine the local emission factor, that should be noted.

NEW MEXICO - DISCUSSION WITH HEATHER LANCOUR

In December of each year, the NM Department of Environmental Protection (DEP) provides each facility with the baseline database that is needed for them to report their emissions for the calendar year just ended. Facilities have until April to submit their emission inventory data. Once received, the facility-supplied emissions data is subject to limited quality control review by the NM DEP staff. Quality control checks include completeness checks and overall reasonableness checks. No other verification or computerized quality control checks are performed on the emissions data. Staffing at NM DEP is one full-time equivalent per year for emission inventory activity (which is met via two part-time staff). NM has about 160 point sources in its inventory.

If sources submit revisions to their emission estimates at a later date, NM has no process for incorporating these data in its inventory. In fact, there is no way to revise a calendar year's emission inventory once it is exported from the system.

NM sources can use any valid emission estimation method for estimating SO_2 emissions, including material balance, emission factors, fuel sulfur content, etc. Sources may not be consistent in methods applied from year-to-year.

The facility that NM was asked to supply 2005 facility-supplied emissions data for is the Dynegy-Monument Gas Plant. This facility was of interest because it indicated recently that its previous 2003 SO_2 emission estimate for the milestone report was incorrect, and should be revised. The plant owner in 2005 is now Targa Gas Resources.

The data submitted by the facility to the NM Environment Department indicate that there were three major SO_2 emission sources at this gas plant - the sulfur incinerator/recovery unit (SRU), and two emergency flares. The facility-supplied data indicate that the SRU emissions were estimated using a calculation method based on the manufacturer's specification. Actual SRU SO_2 emissions during 2005 were estimated to be 825. 77 tons per year (tpy). No information is provided in the submittal about the specific emission factor used or the SRU throughput, so it is difficult to make judgments about the emission estimation methods.

The facility-estimated SO_2 emissions for the two emergency flares were 191.7 and 95.2 tpy, respectively. The emission estimation method for both flares is via a material balance.

Total facility estimated SO_2 emissions submitted by the facility and those in the 2005 milestone report match (1,114 tpy).

While the audit for this facility shows that the facility-supplied emissions match those in the milestone report, Pechan's review finds two potential concerns with the NM data collection process. One is that there is not enough information provided by the facility to allow an independent reviewer to verify the emission estimation methods. The second is that this facility has provided information that indicates that the SO_2 emission estimates that were provided and included in the 2003 milestone report are incorrect and should be changed from 872 to 1,258 tpy of SO_2. There appears to be no mechanism in the milestone process for correcting previously reported values after the reporting and review period is complete.

CITY OF ALBUQUERQUE, NEW MEXICO - DISCUSSION WITH STEPHANIE SUMMERS

The City of Albuquerque, NM Air Quality Division requires facilities to submit emissions information for the National Emissions Inventory (NEI), which is required after the request for SO_2 emissions for the WRAP SO_2 milestone tracking program. The City usually reviews facility permit files (i.e., compliance reports for their permit, etc.) to see if the facility has already submitted SO_2 emissions. Normally, the facilities have not submitted their emissions, so the City will contact the sources directly to obtain their SO_2 emissions data. Currently, the City of Albuquerque has two sources subject to section 309, the City's Southside Water Reclamation Plant, and the GCC Rio Grande Portland Cement Plant.

Both facilities use their hours and appropriate emission factors to calculate their SO_2 emissions. The emission factors are either based on stack testing or applicable permitted emission rates. In 2004, the City actually calculated the emissions for the Water Reclamation Plant as the facility was not able to provide the information in time. The City used the hours that the facility reports on a quarterly basis and the permitted emission factor for SO_2.

Once all SO_2 emissions data is obtained from the two sources, the City performs a quality assurance analysis on the emissions data. Air Division staff checks the emissions data reported by the facilities with previous year emission inventories to make sure that the reported numbers are not remarkably different from what the facilities reported the year before. Another check that the staff performs is to verify that the emissions reported by the facility to the NEI matches the estimates submitted to the SO_2 milestone tracking program. This check is performed after the SO_2 emissions data is reported for the milestone program.

With regards to the SO_2 milestone tracking program, PQA provides the City of Albuquerque with Excel file templates that are to be used by the City to submit annual SO_2 emissions information for all sources that emit more that 100 tons of SO_2 annually. These templates include the following information: source change report; enforcement milestone report; current year SO_2 emissions; and previous year SO_2 emissions. These reports are due to PQA yearly around the first of October. In 2004, the City of Albuquerque filled out the forms and submitted them to PQA, but they also have provided a letter from Mr. Isreal Tavarez, Air Division Manager. This letter stated that the City of Albuquerque would be submitting a letter annually to PQA stating the actual emissions from the two facilities. It also stated that that the City would not be filling out the annual emissions reports, because both facilities are under the 100 tpy mark on an annual basis.

The City of Albuquerque was asked by Pechan to provide the *as received* emission inventory data submittal for calendar year 2005 for the GCC Rio Grande Portland Cement Plant. The purpose of this request was so that Pechan could provide an independent validation and verification of these data. The data submittal shows that SO_2 emissions for this facility are estimated by multiplying an emission factor by the annual actual production to estimate annual SO_2 tons emitted. The SO_2 emission factor was 0.07 lbs of SO_2 per ton of clinker produced. The estimation method for this value is the average result of twelve emission tests on the facilities' kilns. The facility has performed several SO_2 stack tests over the last 5 years. The facility has spent a good deal of time and money in testing for SO_2 emissions because their first test showed what they felt were incorrect and extremely high SO_2 emissions. It was the feeling of the plant manager that this was due to an incorrect testing method, so the facility began to test much more frequently than necessary (every six months for awhile) and to hire a more experienced test contractor to ensure that they were not producing the amount of SO_2 that was assumed from the first test. The facility also replaced the coal being burned in the kiln with very low sulfur content.

The following are AP-42 SO_2 emission factors for Portland Cement Manufacturing:

Source Classification	SO_2 Emission Factor
Wet Process Kiln (SCC 30500706)	4.1
Long Dry Process Kiln (SCC 30500606)	4.9
Preheater Process Kiln (SCC 30500622)	0.27
Preheater/Precalciner Kiln (SCC 30500623)	0.54
Preheater/Precalciner Kiln w/spray tower (30500623)	0.50

The annual actual number of clinker produced was estimated to be 470,032 tons. The resulting annual SO_2 emission estimate (after conversion of pounds to tons) was 16.54 tons.

OREGON - DISCUSSION WITH BRANDY ALBERTSON

The State of OR DEQ requires in its Title V operating permits that point sources submit an annual report to the State, which includes the source's emissions information. These annual reports are due to the state between February and April of the following year. For example, data for 2005 would be due between February and April of 2006. Currently OR DEQ has approximately 124 Title V sources.

The OR DEQ maintains a list of point source facilities that are currently emitting over 100 tons of SO_2. After receiving all annual reports, the State performs a facility-wide emissions inventory to see what that total tons of SO_2 are for all the Title V permits. This check would alert them to any facilities not on the list that have emitted more than 100 tons of SO_2. These facilities would then be added to the list.

When a point source submits emissions to OR DEQ, they are submitted at the sub-facility or emission unit level. Most sources use state and local emission factors, not monitoring data, in the calculation of their emissions. If the source does use monitoring data, they are required to include this information in the Title V permit. OR DEQ is able to obtain from each permit factors (i.e., emission factors, throughput) that go into the emissions calculation to ensure that there are no mistakes in the source's calculations. If a permit inspector finds a mistake with a source's annual report, the OR DEQ would then notify the source of the mistake. Sometimes the source will catch the mistake and automatically send the revision to the State. Any necessary revisions to the emissions data typically occurs within 30 days of permit submittal to the State.

Another quality assurance check OR DEQ performs is in cases when emissions information in a permit appears peculiar, the State will compare the current data with the previous years permit data. If there is an issue, the State will go to the source or permit writer for clarification.

With regards to the SO_2 milestone tracking program, PQA provides OR DEQ with Excel file templates that are to be used by the State to submit annual SO_2 emissions information for all sources that emits more that 100 tons of SO_2 annually. These templates include the following information: source change report; enforcement milestone report; current year SO_2 emissions; and previous year SO_2 emissions. These reports are due to PQA yearly around the first of October.

The OR DEQ was asked by Pechan to provide the *as received* emission inventory data submittal for calendar year 2005 for the Portland General Electric Company – Boardman Plant. The purpose of this request was so that Pechan could provide an independent validation and verification of these data. The data submitted showed that most of the SO_2 emissions for this facility come from emissions unit/device ID "MB.DV." The submittal shows that SO_2 emissions for this unit are estimated by using CEMS data. The resulting annual SO_2 emission estimate was 12,017.4 tons. The submittal also shows emissions for emissions unit/device ID "AB.DV." The SO_2 emissions for this unit are estimated by multiplying an emission factor by the annual actual production to estimate annual SO_2 tons emitted. The SO_2 emission factor was 71 lbs per 1,000 gallons and the estimation method for this value is a Plant Site Emission Limit (PSEL) emission factor. The annual fuel use was estimated as 118,832 gallons. The resulting annual SO_2 emission estimate (after conversion of pounds to tons) was 4.2 tons. Total 2005 SO_2 emissions reported by this facility were 12,022 tons.

UTAH - DISCUSSION WITH CAROL NIELSEN

In January of each year, the Utah Division of Air Quality (UDAQ) sends MS Excel workbooks to the large SO_2 sources in their state for use in reporting their emissions. The UT workbook includes the 1998 (for EGUs) and 1999 (for non-EGU point sources) data and emission estimation methods as a baseline for comparison with the current calendar year values. The workbook is structured so the source can input current activity data for individual equipment units, and emissions are automatically calculated using the base-year calculation methods. In addition, the source enters information about any changes in calculation methodology used in their current annual emissions inventory submittal.

Sources with EGUs in UT estimate their SO_2 emissions using CEM data. Non-EGU point sources estimate their SO_2 emissions using mass balance calculations, CEMs, EPA emission factors, or stack test emission factors. Periodic stack tests are required for equipment units that emit large amounts of SO_2. UT reviews the emission estimates each year to ensure that emission changes from the base year to the current year are not paper increases (or decreases). Changes in emission factors resulting from new stack test results are not considered paper increases/decreases.

UT supplied the 2005 calendar year emission estimates received from the Chevron-Salt Lake refinery. There are four major SO_2 emission sources at the refinery. These include the sulfur recovery unit, fuel gas combustion in boilers and process heaters, the fluid catalytic cracking unit, and flares. SO_2 emissions from all four of these key sources at the Chevron-Salt Lake refinery are present in the 2005 inventory submittal, although there appeared to be some incorrect SCC assignments. These SCC assignments do not affect the milestone report. Since they provide potentially misleading information to the state emission inventory, UDAQ and Chevron are discussing appropriate changes.

The Chevron sulfur plant SO_2 emissions are estimated based on CEMS measurements, which is measured at 993, 274 lbs per year, or 496.6 tpy. Excess SO_2 emissions from the sulfur plant of 0.9 tpy are added to the CEMS measured total for a sulfur plant total of 497.5 tpy. The sulfur plant emissions are assigned to SCC 30600904. It is recommended that the SCC be changed to 30103201 (or one in this series depending on the percentage removal).

Fuel gas and oil combustion emissions are primarily from the source labeled as Boilers #3 and 4. Fuel burning based emissions are less than 0.1 tpy from this source, but 383 tons of excess emissions are assigned. It was not clear from the original information provided why there would be excess SO_2 emissions from this boiler. Correspondence with Chevron via the UDAQ revealed that the amine plant/sulfur plant was not operating for a period during the fall of 2005, so a higher sulfur content fuel was being burned at these boilers.

Emissions from the Chevron fluid catalytic cracking (FCC) Regenerator/carbon monoxide (CO) Boiler are estimated based on an emission factor developed from a stack test (in lbs per hour) and the number of hours of operation during 2005. This calculation is 154.40 lbs per hour times 8688 hours per year converted from lbs to tons (this equals 671.71 tons). The stack test data for the FCC-CO Boiler was collected 1/21/2003. This unit is assigned a boiler SCC code in the emission inventory. It is recommended that this be changed to 30600201, which is the SCC for an FCC unit (FCCU).

Chevron emissions from the coker flare are estimated by an emission factor multiplied by the annual refinery throughput in barrels, plus excess emissions. Reported excess emissions for this source during 2005 are small, so the emissions are primarily based on an emission factor of 79.5 lb per 1000 barrels times 15,884 thousand barrels, which is 631.39 tons. The AP-42 SO_2 emission factor for vapor recovery and flaring is 26.9 lbs per 1,000 barrels refinery feed.

WYOMING - DISCUSSION WITH DANIEL HERMAN

The State of WY DEQ sends out letters to all sources subject to section 309 in January requesting SO_2 emissions data for the previous year. Attached to the letters is an SO_2 emission reporting form for the source to fill out and return to the State. The source can either fill out a hard copy of the form and submit it back to the State, or they can fill out an electronic version of the form on WY DEQ's Air Quality Division website. These forms are due to the Regional Haze Program Inventory Program Manager by April 15. Currently WY DEQ has approximately 42 sources subject to section 309.

Once all SO_2 emissions data is received from the sources, WY DEQ performs an in-depth analysis of the data, which includes discussions with both environmental engineers and the sources themselves to better understand the methods used to calculate the emissions. For reporting year 2005, there were nine facilities that WY DEQ had to resend letters to requesting clarification on the emissions calculation methodologies. The facilities were given until August to reply.

Another quality assurance check that WY DEQ performs is a comparison of the SO_2 emissions data the source reported to the SO_2 milestone program and the SO_2 emissions data submitted for the source's Title V permit application.

When a source submits emissions to WY DEQ, they are submitted at the sub-facility or emission unit level. The source provides the methodology used to estimate emissions along with a clarification as to whether or not there was a change in the emissions calculation method from the base year method. The sources in Wyoming use a combination of either state and local emission factors or monitoring data, such as CEMS, in the calculation of their emissions. Testing data versus CEMS data raises questions regarding accuracy of the emissions. WY DEQ is in close contact with district engineers who perform recalculations of the emissions. This helps WY DEQ know exactly what the source emissions should be, and the State has a better understanding of how the emissions should be adjusted.

PQA provides WY DEQ with Excel file templates that are to be used by the State to submit annual SO_2 emissions information for all sources that emits more that 100 tpy of SO_2. These templates include the following information: source change report; enforcement milestone report; current year SO_2 emissions; and, previous year SO_2 emissions. These reports are due to PQA yearly around the first of October. For the 2005 SO_2 milestone report, WY DEQ only submitted the source change report and the 2005 SO_2 emissions report to PQA. WY DEQ identifies all sources that will require a Part 75 Relative Accuracy Test Audit (RATA) adjustment, which is performed by PQA.

The WY DEQ was asked by Pechan to provide the *as received* emission inventory data submittal for calendar year 2005 for the Frontier Refinery-Cheyenne Plant. The purpose of this request was so that Pechan could provide an independent validation and verification of these data. The data submitted by Frontier showed that most of the SO_2 emissions for this facility came from two different sources, an FCCU Regenerator and a Coker Flare. The submittal shows that SO_2 emissions for the FCCU Regenerator are estimated by using CEMS data. The resulting annual

SO_2 emission estimate was 900.5 tons. The SO_2 emissions for the Coker Flare are estimated by using the permitted emission limit multiplied by the ratio of the actual unit feed rate to the permitted 10,000 bbl/d monthly average feed rate to estimate annual SO_2 tons emitted. The resulting annual SO_2 emission was 465.8 tons. WY DEQ determined that an adjustment to the Coker Flare emissions was required due to Frontier's change in emissions calculation method from the 1998 base year methodology. Using the 1998 methodology, the adjusted emissions were calculated using the average SO_2 test results (1179.8 lb/cycle) multiplied by the estimated number of Coker Unit cycles per year (811). The resulting adjusted annual SO_2 emission (after conversion of pounds to tons) for the Coker Flare was 472.4 tons.

The total 2005 SO_2 emissions reported by Frontier were 1,437.7 tons. This value was adjusted to 1,460.3 tons to account for the adjustment to the Coker Flare emissions. Generally, a source test would produce a more accurate source-specific emission rate than a permitted emission limit-based estimate. Presumably, this adjustment was made for consistency with baseline year reporting methods.

DISCUSSION WITH PERRIN QUARLES ASSOCIATES, INC.

PQA is the contractor that was retained by the WGA to prepare the annual Regional SO_2 Emissions and Milestone Report. Pechan staff observed the 2005 calendar year data collection process and interviewed the PQA staff who worked on the 2005 milestone report. The process began with PQA distributing an MS Excel file that summarized the data needed for the 2005 report as well as the similar data that was submitted previously for calendar year 2004. Teleconferences were held with the state representatives and the process, needed data, and schedules were discussed, with opportunities for questions and comments.

PQA staff indicated that they perform limited quality control checks on submitted SO_2 emission estimates. EGU emission estimates are compared with EPA Clean Air Markets Division estimated values. PQA provides comments on any values that do not make sense. In addition, as a normal part of the milestone process, any SO_2 emission changes equal to or greater than 20 percent (higher or lower) are evaluated further to determine the reason for the change, which is noted in report tables.

PQA indicated that the RATA calculations for the applicable EGUs are performed by the states, not PQA, with the exception of WY, where PQA made these adjustments. For the states that provided the flow RATA adjustment values and associated annual emissions to PQA, there may be instances where the states relied on the sources to calculate the flow RATA related adjustment. The issue of how the flow method differences affect the SO_2 emission estimates for the facilities with CEMs is discussed further in the summary section.

PQA supplied Pechan with the data submitted by the individual states to them, and the data for the sources whose emissions are summarized in Table 1 were reviewed to see if the state submittals matched the data included in the milestone report. It was found that PQA successfully incorporated the state data submittals into the milestone report, including any revisions to the original data submittals when these occurred.

PQA indicated that the comment field in the milestone report emission tables is from information supplied by the states without revision by them. These comments seem to be accurate, with the exception of the comment on the Chemical Lime-Douglas plant, which says that during 2005 "the facility is in full operation." It would be more accurate to say that Kiln 5 was in full operation during 2005. There are two other kilns at the Douglas plant that are inactive.

Table 1. Facility-Specific SO_2 Emissions Review Summary

State/Local Agency	Facility Name	2005 Actual SO_2 tons	2004 Actual SO_2 tons	2003 Actual SO_2 tons
AZ	Chemical Lime Corporation – Douglas	755	126	0
NM	Targa Gas Resources – Monument Gas	1,114	2,416	872 *
City of Albuquerque	Rio Grande Portland Cement	17	17	22
OR	Portland General Electric Company – Boardman	12,022	12,392	13,121
UT	Chevron – Salt Lake Refinery	2,201	1,365	1,191
WY	Frontier Refinery – Cheyenne	1,460	1,565	1,657

* Targa Gas Resources has indicated that their 2003 calendar year SO_2 emissions for the Monument Gas plant were 1,258 tpy.

The annual emission reports for each state include proposed adjustments to ensure consistent comparison of emissions to the milestones. The adjustments account for any differences in emissions that result from changes in the monitoring or calculation methodology used in the year of interest compared with the baseline year method. The State Implementation Plans (SIPs) describe three specific methods for adjusting Part 75 Acid Rain Program EGU emissions due to changes in quality assurance procedures for the flow monitor component of SO_2 CEMS. These changes involve the use of new flow reference methods in the RATA (2F, 2G, 2H, 2J), which were not available in the 1999 baseline year. The flow methods and RATA adjustments provide consistency with the milestone 1999 EGU baseline.

It appears that the rule adjustment methods were written assuming that the reference method would only change once. Two of the adjustment methods require a full year of data quality assured by the new method before the adjustment is made. However, there are instances where sources have made further changes from year-to-year, and this has complicated the adjustments when data in a single year are quality assured by that year's RATA with one flow method, and the previous year's RATA with a different flow method. This has resulted in changing adjustment factors, and years when no adjustment was made due to data quality assured by two different methods. However, the adjustments do achieve their intended purpose by providing a conservative SO_2 emissions estimate that does not allow measurement changes for purposes of meeting the milestone targets.

Table 2 compares reported and adjusted SO_2 emission values for Part 75 units and shows that these adjustments produce higher, not lower, SO_2 emission estimates. The 2003 to 2005 adjustments produce 5 to 9 percent higher SO2 emissions for Part 75 units than had the adjustments not been made. Therefore, these flow RATA adjustments produce conservative estimates of SO_2 emissions reported to the program.

Table 2. Part 75 Unit Reported and Adjusted SO_2 Emissions (tpy)

Year	Reported	Adjusted	Adjustment
2003	209,280	219,920	10,640 (+5% of reported)
2004	202,312	218,447	16,135 (+8% of reported)
2005	197,806	215,425	17,619 (+9% of reported)
Source: Provided by PQA.			

SUMMARY

The annual emission reports for each state include proposed adjustments to ensure consistent comparison of emissions to the milestones. The adjustments account for any differences in emissions that result from changes in the monitoring or calculation methodology used in the year of interest compared with the baseline year method. The State Implementation Plans (SIPs) describe three specific methods for adjusting Part 75 Acid Rain Program EGU emissions due to changes in quality assurance procedures for the flow monitor component of SO_2 CEMS. These flow RATA adjustments add some complexity to the emissions estimation process, but they do produce conservative estimates of SO_2 emissions reported to the program.

It is recommended that there be documentation included in the milestone reporting of the specific basis for establishing a local SO_2 emission factor when it is developed from a stack test or any other method. This documentation would include the year of the stack test or other parameter details if any other method is used.

There needs to be a formal mechanism in the emissions tracking process that allows revisions to be made to previous year's reports under certain circumstances where sources supply revised emissions estimates.. Such a mechanism does not currently exist. Criteria should be developed to determine when such revisions should be made/allowed.

Section 309 states that do not have the resources to perform extensive quality control reviews of the emissions data submitted by the point sources in their states could be assisted by either having additional resources made available to them for performing such tasks, or by some information sharing from other states that may have established routine computerized procedures for such checking. The computerized quality control programs available from EPA focus on ensuring that data are formatted correctly for input to its data system, so they have limited usefulness for the milestone program, which is concerned about emission quantities.

The methods used by PQA to collect annual SO_2 emission estimates from the states and the City of Albuquerque are sound and provide an accurate assessment of how well the Section 309 states are doing relative to the milestones.

Any uncertainties in current SO_2 emission estimation methods are small and do not compromise the finding that SO_2 emissions within the region are well below the milestone established for the 2003-2005 period.

APPENDIX A. WRAP SO_2 REPORT AUDIT - STATE CONTACTS

Arizona

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City of Albuquerque

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New Mexico

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bbohlm@state.wy.us

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Pacific Power |
Rocky Mountain Power
825 NE Multnomah, Suite 2000
Portland, Oregon 97232

August 22, 2012

Derek Nelson
Sierra Club Law Program
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Suite 2
Cambridge, MA 02139
jfisher@synapse-energy.com (C)

RE: OR Docket No. UE-246
Sierra Club 4th Set Data Request (1)

Please find enclosed PacifiCorp's Response to Sierra Club 4th Set Data Request 4.1. Provided on the enclosed CD is Confidential Attachment Sierra Club 4.1. The information provided in the Confidential Attachments is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

If you have any questions, please call Bryce Dalley at (503) 813-6389.

Sincerely,

Bryce Dalley /usw

Bryce Dalley
Director, Regulatory Affairs & Revenue Requirements

Enclosure:
c.c.: Gordon Feigner/CUB Gordon@oregoncub.org (C)
Kay Barnes /OPUC puc.datarequests@state.or.us (C) (2 copies)
Michael Weirich/OPUC Michael.Weirich@state.or.us (C)
Irion A. Sanger/ICNU mail@dvclaw.com ias@dvclaw.com (C)
Donald W. Schoenbeck/ICNU dws@r-c-s-inc.com (C)
Kevin Higgins/Kroger khiggins@energystrat.com (C)

UE-246/PacifiCorp
August 22, 2012
Sierra Club Data Request 4.1

Sierra Club Data Request 4.1

Reference the July 19, 2012 reply testimony of Cathy Woolums.

a. Concerning the modeling referred to on page 17 of Ms. Woolems' testimony (lines 9-12), please provide a table of the SO2 emission rates and stack parameters modeled for each of the Naughton units for both the 3-hour SO2 NAAQS and the 24-hour SO2 NAAQS modeling.
b. Concerning the modeling referred to on page 17 of Ms. Woolems' testimony (lines 9-12), please provide a table with the highest and second highest (high-second-high) 3-hour average and 24-hour average SO2 concentration modeled for each of the Naughton units.
c. Concerning the modeling referred to on page 17 of Ms. Woolems' testimony, please explain what the background 3-hour average and 24- hour average SO2 modeling referred to.
d. Concerning the modeling referred to on page 17 of Ms. Woolems' testimony (lines 9-12), please identify any and all other sources or emitting units of SO2 emissions that were included in the modeling.
e. Please provide a copy of all modeling files that support Ms. Woolems' statement on page 17 (lines 9-12) of her testimony.
f. Please provide copies of all correspondence between PacifiCorp and the Environmental Protection Agency and/or WYDEQ regarding any SO2 modeling analyses conducted from 2005 to the present that indicated that any Naughton unit may be causing exceedances of the 3-hr and/or 24-hr SO2 NAAQS.

