ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R08–OAR–2011–0851; FRL–9655–7]

Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing a Federal Implementation Plan (FIP) to address regional haze in the State of Montana. EPA developed this proposal in response to the State's decision in 2006 to not submit a regional haze State Implementation Plan (SIP) revision. EPA is proposing to determine that the FIP satisfies requirements of the Clean Air Act (CAA or ''the Act'') that require states, or EPA in promulgating a FIP, to assure reasonable progress towards the national goal of preventing any future and remedying any existing man-made impairment of visibility in mandatory Class I areas. In addition, EPA is also proposing to approve a revision to the Montana SIP submitted by the State of Montana through the Montana Department of Environmental Quality on February 17, 2012. The State's submittal contains revisions to the Montana Visibility Plan that includes amendments to the ''Smoke Management'' section, which adds a reference to Best Available Control Technology (BACT) as the visibility control measure for open burning as currently administered through the State's air quality permit program. This change was made to meet the requirements of the Regional Haze Rule. EPA will act on the remaining revisions in the State's submittal in a future action.

DATES: Written comments must be received at the address below on or before June 19, 2012.

Public Hearings. We will be holding two public hearings for this proposal. One hearing is scheduled to be held in Helena, Montana on Tuesday, May 1, 2012 from 2 p.m. until 5:30 p.m. and from 6:30 p.m. until 9 p.m. at the Lewis & Clark Library, 120 S. Last Chance Gulch, Helena, Montana 59601, (406) 447–1690. The other hearing is scheduled to be held in Billings, Montana on Wednesday, May 2, 2012 from 1 p.m. until 5 p.m. and from 6 p.m. until 8 p.m. at the Montana State University—Downtown Campus, Meeting Room—Broadway III A, 2804 3rd Avenue North, Billings, Montana 59101, (406) 896–5860.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R08–OAR–2011–0851, by one of the following methods:

- *http://www.regulations.gov.* Follow the on-line instructions for submitting comments.
- *Email: r8airrulemakings@epa.gov.*
- *Fax:* (303) 312–6064 (please alert the individual listed in **FOR FURTHER INFORMATION CONTACT** if you are faxing comments).
- *Mail:* Carl Daly, Director, Air Program, Environmental Protection Agency (EPA), Region 8, Mailcode 8P–AR, 1595 Wynkoop Street, Denver, Colorado 80202–1129.
- *Hand Delivery:* Carl Daly, Director, Air Program, Environmental Protection Agency (EPA), Region 8, Mailcode 8P–AR, 1595 Wynkoop, Denver, Colorado 80202–1129. Such deliveries are only accepted Monday through Friday, 8 a.m. to 4:30 p.m., excluding federal holidays. Special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–R08–OAR–2011–0851. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to EPA, without going through *http://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional instructions on submitting comments, go to Section I. General Information of the **SUPPLEMENTARY INFORMATION** section of this document.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly-available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air Program, Environmental Protection Agency (EPA), Region 8, Mailcode 8P–AR, 1595 Wynkoop, Denver, Colorado 80202–1129. EPA requests that if at all possible, you contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section to view the hard copy of the docket. You may view the hard copy of the docket Monday through Friday, 8 a.m. to 4 p.m., excluding federal holidays.

FOR FURTHER INFORMATION CONTACT:
Vanessa Hinkle, Air Program, U.S. Environmental Protection Agency, Region 8, Mailcode 8P–AR, 1595 Wynkoop, Denver, Colorado 80202–1129, (303) 312–6561, *hinkle.vanessa@epa.gov.*

SUPPLEMENTARY INFORMATION:

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Definitions

For the purpose of this document, we are giving meaning to certain words or initials as follows:

i. The words or initials *Act* or *CAA* mean or refer to the Clean Air Act, unless the context indicates otherwise.

ii. The initials *A/F* mean or refer to air-to-fuel.

iii. The initials *ARM* mean or refer to Administrative Rule of Montana.

iv. The initials *ARP* mean or refer to the acid rain program.

v. The initials *ASOFA* mean or refer to advanced separated overfire air.

vi. The initials *BACT* mean or refer to Best Available Control Technology.

vii. The initials *BART* mean or refer to Best Available Retrofit Technology.

viii. The initials *CAMD* mean or refer to EPA Clean Air Markets Division.

ix. The initials *CAMx* mean or refer to Comprehensive Air Quality Model.

x. The initials *CCM* mean or refer to EPA Control Cost Manual.

xi. The initials *CCOFA* mean or refer to close-coupled overfire air system.

xii. The initials *CDS* mean or refer to circulating dry scrubber.

xiii. The initials *CELP* mean or refer to Colstrip Energy Limited Partnership.

xiv. The initials *CEMS* mean or refer to continuous exhaust monitoring systems.

xv. The initials *CEPCI* mean or refer to Chemical Engineering Plant Cost Index.

xvi. The initials *CFAC* mean or refer to Columbia Falls Aluminum Company.

xvii. The initials *CFB* mean or refer to circulating fluidized bed.

xviii. The initials *CKD* mean or refer to cement kiln dust.

xix. The initials *CMAQ* mean or refer to Community Multi-Scale Air Quality modeling system.

xx. The initials *CO* mean or refer to carbon monoxide.

xxi. The initials *CPI* mean or refer to Consumer Price Index.

xxii. The initials *CRF* mean or refer to Capital Recovery Factor.