Response to Sierra Club Data Request 4.1

The witness's surname is spelled "Woollums."

The Company objects to this request to the extent it seeks information protected by the attorney-client privilege. Without waiving this objection, the Company provides the response below. The Company waives the attorney-client privilege for the specific documents produced only and is not generally waiving the attorney-client privilege.

a. See Confidential Attachment Sierra Club 4.1 with modeled emission rates for designated iterations and maps showing impacts from the original iteration, along with the original e-mail communication validating the date of the document. The modeling was conducted in 2006 and PacifiCorp no longer has the information regarding modeled stack parameters.

b. See Confidential Attachment Sierra Club 4.1.

c. See Confidential Attachment Sierra Club 4.1.

d. See Confidential Attachment Sierra Club 4.1.

UE-246/PacifiCorp
August 22, 2012
Sierra Club Data Request 4.1

e. The modeling was conducted in 2006 and PacifiCorp no longer has the modeling input files.

f. PacifiCorp does not have any correspondence with the Environmental Protection Agency and/or WYDEQ regarding the Naughton SO_2 modeling. The modeling issue was discussed verbally with the WYDEQ in a meeting in 2006. Because PacifiCorp was addressing the modeling issue in conjunction with the WYDEQ regional haze requirements, no further documentation or correspondence was necessary or required by the WYDEQ.

The information provided in Confidential Attachment Sierra Club 4.1 is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Dave Freudenthal, Governor

John Corra, Director

December 31, 2009

RECEIVED
JAN 08 2010
A. Skinner
Naughton Plant

Ms. Angie Skinner
Plant Managing Director
PacifiCorp
PO Box 191
Kemmerer, WY 83101

Re: Air Quality Permit MD-6042
BART Permit: Naughton Power Plant

Dear Ms. Skinner:

The Division of Air Quality of the Wyoming Department of Environmental Quality has enclosed a copy of the Best Available Control Technology (BART) permit for PacifiCorp's Naughton Power Plant, dated December 31, 2009. Comments received during the public comment period and the public hearing were considered in the final permit. A copy of the decision document for the permit is also enclosed. No permit conditions required revision as a result of the public comment period.

If you have any questions, please feel free to contact this office.

Sincerely,

D. Finley

David A. Finley
Administrator
Air Quality Division

cc: Tony Hoyt/AQD Lander

EXHIBIT
A

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Dave Freudenthal, Governor

John Corra, Director

December 31, 2009

Ms. Angie Skinner
Plant Managing Director
PacifiCorp
PO Box 191
Kemmerer, WY 83101

Permit No. **MD-6042**
(BART Permit for the Naughton Plant)

Dear Ms. Skinner:

The Division of Air Quality of the Wyoming Department of Environmental Quality has completed final review of PacifiCorp's application for a Best Available Retrofit Technology (BART) permit for the three coal-fired boilers at the Naughton Power Plant. The Naughton Power Plant is located in Sections 32 and 33, T21N, R116W, approximately six miles southwest of Kemmerer in Lincoln County, Wyoming.

Following the Division's proposed approval of the permit as published June 4, 2009, a 62-day public notice period ran from June 4, 2009 to August 4, 2009, and a public hearing was held on August 4, 2009 at 1 p.m. in the Lincoln County Library, located at 519 Emerald Street in Kemmerer, Wyoming. Comments were received on the proposed permit and those comments have been considered by the Division in the final permit. Therefore, on the basis of the information provided to the Division, a BART permit is hereby granted pursuant to Chapter 6, Sections 2 and 9 of the Wyoming Air Quality Standards and Regulations (WAQSR) 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)(vi) and Chapter 6, Section 3 of the WAQSR.

4. All notifications, reports and correspondence associated with this permit shall be submitted to the Stationary Source Compliance Program Manager, Air Quality Division, 122 West 25th Street, Cheyenne, WY 82002 and a copy shall be submitted to the District Engineer, Air Quality Division, 510 Meadowview Drive, Lander, WY 82520.

5. Effective upon completion of the performance tests to verify the emission levels below, as required by Condition 6 of this permit, emissions from Naughton Units 1 and 2 shall not exceed the levels below. The lb/hr and tpy limits shall apply during all operating periods. The lb/MMBtu limits shall apply during all operating periods except startup. Startup begins with the introduction of natural gas into the boiler and ends no later than the point in time when the ESP reaches a temperature of 225°F.

Unit	Pollutant	lb/MMBtu	lb/hr	tpy
1	PM/PM_{10} [a]	0.040	74	324
2	PM/PM_{10} [a]	0.040	96	421

[a] Filterable portion only.

6. That no later than 90 days after the installation of new low NO_x burners with advanced overfire air, PM/PM_{10} performance tests shall be conducted and a written report of the results shall be submitted. If a maximum design rate is not achieved within 90 days of installing new low NO_x burners with advanced overfire air, the Administrator may require testing be done at the rate achieved and again when a maximum rate is achieved.

7. Effective upon completion of the initial performance tests to verify the emission levels below, as required by Condition 8 of this permit, emissions from Naughton Units 1-3 shall not exceed the levels below. The NO_x limits shall apply during all operating periods. Unit 3 PM/PM_{10} lb/hr and tpy limits shall apply during all operating periods. Unit 3 PM/PM_{10} lb/MMBtu limit shall apply during all operating periods except startup. Startup begins with the introduction of natural gas into the boiler and ends when the boiler is switched over to coal as fuel.

Unit	Pollutant	lb/MMBtu	lb/hr	tpy
1	NO_x	0.26 (30-day rolling)	481 (30-day rolling)	2,107
2	NO_x	0.26 (30-day rolling)	624 (30-day rolling)	2,733
3	NO_x	0.07 (30-day rolling)	259 (30-day rolling)	1,134
3	PM/PM_{10}[a]	0.015 [b]	56 [b]	243

[a] Filterable portion only.
[b] Upon installation of a PM continuous emissions monitoring system, the averaging period shall become a 24-hour block average.

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

9. Performance tests shall consist of the following:

Coal-fired Boilers (Naughton Units 1 through 3):

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

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

Testing required by the Chapter 6, Section 3 Operating Permit may be submitted to satisfy the testing required by this condition. If a PM CEMS is installed on Unit 3, PM CEMS monitoring data collected in accordance with 40 CFR part 60, subpart Da may be submitted to satisfy the testing required by this condition for Unit 3.

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

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

12. Compliance with the NO_x limits set forth in this permit for the coal-fired boilers (Naughton Units 1-3) shall be determined with data from the continuous monitoring systems required by 40 CFR Part 75 as follows:

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

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

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

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

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

14. Compliance with the PM/PM_{10} limits set forth in this permit for Naughton Units 1-3 shall be determined with data from testing for PM conducted annually, or more frequently as specified by the Administrator, following 40 CFR 60.46 and EPA Reference Test Methods 1-4 and 5. Testing required by the Chapter 6, Section 3 Operating Permit may be submitted to satisfy the testing required by this condition. If a PM CEMS is installed on Unit 3, PM CEMS monitoring data collected in accordance with 40 CFR part 60, subpart Da may be submitted to satisfy the testing required by this condition for Unit 3.

15. Records required by this permit shall be maintained for a period of at least five (5) years and shall be made available to the Division upon request.

16. PacifiCorp shall install new low NO_x burners with advanced overfire air on Units 1 and 2, in accordance with the Division's BART determination, and conduct the performance tests required in Conditions 6 and 8 no later than December 31, 2012 for Unit 1 and June 1, 2012 for Unit 2.

17. PacifiCorp shall, for Units 1 and 2, install flue gas conditioning on the existing ESPs, in accordance with the Division's BART determination, within 90 days of permit issuance.

18. PacifiCorp shall tune the existing low NO_x burners with overfire air and install selective catalytic reduction and a full-scale fabric filter on Unit 3, in accordance with the Division's BART determination, and conduct the initial performance tests required in Condition 8 no later than December 31, 2014.

It must be noted that this approval does not relieve you of your obligation to comply with all applicable county, state, and federal standards, regulations or ordinances. Special attention must be given to Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations, which details the requirements for compliance with condition 3. Attention must be given to Chapter 14, Sections 2 and 3 of the Wyoming Air Quality Standards and Regulations, which detail the requirements for compliance with condition 11. Any appeal of this permit as a final action of the Department must be made to the Environmental Quality Council within sixty (60) days of permit issuance per Section 16, Chapter I, General Rules of Practice and Procedure, Department of Environmental Quality.

If we may be of further assistance to you, please feel free to contact this office.

Sincerely,

David A. Finley
Administrator
Air Quality Division

John V. Corra
Director
Dept. of Environmental Quality

cc: Tony Hoyt/AQD Lander

IN THE MATTER OF A PERMIT APPLICATION (AP-6042) FROM PACIFICORP FOR A BEST AVAILABLE RETROFIT TECHNOLOGY (BART) PERMIT FOR THE NAUGHTON POWER PLANT

DECISION

I. Introduction:

The Air Quality Division received a BART permit application from PacifiCorp for the three coal-fired boilers that operate at their Naughton Power Plant in Lincoln County, Wyoming. Regulations governing the BART program have been established by the U.S. EPA in 40 CFR Part 51 - Appendix Y. As stated in the regulations, a source is eligible for BART if it belongs within a particular group of stationary source categories, was not in operation prior to August 7, 1962, was in existence on August 7, 1977, and has the potential to emit 250 tons per year (tpy) or more of any visibility impairing air pollutant. Fossil fuel boilers with more than 250 million Btu (MMBtu) per hour heat input are listed as an eligible source type. The three boilers at the Naughton plant have heat inputs between 1,850 and 3,700 MMBtu per hour, and were installed between 1963 and 1971. Potential emissions from each boiler for two visibility impairing air pollutants, nitrogen oxides (NO_x) and sulfur dioxide (SO_2), exceed 250 tpy and therefore the units are eligible for BART.

The Division conducted an analysis of the BART permit application for the Naughton plant, and published on June 4, 2009 in the Kemmerer Gazette a public notice and notice of public hearing of the proposed intent to issue BART determinations. Copies of the BART application and the Division's analysis were placed in the Lincoln County clerk's office in Kemmerer, Wyoming in accordance with regulations. A 62-day public notice period ran from June 4, 2009 to August 4, 2009, and a public hearing was held on August 4, 2009 at 1 p.m. in the Lincoln County Library, located at 519 Emerald Street in Kemmerer, Wyoming.

The Division received numerous comment letters on the proposed permit during the public comment period: 1) a letter dated July 21, 2009 from the USDA Forest Service; 2) a letter dated August 3, 2009 from EPA Region 8; 3) a letter dated August 4, 2009 from PacifiCorp; 4) a letter dated August 4, 2009 from the National Park Service; 5) a letter dated August 4, 2009 from the Powder River Basin Resource Council, et al.; 6) a letter received July 20, 2009 from Joanna Taylor; 7) a letter dated July 16, 2009 from Andrew H. Salter; 8) a letter received July 20, 2009 from Evelyn and Marvin Griffin; 9) a letter received July 23, 2009 from Mimi McMillen; 10) a letter received July 24, 2009 from William M. Anderson; 11) a letter received July 24, 2009 from Rebekah Smith; 12) a letter dated July 24, 2009 from Mike Shonsey; 13) a letter dated July 24, 2009 from Susie Mohrmann; 14) a letter dated July 28, 2009 from Janice H. Harris; 15) a letter dated July 28, 2009 from M. Christensen; 16) a letter dated July 27, 2009 from Clint Morrison; 17) a letter dated August 3, 2009 from Ann Fuller; 18) a letter dated August 3, 2009 from Mary Fenton; 19) 725 unsigned letters received under a signed cover letter dated July 28, 2009 from Brad Mohrmann, Sierra Club Associate Regional Representative; and 20) 89 signatures received under a signed cover letter dated July 24, 2009 from Brad Mohrmann, Sierra Club Associate Regional Representative.

Due to the number of public comments with similar concerns, the Division grouped individual comments and developed summary comments and responses. Comments from the EPA, Forest Service, National Park Service, Powder River Basin Resource Council, et al., and PacifiCorp are addressed individually. The comments and responses are presented on the following pages. The Division also received positive comments supporting this project. The Division appreciates these comments but they are not included in this document as no response is required.

The Division received numerous comments that were descriptive of environmental impacts other than the impacts from BART-eligible sources in Wyoming on Class I area visibility. The Division's responses are limited to the comments that dealt with the State's BART analyses.

The Division is also preparing a revised Wyoming State Implementation Plan (SIP) for Regional Haze, and has solicited comments on that SIP. Some comments have been received which were submitted as comments on the Regional Haze SIP, but were principally directed at the Division's BART analyses. These comments will be addressed by the Division as it prepares the response to comments on the Regional Haze SIP.

II. Analysis of Comments from the USDA Forest Service:

II.1 **BART Conclusions for NO_x Controls: SCR for Naughton** – The Forest Service commented that based on their review of the five statutory BART factors, Selective Catalytic Reduction (SCR) should be BART for NO_x control for all units at the Jim Bridger and Naughton power plants. The Forest Service applauds the proposal to install SCR at the four units at the Jim Bridger plant for a long-term strategy, but SCRs at Jim Bridger should be installed as BART on all units by 2015-2016.

Response – The Division determined BART for NO_x control at the Jim Bridger and Naughton power plants based on consideration of all five statutory BART factors, as required by EPA's Appendix Y BART guidance. No single factor was weighted as being more important than another, because the Division looked at all five statutory factors in their entirety. The BART determination for NO_x control on all four units at Jim Bridger included low NO_x burners (LNB) with overfire air (OFA). The BART determinations for NO_x control at Naughton included LNB/OFA on Units 1 and 2 and SCR on Unit 3. The Division's BART analyses provide the basis for the BART determination for both plants.

Regarding the installation of additional control equipment at the Jim Bridger plant, PacifiCorp is required by the BART permit to install SCR on Jim Bridger Unit 3 in 2015 and Jim Bridger Unit 4 in 2016 as well as add-on NO_x control on Units 1 and 2 no later than 2023. The schedule for installation is based on the incorporation of SCR add-on control on these units under the long-term strategy component of Wyoming's SIP for regional haze as well as PacifiCorp's construction plan for pollution control projects. The schedule for the installation of SCR controls at other plants is uncertain at this point due to the demands on PacifiCorp for compliance with BART and other regulatory programs. PacifiCorp operates 19 coal-fired units, 14 of which are BART-eligible. Additional BART-eligible units are owned or partly owned in Arizona, Colorado, and Montana. Table 1 presents a summary of the pollution control projects that are included in PacifiCorp's construction plan through 2014.

Table 1: Status of Pollution Control Projects Undertaken by PacifiCorp

Power Plant	Location	SO_2 Scrubbers New = N Upgrade = U	LNB Installations	Baghouse Installations	SO_2/LNB Project Status
Hunter 3	Utah	Installed	2008	Installed	Completed
Huntington 2	Utah	2007 – N	2007	2007	Completed
Cholla 4	Arizona	2008 – U	2008	2008	Completed
Jim Bridger 4	Wyoming	2008 – U	2008	n/a	Completed
Jim Bridger 2	Wyoming	2009 – U	2005	n/a	Completed
Dave Johnston 3	Wyoming	2010 – N	2010	2010	Under Construction
Huntington 1	Utah	2010 – U	2010	2010	Permitted
Jim Bridger 1	Wyoming	2010 – U	2010	n/a	Under Construction
Naughton 2	Wyoming	2011 – N	2011	n/a	Under Construction
Hunter 2	Utah	2011 – U	2011	2011	Permitted
Jim Bridger 3	Wyoming	2011 – U	2007	n/a	Under Construction
Wyodak	Wyoming	2011 – U	2011	2011	Permitted
Dave Johnston 4	Wyoming	2012 – N	2009	2012	Under Construction
Naughton 1	Wyoming	2012 – N	2012	n/a	Under Construction
Hunter 1	Utah	2014 – U	2014	2014	Permitted
Naughton 3	Wyoming	2013 – U	2013	2013	Permitted

II.2 **BART Conclusions for SO_2 Controls: WFGD** – The Forest Service commented that, based on their review of the five statutory factors for BART, wet flue gas desulfurization (WFGD) should be BART for SO_2 control for all units at the Jim Bridger and Naughton power plants.

Response – WFGD upgrades have already been (or are scheduled to be) installed on all units at the Jim Bridger plant. For the Naughton plant, WFGD is scheduled to be installed on Units 1 and 2 and WFGD is scheduled to be upgraded for Unit 3. BART limits for SO_2 will not be set because Wyoming is a §309 state participating in the Regional SO_2 Milestone and Backstop Trading Program. §308(e)(2) provides states within the Transport Region addressed by the Grand Canyon Visibility Transport Commission 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.

II.3 **NO_x Step 5: Visibility Improvement Determination (Class I areas modeled)** – The Forest Service commented that all Class I areas within 300 km of a given source should be modeled and the cost of each BART alternative divided by the sum of the deciview (dv) improvement at all impacted Class I areas. If modeling exists for Class I areas that yield impacts above 0.5 dv just beyond 300 km, those results should be considered also. Savage Run Wilderness Area should also be modeled and considered.

Response – Only those Class I areas most likely to be impacted by sources subject to BART at a given facility were modeled, as determined by source/Class I area locations, distances to each Class I area, and professional judgment considering meteorological and terrain factors. The Division recognizes that more distant Class I areas may yield modeled impacts of some magnitude, but the Division is also satisfied that Class I areas at a greater distance and in directions of less frequent plume transport would not yield modeled impacts greater than those yielded by the Class I areas chosen for BART modeling. The modeling results for the Class I areas chosen for analysis allowed the Division to make an informed decision on the effect on visibility from the various BART control options. Additionally, EPA's Appendix Y BART guidance does not include any requirements for modeling distance.

EPA's Appendix Y BART guidance does mention that "dollars per deciview" ($/dv) is a metric that could be used to evaluate the cost of BART compliance, but by no means identifies $/dv as an essential or required metric. The Division considered capital cost, annual cost, cost effectiveness, and incremental cost effectiveness in the cost evaluation of each proposed BART control option. The Division chose not to use a hybrid metric such as $/dv primarily because of the lack of historical precedent regarding reasonable/acceptable levels for such a metric. Additionally, the use of a hybrid cost metric such as $/deciview can introduce uncertainty as to how the value was calculated. The value of "/deciview" could be based on the highest modeled value in a given area or the 98th percentile modeled value. It could be based on the 98th percentile value for any one modeled year or it could be an average for multiple years. It could even be based on an average modeled value across an entire Class I area or the sum of deciview changes across multiple areas. The Division has found that $/dv values are often presented without explanation of the basis for the calculation. To avoid these confounding factors, the Division chose to evaluate and present the cost analyses and visibility analyses separately.

EPA's Regional Haze Rule affects sources that may cause or contribute to visibility impairment at any mandatory, federal Class I Area. Because Savage Run is a state-designated Class I area, the Division was not required to include it in the BART modeling. Additionally, the Division did not include Savage Run in any of its analyses for the State's Regional Haze Visibility SIP. For BART, the Division did model the impacts at several mandatory Class I areas that are located in the same general plume transport direction downwind of Savage Run, including Mt. Zirkel Wilderness, Rawah Wilderness, and Rocky Mountain National Park. Based on the modeling results for these Class I Areas in the proximity of Savage Run, the Division anticipates similar improvements in visibility from the analyzed emission reductions.

II.4 **NO_x Step 5: Visibility Improvement Determination (significant impact)** – The Forest Service commented that it is incorrect to dismiss a control strategy on the basis that the modeled visibility improvement is not perceptible or significant.

Response – The Division used 0.5 dv as the threshold level to exempt a source from BART or to deem modeled impacts as insignificant. EPA's *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations* (Appendix Y to 40 CFR part 51), suggest that 0.5 dv can represent the level at which a source "contributes" to visibility impairment. This is also consistent with the rules which are being applied by most states in the Western Regional Air Partnership (WRAP) region.

II.5 **Five Factor Analysis for BART Selection: Coal Composition** – The Forest Service commented that PacifiCorp's analysis of coal composition is flawed and it does not meet the requirement for a demonstration of why presumptive limits cannot be reached.

Response – Although the BART emission limits for NO_x for Naughton Units 1 and 2 exceed the presumptive BART limit for tangential-fired boilers burning sub-bituminous coal, PacifiCorp's analysis of coal composition was not a factor in the Division's determination. The Division established NO_x emission limits for BART at the Naughton plant based on consideration of all five statutory factors, as required by EPA's Appendix Y BART guidance. The Division interpreted the presumptive emission levels for NO_x and SO_2 as recommended control levels proposed by EPA after reviewing technical data related to BART. Requiring sources to meet presumptive emission levels was not required as one of the five statutory factors. Conversely, the Division did not automatically determine emission levels below presumptive levels to be BART, but considered all five statutory factors before making a BART determination.

II.6 **NO_x Controls: SCR** – The Forest Service commented that significant, cumulative visibility improvements modeled for SCR installations at the Jim Bridger and Naughton plants indicate that SCR should be BART for all units at those two plants. The Forest Service questions why DEQ chose SCR as BART only for Naughton Unit 3 when SCR costs for other Naughton units and all Jim Bridger units are similar. Also, environmental degradation from the operation of SCR should not be a factor in the BART determinations and energy impacts from SCR should not be a factor because they have already been considered in the cost analysis.

Response – The costs for SCR controls, as described in the Division's BART analyses, were deemed by the Division to be reasonable for all units at the Jim Bridger and Naughton plants, but the Division's BART determinations for the two plants were based on consideration of all five statutory BART factors, as required by EPA's Appendix Y BART guidance. PacifiCorp proposed a BART limit for NO_x emissions from Naughton Unit 3 of 0.37 lb/MMBtu, which would be achieved by tuning the existing LNB/OFA system. For Naughton Units 1 and 2, PacifiCorp proposed a BART limit for NO_x of 0.26 lb/MMBtu for each unit using new LNB/OFA. Visibility modeling showed that the NO_x emission level proposed by PacifiCorp for Naughton Unit 3 provided less in terms of modeled visibility reductions from baseline as compared to other units at the two plants. For example, Naughton Units 1 and 2 showed a 72% to 73% reduction in the number of days with predicted impacts of 0.5 dv or more at the nearest Class I area (Bridger Wilderness) for LNB/OFA as compared to baseline. The reduction for Naughton Unit 3 for LNB/OFA vs. baseline was only 31%. Appendix A includes graphs of the modeled results at the Class I area that yielded the highest modeled impacts for the Jim Bridger and Naughton plants (Bridger Wilderness) and the Class I area that yielded the highest modeled impacts for the Wyodak, Dave Johnston, and Laramie River Station plants (Wind Cave National Park). As shown in the graphs, the LNB/OFA option reduces the 98th percentile result to less than 1.0 dv for every unit with the exception of Naughton Unit 3 (1.4 dv). The predicted number of days above 0.5 dv for the LNB/OFA option was 40 for Naughton Unit 3, and 16 or less for each of the other twelve units. The Division determined that SCR would be required on Naughton Unit 3 to bring about additional NO_x emissions reductions and modeled visibility improvement, and these factors differentiated the Naughton Unit 3 BART analysis from the others.

It was the full consideration of all five statutory BART factors, principally the pronounced visibility improvement for LNB/OFA as compared to baseline and the lack of non-air quality environmental impacts that led the Division to conclude that LNB/OFA would be BART for NO_x control at the Jim Bridger plant and for Units 1 and 2 at the Naughton Plant. Modeled visibility impacts for Naughton Unit 3 were reduced to levels comparable to those yielded by LNB/OFA controls on Naughton Units 1 and 2 only through the addition of SCR as BART on Naughton Unit 3. Potential energy losses and environmental impacts from the operation of SCR were mentioned in the Division's BART analysis for both the Naughton and Jim Bridger plants, but were only part of the larger evaluations that considered all five statutory factors.

II.7 **NO_x Controls: SCR Efficiencies** – The Forest Service commented that greater SCR control efficiencies should be factored into the cost and visibility analyses.

Response – The Division conducted a search of the EPA RACT/BACT/LAER Clearinghouse (RBLC) to find NO_x emission limits as BACT associated with SCR control in recently issued permits. Table 2 presents a summary of the Division's RBLC search. Two plants have limits of 0.05 lb/MMBtu NO_x with a 12-month rolling average, which is significantly longer than a 30-day averaging period. Because the 0.05 lb/MMBtu limits are based on a 12-month averaging period, they are not comparable to the 30-day limits established by the Division. The two plants with 30-day averaging periods will be subjected to either a 0.08 lb/MMBtu or 0.07 lb/MMBtu limit, and the limits established by the Division meet these lower limits. A spreadsheet compiled by the National Park Service with a summary of nationwide BART determinations shows that both units outside of Wyoming for which SCR is proposed as BART will be subject to a NO_x emission limit of 0.07 lb/MMBtu, and both will be based on a 30-day averaging period.

The RBLC search showed two plants that will be subject to 24-hour NO_x limits of less than 0.07 lb/MMBtu (0.067 lb/MMBtu), but these limits are for newly constructed plants which have been engineered to meet these levels. BART will require the retrofit of significant controls at plants that were not designed to meet these lower levels. Based on the Division's evaluation, the Division is satisfied that the NO_x emission limit of 0.07 lb/MMBtu (30-day rolling average) that was evaluated for SCR control under BART is the most stringent control level likely to be achieved in a retrofit.

Table 2: SCR Permit Limits from the RBLC				
Facility/Location	**Size of Source**	**Source Description**	**NO_x Permit Limit(s) for SCR Control**	**Permit Date**
John W. Turk Power Plant/Arkansas	600 MW	6,000 MMBtu/hr PC Boiler (PRB Coal)	1) 0.067 lb/MMBtu (24-hr rolling) 2) 0.05 lb/MMBtu (12-month rolling) [SCR, BACT]	Nov 2008
Dry Fork Station/Wyoming	385 MW	PC Boiler	0.05 lb/MMBtu (12-month rolling) [SCR, BACT]	Oct 2007
WYGEN3/Wyoming	100 MW	1,300 MMBtu/hr PC Boiler	0.05 lb/MMBtu (12-month rolling) [SCR, BACT]	Feb 2007
Iatan Station/Missouri	--	PC Boiler	0.08 lb/MMBtu (30-day rolling) [SCR, BACT]	Jan 2006
Big Cajun II Power Plant/Louisiana	675 MW	PC Boiler	0.07 lb/MMBtu (annual average) [SCR, BACT]	Aug 2005
TS Power Plant/Nevada	200 MW	PC Boiler	0.067 lb/MMBtu (24-hour rolling) [SCR, BACT]	May 2005
OPPD – Nebraska City Station/Nebraska	--	--	0.07 lb/MMBtu (30-day rolling) [SCR, BACT]	Mar 2005

Note: "--" indicates that this value was not provided in the RBLC

II.8 **Reasonable Progress Controls** – The Forest Service asked why Naughton Units 1 and 2 are not required to install SCR as part of reasonable progress like other PacifiCorp units.

Response – See response to Forest Service comment II.1.

II.9 **SO_2 Controls (cost effectiveness)** – The Forest Service commented that performance for a wet scrubber on Naughton Unit 3 was stated to be 0.10 lb/MMBtu, but the cost effectiveness was based on 0.15 lb/MMBtu. Cost per ton for SO_2 reduction should be based on 0.10 lb/MMBtu if that is the correct value.

Response – The application of wet FGD on Unit 3 is anticipated to lower SO_2 emissions to 0.10 lb/MMBtu, based on an average coal sulfur content of 0.58% by weight, and to 0.15 lb/MMBtu, based on an average coal sulfur content of 1.02% by weight. Because both low sulfur and high sulfur coals are used to fuel the boilers at Naughton, 0.15 lb/MMBtu was used as the basis for cost effectiveness. The cost effectiveness is not relevant because BART limits for SO_2 will not be set. 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.

II.10 **SO_2 Controls (Section 309)** – The Forest Service understands the role of Section 309 in exempting the State of Wyoming from making BART determinations for SO_2 controls based on the demonstration that the benefits from SO_2 emissions reductions under Section 309 exceed those that would have resulted from BART. Are the existing SO_2 controls in place at the Jim Bridger and Naughton plants at least equivalent to the control scenario used in the demonstration, i.e., are the existing controls needed to accomplish the "Better than BART" demonstration for Section 309? They also note that the 309 program sunsets in 2018 and added SO_2 controls may be needed for reasonable progress at that time.

Response – The State of Wyoming submitted a 309 SIP as is allowed by the Regional Haze Rule. Part of the SIP submittal is a "Better than BART" demonstration, required by rule, which does not require that each and every unit demonstrate emission controls that are "Better than BART". The demonstration is a regional demonstration. The Division is aware than the 309 program only establishes milestones through 2018, and that following 2018 another strategy may be necessary to reduce visibility-impairing pollutants. Additional strategies will be addressed in future SIP revisions.

II.11 **Visibility Impairment** – The Forest Service commented that because EPA BART guidelines state that 0.5 dv "contributes" to visibility impairment, and 1.0 dv "causes" visibility impairment, the discussion from Ronald Henry regarding perceptibility in the BART applications from PacifiCorp is irrelevant and used in an improper context.

Response – The Division did not attempt to endorse a particular threshold for human eye "perceptibility" since the level of perceptibility has long been disputed. Instead, the Division has relied on EPA's Appendix Y BART guidance, which suggests a value of 0.5 dv as the level that a source "contributes" to visibility impairment. One of the metrics used by the Division to evaluate the relative benefit of a given BART control option was the number of days yielding a modeled impact of 0.5 dv or more.

III. Analysis of Comments from EPA Region 8:

III.1 **Background Ozone Concentration in CALPUFF** – EPA Region 8 commented that the Division's visibility modeling used 44 ppb as a background ozone concentration as the default value for periods when measured data was missing. This value appears to be too low based on the average annual concentrations at sites near the facilities (Thunder Basin = 50-55 ppb, Jonah = 55-58 ppb). DEQ should provide an analysis of how higher ozone background concentrations would affect results.

Response – The default ozone background concentration is used by CALPUFF as a domain-wide substitute for any hour for which all measured ozone concentrations are missing. For the Division's visibility modeling for BART, hourly ozone concentrations measured at seven monitoring stations spaced across the modeling domain were input to CALPUFF. A visual inspection of the ozone files that were input to CALPUFF reveals that at least one valid ozone observation was available for every hour of the modeled period (2001-2003), making it unnecessary for the model to use the default background of 44 ppb.

Although the model did not use the default background value for the BART analyses, the Division calculated annual average concentrations for recent years (2007-2008) and all available data for 2009 for many of the stations that were used for input to CALPUFF, including Thunder

Basin, Jonah, Rocky Mountain National Park, Centennial, and Pinedale. Annual average values for these stations ranged from 35 ppb to 49 ppb, with an overall average of approximately 40 ppb. The Division is confident that the default background value of 44 ppb was appropriate for the BART modeling, and that there is no need for additional analyses to explore alternate background concentrations.

III.2 **Weight of Visibility Modeling Results in BART Determinations** – EPA Region 8 commented that DEQ should provide an explanation of how modeled visibility improvements were weighed in making BART determinations.

Response – The Division's BART determinations were based on consideration of all five statutory factors, as required by EPA's Appendix Y BART guidance. The modeled visibility improvements for a given control strategy were one of the five factors that were considered. No single factor was weighted as being more important than another, because the Division looked at all five statutory factors in their entirety. EPA guidance did not provide a quantification of the amount of modeled visibility improvement that would be acceptable or significant. The Division used two metrics that were mentioned in the EPA BART guidance, the 98th percentile result for a given year and the level at which a source "contributes" to visibility degradation (0.5 Δdv), to present the results of the BART visibility modeling. Also see the response to USDA Forest Service comment II.6.

III.3 **Cumulative Modeled Impacts** – EPA Region 8 commented that cumulative, modeled Class I impacts from all units at a facility (or combined impacts from multiple facilities) should be presented in addition to the results for individual units.

Response – The visibility impacts from BART-eligible sources are to be modeled separately. As stated in the EPA's Appendix Y guidance, relative to the use of the CALPUFF model for BART determinations, "*We believe that CALPUFF is an appropriate application for States to use for the particular purposes of this rule, to determine if an individual source is reasonably anticipated to cause or contribute to impairment of visibility in Class I areas, and to predict the degree of visibility improvement which could reasonably be anticipated to result from the use of retrofit technology **at an individual source**. We encourage States to use it for these purposes.*" [emphasis added]

III.4 **Language from BART Determinations** – EPA Region 8 commented that the Division should clarify the statements of "3-year average visibility improvements". Are dv improvements calculated for each Class I area added together? If so, what is the meaning of the number? Are three Class I areas sufficient to quantify cumulative impacts? Were all Class I areas within 300 km considered?

Response – To arrive at the "3-year average visibility improvements" that were reported in the Division's BART analyses, the modeled 98th percentile dv change or the number of days above 0.5 dv predicted for a given year of meteorology was averaged with the similar result from the other two years of meteorology. These 3-year average values were determined for each modeled Class I area separately, and were devised to allow a straightforward, direct comparison of one control option to another. Regarding the sufficiency of the number of modeled Class I areas and the question of other Class I areas within 300 km, see response to USDA Forest Service comment II.3.

III.5 **NO_x Controls** – EPA Region 8 commented that the most stringent emission control levels for NO_x controls have not been evaluated, resulting in inflated calculated cost effectiveness values. Lower emission limits should be evaluated for selective non-catalytic reduction (SNCR) and SCR.

Response – The Division has analyzed the most stringent levels for SNCR and SCR, and does not agree that the cost effectiveness numbers have been inflated. See response to USDA Forest Service comment II.7. Furthermore, the Division has deemed the costs associated with all analyzed BART NO_x control options, including SNCR and SCR, to be reasonable (see the conclusions listed under the section: **NOx: EVALUATE IMPACTS AND DOCUMENT RESULTS** in each of the five BART Application Analyses).

III.6 **12-Month Average for NO_x** – EPA Region 8 commented that there is no formula to calculate if the 12-month rolling emission limit has exceeded the permit condition. A permit condition to match condition 12.a.iii from the Laramie River Station analysis should be created.

Response – The BART limits for NO_x emissions from the PacifiCorp plants include 30-day rolling limits in terms of lb/MMBtu and lb/hr. The ton per year limit is based on a calendar year rather than a rolling average, and therefore the formula associated with the annual BART limit for NO_x at the Laramie River Station is not relevant.

III.7 **PM Controls: Averaging Periods** – EPA Region 8 commented that the BART conclusions and the permit conditions should include associated averaging periods for all PM/PM_{10} limits.

Response – The averaging periods for the PM/PM_{10} limits are dictated by the performance test requirements in the BART permits. Compliance with the lb/MMBtu and lb/hr PM/PM_{10} limits is based on the average of three 1-hour tests per 40 CFR 60.46.

III.8 **PM Controls: Control Effectiveness** – EPA Region 8 commented that the Division should explain why 0.015 lb/MMBtu for baghouse/fabric filter control effectiveness is acceptable, when 0.012 lb/MMBtu has been approved by the Division for other permits and 0.010 lb/MMBtu was approved for the Desert Rock project. The BART determinations should include analyses of electrostatic precipitators (ESPs) and baghouses at lower control levels.

Response – Recent Prevention of Significant Deterioration (PSD) permits issued by the Division did include PM/PM_{10} limits of 0.012 lb/MMBtu for fabric filter controls, but those limits (and PM/PM_{10} limits established for the Desert Rock Project in New Mexico) were determined through Best Available Control Technology (BACT) analyses for new sources. The BART process deals with retrofit controls on existing units, and therefore is not directly comparable to BACT determinations. Additionally, visibility modeling described in the Division's BART analysis for the Jim Bridger plant showed that the addition of a fabric filter to replace an Electrostatic Precipitator (ESP) provided very little in the way of visibility improvement, with predicted cumulative improvements across three Class I areas of only 0.03 to 0.1 Δdv for Units 1-4. These results indicate that requiring more stringent control levels for a fabric filter would not provide significant visibility improvement.

As described on page 17 of the Division's BART analysis for the Naughton plant, ESP performance enhancements using FGC were considered for Units 1 and 2, and will be utilized for BART control. For Unit 3, a new full-scale fabric filter will be installed for BART control.

III.9 **PM Controls: Permit Exemption** – EPA Region 8 commented that Condition 5 in the proposed EGU BART permits contains an inappropriate exemption for startup. The exemption from the lb/MMBtu PM limit during startup should be removed or it may be appropriate to analyze the need for a startup BART limit.

Response – For each EGU subject to BART in Wyoming, only the BART limits for PM/PM_{10} that are expressed in lb/MMBtu will not apply during startup. The BART limits for PM/PM_{10} that are expressed in lb/hr and tpy (as based on the lb/MMBtu limits) will apply during all operating periods including startup.

The Division considers the BART limits expressed in terms of lb/hr and tpy to be appropriate limits for startup. For the four units at the Jim Bridger plant, PacifiCorp calculated that the particulate emissions from the startup fuel (fuel oil) would be no greater than 10.9 lb/hr per unit, conservatively assuming that the ESP controls had zero control efficiency during the startup process. As a comparison, the BART limit that would apply for each unit during startup is 180 lb/hr. Further, PacifiCorp has agreed to minimize startup emissions from the four units at the plant by placing the ESPs in service prior to the introduction of coal to the boilers, which is contrary to the manufacturer's recommendation to energize the ESP only after the unit is at full operating temperature and combustion of fuel oil has ceased.

Similarly for Unit 1 at Wyodak, particulates are controlled by an ESP and startup is accomplished with fuel oil. The maximum emissions estimated for startup (8.9 lb/hr) would be well below the BART limit of 71 lb/hr. The three units at LRS are also started on fuel oil and controlled with ESPs, and the particulate emissions during startup are expected to be well below the BART limits, which are set at 193 lb/hr to 198 lb/hr for the three units.

For units with baghouse controls for particulate matter such as Dave Johnston Units 3 and 4, emissions from fuel oil during the startup process are also estimated to be well below the allowable lb/hr BART limits.

In the case of the Naughton plant, particulate controls will include a mixture of ESPs (Units 1 and 2) and a fabric filter/baghouse (Unit 3). Natural gas is the startup fuel for each of these units, and particulate emissions during startup are expected to be well below the established lb/hr BART limits.

III.10 **PM Controls: FGC** – EPA Region 8 commented that flue gas conditioning (FGC) must be applied only after FGD is installed or upgraded to avoid increases in the emissions of sulfuric acid (H_2SO_4) mist. A control option should not be considered as a BART option if it will result in an increase in visibility-reducing pollutants.

Response – The Division has already evaluated the impacts of FGC at the Naughton plant as part of the review of PacifiCorp's permit application for permit MD-5156, which was issued on May 1, 2009. Permit MD-5156 authorized FGC to enhance the performance of the ESPs on Units 1 and 2. The permit application included a modeling evaluation of the impacts to Class I area visibility from the FGC, and the impacts were predicted to be insignificant.

III.11 **SO$_2$ Controls: Reasonable Progress** – EPA Region 8 commented that the Division must evaluate the visibility impacts of SO_2 controls and demonstrate reasonable progress for the Class I areas away from the Colorado Plateau.

Response – Wyoming, along with other 309 states in the WRAP region, evaluated the impact of the 309 program on all Class I areas in the west, even though the requirement by rule was to demonstrate improvement in Class I areas on the Colorado Plateau. The WRAP modeling for sulfates shows that all Class I areas in and around Wyoming sources are benefiting from the sulfur dioxide emission reductions instituted in the 309 program. Sulfate extinction levels show improvement on the 20% worst days and improvement or at least no degradation on the 20% best days. Furthermore, the Regional Haze rule allows a state to take full credit for strategies implemented under 309 when addressing Class I Areas away from the Colorado Plateau (51.309(g)(4)(i)).

III.12 **CALPUFF Visibility Modeling: Other Class I Areas** – EPA Region 8 commented that visibility impacts at Flattops Wilderness Area in Colorado should have been modeled for the Jim Bridger and Naughton plants.

Response – See response to USDA Forest Service comment II.3.

III.13 **NO$_x$ Controls** – EPA Region 8 commented that the control efficiencies assumed for all NO_x technologies are underestimated, resulting in inflated calculated cost effectiveness values. A revised analysis should indicate that SCR is cost effective at Naughton.

Response – See response to EPA Region 8 comment III.5.

III.14 **PM Controls: FGC** – EPA Region 8 commented that flue gas conditioning (FGC) will be applied to Naughton Units 1 and 2 and decommissioned from Unit 3 upon installation of a fabric filter permitted under PSD. The application of FGC prior to FGD upgrades will result in a significant increase in emissions of sulfuric acid (H_2SO_4) mist. This collateral increase should be avoided to maintain visibility improvements at Class I areas.

Response – See response to EPA Region 8 comment III.10.

IV. Analysis of Comments from PacifiCorp:

IV.1 **General Comments: Cost Metrics** – PacifiCorp commented that EPA's Appendix Y BART guidance states that a proper BART evaluation should include "other cost-effectiveness measures (such as $/deciview)". Thus, any BART determination that is limited to use only cost effectiveness and incremental cost effectiveness may be unacceptably narrow.

Response – EPA's Appendix Y BART guidance does mention that "dollars per deciview" ($/dv) is a metric that could be used to evaluate the cost of BART compliance, but by no means identifies $/dv as an essential or required metric. The Division considered capital cost, annual cost, cost effectiveness, and incremental cost effectiveness in the cost evaluation of each proposed BART control option. The Division chose not to use a hybrid metric such as $/dv primarily because of the lack of historical precedent regarding reasonable/acceptable levels for such a metric. Additionally, the use of a hybrid cost metric such as $/deciview can introduce uncertainty as to how the value was calculated. The value of "/deciview" could be based on the highest modeled value in a given area or the 98th percentile modeled value. It could be based on the 98th percentile value for any one modeled year or it could be an average for multiple years. It could even be based on an average modeled value across an entire Class I area or the sum of deciview changes across multiple areas. The Division has found that $/dv values are often presented without explanation of the basis for the calculation. To avoid these confounding factors, the Division chose to evaluate and present the cost analyses and visibility analyses separately.

IV.2 **General Comments: Cost Effectiveness** – PacifiCorp commented that any BART determination requiring a source to install post-combustion controls like SCR or spend more than $1,500 per ton of NO_x removed would be contrary to EPA Appendix Y BART guidance.

Response – The EPA's Appendix Y guidance describes the EPA's selection of presumptive NO_x limits for coal-fired EGUs, and provides approximate cost levels for meeting the presumptive limits with current combustion controls and a somewhat higher cost level for a subset of units that would require advanced combustion controls such as rotating opposed fire air (ROFA). The EPA guidance does not attempt to establish cost thresholds that would be considered unreasonable for a given control technology, nor does it present the approximate costs associated with the presumptive levels as absolute limits above which cost should be deemed unreasonable. The guidance also states that states may in specific cases find that the use of SCR is appropriate. As stated previously, the Division established NO_x emission limits for BART based on consideration of all five statutory factors in their entirety, as required by the Appendix Y guidance.

IV.3 **General Comments: Power Plants More Than 750 MW** – PacifiCorp commented that Appendix Y indicates that states must follow Appendix Y guidelines in making BART determinations on a source-by-source basis for 750 MW plants. Wyoming rules impose similar requirements for power plants greater than 750 MW.

Response – The Division followed EPA and State of Wyoming rules for the BART analyses. Specifically, the Division followed WAQSR Chapter 6, §9(c)(ii), which states that power plants with generating capacities greater than seven hundred fifty megawatts shall comply with EPA Appendix Y, and that Appendix Y should be used as guidance for preparing BART analyses for all other facilities.

IV.4 **General Comments: Post-Combustion Controls** – PacifiCorp commented that EPA never contemplated the use of post-combustion controls to meet BART limits for tangentially-fired boilers, and that it is nearly impossible under Appendix Y guidance to show that anything other than combustion controls should be required as BART.

Response – See response to PacifiCorp comment IV.2.

IV.5 **General Comments: Visibility Improvement** – PacifiCorp commented that a BART determination that only relied on the 98th percentile, three-year average results from CALPUFF may be too narrow to satisfy Appendix Y.

Response – The Division did not rely solely on the three-year average of the 98th percentile CALPUFF results to evaluate the expected visibility changes for the BART control options. The 98th percentile values and the number of days with predicted results above 0.5 dv were presented in the Division's BART analyses for each of three modeled years, for each Class I area, and for each control option. The three-year average of the 98th percentile results and the number of days above 0.5 dv were chosen for graphical representation and were mentioned prominently in the Division's conclusions because they offered the clearest comparison of one control option to another (see graphs in Appendix A).

IV.6 **General Comments: Modeling** – PacifiCorp commented that visibility modeling contains inherent bias or exaggeration because it assumes that a particular source will operate at its maximum capacity 100% of the time and that each unit at a facility operates in the same way.

Response – The results from BART visibility modeling, as required by EPA guidance, are based on daily (24-hour) averages. Reported results for a given control scenario, expressed in units of deciviews, represent the predicted change in visibility as compared to natural background over the course of 24-hour periods of meteorology. The modeled emission rates for a given unit at a power plant should reflect the highest rate that could be achieved over a 24-hour period, and therefore the assumption that a given unit is operating at its maximum operating capacity is appropriate for each unit at a base-load power plant such as Naughton. Additionally, the conclusions drawn from BART visibility modeling primarily involve comparisons between control scenarios for which the emissions are determined similarly.

IV.7 **General Comments: NO_x Emissions** – PacifiCorp commented that emissions of NO_x during the 20% best and 20% worst days at Class I areas in Wyoming are not a significant contributor to regional haze as compared to other emissions, and therefore the Division should consider this before requiring extreme NO_x control measures such as SCR as BART.

Response – For the 20% worst days during the years 2000-2004 at the Bridger Wilderness Area, 6.21% of the total visibility degradation was attributable to nitrates. Source apportionment modeling provided by the WRAP showed that 19% of the nitrates come from Wyoming sources. The Division recognizes that pollutants other than nitrates contribute more toward the total visibility degradation at the Bridger Wilderness Area, but the Division has concluded that the contribution from Wyoming sources toward the formation of nitrates at the Bridger Wilderness Area and other Class I areas warrants a full consideration of prospective NO_x controls under the BART process.

IV.8 **Perceptibility** – PacifiCorp commented that credible studies indicate that only changes in visibility as high as 1.5-2.0 dv are perceptible to the human eye. The Division should consider this while drawing conclusions based on the results of the visibility modeling and before requiring extreme NO_x control measures such as SCR.

Response – See response to USDA Forest Service comment II.11.

IV.9 **Cost Metrics for Naughton Unit 3** – PacifiCorp commented that it opposes the determination that SCR is BART for NO_x control, and that the Division should have considered other cost-benefit metrics such as \$/dv. Using \$/dv, the cost for 1 dv of visibility improvement is more than \$15 million per year. If one considers that changes of less than 1.5 dv are not perceptible to the human eye, the cost per deciview reduction is not reasonable.

Response – See responses to PacifiCorp comment IV.1 and USDA Forest Service comment II.11.

IV.10 **Presumptive BART** – PacifiCorp commented that the Division's reference in the BART analysis for the Naughton plant to a presumptive BART limit for NO_x of 0.15 lb/MMBtu is not correct. For reasons stated in PacifiCorp's most recent submittals to the Division, primarily an argument regarding coal characteristics, the correct presumptive BART limit for Naughton Units 1-2 is 0.28 lb/MMBtu.

Response – See response to USDA Forest Service comment II.5.

IV.11 **Reasonable Costs for SCR on Naughton Unit 3** – PacifiCorp commented that the calculated costs for SCR on Naughton Unit 3 are not reasonable, according to EPA's Appendix Y guidance.

Response – The EPA's Appendix Y guidance describes the EPA's selection of presumptive NO_x limits for coal-fired EGUs, and provides approximate cost levels for meeting the presumptive limits with current combustion controls and a somewhat higher cost level for a subset of units that would require advanced combustion controls such as ROFA. The EPA guidance does not attempt to establish cost thresholds that would be considered unreasonable for a given control technology, nor does it present the approximate costs associated with the presumptive levels as absolute limits above which cost should be deemed unreasonable. The guidance also states that states may in specific cases find that the use of SCR is appropriate. As stated previously, The Division established NO_x emission limits for BART at the Naughton power plant based on consideration of all five statutory factors, as required by the Appendix Y guidance.

IV.12 **Incremental Costs for SCR on Naughton Unit 3** – PacifiCorp commented that the incremental costs per ton of NO_x reduction for SCR on Naughton Unit 3 shown in Table 10, page 15 of the Division's BART analysis is incorrect. The correct value is more than $4,000 per ton rather than the value of $1,783 that is shown in Table 10. When considering the true incremental costs of SCR, the Division's BART determination cannot stand.

Response – The incremental cost listed for SCR control in Table 10 of the Division's BART analysis for Naughton Unit 3 was incorrect, and should have been listed as $4,049 per ton. However, the Division concluded that the correct cost per ton of NO_x reduction ($2,830/ton) and the incremental cost per ton of NO_x reduction ($4,049) are both reasonable for SCR control on Naughton Unit 3. Table 3 below presents a comparison of the costs associated with SCR control for Naughton Units 1 through 3 which shows that the costs associated with all three units are comparable and the incremental costs for Unit 3 are lower compared to the other two units at the plant. Furthermore, costs for Units 1 and 2 were identified in the analysis as reasonable and the costs for Unit 3 are within that range. The Division's error had no bearing on the BART determination.

Table 3: Costs for SCR Control on Naughton Units 1 Through 3

Unit	Cost Per Ton of NO_x Reduction	Incremental Cost Per Ton of NO_x Reduction
1	$2,750	$8,089
2	$2,848	$7,852
3	$2,830	$4,049

IV.13 **Boardman, Oregon BART Determination** – PacifiCorp commented that the state of Oregon determined that SCR control was not appropriate for the Boardman Power Plant, yet the cost-benefit values for Boardman are more favorable for SCR installation than for Naughton Unit 3.

Response – The Division determined BART for NO_x control for Naughton Unit 3 based on consideration of all five statutory factors, as required by EPA's Appendix Y BART guidance. The costs for SCR controls, as described in the Division's BART analysis, were deemed by the Division to be reasonable. Modeled visibility reductions from baseline for the LNB/OFA option on Naughton Unit 3 were not nearly as pronounced as they were for other BART-eligible units in the state. The Division determined that SCR would be required on Naughton Unit 3 to bring about additional NO_x emission reductions and additional modeled visibility improvement, and these factors differentiated the Naughton Unit 3 analysis from the others. For additional details, see response to USDA Forest Service comment II.6 and the graphs in Appendix A.

IV.14 **Presumptive BART for Naughton Unit 3 and LNB/OFA Emissions Compared to Units 1/2** – PacifiCorp commented that presumptive BART for NO_x control on Naughton Unit 3 is not 0.15 lb/MMBtu as stated in the Division's BART analysis, but is 0.28 lb/MMBtu. Sufficient justification exists under Appendix Y to select a higher calculated BART limit of 0.35 lb/MMBtu. Even if the 0.015 lb/MMBtu presumptive limit is assumed to be correct, the requirements for SCR control at 0.07 lb/MMBtu cannot be justified as BART because it is so far below the EPA's presumptive limit of 0.15 lb/MMBtu. PacifiCorp also commented that the modeled deciview reductions for Naughton Units 1 and 2 as compared to Unit 3 are interesting but not relevant in making a BART determination. The fact that Units 1 and 2 can achieve greater modeled visibility improvements is only an indication that Unit 3 has already installed and achieved a significant level of NO_x reductions.

Response – The Division determined BART for NO_x control for Naughton Unit 3 based on consideration of all five statutory factors, as required by EPA's Appendix Y BART guidance. PacifiCorp's analysis of coal composition and how it might affect the presumptive NO_x limit for Naughton Unit 3 was not a factor in the Division's determination. The NO_x emission level proposed by PacifiCorp for Naughton Unit 3 using LNB/OFA provided less in the way of modeled visibility reductions from baseline as compared to other BART-eligible units in the state. For example, Naughton Units 1 and 2 showed a 72% to 73% reduction in the number of days with predicted impacts of 0.5 dv or more at the Bridger Wilderness Area for LNB/OFA as compared to baseline. The reduction for Naughton Unit 3 with LNB/OFA vs. baseline was only 31%. Modeled visibility impacts for Naughton Unit 3 were reduced to levels comparable to those yielded by LNB/OFA controls on Naughton Units 1 and 2 only through the addition of SCR on Naughton Unit 3 (see graphs in Appendix A). A comparison between the modeled visibility for Naughton Units 1 and 2 at the proposed level for LNB/OFA control (0.26 lb/MMBtu) and the proposed level for LNB/OFA control for Naughton Unit 3 (0.37 lb/MMBtu) is certainly relevant for making a BART determination for Naughton Unit 3. Also see response to USDA Forest Service comment II.6.

V. **Analysis of Comments from the National Park Service:**

V.1 **NO_x Step 3: Evaluate Effectiveness of Remaining Control Technologies (SCR capabilities)** – The NPS commented that the Division underestimated the ability of SCR to reduce emissions. The proposed NO_x limit for SCR (0.07 lb/MMBtu) is not low enough. SCR can achieve greater reductions. NPS suggests 0.06 lb/MMBtu for 30-day limit, 0.05 lb/MMBtu or lower for an annual limit.

Response – See response to USDA Forest Service comment II.7.

V.2 **NO_x Step 4: Evaluate Impacts and Document Results (SCR costs)** – The NPS commented that SCR costs were generally overestimated because the OAQPS Control Cost Manual was not used for cost estimates.

Response – PacifiCorp developed cost estimates for SCR control using a combination of the OAQPS Control Cost Manual, vendor-obtained price quotes, and a database developed by the engineering firm Sargent & Lundy. The degree to which the SCR costs may have been overestimated does not require further review because the Division has concluded that the estimated costs are reasonable and that costs alone would not preclude the use of SCR.

V.3 **NO_x Step 4: Evaluate Impacts and Document Results (incremental costs for SCR)** – The NPS commented that the Division over-emphasized the incremental costs for the addition of SCR in the BART determinations. The Division should consider the average costs calculated for combustion controls plus SCR.

Response – See response to PacifiCorp comment IV.1 and NPS comment V.2.

V.4 **NO_x Step 4: Evaluate Impacts and Document Results (basis for costs)** – The NPS commented that cost estimates should be documented by vendor or by the EPA Control Cost Manual.

Response – See response to NPS comment V.2.

V.5 **NO_x Step 5: Visibility Improvement Determination (Class I Areas Modeled)** – The NPS commented that the Division should consider visibility impacts at all Class I areas within 300 kilometers (km) of a source.

Response – See response to USDA Forest Service comment II.3.

V.6 **NO_x Step 5: Visibility Improvement Determination (incremental benefits of SCR)** – The NPS commented that the Division placed too much emphasis on the incremental improvement in visibility that was predicted for the addition of SCR. The total predicted visibility improvement resulting from a combination of control options should have been presented.

Response – The incremental improvement in modeled visibility with the addition of SCR was mentioned prominently in the summary of the Division's BART conclusions, but all visibility modeling results were considered. For more information on the presentation of the visibility modeling results in the Division's BART analyses, see the response to EPA Region 8 comment III.2 and PacifiCorp's comment IV.5.

V.7 **NO_x Step 5: Visibility Improvement Determination (sulfuric acid mist emissions)** – The NPS commented that the modeled sulfuric acid mist emissions increased for the SCR control scenario, and the Division should provide a detailed explanation of how the sulfuric acid mist emissions were calculated by PacifiCorp.

Response – PacifiCorp's consultant, CH2M HILL, used the following methodology to calculate sulfate emissions for SCR for the PacifiCorp coal-fired power plants (as provided in a letter from PacifiCorp that was submitted to the Division on September 16, 2009):

- 1.0% of the SO_2 in the boiler is converted to SO_3
- An additional 1.0% of the SO_2 is converted to SO_3 in an SCR unit
- The SO_3 is converted to H_2SO_4 mist in the flue gas
- 50% of the H_2SO_4 mist is removed in a wet FGD unit
- 95% of the H_2SO_4 mist is removed in a dry FGD unit
- An SCR unit has 2.0 ppmvd NH_3 slip
- 50% of the NH_3 slip is converted to ammonium sulfate and 50% is converted to ammonium bisulfate
- 50% of the ammonium sulfate and bisulfate are removed in a wet FGD unit and 90% of the ammonium sulfate and bisulfate are removed in a dry FGD unit
- Total sulfate emissions are made up of H_2SO_4 mist, ammonium sulfate and ammonium bisulfate

V.8 **BART Conclusions for NO_x Controls: $/dv** – The NPS commented that the Division should use $/dv as an additional metric for evaluating BART controls.

Response – See response to PacifiCorp response IV.1.

V.9 **BART Conclusions for NO_x Controls: Cost Benchmarks** – The NPS commented that the Division determined that the costs for SCR were reasonable, yet rejected SCR for BART control. DEQ should explain why and provide the cost benchmarks used to determine reasonable costs.

Response – The Division established NO_x emission limits for BART based on consideration of all five statutory factors (as required by EPA's Appendix Y BART guidance) and not merely based on cost. The Division relied on past experience with BACT determinations for similar sources/control options to determine the range of control costs that were reasonable.

V.10 **BART Conclusions for NO_x Controls: Non-Air Quality Impacts** – The NPS commented that the Division mentioned non-air quality impacts as reasons to reject SCR for BART controls. Recent PSD permits issued by DEQ and requiring SCR did not mention such impacts. Why were such impacts mentioned in these particular cases? SCR has been used at many facilities with minimal problems with transport and storage of ammonia, why would this be a particular problem for SCR as BART control?

Response – The Division's BART determinations for the Naughton plant were based on consideration of the five statutory factors, including the cost of compliance and the energy and non-air quality environmental impacts of compliance. Potential energy losses and environmental impacts from the operation of SNCR and SCR were mentioned in the Division's BART analysis, but were only part of the larger evaluation that considered all five statutory factors.

V.11 **BART Conclusions for NO_x Controls: Parasitic Power Loss** – The NPS commented that the Division mentioned parasitic power loss in association with the operation of OFA and SCR. Parasitic power loss associated with SCR has already been accounted for in the cost analysis for NO_x and should not be "double-counted" by using it to draw conclusions for BART control unless it would cause a power shortage.

Response – See response to NPS comment V.10.

V.12 **BART Conclusions for NO_x Controls: Fly Ash Sales** – The NPS commented that the Division stated that the operation of SCR could impact the "salability" of fly ash. Evidence should be presented and the economic impact quantified.

Response – See response to NPS comment V.10.

V.13 **BART Conclusions for NO_x Controls: Ammonia Injection** – The NPS commented that the Division stated that SCR could create "blue plume" if the ammonia injection rate is not well controlled. NPS states that it assumes that PacifiCorp can properly control the injection rate.

Response – See response to NPS comment V.10.

V.14 **BART Conclusions for NO_x Controls: SCR Installation** – The NPS commented that PacifiCorp states that SCR would take a minimum of six years to plan and install. NPS states that Minnesota Power plans to install SCR, fabric filter, and a new chimney on the 330 MW Boswell Unit #3 in half of that time. PacifiCorp should explain why so much extra time is needed.

Response – A letter provided to the Division by PacifiCorp dated September 16, 2009 provided information on the time needed to plan, design, and install SCR:

- Develop and Permit: 18-24 months
- Design: 9-12 months
- Procurement: 9-13 months
- Construct: 18-24 months
- Start, Tune, and Test 4-6 months
- Total (including overlap of individual tasks): 60-66 months

V.15 **BART Conclusions for PM_{10} Controls: Control Effectiveness** – The NPS commented that the Division should explain why 0.015 lb/MMBtu was acceptable to the Division as a control effectiveness for a ESP/polishing fabric filter combination, when 0.012 lb/MMBtu has been approved by the Division for other recent permits involving fabric filters and limits as low as 0.010 lb/MMBtu have recently been approved for fabric filters (e.g., Desert Rock Project).

Response – See response to EPA Region 8 comment III.8.

V.16 **BART Conclusions for PM_{10} Controls: Fabric Filters** – NPS believes that PacifiCorp would not have agreed to install fabric filters unless it finds the option to be reasonable or is compelled to do so. DEQ should accept fabric filters as a reasonable BART alternative in the context of the PM reductions and associated costs, or state what it considers reasonable average and incremental costs for a fabric filter.

Response – The Division concluded that the costs of a fabric filter for Naughton Unit 3 was not reasonable. However, as stated on page 51 of the Division's BART analysis for Naughton: "PacifiCorp is committed to installing this control device and has permitted the installation of a full-scale fabric filter on Naughton Unit 3 in a recently issued New Source Review construction permit. A full-scale fabric filter is the most stringent PM/PM_{10} control technology and therefore the Division will accept it as BART."

VI. Analysis of Comments from the Powder River Basin Resource Council, et al.:

VI.1 **Modeled Class I Areas** – The Powder River Basin Resource Council, et al. commented that all Class I areas within 300 km of a given source should be modeled for visibility impacts.

Response – See response to USDA Forest Service comment II.3.

VI.2 **Presumptive BART** – The Powder River Basin Resource Council, et al. commented that DEQ failed to impose the presumptive BART limit for NO_x of 0.15 lb/MMBtu for Naughton Units 1 and 2, applying the mistaken logic that the presumptive limits do not apply because Naughton's cumulative capacity is less than 750 MW.

Response – See response to USDA Forest Service comment II.5.

VI.3 **Reasonably Attributable Visibility Impairment** – The Powder River Basin Resource Council, et al. commented that because of the magnitude of modeled visibility impacts, DEQ should certify that Wyoming power plants are causing reasonably attributable visibility impairment, and establish more stringent BART controls. A single source that is responsible for a 1.0 deciview change or more should be considered to "cause" visibility impairment, according to WAQSR Chapter 6, §9(d)(i)(A). Because of the reasonably attributable visibility impairment, BART must be determined under WAQSR Chapter 9, §2(d)(ii) and 40 CFR §51.302(c)(4)(iii). These regulations provide that BART is presumed to be at least at NSPS levels. This would require at least 0.11 lb/MMBtu for NO_x limits, but SCR should be required at 0.07 lb/MMBtu.

Response – WAQSR Chapter 6, §9(d)(i)(A) applies to the determination of which sources in Wyoming are subject to BART under the regional haze program, and is not relevant to the determination of *reasonably attributable visibility impairment*. Since adoption of Wyoming's Visibility SIP and visibility regulations to address *reasonably attributable visibility impairment*, neither the Federal Land Managers of any Class I area nor the Division has certified that visibility impairment, attributable to a source or small group of sources, exists in any Wyoming Class I area pursuant to provisions in Chapter 9, Section 2 of the WAQSR. The provisions of Chapter 9, Section 2 of the WAQSR are therefore not relevant to the Division's BART analyses.

VI.4 **Section 309 Milestone Program** – The Powder River Basin Resource Council, et al. commented that DEQ should impose BART limits for SO_2 because participation in the Section 309 program only excuses DEQ from setting BART limits if the State's 309 SIP is approved by the EPA and if the 309 SIP demonstrates that emissions levels would result in greater visibility improvement than source-specific BART limits.

Response – The Regional Haze Rule allows the State of Wyoming to submit a 309 SIP in lieu of establishing BART limits for SO_2. The 309 SIP submittal includes a "Better than BART" demonstration. The entire submittal is currently undergoing EPA review and the State has no control over how long the EPA takes to review the SIP. The State, however, does not wait for EPA to complete its review before implementing a SIP. All of the 309 states have been participating in the 309 program, collecting SO_2 inventories, allowing independent audits of the information, comparing the regional totals to the milestones, and taking public comment on the regional figures and the comparisons with the milestone figures. The SO_2 levels have shown compliance with the milestones and continue to demonstrate declining SO_2 emissions levels. Also see responses to USDA Forest Service comment II.10 and EPA comment III.11.

VI.5 **BART Conclusions for PM_{10} Controls** – The Powder River Basin Resource Council, et al. commented that the Division should require PacifiCorp to meet, at a minimum, a PM limit 0.015 lb/MMBtu at the Naughton plant using full baghouse or polishing baghouse because: 1) the plant is causing reasonably attributable visibility impairment in at least two Class I areas, and 2) because BART is supposed to be the "best system of continuous emission reduction" and the Division's analysis identified fabric filters as the most stringent PM control.

Response – The Division established PM/PM_{10} emission limits for BART at the Naughton plant based on consideration of all five statutory factors, as required by EPA's Appendix Y BART guidance. Various control technologies were evaluated for each source subject to BART, including the most advanced controls, but the BART guidance does not dictate that a state require the control technology with the highest level of control in all cases. Regarding the relevance of *reasonably attributable visibility impairment*, see response to Powder River Basin Resource Council, et al. comment VI.3.

VII. Analysis of Comments from the Sierra Club and Citizens Associated with the Sierra Club:

VII.1 **Air Quality Laws and Regulations** – The Sierra Club commented that it is important that air quality laws and regulations are strictly complied with to preserve park resources for present and future generations.

Response – The Division followed federal regulations and guidance as well as state regulations in assessing the BART applications and for making the BART determination for all sources eligible for BART in the State of Wyoming. The BART rules and guidance used by the Division included:

- Section 308 of the Regional Haze Rule [40 CFR 51.308(e)]
- *Guidelines for BART Determinations Under the Regional Haze Rule* [Appendix Y to part 51]
- Chapter 6, Section 9 of the Wyoming Air Quality Standards and Regulations (WAQSR), *Best Available Retrofit Technology*

VII.2 **Regional Haze Rule** – The Sierra Club commented that the State of Wyoming can and should do more to protect air quality as the Regional Haze Rule is implemented.

Response – The Division's BART determinations for Wyoming sources, as well as additional air pollution controls that will be required to further reduce regional haze, will be addressed in the Wyoming State Implementation Plan (SIP) for regional haze. The SIP incorporates the emissions reductions associated with the Long-Term Strategy for regional haze.

VII.3 **Control of Nitrogen Oxide Emissions** – The Sierra Club commented that the State of Wyoming should require the coal plants to install devices that reduce nitrogen oxide emissions.

Response – All of the Division's BART determinations for coal-fired power plants in the State of Wyoming include pollution control equipment that will substantially reduce nitrogen oxide emissions.

VII.4 **20-Year Trend** – A commenter stated that the amount of air and water pollution has clearly escalated in the past 20 years, with little relief for citizens or for the health of forests and the environment.

Response – The Division's BART determinations and other requirements under the regional haze program will result in large, state-wide emission reductions for three visibility-impairing pollutants; nitrogen oxides (NO_x), particulate matter (PM/PM_{10}), and sulfur dioxide (SO_2). As an example, BART controls at the Jim Bridger plant will result in a total annual reduction in potential NO_x emissions of approximately 13,500 tons per year.

VII.5 **Wind Power** – A commenter stated that Wyoming can readily replace aging coal-fired power plants with wind power to protect public health and to protect our national parks and wilderness areas.

Response – The BART program is designed to assess Best Available Retrofit Technology on existing sources of air pollution, including the existing power plants in the State. The Division's BART determinations will result in significant reductions in air pollutants from several power plants in Wyoming, but complete replacement of the power plants with an alternate source of energy is well beyond the scope of the BART program.

VII.6 **Pollution Reduction from Power Plants** – A commenter stated that Wyoming has an obligation to protect treasured public spaces by adhering to federal air quality laws. The State must reduce air pollutants from the old coal plants that are federally required to utilize the most advanced technical developments in ensuring that air pollution is minimized.

Response – The Division determined BART controls based on the five statutory factors developed by the EPA. Various control technologies were evaluated for each source subject to BART, including the "most advanced technical developments", but the ultimate BART determinations were made based on a full consideration of all five statutory factors in their entirety.

VII.7 **SCR Controls** – Several commenters stated that BART for NO_x control should be SCR for all plants.

Response – See responses to USDA Forest Service comments II.1 and II.6.

VIII. Analysis of Public Comments:

VIII.1 **SCR Controls** – Several commenters stated that BART for NO_x control should be SCR for all plants.

Response – See responses to USDA Forest Service comments II.1 and II.6.

IX. Decision:

On the basis of comments received during the public comment period, an analysis of those comments, and representations made by PacifiCorp, the Department of Environmental Quality has determined that the permit application filed by PacifiCorp complies with all applicable Wyoming Air Quality Standards and Regulations and that a BART permit will be issued for the Naughton Power Plant. All of the conditions proposed in the Division's analysis will be included in the permit. No permit conditions required revision as a result of the public comment period.

Dated this 31st day of December, 2009.

David A. Finley
Administrator
Wyoming Air Quality Division

John V. Corra
Director
Wyoming Department of Environmental Quality

APPENDIX A

VISIBILITY MODELING RESULTS (Baseline vs. LNB and SCR)

Figure 1
Modeled BART Impacts in Bridger Wilderness Area
Naughton and Jim Bridger Power Plants: 98th Percentile (delta-dv)

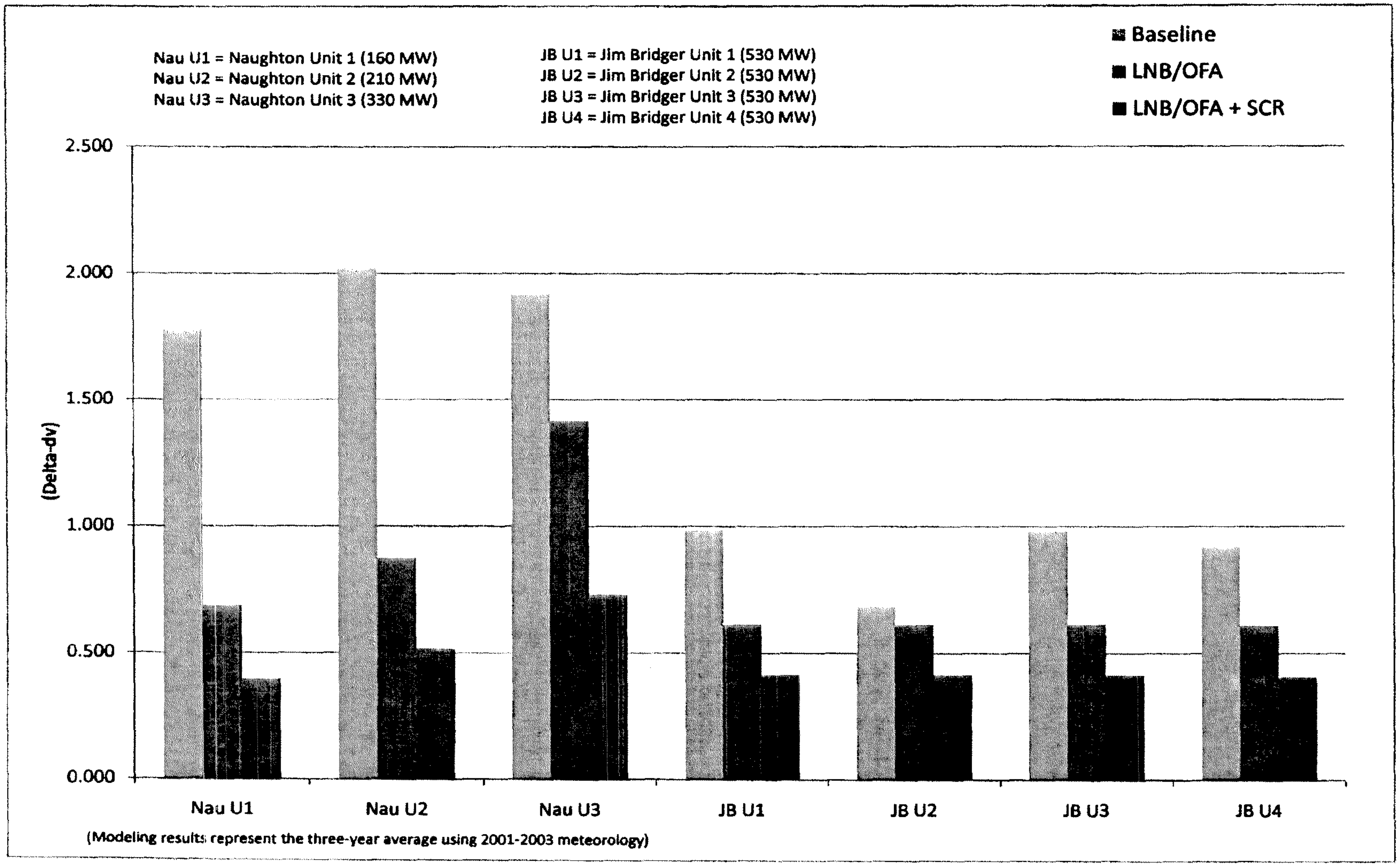
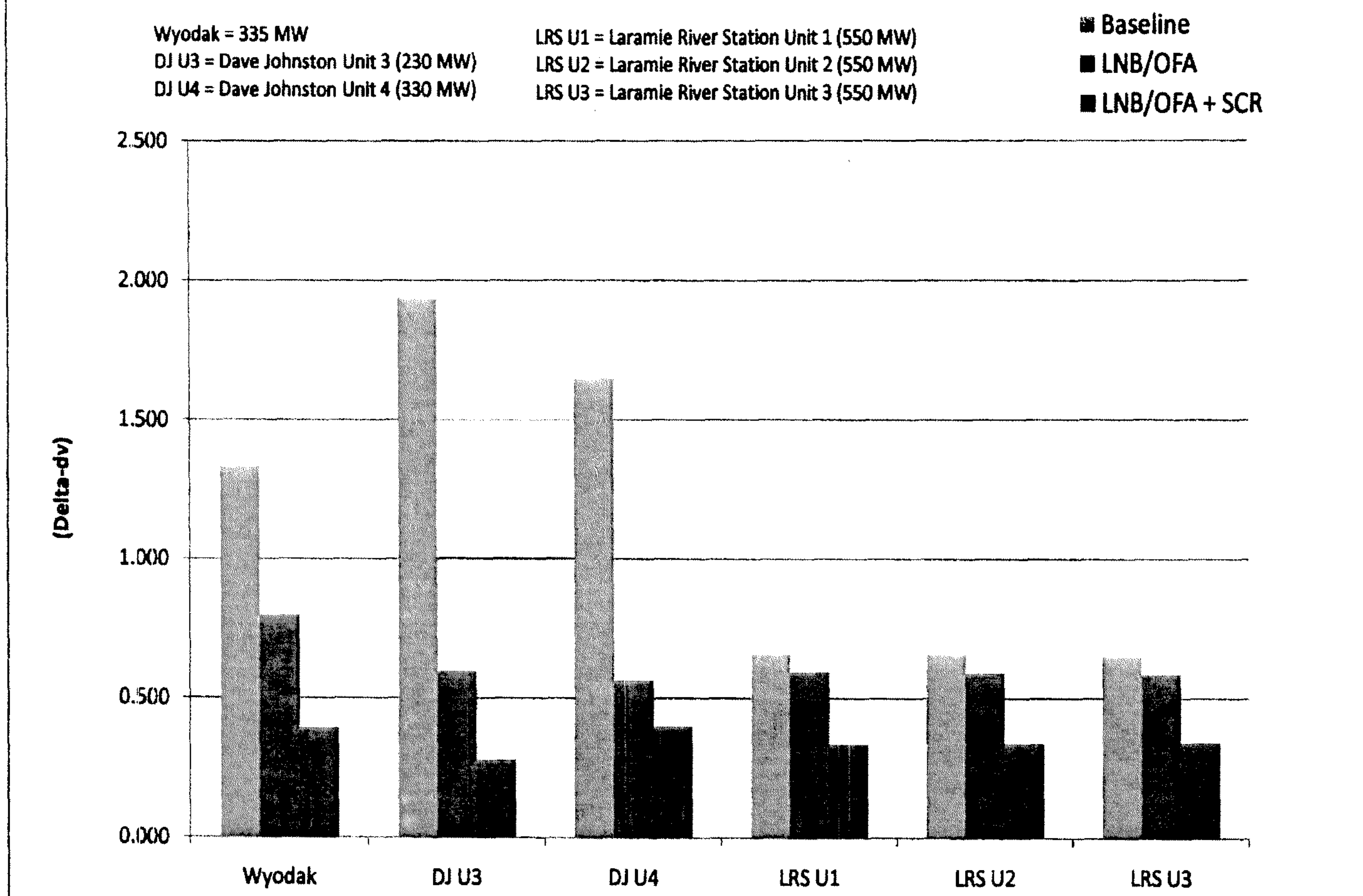


Figure 2
Modeled BART Impacts in Wind Cave National Park
Wyodak, Dave Johnston, and Laramie River Station Power Plants: 98th Percentile (delta-dv)



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

Figure 3
Modeled BART Impacts in Bridger Wilderness Area
Naughton and Jim Bridger Power Plants: # Days > 0.5 delta-dv

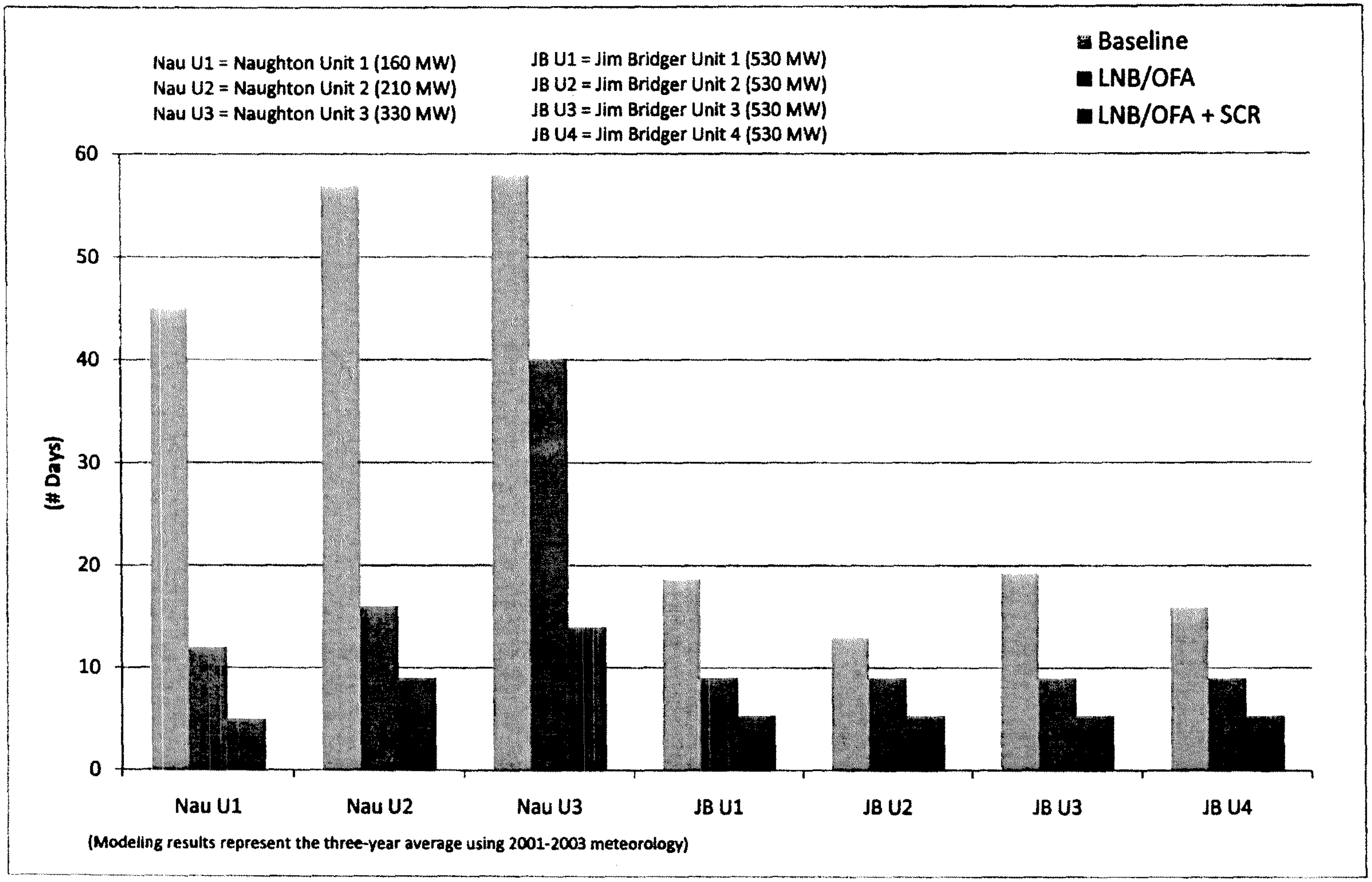
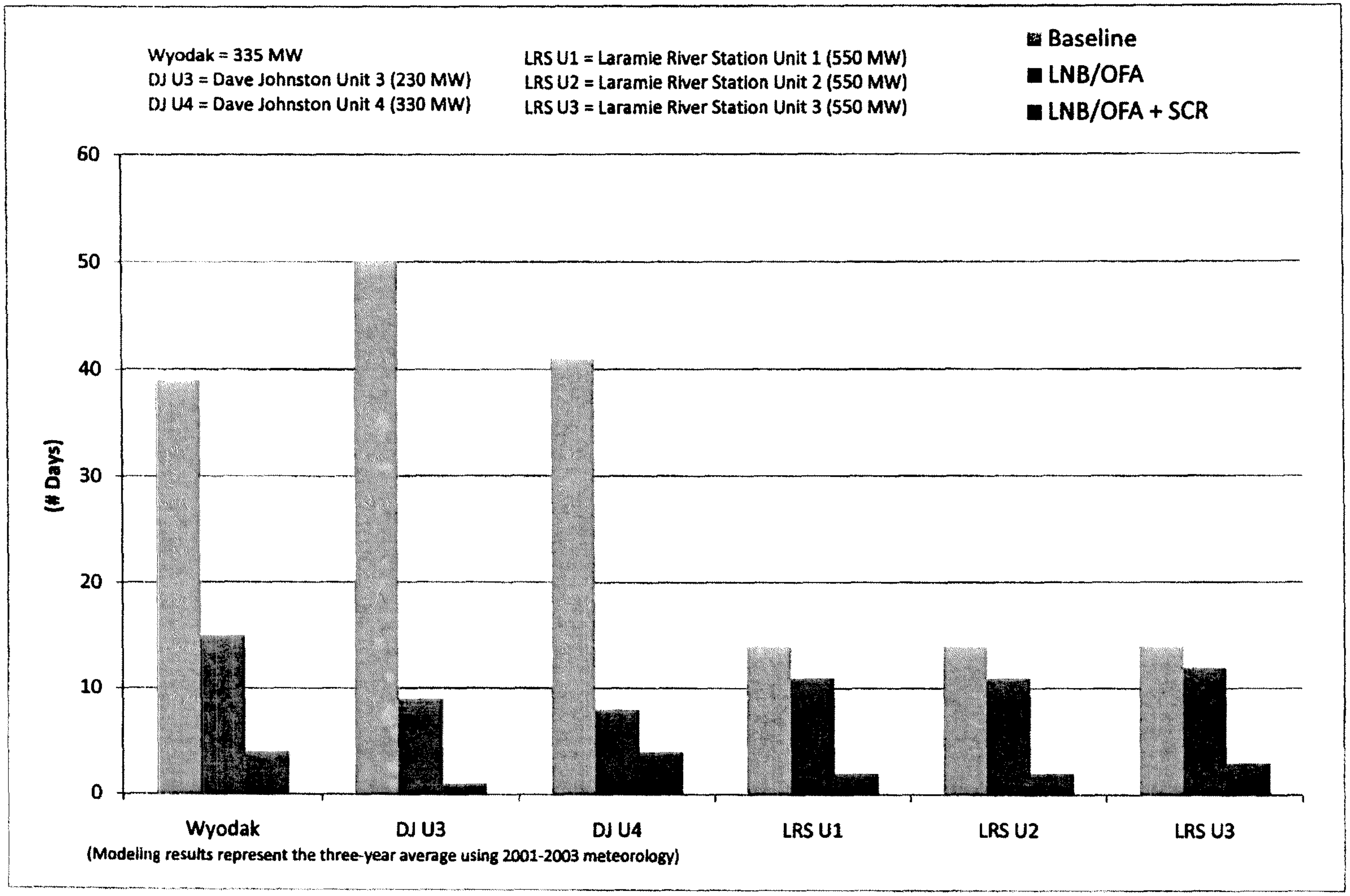


Figure 4
Modeled BART Impacts in Wind Cave National Park
Wyodak, Dave Johnston, and Laramie River Station Power Plants: # Days > 0.5 delta-dv



Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Dave Freudenthal, Governor

John Corra, Director

December 31, 2009

Mr. Robert Arambel
Managing Director
PacifiCorp
P.O. Box 158
Point of Rocks, WY 82942

Re: Air Quality Permit MD-6040
BART Permit: Jim Bridger Power Plant

Dear Mr. Arambel:

The Division of Air Quality of the Wyoming Department of Environmental Quality has enclosed a copy of the Best Available Control Technology (BART) permit for PacifiCorp's Jim Bridger Power Plant, dated December 31, 2009. Comments received during the public comment period and the public hearing were considered in the final permit. A copy of the decision document for the permit is also enclosed. No permit conditions required revision as a result of the public comment period.

If you have any questions, please feel free to contact this office.

Sincerely,

David A. Finley
Administrator
Air Quality Division

cc: Tony Hoyt/AQD Lander

RECEIVED
JAN 0 7 2010
M.M

Naughton Power Plant

Chapter 6, Section 2
Construction Permit Application

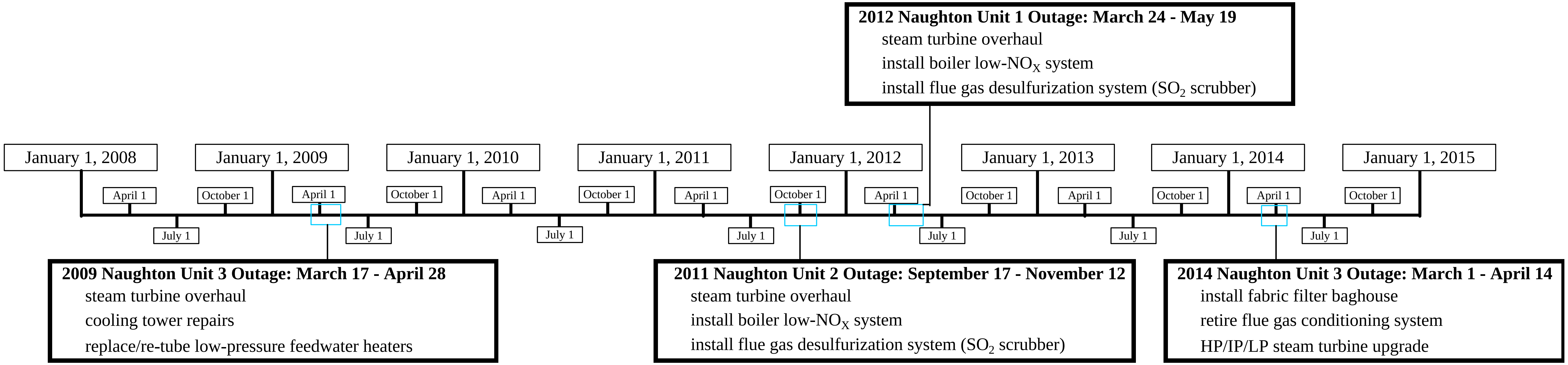
Submitted to the Wyoming Air Quality Division
And Prepared by

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

1407 West North Temple
Salt Lake City, Utah 84116

March 2008

Table 2.1: Naughton Project Schedule



<u>Major 2008 Projects</u>
- Install Unit 1 Flue Gas Conditioning System
- Install Unit 2 Flue Gas Conditioning System

<u>Major 2009 Activities</u>
- Overhaul Unit 3 Steam Turbine
- Repair Unit 3 Cooling Tower
- Replace or Re-Tube Low-Pressure Feedwater Heaters

<u>Major 2011 Projects</u>
- Overhaul Unit 2 Steam Turbine
- Install Unit 2 Low-NO_X System
- Install Unit 2 Flue Gas Desulfurization System (SO_2 Scrubber)

<u>Major 2012 Projects</u>
- Overhaul Unit 1 Steam Turbine
- Install Unit 1 Low-NO_X System
- Install Unit 1 Flue Gas Desulfurization System (SO_2 Scrubber)

<u>Major 2014 Projects</u>
- Upgrade Unit 3 HP/IP/LP Steam Turbine
- Install Unit 3 Fabric Filter Baghouse (Replace Existing Electrostatic Precipitator)
- Retire Unit 3 Flue Gas Conditioning System

Utah State Implementation Plan

Section XX

Regional Haze

Addressing Regional Haze Visibility Protection for the Mandatory Federal Class I Areas Required Under 40 CFR 51.309

Adopted by the Air Quality Board
April 6, 2011

TABLE OF CONTENTS

D. LONG-TERM STRATEGY FOR STATIONARY SOURCES

1. Regulatory History and Requirements

The Grand Canyon Visibility Transport Commission (GCVTC) studied the long-term projected changes of emissions from stationary sources. It was found that emissions of sulfur dioxide from stationary sources would decline by at least 13% between 1990 and 2000. Also, emissions of sulfur dioxide would continue to decline through 2040 when only 30% to 50% of the 1990 emission levels would remain. This decline was due to the normal turnover of source technology as older sources retire and are replaced by newer and cleaner technologies.

The GCVTC decided that the most appropriate way to address emissions of sulfur dioxide from stationary sources was to establish regional emission milestones and allow voluntary measures to achieve the emission reductions. If the emission milestones are not achieved, then a backstop market trading program would be implemented to guarantee the emission reductions are achieved. The GCVTC did not have sufficient time to develop the details of the emission milestones or backstop program, but committed to develop it and submit it to EPA.

In the 1999 Regional Haze Rule, EPA required the states to complete the development of the stationary source program for sulfur dioxide and to submit it as an Annex to the GCVTC recommendations. The WRAP submitted the Annex in September, 2000.[15] On June 5, 2003, EPA issued the final rules related to the sulfur dioxide program for stationary sources.[16] These rules incorporated the materials in the Annex.

EPA's approval of the Annex was challenged, and on February 18, 2005 the DC Circuit Court of Appeals vacated EPA's 2003 rules.[17] The Court determined that EPA had required a Best Available Retrofit Technology (BART) demonstration in the Annex that was based on a methodology that had been vacated by the Court in 2002.[18] On October

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[15] Western Regional Air Partnership. *Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and a Backstop Market Trading Program, An Annex to the Report of the Grand Canyon Visibility Transport Commission.* Denver, CO. September 29, 2000.

[16] 68 FR 33764.

[17] Center for Energy and Economic Development (CEED) vs. Environmental Protection Agency, February 18, 2005.

[18] American Corn Growers Association vs. Environmental Protection Agency, May 24, 2002.

13, 2006 EPA revised the regional haze rule to establish the methodology for states to develop an alternative to BART that was consistent with the Court's decision.[19]

2. Achievement of a 13% or Greater Reduction of Sulfur Dioxide Emissions by 2000

The GCVTC projected a 13% or greater reduction of sulfur dioxide (SO_2) emissions between the years of 1990 and 2000. As shown in Table 2, regional SO_2 emission totals show that there was a 25% reduction in these emissions from 1990 to 2000.[20] There was a 33% decrease in SO_2 emissions during this time period from the three states that developed SIPs under 40 CFR 51.309 (New Mexico, Utah, and Wyoming, excluding emissions from sources in those states that are under tribal jurisdiction).

Table 2. State-by-State Comparison of 1990 and 2000 Stationary Source Sulfur Dioxide Emissions in the 9 GCVTC Transport Region States (tons per year)

States	**1990**	**2000**
Arizona	185,398	99,133
California	52,832	38,501
Colorado	95,534	99,161
Idaho	24,652	27,763
Nevada	52,775	53,943
New Mexico	177,994	117,344
Oregon	17,705	23,362
Utah	85,567	38,521
Wyoming	136,318	124,110
Totals	828,775	621,838

3. Strategy for Stationary Sources of Sulfur Dioxide

The long-term strategy for stationary sources implements the Grand Canyon Visibility Transport Commission (GCVTC) recommendation to develop regional sulfur dioxide (SO_2) milestones and a backstop trading program to ensure that the milestone goals are achieved. The GCVTC recommendations were further refined in an Annex to the Commission report that was submitted to EPA in September 2000.

The long-term strategy for stationary sources is implemented through the following documents:

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[19] 71 FR 60612

[20] E.H. Pechan & Associates, Inc. for the Western Governors' Association. *Year 2000 Point Source SO_2 Emissions Analysis - 9 State Western Region Report.* Denver, CO, May 2002.

- Sulfur Dioxide Milestones and Backstop Trading Program, Part E of this plan, describes the overall program and contains Utah's commitment to implement all parts of the program as outlined in the plan. The plan establishes the regional SO_2 milestones, emissions tracking requirements, and, if the Western Backstop SO_2 Trading Program (WEB Trading Program) is triggered, the plan also describes how Utah will determine allocations and manage the allowance tracking system that is needed to implement the program.

- R307-250, Western Backstop Sulfur Dioxide Trading Program, contains the requirements that will apply to major industrial sources of sulfur dioxide as a backstop regulatory program if the SO_2 milestones are exceeded. The rule may never be implemented if the goal to meet the regional SO_2 milestones through voluntary means is achieved. If the rule is implemented, it establishes the procedures and compliance requirements for sources in the trading program.

- R307-150 requires major industrial sources of SO_2 to submit an annual emissions inventory in the pre-trigger phase of the program to measure compliance with the regional SO_2 milestones. If the backstop program is triggered, then these requirements will eventually be replaced by more rigorous monitoring requirements in R307-250.

a. 2018 Milestone

The 2018 milestone of 141,849 tons represents an emission reduction of approximately 216,515 tons of SO_2 from the 1990 baseline emissions of 358,364 tons for the three participating states, and is well on the way to the GCVTC's goal of a 50-70% reduction by 2040. The 2018 regional sulfur dioxide milestone provides for greater reasonable progress[21] than would be achieved by application of best available retrofit technology (BART) for SO_2, as required by 40 CFR 51.309(d)(4) for both the 16 Class I Areas on the Colorado Plateau and other Class I Areas that are affected by sources in the 3-state region that are subject to BART. The participating states estimated that BART reductions would total approximately 48,737 tons of SO_2 by 2018. In accordance with 40 CFR 51.309(g)(ii), no further demonstration will be needed prior to 2018 for Utah's stationary sources identified in the Annex, in terms of satisfying BART for SO2 under 40 CFR 51.308(e).

b. Interim Milestones

Interim milestones were set based on expected emission reductions that were already planned between 2003 and 2018. These milestones show steady and continuing emission reductions, with most of the emission reductions occurring by 2013.

[21] October 6, 2010 Demonstration that the SO2 Milestones Provide Greater Reasonable Progress than BART

c. Triggering the Trading Program

States and tribes will collect an annual SO_2 inventory. Compliance with the milestones is determined by an annual comparison of the rolling 3-year average of total regional emissions with the rolling 3-year average of the milestones. For 2018, total emissions will be compared with the 2018 milestone. If a milestone is exceeded, the trading program is activated and emission allocations are made one year later with sources having five years from the year of exceedance to comply with their allocation. Sources may comply by retrofitting to bring emissions below their allocation, by buying credits to emit from other sources, by retiring the source, or by other means.

d. Certainty that 2018 Milestone Will Be Met on Time

Part E of this Plan includes a mechanism for the states and tribes to activate the trading program in 2013 if available evidence indicates the 2018 milestone will not be reached. In order to be in compliance with the 2018 milestone, the 2018 emissions must be less than the 2018 milestone. Sources that have not controlled their emissions in accordance with their allocations will be subject to financial penalties.

e. Trading Program Features

Details of the backstop trading program such as applicability, monitoring and reporting, trading procedures, compliance requirements and penalties, are defined in R307-250. Sources that reduce their emissions below their allocation will be able to sell excess allowances to other sources, within certain programmatic restrictions.

f. Allocations

If the program is triggered, 2,500 tons of SO_2 allocations will be set aside for tribal interests, acknowledging that tribal lands are largely undeveloped and that tribes would not benefit from a plan based only on past emissions. There will be a new source set-aside to accommodate growth within the region. Existing sources will receive a "floor" allocation based on a "clean unit" emission rate. The remainder of the allowances, which will decline over the years, will be allocated to existing sources. If the program is triggered, sources may buy and sell allowances to come into compliance.

g. State and Tribal Opt-In or Opt-Out

In the event that any other states or tribes choose to participate in the regional trading program in the future the milestones will be adjusted through a SIP revision to reflect the changes.

4. Geographic Enhancement Program

40 CFR 51.308(e)(2) allows states to submit a SIP, or tribes a TIP, which adopts an alternative measure to regional haze BART. Geographic enhancement is a voluntary approach provided in Section 308(e)(2)(v) that can be included in the plan for addressing reasonably attributable visibility impairment (RAVI) for stationary sources, under the provisions of 40 CFR 51.302(c). RAVI is different from regional haze in that it

addresses “hot spots” or situations where visibility impairment in a Class I area is reasonably attributable to a single source or small group of sources in relatively close proximity to the Class I area. In December 2004, the State of Utah signed a Memorandum of Agreement (MOA) with the Federal Land Managers to provide sources greater certainty regarding their potential risk of being certified as a RAVI source by a Federal Land Manager. Sources can incorporate this information into their business planning process, and use the efficiencies and reduced costs of the market to address potential RAVI issues.

a. Procedure for addressing Reasonably Attributable Visibility Impairment under the Regional Haze Rule.

If the National Park Service certifies impairment, the State of Utah will fulfill its obligations to determine attribution and if necessary determine BART for the applicable source or group of sources in accordance with Utah's SIP for visibility protection submitted to EPA on April 26, 1985, and approved on May 30, 1986. Additional information regarding possible technical approaches for determining attribution is contained in the WESTAR report, *Recommendations for Making Attribution Determinations in the Context of Reasonably Attributable BART*.

5. Report on Assessment of NO_x/PM Strategies

a. Assessment of Need for NO_x and PM milestones.

The State of Utah has evaluated the need for NO_x and PM emission control strategies, the degree of visibility improvement expected, and whether such milestones are needed to avoid any net increase in these pollutants. This evaluation was based on an assessment of NO_x and PM stationary source emissions made by the WRAP Market Trading Forum for all WRAP states, including the transport region states.[22]

Several conclusions were reached based on the analyses.

- For the vast majority of Class I areas throughout the WRAP region, stationary source NO_x and PM emissions are not a major contributor to visibility impairment on the average 20% best and 20% worst days. However, on some of the worst days nitrates and PM are the main components of visibility impairment.
- Stationary source NO_x emissions are projected to increase by 4% between 1996 and 2018. Stationary source NO_x emissions probably cause 2% - 5% of the visibility impairment on the Colorado Plateau.
- Stationary source PM emissions are projected to increase by 29% between 1996 and 2018. Stationary source PM emissions probably cause less than 2% of the regional visibility impairment.

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[22] WRAP. *Stationary Source NOx and PM Emissions in the WRAP Region: An Initial Assessment of Emissions, Controls, and Air Quality Impacts.* Denver, CO. Presented to the WRAP Board October 15, 2003.

- The current regional modeling does a poor job of predicting nitrate concentrations in the winter when NO_x has the greatest impact on visibility impairment. The modeling also does a poor job of predicting the impact of localized fugitive dust impact. The WRAP is currently making significant improvements to the model and to the emission inventories to address these issues.
- There is a wide range of emission reduction techniques available to control NO_x and PM emissions, and many of the technologies are cost-effective. The current emission inventory does not contain enough information to determine what technologies are currently in place in the West and the cost of additional controls.
- RAVI remedies are available in cases where particular stationary sources may impact particular Class I areas.

The complete report is provided in the 2003 Utah TSD Supplement.

6. Best Available Control Technology (BART) Assessment for NO_x and PM.

a. Regional Haze Rule BART Requirements

Pursuant to 40 CFR 51.309(d)(4)(vii), certain major stationary sources are required to evaluate, install, operate and maintain BART technology or an approved BART alternative for NO_x and PM emissions. BART requirements can be addressed through a case-by-case review under 40 CFR 51.308(e)(1) or through an alternative program under 40 CFR 51.308(e)(2). The State of Utah has chosen to evaluate BART for NO_x and PM under the case-by-case provisions of 40 CFR 51.308(e)(1). BART for SO_2 is addressed through an alternative program under 40 CFR 51.309 that is described in Part E of this plan.

EPA issued guidelines for BART determinations on July 6, 2005 that are codified in Appendix Y to 40 CFR Part 51. These guidelines establish a three step process.

- States identify sources which meet the definition of BART eligible
- States determine which BART eligible sources are "subject to BART"
- For each source subject to BART States identify the appropriate control technology.

The determination of NO_x limits for fossil-fuel fired power plants having a total generating capacity greater than 750 megawatts must be made pursuant to the guidelines in 40 CFR 51 Appendix Y, Section E.5. [23]

[23] 40 CFR Part 51 Appendix Y Guidelines for BART Determinations under the Regional Haze Rule (70 FR 39158)

b. BART-Eligible Sources.

BART-eligible sources are those sources that fall within one of 26 specific source categories, were built during the 15-year window of time from 1962 to 1977, and have potential emissions of at least 250 tons per year of any visibility impairing air pollutant (40 CFR 51.301). Pursuant to 40 CFR 51.308 (e)(1)(i) a State is required to list all BART-eligible sources within the State.

Four BART-eligible electric generating units have been identified in the State of Utah: PacifiCorp's Hunter Units 1 and 2 and Huntington Units 1 and 2. The units are located at fossil-fuel fired steam electric plants of more than 250 million Btu per hour heat input, one of the 26 specific BART source categories. The units have potential emissions greater than 250 tons per year of a visibility impairing pollutant. The units had commenced construction within the BART time frame of August 7, 1962 to August 7, 1977.

Table 3. BART-Eligible Sources in Utah.

SOURCE	UNIT ID	SERVICE DATE	NET DEPENDABLE CAPACITY (MWn)	BART CATEGORY	COAL TYPE	BOILER TYPE
Hunter	1	1978	430	Fossil fuel fired	Bituminous	Tangential
Hunter	2	1980	430	Fossil fuel fired	Bituminous	Tangential
Huntington	1	1977	430	Fossil fuel fired	Bituminous	Tangential
Huntington	2	1974	430	Fossil fuel fired	Bituminous	Tangential

Note: Hunter Unit 3 commenced construction after 1977 and is therefore not BART-eligible.

c. Sources Subject to BART

Pursuant to 40 CFR 51.308(e)(1)(ii) the State is required to determine which BART-eligible sources are also "subject to BART." BART-eligible sources are subject to BART if they emit any air pollutant that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area.

PacifiCorp's Hunter Units 1 and 2 and Huntington Units 1 and 2 were determined by the State to be subject to BART. The State utilized the technical modeling services of the WRAP Regional Modeling Center (RMC). Modeling was performed according to the RMC modeling protocols[24]. For the WRAP BART exemption screening modeling, the RMC followed the EPA BART Guidelines in 40 CFR 51, Appendix Y and the applicable CALMET/CALPUFF modeling guidance (e.g., IWAQM, 1998; FLAG, 2000; EPA,

[24] CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States

2003c) including EPA's March 16, 2006 memorandum: "Dispersion Coefficients for Regulatory Air Quality Modeling in CALPUFF".[25]

The basic assumptions of the WRAP BART CALMET/CALPUFF modeling protocols are as follows:

- Three years of modeling (2001, 2002 and 2003) were used.
- Visibility impacts due to emissions of SO_2, NO_x and primary PM emissions were calculated
- Visibility was calculated using the Original IMPROVE equation and Annual Average Natural Conditions.
- The effective range of CALPUFF modeling was set at 300km from the sources
- For pre-control modeling, maximum 24-hour average actual emissions from the Acid Rain database were used in CALPUFF model.
- For post-control modeling, expected New Source Review (NSR) permitted limits were used in the CALPUFF model.

According to 40 CFR Part 51, Appendix Y, a BART-eligible source is considered to "contribute" to visibility impairment in a Class I area if the modeled 98th percentile change in deciviews is equal to or greater than the "contribution threshold." The State of Utah evaluated BART exemption screening modeling results at the EPA-suggested contribution threshold of 0.5 deciviews within a 300 Km radius of the BART-eligible sources.[26] BART-eligible sources Hunter Unit 1, Hunter Unit 2, Huntington Unit 1, and Huntington Unit 2 had a modeled impact greater than the threshold level of 0.5 change in deciviews in at least one of the seven Class I areas within a 300 km radius of the sources.

[25] Atkinson and Fox, 2006

[26] WRAP RMC BART Modeling for Utah Draft #6 April 21, 2007

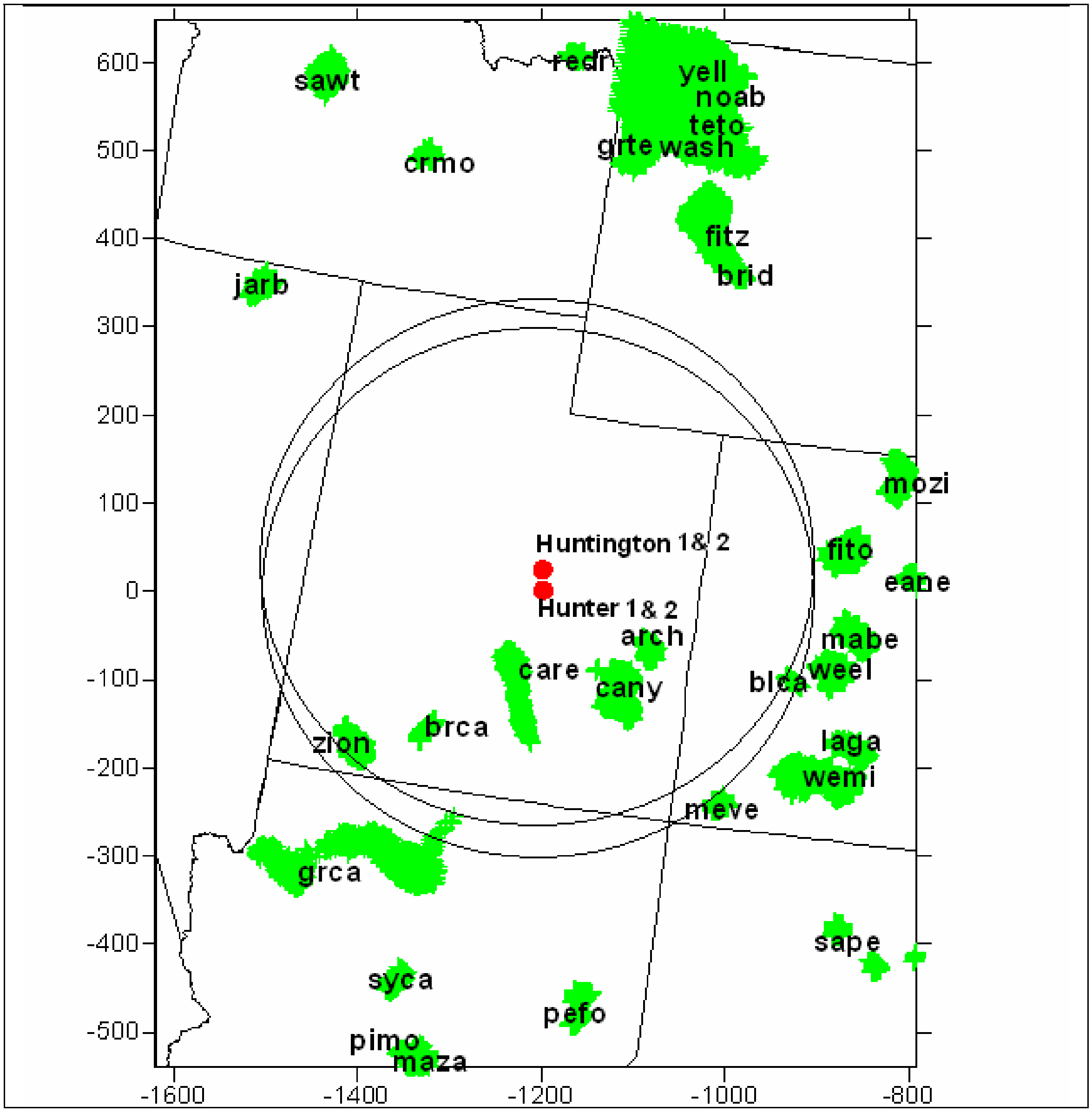

Figure 4. Relationship between Utah potential BART-eligible sources and Class I areas. Hunter Units 1 and 2 and Huntington Units 1 and 2 modeled separately at maximum 300 km.

Table 4. Subject to BART Modeling

	Subject to BART Modeling - 98th Percentile 3 year average Delta Deciview							
	Capitol Reef	Canyonlands	Arches	Bryce Canyon	Zion	Grand Canyon	Black Canyon Gunnison	Mesa Verde
Hunter 1	2.13	1.87	1.53	0.55	0.46	0.59	0.60	0.53
Hunter 2	1.89	1.62	1.36	0.47	0.41	0.52	0.53	0.47
Huntington 1	1.92	1.64	1.39	0.48	0.43	0.55	0.56	0.48
Huntington 2	2.43	2.26	1.89	.091	.078	.099	1.14	0.91

d. BART Determination

As required under 51.308 (e)(1)(A) the determination of BART must be based on an analysis of the best system of continuous emission control technology available. In the analysis the State must take in to account five factors:

- Available technology
- Costs of compliance
- Energy and non-air quality environmental impacts
- Existing control equipment and the remaining useful life of the facility
- The degree of improvement in visibility reasonably anticipated to result from the use of such technology

PacifiCorp has installed or has received permits to install the following retrofit control equipment at the Hunter Unit 1, Hunter Unit 2, Huntington Unit 1, and Huntington Unit 2 fossil fuel fired electric generating units (EGU):

Hunter Units 1 and 2:

- Conversion of existing electrostatic precipitators to pulse jet fabric filter bag-houses
- The replacement of existing, first generation low-NO_x burners with Alstom TSF 2000TM low-NO_x firing system and installation of two elevations of separated overfire air.
- Upgrade of existing flue gas desulfurization system to > 90% sulfur dioxide removal.

Huntington Units 1 and 2:

- Conversion of existing electrostatic precipitators to pulse jet fabric filter bag-houses
- The replacement of existing, first generation low-NO_x burners with Alstom TSF 2000TM low-NO_x firing system and installation of two elevations of separated overfire air.
- Installation of a new wet-lime, flue gas de-sulfurization system at Unit 2 (FGD).
- Upgrade of existing flue gas desulfurization system to > 90% sulfur dioxide removal at Unit 1.

Table 5. Emissions Rates (lb/MMBtu) for the Retrofitted Hunter and Huntington Units

Units		Utah Permitted Rates[27]			Presumptive BART Limits[28]	
Rate: lb/MMBtu		SO2	NOx	PM	SO2	NOx
Hunter 1		0.12	0.26	0.05	0.15	0.28
Hunter 2		0.12	0.26	0.05	0.15	0.28
Huntington 1		0.12	0.26	0.05	0.15	0.28
Huntington 2		0.12	0.26	0.05	0.15	0.28

Table 6. Change in Emissions (tons/yr) for Retrofitted BART Units

Unit	Pre-Control SO_2	Pre-Control NOx	Pre-Control PM_{10}	Post-Control SO_2	Post-Control NO_x	Post-Control PM_{10}	Delta SO_2	Delta NO_x	Delta PM_{10}
Hunter 1	2741	6833	533	2239	4851	280	-502	-1981	-253
Hunter 2	2425	5922	533	2185	4734	273	-240	-1187	-260
Huntington 1	2538	5676	444	2052	4445	256	-486	-1231	-188
Huntington 2	13703	5582	443	1743	3776	218	-11960	-1806	-225
TOTALS	**21,407**	**24,013**	**1,953**	**8,219**	**17,807**	**1,027**	**-13,189**	**-6,206**	**-926**

Pursuant to 51.308(e)(1)(C)(iv) each source subject to BART is required to install and operate BART no later than 5 years after approval of the implementation plan. The PacifiCorp schedule for the four EGUs at Huntington and Hunter sources is as follows.

Source	**Notice of Intent Submitted**	**Permit Issued**	**Estimated In Service Date**
Hunter 1	June 2006	March 2008	Spring 2014
Hunter 2	June 2006	March 2008	Spring 2011
Huntington 1	April 2008	August 2009	Fall 2010
Huntington 2	October 2004	April 2005	Dec 2006

EPA under the BART Rule requires coal-fired electric generating plants of greater than 750 MW to meet BART presumptive limits. While EPA considers presumptive limits to be appropriate for all coal-fired power plants greater than 750 MW, the State may establish different requirements if the State can demonstrate that an alternative is justified based on a consideration of the five BART factors.

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[27] Utah Division of Air Quality Approval Orders: Huntington Unit 2 - AN0238012-05, Huntington Unit 1 - DAQE-AN0102380019-09 (note – on January 19, 2010 an administrative amendment was made to the 2009 AO), Hunter Units I and 2 - DAQE-AN0102370012-08

[28] 40 CFR Part 51 Appendix Y Guidelines for BART Determinations under the Regional Haze Rule (70 Federal Register 39135)

> "States, as a general matter, must require owners and operators of greater than 750 MW power plants to meet these BART emission limits… a State may establish different requirements if the State can demonstrate that an alternative determination is justified based on a consideration of the five statutory factors."[29]
>
> "For Coal-fired EGU's greater than 200 MW located at greater than 750 MW power plants and operating without post-combustion controls (i.e. SCR or SNCR), we have provided presumptive NOx limits, differentiated by boiler design and type of coal burned. You may determine that an alternative control level is appropriate based on careful consideration of the statutory factors." (Appendix Y Part 51 – IV (E)(5).[30]

EPA determined presumptive limits for SO_2 and NO_x for EGUs based on a methodology equivalent to that required in 50 CFR 51 Appendix Y for BART Rule. The EPA determination of presumptive limits included:

- Identification of all potential BART-eligible EGUs (all BART-eligible EGU's were assumed to be Subject to BART)
- Technical analyses and industry research to determine applicable and appropriate SO_2 and NO_x control options,
- Economic analysis to determine cost effectiveness for each potentially BART-eligible EGU
- Evaluation of historical emissions and forecast emission reductions for each potentially BART-eligible EGU[31].
- NOx and SO_2 CALPUFF modeling of emission impacts at model Class I area.

> The analysis included 491 potential BART EGUs including Hunter Units 1 and 2 and Huntington Units 1 and 2. The technical analysis conducted by EPA to determine presumptive BART limits for SO_2 and NO_x is in effect a BART determination analysis for 419 EGUs including Hunter Units 1 and 2 and Huntington Units 1 and 2.[32]

Section IV (E) (5) of Appendix Y Part 51 clearly requires the implementation of presumptive NOx limits for coal-fired EGU's greater than 200 MW located at greater than 750 MW power plants. Under Appendix Y, states are given the discretion to

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[29] Ibid. (70 Federal Register 39131).

[30] 70 Federal Register 39171

[31] Ibid. (70 Federal Register 39134)

[32] "Methodology for Developing BART NOx Presumptive Limits" EPA Clean Air Market Division June 15, 2005 HQ-OAR-2002-0076-0445 and "Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet, Memorandum April 15, 2005 HQ-OAR-2002-0076-0369

challenge presumptive limits through a five factor analysis, but presumptive limits were developed by EPA as a reasonable, equivalent and mandated substitution for a five factor analysis.[33]

Utah's long-standing Prevention of Significant Deterioration (PSD) permitting program (SIP Section VII and R307-405), New Source Review permitting program (SIP Section II and R307-401) and Visibility program (SIP section XVII and R307-406) will continue to protect Class I area visibility by requiring best available control technology for new sources, and assuring that there is not a significant degradation in visibility at Class I areas due to new or modified major sources.

E. SULFUR DIOXIDE MILESTONES AND BACKSTOP TRADING PROGRAM

1. Milestones and Determination of Program Trigger

a. Regional Sulfur Dioxide Milestones

(1) Milestone Values.

The regional sulfur dioxide (SO_2) milestones for the years 2008 through 2018 are provided in Table 7. The milestones will be adjusted annually as described in paragraph E.1.a(2) of this plan.

Table 7. Sulfur Dioxide Emissions Milestones

For the year	the regional sulfur dioxide milestone is	and the annual SO_2 emissions for these years will determine whether emissions are greater than or less than the milestone
2008[34]	269,083 tons SO_2	Average of 2006, 2007 and 2008
2009	234,903 tons SO_2	Average of 2007, 2008 and 2009
2010	200,722 tons SO_2	Average of 2008, 2009 and 2010
2011	200,722 tons SO_2	Average of 2009, 2010 and 2011
2012	200,722 tons SO_2	Average of 2010, 2011 and 2012
2013	185,795 tons SO_2	Average of 2011, 2012 and 2013
2014	170,868 tons SO_2	Average of 2012, 2013 and 2014
2015	155,940 tons SO_2	Average of 2013, 2014 and 2015
2016	155,940 tons SO_2	Average of 2014, 2015 and 2016

[33] CFR Part 51 Appendix Y Guidelines for BART Determinations under the Regional Haze Rule (70 Federal Register 39171)

[34] The 2006 and 2007 annual milestones that are used to calculate the 2008 3-year average milestone in Table 8 have been adjusted to include only the three states that are part of the regional backstop trading program using the adjustment methodology in the 2003 Regional Haze SIP

For the year	the regional sulfur dioxide milestone is	and the annual SO_2 emissions for these years will determine whether emissions are greater than or less than the milestone
2017	155,940 tons SO_2	Average of 2015, 2016 and 2017
2018	141,849 tons SO_2	Year 2018 only
2019 forward, until replaced by an approved SIP	141,849 tons SO_2	Annual; no multiyear averaging

(2) Milestone Adjustments.

(a) All milestone adjustments will require a SIP revision. Paragraph E.1.c(3) of this plan outlines adjustments to be made to the emissions inventory to ensure a consistent comparison to the milestones. These adjustments will be incorporated into the milestones every five years as part of the periodic implementation plan revisions required by 40 CFR 51.309(d)(10). Adjustments to the milestones will be tracked in the annual emissions report described in paragraph E.1.c(4) of this Plan.

(b) Within ninety days of adoption by the Utah Air Quality Board of the periodic Implementation Plan revision incorporating adjustments based on paragraph E.1.c(3) or (4) of this Plan, the State of Utah will provide notice to sources whose records were used to calculate the adjustments, including the date of the SIP adoption and a statement that the source needs to retain the applicable records for at least five years from the date that the SIP was adopted, or ten years from the date of establishing the record, whichever is longer.

(c) Opt-in Provisions for States and Tribes. The regional milestones in Table 7 were developed for a 3-state region: New Mexico, Utah, and Wyoming. Other western states and tribes may choose to join this backstop trading program in the future. The addition of a state or tribe to the program will require a SIP/TIP revision of all participating states and tribes to adjust the regional milestones, and will not occur automatically. Any state or tribe that wishes to opt in to the program will propose milestone adjustments to the participating states and tribes using the same methodology that was used to develop the milestones in Table 7. A new participant must agree to develop a SIP and backstop trading rule that is consistent with those adopted by the other participating states and tribes.

b. Regional Program Administration

(1) Pre-trigger tracking of regional SO_2 emissions.

The executive secretary will work cooperatively with the states and tribes that are participating in the SO_2 Milestones and Backstop Trading Program to ensure that an emission tracking system for the regional SO_2 inventory is developed and maintained.

The executive secretary is responsible for all regional program administration functions as described in this plan. The executive secretary will perform these functions using the WRAP as the executive secretary's agent. The Western Regional Air Partnership (WRAP) compiled the SO_2 emission inventories that were used during the development of the Annex and subsequent SIP revisions, and the WRAP continues to refine and improve the overall tracking system for regional haze. The WRAP will maintain the pre-trigger emissions tracking functions described in this plan for the foreseeable future. If the WRAP is no longer able to fulfill this function, then the executive secretary will ensure that other arrangements are made, either through a different regional organization or through a contractor, to maintain the SO_2 tracking system that is described in this plan. The WRAP has no authority to make regulatory determinations. The WRAP has limited authority under this plan to perform tracking and accounting functions, prepare reports, and perform other administrative functions as directed by the executive secretary. The executive secretary will work expeditiously to correct any problems if the WRAP fails to perform any of the functions described in this plan in a timely manner.

(2) Designation of the Tracking System Administrator.

If the backstop trading program is triggered due to an exceedance of the SO_2 milestones as outlined in Part E.1.c of this plan, the executive secretary will work cooperatively with the other participating states and tribes to designate one Tracking System Administrator (TSA). The TSA will be designated as expeditiously as possible, but no later than six months after the program trigger date. In addition, before the TSA is designated, the executive secretary will enter into a binding contract with the TSA that will require the TSA to perform all TSA functions described in this plan. The State of Utah has sufficient authority under State contract law to ensure that the functions in this plan are carried out by the TSA.

(3) Information Provided by other States and Tribes.

The executive secretary will accept the emission inventory and permitting information provided by the other participating states and tribes in order to determine the milestone value and program trigger if such other states and tribes have provided proper documentation and followed the public notification process in their federally approved implementation plans.

c. Determination of Program Trigger

(1) The executive secretary will submit an annual emissions report to the WRAP and all participating states and tribes by September 30 of each year. The report will document actual sulfur dioxide emissions during the previous calendar year for all sources subject to the Sulfur Dioxide Milestone Inventory requirements of R307-150. The first report for calendar year 2003 was submitted in 2004. If the WEB Trading Program is triggered as outlined in paragraph E.1.c(10) of this plan, annual reports will be prepared during the interim period for informational purposes until the trading program is fully implemented. The executive secretary will prepare the supporting documentation that is included with the annual emissions report as noted in (2) and (3) below.

(2) The annual emissions report for Utah will include a source emissions change report that contains the following information:

(a) identification of any new sources that were not contained in the previous calendar year's emissions report, and an explanation of why the source is now included in the program;

(b) identification of any sources that were included in the previous year's report and are no longer included in the program, and an explanation of why this change has occurred; and

(c) an explanation for increases or decreases of emissions at any applicable source of more than twenty percent from the previous year.

(3) The annual emissions report for Utah will include the proposed emissions adjustment to ensure a consistent comparison to the milestones. Actual emission inventories for sources that change the method of monitoring or calculating their emissions will be adjusted to be comparable to the emission monitoring or calculation method that was used in the 2006 base year inventory.

(4) The annual sulfur dioxide milestone and emissions report for Utah will document any adjustments that should be made to the milestone for the previous year as follows.

(a) Changes due to enforcement actions.

(i) Adjustments due to settlements arising from enforcement actions. Adjustments to the milestones will be made, as specified in subsection (iii) below, if:

(A) an agreement to settle an action, arising from allegations of a failure of an owner or operator of an emissions unit at a source in the program to comply with applicable regulations which were in effect during the base year, is reached between the parties to the action;

(B) the alleged failure to comply with applicable regulations affects the assumptions that were used in calculating the source's base year and forecasted sulfur dioxide emissions; and

(C) the settlement includes or recommends an adjustment to the milestones.

(ii) Adjustments due to administrative or judicial orders. Adjustments to the milestones will be made as directed by any final administrative or judicial order, as specified in (iii) below. Where the final administrative or judicial order does not include a reforecast of the source's baseline, the executive secretary will evaluate whether a reforecast of the source's baseline emissions is appropriate.

(iii) Adjustments method and effective dates. The milestone will be decreased by an appropriate amount based on a reforecast of the source's decreased sulfur dioxide emissions. The adjustments will not be made to the milestone until after the source has reduced its sulfur dioxide emissions as required in the settlement agreement, or administrative or judicial order.

(iv) Documentation of adjustments for enforcement actions. The report will include the following documentation of any adjustment due to an enforcement action or a settlement agreement:

(A) identification of each source in Utah that has reduced sulfur dioxide emissions pursuant to a settlement agreement or an administrative or judicial order;

(B) for each source identified, a statement indicating whether the milestones were adjusted in response to the enforcement action;

(C) discussion of the rationale for the executive secretary's decision to adjust or not to adjust the milestones; and

(D) if SO_2 emissions reductions over and above those reductions needed for compliance with the applicable regulations were part of an agreement to settle an action, a statement indicating whether such reductions resulted in any adjustment to the milestones or allowance allocations, and a discussion of the rationale for the executive secretary's decision on any such adjustment.

(v) The State of Utah will include all accumulated milestone adjustments due to enforcement actions or settlement agreements in the periodic SIP revisions required under 40 CFR 51.309(d)(10).

(5) Compilation of Reports.

(a) The WRAP will compile the annual emissions reports submitted by all participating states and tribes into a draft regional emission report for sulfur dioxide. The WRAP will follow additional quality assurance procedures developed by member states and tribes to identify possible errors in the emissions data, including screening for missing or added sources, name changes, and significant changes in reported emissions. Any questions or anomalies regarding

Utah's report will be resolved by the executive secretary prior to the submission of the draft regional emission report.

(b) By December 31 of each year, the WRAP will submit the draft regional emission and milestone report to the executive secretary and all participating states and tribes and will post the report on the WRAP's web page. The report will include the following information:

(i) actual regional sulfur dioxide emissions in tons per year;

(ii) adjustments to account for changes in emission monitoring or calculation methods;

(iii) average adjusted emissions for the last three years for comparison to the regional milestone, if adjustments were made; and

(iv) regional milestone adjustments due to enforcement actions or settlement agreements.

(6) The executive secretary will evaluate the draft regional emissions report and will propose a draft determination that the sulfur dioxide milestone has either been met in the region, or has been exceeded. In the event that the WRAP has not submitted a draft regional emissions and milestone report to the executive secretary by the December 31 deadline for any year, the executive secretary will prepare the report for that year based upon the annual emissions reports submitted by all participating states and tribes to the WRAP for that year. The executive secretary will modify the data in these annual emissions reports, or use data where such report(s) have not been submitted, based upon direction received from the Environmental Protection Agency.

(7) The executive secretary will advertise availability of the draft regional emissions report and will notify the public of the draft determination by publishing a notice in newspapers of general circulation throughout Utah. A 30-day public comment period will be established, and a public hearing will be held during the public comment period. The executive secretary will also submit the draft determination to EPA for review and comment concurrently.

(8) The executive secretary will consider any comments received during the comment period, and will submit a copy of all comments to the WRAP and to all participating states and tribes along with a response that addresses the comments.

(9) The WRAP will compile the comments and responses from all participating states and tribes and prepare a draft final regional emissions report. The report will be submitted to the states and tribes that are participating in the program and, if necessary, the report will propose a common program trigger date.

(10) The executive secretary will review and approve the final regional emissions report. The executive secretary will then submit this report to the Environmental Protection Agency along with a final determination that the milestone either has been met in the region, or that the milestone has been exceeded and the WEB Trading Program has been triggered in Utah. This determination will be submitted to the Environmental Protection Agency by the end of March, fifteen months following the milestone year. The first determination was submitted in 2005, for the 2003 milestone. If the milestone has been exceeded, the common trigger date proposed in the regional report will become the program trigger date for purposes of implementing the WEB Trading Program. In the event that the program trigger date must be established by the executive secretary in the absence of a regional emissions and milestone report prepared by the WRAP, the program trigger date will be March 31 of the applicable year.

(11) The executive secretary will publish a notice of the final determination in newspapers of general circulation throughout the state of Utah. This notice will include the milestone and the final annual regional SO_2 emissions for that year. If the milestone has been exceeded, the notice will specify the program trigger date and the first year that WEB sources must be in compliance with the WEB Trading Program provisions as outlined in R307-250-12.

d. Year 2013 Assessment

(1) Initial Assessment in 2013 Periodic SIP Review.

(a) The executive secretary will work cooperatively through the WRAP with other participating states and tribes to develop a projected emission inventory for SO_2 through the year 2018, using the 2010 regional inventory as a baseline. This projected inventory will be included in the 2010 annual emission and milestone report that will be completed in March 2012 as outlined in paragraph E.1.c of this plan.

(b) The executive secretary will evaluate the projected inventory, and based upon this information will make an assessment of the likelihood of meeting the regional milestone for the year 2018. The executive secretary will include this assessment as part of Utah's progress report that must be submitted by December 31, 2013, as required by 40 CFR 51.309(d)(10).

(2) Regional Emissions Report for 2012.

(a) The executive secretary will prepare an SO_2 emission report for the year 2012 by September 30, 2013, as described in paragraph E.1.c(1) of this plan. The executive secretary will include a list of all known or anticipated sources in Utah that are anticipated to affect total SO_2 emissions in 2018. This may include permitted sources, projects that are still in the planning stage, or projections from the affected sources of anticipated emissions in 2018. The status of these projects will be described to provide a better understanding of the degree of certainty that individual projects will be completed by 2018.

(b) The WRAP will compile the information from all participating states and tribes, prepare draft SO_2 inventory projections for the year 2018, and estimate the effect of known future sources on SO_2 emissions. Projected 2018 emissions will be compared to the 2018 milestone. This information will be included in the draft regional emissions report for 2012 that will be submitted to the executive secretary by December 31, 2013, as outlined in paragraph E.1.c(5) of this Plan. The draft report will be published on the WRAP web site for a period of public review and comment for not less than 30 days.

(3) Consensus Decision.

The executive secretary commits to meet with the participating states and tribes in March 2014 to discuss any comments received on the 2018 emission projections in the draft report. The participating states and tribes will decide, through a consensus process, whether it is necessary to trigger the WEB trading program early in order to meet the SO_2 emission reduction goals in 2018.

(4) Early Trigger: Timing.

If the participating states and tribes unanimously decide in the March 2014 meeting that an early trigger of the backstop trading program is necessary, the executive secretary will trigger the WEB Trading Program and the timing of the program elements will be adjusted as follows to ensure that the WEB Trading Program is in place in 2018.

(a) The date of the consensus decision by the participating states and tribes to voluntarily trigger the WEB trading program will become the program trigger date.

(b) Allowances for 2018 will be distributed to WEB sources by January 1, 2015.

(c) The first control period will be the year 2018. WEB sources will need to demonstrate at the end of the first control period that they have enough allowances to cover their 2018 SO_2 emissions.

(5) Public Notification.

The executive secretary will publish notice of the decision in newspapers of general circulation in Utah. If applicable, the notice will include a statement that the WEB Trading Program is in effect and will specify the program trigger date.

e. Special Penalty Provisions for the 2018 Milestone

If the WEB Trading Program is triggered as outlined in paragraph E.1.c of this Plan, and the first control period will not occur until after the year 2018, a special penalty will be assessed if the 2018 milestone is exceeded.

Details of the penalty provisions for violation of the 2018 milestone can be found in R307-250-13. In general, the penalty involves an assessment of the minimum $5,000 per ton of SO_2 emissions in excess of the WEB source's allowance limitation. The source can resolve its excess emissions violation by agreeing to the streamlined settlement approach outlined in R307-250-13.

The amount of the minimum monetary penalty in R307-250-13 will be evaluated at each five-year SIP review, and adjusted if needed, to ensure that the penalty per ton substantially exceeds the expected cost of allowances to ensure that this remains a stringent penalty.

The 2018 special penalty provision will continue to be applied each year after 2018 until the 2018 milestone has been achieved.

2. Pre-Trigger Emissions Tracking Requirements

a. SO_2 Emission Inventory

40 CFR 51.309 sets forth emissions inventory requirements for tracking compliance with the SO_2 milestones. R307-150 has been revised to supplement Utah's inventory requirements to satisfy the needs of this program.

(1) Applicability. The sulfur dioxide milestone inventory requirements of R307-150 require all stationary sources with actual emissions of 100 tons per year or more of SO_2 in the year 2000, or in any subsequent year, to submit an annual inventory of SO_2 emissions, beginning with the 2003 emission inventory. A source that meets these criteria and then emits less than 100 tons per year in a later year must continue to submit an SO_2 inventory for tracking compliance with the regional SO_2 milestones until 2018 or until the WEB Trading Program has been fully implemented and emission tracking is occurring under R307-250-9, whichever is earlier.

(2) R307-150 contains enforceable requirements for WEB sources.

(a) Each source will submit an annual inventory of SO_2 emissions.

(b) Each source will use appropriate emission factors and estimating techniques and document the emissions monitoring or estimation methodology used.

(c) Each source will include emissions from start up, shut down, and upset conditions in the annual total inventory.

(d) Each source subject to the federal acid rain program will use methods from 40 CFR Part 75 to report emissions from all sources.

(e) Each source will include the rate and period of emissions, the specific installation that is the source of the air pollution, composition of air contaminant, type and efficiency of the air pollution control equipment and other information necessary to quantify operation and emissions, and to evaluate pollution control.

(f) Each source will retain records for a minimum of 10 years from the date of their creation, or if the record was the basis for an adjustment to a milestone, 5 years from the date of an implementation plan revision, whichever is longer.

(3) The executive secretary will quality-assure the submitted inventory data as outlined in the Inventory Preparation Plan. The executive secretary will screen the inventories to identify changes in emission measurement techniques that would require an inventory and milestone adjustment as outlined in paragraph E.1.c(3) of this Plan.

(4) The executive secretary will retain historical emission inventory records for non-utilities from 2006 that may affect milestone calculations under paragraph E.1.c(3) and allocation decisions under paragraph E.3.a of this plan until the year 2018 to ensure that changes in emissions monitoring techniques can be tracked.

b. Development of Emission Tracking System

The executive secretary will work cooperatively with the WRAP to ensure that an emission tracking system for the regional SO_2 inventory is developed and maintained.

c. Periodic Audit of Pre-Trigger Emission Tracking Database

(1) During the pre-trigger phase when the executive secretary is tracking compliance with the regional SO_2 milestones, the executive secretary will work cooperatively with the participating states and tribes to ensure that an independent audit of the tracking database is conducted to make sure that the WRAP is accurately compiling the regional emissions report.

(a) The first audit will occur during the year 2006 and will review data collected during the first two years of the program.

(b) Subsequent audits will occur in 2011, which will cover emissions years 2005-2009, and 2016, which will cover emissions years 2010-2014.

(2) The primary focus of the audit will be the process that is used to compile the regional inventory from the data provided by each state and tribe, and the tracking of accumulated changes during the period between SIP revisions. The audit will also review the accuracy and integrity of the regional reports that are used to determine compliance with the milestones. The audit will not be a full review of Utah’s process for compiling and reporting SO_2 emissions, but will include a broad review of Utah’s inventory management and quality assurance systems, including the presence and exercise of systems to assure data quality and integrity.

(3) The audit will discuss the uncertainty of emissions calculations, and whether this uncertainty is likely to affect the annual determination of whether the milestone is exceeded. It will identify any recommended changes to emissions monitoring or calculation methods or data quality assurance systems. It will also review and recommend any changes to improve the administrative process of collecting the annual emissions data at the state and tribal level, compiling a regional emission inventory, and making the annual determination of whether the WEB Trading Program has been triggered.

(4) Changes to the SO_2 Milestones and Backstop Trading Program, including any changes to the milestones due to the results of these periodic audits, will be submitted to EPA as a SIP revision as part of the five-year SIP review required by 40 CFR 51.309(d)(10).

(5) The executive secretary will advertise the availability of the draft audit report by publishing a notice in newspapers of general circulation in Utah. A 30-day public comment period will be established, and a hearing will be held during the public comment period. The executive secretary will respond to comments and provide notice of the availability of the final audit report. The executive secretary will submit the final audit report to the EPA regional office.

3. WEB Trading Program Requirements

a. Initial Allocation of SO_2 Allowances

(1) Draft Allocation Report.

Within six months of the program trigger date, as outlined in paragraph E.1.c(11) of this plan, the executive secretary will submit a draft allocation report to all participating states and tribes and to the TSA. This report will contain the following information:

(a) A list of all WEB sources in Utah as defined in R307-250-2 that groups the sources into two categories:

(i) Category 1: WEB sources that commenced operation prior to January 1, 2008. These sources will receive a floor allocation and will be eligible for the reducible portion of the allocation.

(ii) Category 2: WEB sources that commenced operation on January 1, 2008 or a later date. These sources will receive a floor allocation, but will not be eligible for the reducible allocation. The floor allocation for Category 2 sources will be deducted from the new source set-aside.

WEB sources that have received a retired source exemption under R307-250-4(4) will be included in the allocation process in the same manner as WEB sources that are currently operating. However, sources that were permanently shut down prior to the program trigger date are not considered WEB sources under R307-250-4(1) and would therefore not be included in the allocation process.

(b) The floor allocation for all WEB sources in Utah.

(i) For non-utility category 1 WEB sources, the floor allocation will be as established in the E.H. Pechan Report, "Market Trading Forum Non-Utility Sector Allocation Final Report from the Allocations Working Group" (November 2002). If any additional category 1 sources are identified, the executive secretary will calculate a floor allocation using the methodology outlined in the E.H. Pechan Report.

(ii) For utility category 1 WEB sources, the floor will be calculated by first assigning a "clean unit" emission rate to each unit. The clean unit emission rate will then be multiplied by an annual heat input (MMBtu) that represents a realistic upper bound for the unit.

(Note: The floor level approach described above is designed to address equity issues regarding the allocation process for utilities. The State of Utah is participating in ongoing discussions with the other participating states, tribes and regional stakeholders to ensure that all equity issues have been addressed. The State of Utah will work with the other participating states and tribes to ensure that the floor allocation is calculated in a consistent manner for all participants. As outlined further in this allocation methodology, the floor for both utilities and non-utilities is limited by the utility/non-utility split in Table 10. The floor allocation methodology will ensure that credits are available for early reduction allocations. In addition, the regional number of allowances allocated for each year cannot exceed the milestone for that year under any circumstances.)

Principles

- Each unit will have enough allowances to operate as a clean source and at an operating rate (capacity factor) that is a realistic upper bound for the unit.
- There will not be significant winners and losers in this process.
- The focus is on a fair approach that is applied equally to all sources rather than on state and tribal budgets.
- The allocation process will use data that reflect current conditions, including current monitoring methodologies.

Equity Issues

- Sources that are currently burning very low sulfur coal may see changes in their supply in the future. Historic actual emissions may not reflect future operations.

- Sources that are currently operating at a low utilization may not reach full capacity in the future. Assumptions about growth that are realistic on the regional level may provide a windfall to some sources, and not provide adequate allowances for other sources.

- There are some utility units in the region that are not BART-eligible and are operating at a low level of control for SO_2. The relative responsibility of BART-eligible vs. non-BART-eligible is a consideration in the process.

- Sources that are operating at a high level of control are already bearing the cost of control and this affects their ability to compete in the market.

- Sources that have no SO_2 controls are facing a large expense that could affect their ability to continue to operate.

- Emission rate disparities exist throughout the region.

(iii) For Category 2 WEB sources the floor allocation will be the lower of the permitted SO_2 annual emissions for the WEB source, or SO_2 annual emissions calculated based on a level of control equivalent to BACT and assuming 100% utilization of the WEB source.

(c) A list of certified early reductions, expressed as tons of SO_2. Early reductions will be calculated and certified as follows:

(i) Any WEB source that installs control technology and accepts new permit emissions limits that are, for a non-utility source, below its floor as established in this section, or, for a utility source, below BACT, may apply for an early reduction bonus allocation as outlined in R307-250-7(5). The bonus allocation will be available for reductions that occur between 2008 and the program trigger year. The application must show that the floor was calculated in a manner that is consistent with the monitoring requirements of R307-250-9(1)(a) and the new permit must contain monitoring requirements that are consistent with R307-250-9(1)(a). Emission units that are monitored using the less stringent monitoring requirements of R307-250-9(1)(b) are not eligible for early reduction bonus allocations. The bonus allocations accumulate from the time the new controls come on line until the program trigger date and will be allocated to the WEB source over a 10 year period. The use of early reduction bonus allocations in any control period is limited to no more than five percent, systemwide, of the existing available allowances, as provided in paragraph E.3.a(2)(e) of this plan.

(ii) The executive secretary will review the application and will certify early reductions for each full year between 2008 and the program trigger year that meet the requirements of R307-250-7(5) and this plan.

(iii) A source's certified early reductions for all years will be added together to obtain the total certified early reductions for that source.

(d) Historical SO_2 emissions data for all Category 1 sources for the purposes of calculating the reducible allocation.

(i) For utilities, annual SO_2 emissions for the year 2006. Another time period may be used for individual emission units, if needed, to be representative of normal operating conditions.

(ii) For non-utilities, the annual SO_2 emissions for the year 2006.

(e) Changes due to settlements arising from enforcement actions or due to administrative or judicial orders. The adjustment will be determined in accordance with paragraph E.1.c.(4)(b)(3)(c) of this Implementation Plan. The difference between the WEB source's allocations prior to enforcement and after the enforcement action will be removed from the allocation pool.

(2) Compiled Allocation Report.

The TSA will compile the information provided by all participating states and tribes into a draft regional allocation report, and will submit this draft regional report to the executive secretary and all participating states and tribes for review and comment thirty days after receiving the preliminary allocation reports. The draft regional allocation report will include a proposed budget for each state and tribe and the proposed allocation for each WEB source in Utah.

The State of Utah will work closely with the other participating states and tribes to ensure that the regional allocation is distributed consistently and fairly and to address any change in status that may affect this process.

The following methodology distributes the allowances available under the milestone in the following order: tribal set-aside, new source set-aside, floor, renewable energy credit, reducible allocation. The allocation process is limited by the number of allowances available under the milestone. It is not possible under this methodology to distribute more allowances that are available under the milestone. The State of Utah expects that there will be allowances available for all of the categories listed above. However, if at any time in the process there are not enough allowances available to fully cover a particular category, then the sources eligible for that category will receive a pro-rated allowance, and the process will stop. For example, if the renewable energy allocation is greater than the remaining available allowances under the milestone, then each of the renewable energy sources would receive a reduced renewable energy allocation, and there would be no reducible allocation.

(a) Table 8 shows the major categories that will be used to allocate allowances under the milestone. The methodology to calculate the available allocation for existing sources is described below. The milestone for the 4-state region is the starting point.

Table 8. Utility/Non-utility Split

	Milestone from Table 7	**Tribal Set-Aside**	**New Source Set-aside**	**Remaining Allocation**	**Utility Portion**	**Non-utility portion**
2008	269,083 tons	2,500 tons	6,143 tons	260,444 tons	210,480 tons	76,635 tons
2009	234,903 tons	2,500 tons	6,143 tons	226,260 tons	176,299 tons	76,635 tons
2010	200,722 tons	2,500 tons	6,143 tons	192,079 tons	142,119 tons	76,635 tons
2011	200,722 tons	2,500 tons	6,143 tons	192,079 tons	142,119 tons	76,635 tons
2012	200,722 tons	2,500 tons	6,143 tons	192,079 tons	142,119 tons	76,635 tons
2013	185,795 tons	2,500 tons	12,286 tons	171,009 tons	121,048 tons	76,635 tons
2014	170,868 tons	2,500 tons	12,286 tons	156,082 tons	106,121 tons	76,635 tons
2015	155,940 tons	2,500 tons	12,286 tons	141,154 tons	91,194 tons	76,635 tons
2016	155,940 tons	2,500 tons	12,286 tons	141,154 tons	91,194 tons	76,635 tons
2017	155,940 tons	2,500 tons	12,286 tons	141,154 tons	91,194 tons	76,635 tons
2018	141,849 tons	2,500 tons	12,286 tons	127,063 tons	80,402 tons	75,935 tons

(b) Subtract the floor allocation for all WEB sources in the region that were identified as Category 2 from the new source set-aside to determine the available allocation for new sources that begin operation after the program trigger date.

This allocation methodology treats all Category 2 sources as existing sources because these sources will be operating on the program trigger date. However, the allowances for all Category 2 sources are actually drawn from the new source set-aside. If new source growth exceeds the projections used to develop this plan, it is possible that the above calculation will result in a negative number. Therefore, to address this problem, Category 2 sources will be ranked based on the date the permit is issued for each source. Sources will then be removed from the list of Category 2 sources, starting with the most recent permit, until the new source set-aside is no longer depleted. The last source on the list will receive a partial allocation. The sources that were removed from the list will be considered new sources as described in Part E.3.c of this plan. These sources will need to purchase allowances to cover their emissions because the new source set-aside for sources that begin operation after the program trigger date would be calculated as zero until it is replenished in the next 5-year period. The allocation process for these new sources is described in Part E.3.c of this plan.

Example calculation of the new source set-aside.

The example uses the following assumptions:

- Emissions exceed the milestones based on an average of the years 2004-2006.
- The program trigger date is March 31, 2008.
- The first 5 years of the program are 2012-2016.
- New sources that commenced operation between January 1, 2008 and the program trigger date have a total floor allocation of 600 tons.

	2012	**2013**	**2014**	**2015**	**2016**
Maximum Possible Set-Aside	6,143	12,286	12,286	12,286	12,286
Floor for Category 2 Sources	-600	-600	-600	-600	-600
Remaining New Source Set-aside	5,543	11,686	11,686	11,686	11,686

(c) The remaining allocation shown in Table 8 is available for distribution to category 1 sources. The final two columns in Table 8 split this remaining allocation into a utility allocation and a non-utility allocation.

(d) Subtract the floor allocations for all category 1 utility and non-utility sources in the region from the utility allocation or the non-utility allocation.

In the unlikely event that the total floor allocation for either utility or non-utility sources submitted by the participating states and tribes exceeds the total allocation available for that category, the TSA will notify the participating states and tribes of the discrepancy. The State of Utah commits to work with the participating states and tribes through a consensus process to ensure that the floor allocation has been calculated in a consistent manner for all participants and to ensure that the floor allocation does not exceed the total allocation available for that category. The total number of allowances distributed can not exceed the milestone for any given year.

(e) Calculate the early reduction bonus allocation.

(i) Divide the number of certified early reductions for all WEB sources in the region by ten.

(ii) Add the utility allocation for 2018 to the non-utility allocation for 2018 and then multiply this total by 0.05.

(iii) If the product of paragraph (i) is no more than the product of paragraph (ii), the product of paragraph (i) is the early reduction bonus allocation, and each source is allocated ten percent of its early reduction bonus allocation.

(iv) If the product of paragraph (i) is more than the product of paragraph (ii), the early reduction bonus allocation for the region is the product of paragraph (ii). To determine a source's allocation, divide the product of paragraph (ii) by 0.10 times the total number of early reduction bonus allocations and apply that ratio to the certified early reductions for the source.

(v) Split the regional early reduction bonus allocation based on the ratio of utility to non-utility allocations in 2018 and subtract the early reduction bonus allocation from the utility and non-utility allocation totals.

(vi) The early reduction bonus allocation will be calculated in a similar manner for the second five-year allocation period under this program, and will then be discontinued for any future allocation periods.

(f) Any remaining allowances in the utility allocation or the non-utility allocation after subtraction of the early reduction allocation is considered the reducible allocation and will be assigned to Category 1 sources.

(i) For non-utility sources, add together the historic SO_2 emissions in accordance with paragraph E.3.a(1)(d) of this plan for all Category 1 non-utility sources in the region to determine an historic emission total. Determine a percent contribution of SO_2 emissions for each WEB source to the historic emission total. Multiply the non-utility reducible allocation by the percent contribution for each WEB source to determine a reducible allocation for each WEB source.

(ii) For utility sources, the reducible allocation will be distributed to sources that emitted above their floor in the baseline period (2006) based on their percentage of total floor emissions for sources emitting above the floor times the number of reducible allowances available for the first five years of the WEB Trading Program. The number of allowances for any source receiving a reducible allocation will not exceed a recent historic emission rate times a heat input that represents a realistic upper bound for the unit.

[Note: The approach for distributing the reducible utility allocation described above is designed to address equity issues regarding the allocation process for utilities. The State of Utah is participating in ongoing discussions with the other participating states, tribes and regional stakeholders to ensure that all equity issues have been addressed. The principles and equity issues that are under discussion are listed in paragraph E.3.a.(1)(b)(ii) of this plan.]

(g) Add together the floor allocation, early reduction allocation, and reducible allocation for each WEB source to determine the proposed allocations for the first five years of the WEB Trading Program.

(h) Add together the proposed allocations for all of the WEB sources in the jurisdiction of each participating state and tribe to determine a draft SO2 allowance budget for each state and tribe.

(3) Public Comment Period.
The executive secretary will publish notice of availability of the draft regional allocation report in newspapers of general circulation throughout Utah. A 30-day public comment period will be established, and a hearing will be held during the comment period. The executive secretary will consider the comments, and will revise the draft report as needed if the recommended changes are consistent with the allocation process outlined in this plan. The executive secretary will prepare a written response that explains why each comment has either been accepted or has been determined to be inconsistent with the allocation process outlined in this plan.

(4) Proposed Changes Submitted to Tracking System Administrator.
The executive secretary will submit a copy of all comments received, the response to those comments, and any proposed changes to the budget and source allocations to the TSA within sixty days of receipt of the draft regional allocation report.

(5) Compilation of Changes.
The TSA will compile the comments, responses, and proposed changes to the report and will submit a final draft regional allocation report that is consistent with the allocation methodology outlined in this plan to the executive secretary within 90 days of the receipt of the draft regional allocation report.
Final Regional Allocation Report.
The executive secretary will review the final regional allocation report and will determine the budget for Utah and allocations for WEB sources within Utah in accordance with the allocation methodology outlined in this plan within thirty days of receipt of the final draft allocation report. The executive secretary will submit the budget and allocations for all WEB sources in Utah to EPA, and will notify the TSA that the WEB source allocations should be recorded in the allowance tracking system.

(6) Notification.
The executive secretary will notify all WEB sources within Utah of the number of allowances that have been recorded in their compliance account. The notice will include a warning to the WEB sources that reported annual sulfur dioxide emissions may change due to the implementation of new monitoring methods as required by R307-250-9. Allocations for the first five years of the program will not be adjusted to account for changes due to the new monitoring method. However, allocations during the next five-year distribution will be adjusted as needed to account for paper changes in emissions due to changes in monitoring methodology.

b. Distribution of Allowances for Future Control Periods

By December 1 of the year five years after the initial allocation, the executive secretary will follow the process outlined in paragraph E.3.a of this plan to distribute allowances for the next five-year period. This process will continue every five years until allowances have been allocated through the year 2018.

c. Distribution of the New Source Allocation

(1) The new source set-aside will be available for two categories of sources.

(a) A new WEB source is eligible to receive an annual floor allocation equal to the lower of the annual sulfur dioxide limit in the source's approval order, or sulfur dioxide annual emissions calculated based on a level of control equivalent to BACT and assuming 100% utilization of the WEB source, beginning with the first full calendar year of operation and in accordance with the provisions of R307-250-7(6).

(b) An existing WEB source that has increased production capacity after obtaining a new approval order issued under R307-401 is eligible to receive an allocation from the new source set-aside equal to:

(i) the permitted annual sulfur dioxide emission limit for a new unit; or

(ii) the permitted annual SO_2 emission increase for the WEB source due to the replacement of an existing unit with a new unit or the modification of an existing unit that increased the production capacity of the WEB source.

Permitted emission increases due to fuel switching or other process changes that are not directly related to increased production capacity are not eligible for allocations from the new source set-aside. The allocation from the new source set-aside in the first year of operation will be adjusted to account for the number of days that the source is operating in that first year.

EXAMPLE. A new unit with a nameplate capacity of 400 MW is constructed at a power plant with two existing units with nameplate capacities of 400 MW and 300 MW. The two existing units install SO_2 controls and reduce emissions to meet PSD requirements for the construction of the new unit. In this example, the source would continue to receive a floor and a reducible allocation for each of the existing units, and would also be eligible to receive an allocation from the new source set-aside for the new unit. Even though total SO_2 emissions will decrease at this plant due to the construction of the new unit, the allowances allocated to the source will increase to reflect the increase in production capacity of 400 MW of electricity. If the new unit comes on line on July 1 the allocation for the first year will be reduced by 50 percent because the unit was operational for half of the year.

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(2) Allocations from the new source set-aside will remain constant for the applicable WEB source and will be made on an annual basis by March 31 of each year for the current control period. When the next five-year allocation block is distributed as outlined in paragraph E.3.b of this plan, all sources with an allocation under the new source set-aside will receive a five-year allocation block from the new source set-aside, and will continue to receive this allocation in future five-year allocation blocks.

(3) Owners or operators of new WEB sources or modified WEB sources that meet the eligibility requirements of (1) may apply for an allocation from the new source set-aside by submitting a written request to the executive secretary as outlined in Subsection R307-250-7(6).

(4) The executive secretary will review the application for an allocation for accuracy and completeness, and will notify the source of intent to distribute allocations from the regional new source set-aside pending verification that allowances are available in the new source set-aside account. The executive secretary will then forward the request to the TSA.

(5) The TSA will document the date that the request is received by the TSA. Requests for allocation of allowances from the new source set-aside will be processed in the order received. The TSA will deduct the number of allowances requested from the regional new source set-aside that was established by the participating states and tribes, and will then record an equal number of allowances in the source's compliance account for each remaining year of the five-year period. The TSA will then send written notification to the source and to the executive secretary that the allowances have been recorded in the source's compliance account.

(6) If there are insufficient allowances remaining in the new source set-aside to fulfill the request, the source must purchase the allowances required to demonstrate compliance. Any eligible WEB source that does not receive an allocation from the new source set-aside because the set-aside was depleted will be first in line to receive an allocation when the new source set-aside is increased in the next five-year period as outlined in Table 8 of this plan. If there is more than one such source, their allocation requests will be processed in the order they were received by the TSA.

(7) A source that has received a retired source exemption and continues to receive an allocation as a retired WEB source is not eligible to receive an allocation from the new source set-aside.

d. Regional Tribal Set-aside

(1) Each year after the program is triggered for which allowances are allocated, 2,500 allowances will exist as a tribal set-aside.

(2) The tribal caucus of the WRAP has stated its intent to determine the means for distributing the allowances among the tribes within one year after the program trigger date. The executive secretary understands that there will be a process that will meet the tracking and data security requirements of the allowance tracking system by which a tribe will move its set-aside allowances into the trading program for the purposes of trading.

(3) The executive secretary recognizes that the tribal set-aside allowances are bonus allowances for the tribes and, as such, are separate and additional to any allowances included in a tribal budget or the new source set-aside as outlined in the allocation report that is prepared in accordance with paragraph E.3.a(6) of this plan.

e. Opt-in Sources

The WRAP Market Trading Forum has recommended including provisions in this plan that would allow smaller sources to opt in to the program. Opt-in sources may provide a more cost-effective way to reduce overall regional SO_2 emissions, and therefore may strengthen the market incentives of this program. While the benefits of allowing sources to opt in to the program are important, the program must also provide safeguards to ensure that the integrity of the program is not affected. For example, it would be counterproductive to allow sources that were already planning to shut down to opt in to the program and then sell allowances to an existing source. In this example, regional emissions could slowly creep upward in a manner that is not consistent with the goals of the SO_2 milestones.

The State of Utah is deferring inclusion of provisions for opt-in sources until a future SIP revision to allow time to thoroughly consider how to provide the flexibility and potential benefits to the market by expanding the program while also ensuring that the SO_2 emission reduction goals are maintained.

f. WEB Emissions and Allowance Tracking System (WEB EATS)

The participating states and tribes will provide a centralized system for the tracking of allowances and emissions. The centralized system will be referred to as the WEB Emissions and Allowance Tracking System (WEB EATS or EATS). The WEB EATS must provide that all necessary information regarding emissions, allowances, and transactions is publicly available in a secure, centralized database. The EATS must ensure that each allowance is uniquely identified, allow for frequent updates, and include enforceable procedures for recording data.

The executive secretary will work cooperatively with other states and tribes participating in the WEB Trading Program to design this system. The executive secretary will be responsible for ensuring that all the EATS provisions are completed as described in this plan.

The EATS will not exist unless the program is triggered. Prior to the implementation of the WEB Trading Program, a separate emissions tracking database will be employed to track the ongoing emissions of sources emitting SO_2 at amounts equal to or greater than 100 tons per year. The emissions tracking database, which was used to track and measure SO_2 emissions against the milestones, will still exist once the WEB Trading Program is triggered; however, it will become incorporated into the SO_2 Emissions and Allowance Tracking System. Both the emissions tracking database and the EATS will be centralized systems and data will be posted in an electronic, Web-based program and available to all persons.

The participating states and tribes will contract with a common TSA to service and maintain the WEB EATS. It is envisioned that the EATS will require the use of a contracted consultant or database design engineer to create a secure, efficient and transparent tracking system. Because the EATS will be utilized by all states and tribes participating in the program, the design will require a uniform approach and level of security that will satisfy regional needs and concerns as well as meet the electronic, Web-based, access needs and security provisions. Due to the dynamic needs of the marketplace, the EATS will require a database that will reflect the current status of allowances and allowance transactions. The EATS will be operational within one year after the program trigger date.

Specifications of the WEB EATS such as emissions tracking, the recording of allowance transactions, account management, system integrity and transparency are outlined in the Utah TSD Supplement. The specifications will be used as a guideline for developing the EATS if the program is triggered. However, the overall design will be greatly affected by computer software and hardware changes that will occur between the adoption of this Plan and the program trigger date. The on-going experience gained from other trading programs also may lead to improvements in the design of the system. The specifications and related sections of R307-250 detail how a WEB source will register for the EATS and how the source will, through an account representative, establish accounts, transfer allowances, and track unused allowances from a previous year.

Neither the executive secretary nor the TSA will adjudicate any dispute between the parties concerning the authorization of any account representative with regard to any representation, action, inaction, or submission of the account representative.

As an example of how the WEB EATS will generally function, once the WEB Trading Program is triggered, a WEB source will have its allowance allocation determined. At the same time, the WEB source’s account representative will register for the EATS under R307-250-6, and a compliance account will be established under R307-250-8. Each allowance will be assigned a serial number. The allowance serial number will be used by the WEB EATS to track allowance allocations, transfers (R307-250-10), and deductions, and to account for any unused allowances from a previous year (R307-250-11). The serial number also will be assigned to each allowance recorded in a general account, which is an account for allowances that are not held to meet program compliance requirements. Furthermore, the EATS will track tribal allowance set-asides and new source allowance set-asides not yet assigned to either a compliance or general account.

It is important to note that while this plan has provided a design for and an operational understanding of the EATS, the components of the EATS will need to be examined and possibly altered upon each required SIP revision.

g. Allowance Transfers

(1) Allowance transfers are defined as the conveyance from one account to another account (compliance account or general account) of one or more allowances by whatever means, including but not limited to purchase, trade, or gift in accordance with the procedures established in R307-250-10. This includes the transfer of allowances for the purpose of retirement. Once an allowance is retired, it is no longer available for transfer to or from any account. Allowances may be purchased by any person for the purpose of retirement.

(2) The TSA will have specific recording duties involving transfers. These required procedures will be detailed in the service contract and will include the following activities.

(a) Recording of Allowance Transfers.

(i) Within five business days of receiving an allowance transfer, except when the transfer does not meet the requirements of R307-250-10, the TSA will record an allowance transfer by moving each allowance from the transferor account to the transferee account as specified by the request, provided that the transfer is correctly submitted and that the transferor account includes each allowance identified in the transfer.

(ii) Any allowance transfer that is submitted for recording following the allowance transfer deadline and that includes any allowances allocated for a control period prior to or the same as the control period to which the allowance transfer deadline applies will not be recorded until after completion of the compliance account reconciliation.

(iii) Where an allowance transfer submitted for allowance transfer recording fails to meet the requirements of R307-250-10, the TSA will not record the transfer.

(3) Notification of the Recording of Allowance Transfers. The TSA has specific responsibilities involving the notification of the recording of any transferred allowances, including the failure to record any transfer of allowances. Again, these required procedures will be outlined in the service contract, but include the following.

(a) Within five business days of the recording of an allowance transfer, the TSA will notify the transferor's and transferee's account representatives of both accounts, and make the transfer information publicly available on the Internet.

(b) Within five business days of receipt of an allowance transfer that fails to meet the requirements of R307-250-10, the TSA will notify the account representatives of both accounts of the decision not to record the transfer, and the reasons for not recording the transfer.

h. Use of Allowances from a Previous Year

(1) Background.

Unused allowances may be kept for use in future years in accordance with R307-250-11 and there are restrictions on the use of the allowances in accordance with R307-250-11. R307-250-11 prohibits the use after the year 2017 of allowances allocated for the years 2003 – 2017. This provision ensures that actual emissions will be less than the 2018 milestone because only allowances allocated for the year 2018 could be used to show compliance in that year. The provision also maintains flexibility by resetting the baseline to the year 2018 and then allowing sources to once again use extra allowances to show compliance in any future year. This flexibility is important for sources that have variable operations because the source may build up a reserve of unused allowances for use in a high production year.

The Annex explains the benefits of allowing the WEB source to use unused allowances from previous years, including increased flexibility and early reduction stimulus. The risk in allowing the use of allowances carried from a previous year could be an increase in emissions in later years as the unused allowances are withdrawn for compliance.

Because the regional haze SIP is based on reasonable progress requirements related to the remedying or prevention of any future visibility impairment, it is important to assure the use of these allowances will not interfere with attainment or maintenance of any reasonable progress goals. The safeguard employed here to mitigate this type of risk is termed, “flow control”, and is described in paragraph (2) below.

(2) Flow Control Provisions.

(a) At the end of each control period, WEB sources may transfer allowances in and out of their compliance account for a period of 60 days to ensure that the account will contain enough allowances to cover sulfur dioxide emissions during the previous year. At the end of the sixty-day transfer period, allowances will be deducted from the compliance account of each WEB sources in an amount equal to the sulfur dioxide emissions of that source during the control period.

(b) After the deductions have been completed, the Tracking System Administrator will perform the following calculations and prepare a report according to paragraph E. 3.k(1)(b) of this Plan.

(i) Determine the total number of allowances remaining in the allowance tracking system that were allocated for the just completed control period and all previous control periods.

(ii) If the number calculated in (i) exceeds 10 percent of the milestone for the next control period, then the flow control procedures in R307-250-11 will be triggered for that next control period. These flow control provisions will discourage the excessive use of allowances that were allocated for an earlier control period without establishing an absolute limit on their use. WEB sources will maintain the option to use allowances allocated for an earlier control period, but will be required to use two allowances for each ton of SO_2 emissions. Flow Control operates as follows.

(A) The flow control ratio will be calculated by multiplying 0.1 times the milestone for the next control period, divided by the total number of unused allowances remaining in the system.

(B) To calculate the number of prior-year allowances that can be used without restriction by a source for the next control period, the TSA will multiply the prior-year allowances by the flow control ratio. The resulting number of allowances may be used on a one-to-one ratio to show compliance with the source's allowance limitation as outlined in paragraph E.3.j of this Plan.

(C) The remaining prior-year allowances may be used on a two-to-one ratio to show compliance. Thus, WEB sources will maintain the option to use allowances allocated for an earlier control period, but will be required to use two of those allowances for each ton of SO_2 emissions.

Example: On March 1, 2010 (the compliance transfer deadline for the 2009 control period) the Tracking System Administrator deducts allowances from the compliance account for each WEB source to cover 2009 SO_2 emissions from that source. After completing these deductions, the TSA reports the following information:

Total number of allowances still in the system for the years 2003 – 2009	=	30,000
2010 milestone	=	200,722
Percent of milestone	=	14.94 %

Because the number of allowances not used in previous control periods is greater than 10% of the milestone, flow control procedures are triggered. In the annual report required in paragraph E.3.k of this Plan, the TSA will then calculate the flow control ratio for 2010:

0.1 x 2010 Milestone ÷ prior year allowances = flow control ratio
0.1 x 200,722 ÷ 30,000 = 0.70

On March 1, 2011 (the compliance transfer deadline for the 2010 control period) the TSA will apply the 2010 flow control ratio before deducting allowances from each WEB source's compliance account

WEB Source A		
2010 Allowances	=	1,000
Remaining Prior Year Allowances	=	600
2010 Emissions	=	1,580

In this example, the TSA would multiply the prior year allowances by 0.70 to determine the number of prior year allowances that could be used without restriction, at a one-to-one ratio. This would equal 420. The remaining prior year allowances would then be used at a 2:1 ratio. 360 allowances would be needed to cover the remaining 180 tons of SO_2 emissions. The TSA would therefore deduct a total of 1,780 allowances (1,000 + 420 +360) to cover 1,580 tons of SO_2 emissions.

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i. Monitoring/Recordkeeping

(1) For WEB sources subject to 40 CFR Part 75, the TSA will use data that has been quality assured and finalized by the EPA. For WEB sources subject to the monitoring protocol in Appendix B of this Plan, the executive secretary will quality assure and finalize the data in accordance with these provisions for submission to the TSA.

(2) The executive secretary will verify and submit the data to the emissions tracking database as soon as reasonably feasible after annual emissions are reported by the WEB sources. These timelines will be modified, as necessary, according to the monitoring protocols.

(3) Special Reserve Compliance Accounts. The WEB Trading Program requires most WEB sources to install continuous emission monitoring systems (CEMS) that meet the monitoring, recordkeeping and reporting requirements of 40 CFR Part 75. However, there are some emission units that are not physically able to install CEMS and there are also emission units that do not emit enough sulfur dioxide to justify the expense of installing these systems (see R307-250-9(1)(b)). The WEB Trading Program allows these emission units to continue to use their pre-trigger monitoring methodology, but does not allow the WEB source to transfer any allowances that were allocated to that unit for use by another WEB source. The restriction on transferring these allowances is needed to ensure that an emission reduction of sulfur dioxide and the corresponding increase in sulfur dioxide are equal. The allowances associated with emission units that continue to use their pre-trigger monitoring methodology are placed in a special reserve compliance account, while allowances for other emission units are placed in a regular compliance account. Allowances may not be traded out of a special reserve compliance account, even for use by emission units with CEMS at the same WEB source. However,

the WEB source may transfer allowances into the account as needed to demonstrate compliance with the WEB source's allowance limitation.

R307-250-9(b) allows WEB sources with any of the following emission units to apply to establish a special reserve compliance account:

> (a) any smelting operation where all of the emissions from the operation are not ducted to a stack; or
>
> (b) any flare, except to the extent such flares are used as a fuel gas combustion device at a petroleum refinery; or
>
> (c) any other type of unit without add-on sulfur dioxide control equipment, if the unit belongs to one of the following source categories: cement kilns, pulp and paper recovery furnaces, lime kilns, or glass manufacturing.

The emission units described in (a) and (b) cannot physically be monitored using a CEM. The emission units described in (c) do not typically have add-on controls for sulfur dioxide. These units, described in R307-250-9(1)(b), are expected to operate within their floor-level allocation and therefore will not be affected by the market, unless they make a process change and wish to sell allowances on the market. Other sources that are meeting the more rigorous monitoring requirements opf R307-250-9(1)(a) and emit sulfur dioxide above their expected allocation will either need to purchase allowances or install sulfur dioxide controls. Therefore, it is important that all emission units that participate in emission trading have an accurate monitoring methodology that is comparable to other sources in the program to ensure that a ton of reductions is the same regardless of where the reductions originate.

The executive secretary will review the application to monitor under R307-250-9(1)(b). If the emission units meet the criteria in R307-250-9(1)(b), the executive secretary will determine the portion of the WEB source's allocation that is associated with the emission units that will be monitored under R307-250-9(1)(b) and will require the TSA to record that portion of the WEB source's allocation in the special reserve compliance account. The executive secretary will use the methodology for determining allocations described in paragraph E.3.a of this Plan to determine the portion of the allocation that is associated with the Subsection R307-250-9(1)(b) emission units. The executive secretary will notify the WEB source that the application has either been accepted or rejected, including a notification of the allowances that are to be recorded in the WEB source's regular compliance account and the special reserve compliance account.

If an emission unit that is monitored under R307-250-9(1)(b) is permanently retired, the TSA will transfer the portion of allowances that were associated with that emission unit from the WEB source's special reserve compliance account to the source's compliance account. These allowances will then be available for use or sale by the WEB source. The allowances will be transferred after the compliance deduction has taken place for the last control period that the unit was in operation.

j. Compliance, Excess Emissions, and Penalties

When a WEB source exceeds its allowance limitation in R307-250-12, the executive secretary will require the TSA to deduct allowances from the following year's allocation in an amount equal to three times the WEB source's emissions of SO_2 in excess of its allowance limitation. This deduction will be made from the WEB source's compliance account after deductions for compliance are made under R307-250-12. If sufficient allowances do not exist in the compliance account for the next control period to cover this amount, the executive secretary will require the TSA to deduct the required number of allowances, regardless of the control period for which they were allocated, whenever the allowances are recorded in the account.

Sources may also be liable for each day of violation of any other provision of the market trading program.

k. Periodic Evaluation of the Trading Program

(1) Annual Report.

(a) Beginning one year after compliance with the trading program is required, the executive secretary will obtain from the TSA an annual report that contains the following information:

(i) the level of compliance program-wide;

(ii) a summary of the use and transfer of allowances, both geographically and temporally;

(iii) a source-by-source accounting of allocations compared to emissions;

(iv) a report on the use of unused allowances from a previous year, in order to determine whether these emissions have or have not contributed to emissions in excess of the cap; and

(v) the total number of WEB sources participating in the trading program and any changes to eligible sources, such as retired sources, or sources that emit more than 100 tons of SO_2 after the program trigger date.

(b) Within 2 months after the allowance transfer deadline for each control period when compliance with the trading program is required, the TSA will prepare a draft report that lists:

(i) the total number of allowances deducted for the control period,

(ii) the total number of allowances remaining in the Allowance Tracking System allocated for that control period and any earlier control period,

(iii) a proposed determination that flow control procedures have either been triggered or have not been triggered for the next control period, and

(iv) if flow control procedures have been triggered, a draft flow control ratio calculated according to paragraph E.3.h(2) of this Plan.

(c) The executive secretary will evaluate the draft report, and will propose a determination that flow control procedures either have been triggered or have not been triggered for the next control period.

(d) The executive secretary will publish a notice of availability of the draft report in newspapers of general circulation in Utah, and will hold a 30-day public comment period.

(e) After the comment period the executive secretary will make a final determination that the flow control procedures either have been triggered or have not been triggered for the next control period. If the flow control procedures have been triggered, the executive secretary will notify all WEB sources in Utah that flow control procedures will be in effect during the next control period.

(2) Five-year Evaluation.

(a) The executive secretary will work cooperatively with other participating states and tribes to conduct an audit of the WEB Trading Program no later than three years following the first full year of the trading program, and at least every five years thereafter. This evaluation does not replace the Plan assessments in 2008, 2013, and 2018. The evaluation will be conducted by an independent third party and include an analysis of:

(i) whether the total actual emissions could exceed the values in Table 7 of this Implementation Plan of the WEB Trading Program even though sources comply with their allowances;

(ii) whether the program achieved the overall emission milestone it was intended to reach;

(iii) the effectiveness of the compliance, enforcement and penalty provisions;

(iv) a discussion of whether states and tribes have enough resources to implement the WEB Trading Program;

(v) whether the trading program resulted in any unexpected beneficial effects, or any unintended detrimental effects;

(vi) whether the actions taken to reduce sulfur dioxide have led to any unintended increases in other pollutants;

(vii) whether there are any changes needed in emissions monitoring and reporting protocols, or in the administrative procedures for program administration and tracking;

(viii) the effectiveness of the provisions for interstate trading, and whether there are any procedural changes needed to make the interstate nature of the program more effective; and

(ix) the integrity of the emissions and allowance tracking system, including whether the procedures for recording transactions are adequate, whether the procedures are being followed and in a timely manner, whether the information on sources' emissions are accurately recorded, whether the emissions and allowance tracking system has procedures in place to ensure that the transactions are valid, and whether back-up systems are in place to account for problems with loss of data.

(b) The public will have an opportunity to participate in this trading program evaluation.

(c) In the event that any audit results in recommendations for program revisions, the State of Utah, in consultation with the WRAP, will make appropriate modifications to this Plan. The State of Utah will revise this Plan if the program is not meeting its emission reduction goals.

(d) The executive secretary will submit a copy of the report to the EPA regional office.

l. Retired Source Exemption

R307-250-4(4) outlines the procedure that a WEB source must follow to receive a retired source exemption. The exemption would allow the source to continue to receive an allocation, but would exempt the source from monitoring and recordkeeping requirements that would serve no useful function for a source that has ceased operations. The executive secretary will notify the source of its obligation to apply for a retired source exemption upon the cancellation or relinquishment of a permit.

To receive a retired source exemption, the source must submit a request for the exemption to the executive secretary. The executive secretary will review this request, and within 60 days of receipt of the request will notify the source that the retired source exemption has been granted or has been rejected. If the exemption has been rejected, the notification will contain an explanation of the reasons for rejecting the request.

The TSA will continue to record an allocation to a WEB source that has received a retired source exemption. However, the allowances will be recorded in a general account rather than a compliance account for the source. The TSA will transfer any existing allowances in the retired source's compliance account or special reserve compliance account into the general account for the retired source, and will close the compliance accounts.

A WEB source that is permanently retired and that does not request a retired source exemption will forfeit all abandoned allowances in that source's compliance account, as outlined in R307-250-4(4)(e). The forfeited allowances will not be redistributed to other sources, and will be permanently retired from the Allowance Tracking System, as outlined in R307-250-10(3). During the next five-year allowance distribution period the retired source will not receive an allocation, and the allowances that would have been distributed to that source will be added to the new source set-aside.

m. Integration into Permits

It is expected that all WEB sources at least initially will be subject to Utah's Title V permitting requirements. Under R307-415, Utah's delegated Title V permitting program, the pre- and post-trigger requirements of the market trading program fall under the definition of "applicable requirement," and will be incorporated into each source's Title V permit according to the schedules and procedures contained in that rule. R307-250-14 requires that any source that for any reason and at any time is not required to have a permit under R307-415 must obtain a New Source Review permit pursuant to R307-401 et seq. that incorporates the same requirements by submitting a Notice of Intent within 90 days of the program trigger. Both types of permits are enforceable both federally and by citizens pursuant to Utah's SIP.

4. 2013 SIP Revision; Backstop for Beginning of Second Planning Period

In addition to the requirements of 40 CFR 51.309(d)(10), the periodic SIP revision due in 2013 will include the following information:

a. Source specific allocations for all WEB sources in Utah for the year 2018; and

b. Either the provisions of a program designed to achieve reasonable progress for stationary sources of SO_2 beyond 2018 or a commitment to submit a SIP revision containing the provisions of such a program no later than December 31, 2016. The program will ensure that the requirements of 40 CFR 51.309 are achieved for the first planning period, including requirements that cannot be measured until after 2018, such as the determination of compliance with the 2018 milestone.

This 2013 SIP revision will provide certainty to sources regarding their potential liability under the special penalty provisions for the year 2018 outlined in paragraph E.1e of this Plan. The calculation of these allocations is delayed until 2013 to provide certainty about the number of sources that will qualify as WEB sources at that time; the allocations needed for new sources in the region, and early reductions that will be included in the allocation process. It is difficult to estimate the impact of these factors in 2003 because circumstances may change during the next 10 years.

If the 2018 milestone is not met, the starting point for the next planning period will be the 2018 milestones, not actual emissions in 2018.