xxiii. The initials *DAA* mean or refer to Dry Absorbent Addition.

xxiv. The initials *DPCS* mean or refer to digital process control system.

xxv. The initials *D–R* mean or refer to Dresser-Rand.

xxvi. The initials *DSI* mean or refer to dry sorbent injection.

xxvii. The initials *EC* mean or refer to elemental carbon.

xxviii. The initials *EGU* mean or refer to Electric Generating Units.

xxix. The words *EPA, we, us* or *our* mean or refer to the United States Environmental Protection Agency.

xxx. The initials *ESP* mean or refer to electrostatic precipitator.

xxxi. The initials *FCCU* mean or refer to fluid catalytic cracking unit.

xxxii. The initials *FGD* mean or refer to flue gas desulfurization.

xxxiii. The initials *FGR* mean or refer to flue gas recirculation.

xxxiv. The initials *FIP* mean or refer to Federal Implementation Plan.

xxxv. The initials *FLMs* mean or refer to Federal Land Managers.

xxxvi. The initials *HAR* mean or refer to hydrated ash reinjection.

xxxvii. The initials *HDSCR* mean or refer to high-dust selective catalytic reduction.

xxxviii. The initials *HC* mean or refer to hydrocarbons.

xxxix. The initials *IMPROVE* mean or refer to Interagency Monitoring of Protected Visual Environments monitoring network.

xl. The initials *IPM* mean or refer to Integrated Planning Model.

xli. The initials *LDSCR* mean or refer to low-dust selective catalytic reduction.

xlii. The initials *LEA* mean or refer to low excess air.

xliii. The initials *LNBs* mean or refer to low NO_X burners.

xliv. The initials *LSD* mean or refer to lime spray drying.

xlv. The initials *LSFO* mean or refer to limestone forced oxidation.

xlvi. The initials *LTS* mean or refer to Long-Term Strategy.

xlvii. The initials *MDEQ* mean or refer to Montana's Department of Environmental Quality.

xlviii. The initials *MDF* mean or refer to medium density fiberboard.

xlix. The initials *MISO* mean or refer to Midwest Independent Transmission System Operator.

l. The initials *MDU* mean or refer to Montana-Dakota Utilities Company.

li. The initials *MKF* mean or refer to mid-kiln firing of solid fuel.

lii. The words *Montana* and *State* mean the State of Montana.

liii. The initials *MSCC* mean or refer to Montana Sulphur and Chemical Company.

liv. The initials *NEI* mean or refer to National Emission Inventory.

lv. The initials *NESHAP* mean or refer to National Emission Standards for Hazardous Air Pollutants.

lvi. The initials NH_3 mean or refer to ammonia.

lvii. The initials NO_X mean or refer to nitrogen oxides.

lviii. The initials *NP* mean or refer to National Park.

lix. The initials *NSCR* mean or refer to non-selective catalytic reduction.

lx. The initials *NSPS* mean or refer to New Source Performance Standards.

lxi. The initials *NWR* mean or refer to National Wildlife Reserve.

lxii. The initials *OC* mean or refer to organic carbon.

lxiii. The initials *OFA* mean or refer to overfire air.

lxiv. The initials *PC* mean or refer to pulverized coal.

lxv. The initials *PH/PC* mean or refer to preheater/precalciner.

lxvi. The initials *PM* mean or refer to particulate matter.

lxvii. The initials $PM_{2.5}$ mean or refer to particulate matter with an aerodynamic diameter of less than 2.5 micrometers (fine particulate matter).

lxviii. The initials *PM_{10}* mean or refer to particulate matter with an aerodynamic diameter of less than 10 micrometers (coarse particulate matter).

lxix. The initials *PMCD* mean or refer to particulate matter control device.

lxx. The initials *ppm* mean or refer to parts per million.

lxxi. The initials *PRB* mean or refer to Powder River Basin.

lxxii. The initials *PSAT* mean or refer to Particulate Matter Source Apportionment Technology.

lxxiii. The initials *PSD* mean or refer to Prevention of Significant Deterioration.

lxxiv. The initials *RAVI* mean or refer to Reasonably Attributable Visibility Impairment.

lxxv. The initials *RICE* mean or refer to Reciprocating Internal Combustion Engines.

lxxvi. The initials *RMC* mean or refer to Regional Modeling Center.

lxxvii. The initials *ROFA* mean or refer to rotating opposed fire air.

lxxviii. The initials *RP* mean or refer to Reasonable Progress.

lxxix. The initials *RPG* or *RPGs* mean or refer to Reasonable Progress Goal(s).

lxxx. The initials *RPOs* mean or refer to regional planning organizations.

lxxxi. The initials *RRI* mean or refer to rich reagent injection.

lxxxii. The initials *RSCR* mean or refer to regenerative selective catalytic reduction.

lxxxiii. The initials *SCOT* mean or refer to Shell Claus Off-Gas Treatment.

lxxxiv. The initials *SCR* mean or refer to selective catalytic reduction.

lxxxv. The initials *SDA* mean or refer to spray dryer absorbers.

lxxxvi. The initials *SIP* mean or refer to State Implementation Plan.

lxxxvii. The initials *SMOKE* mean or refer to Sparse Matrix Operator Kernel Emissions.

lxxxviii. The initials *SNCR* mean or refer to selective non-catalytic reduction.

lxxxix. The initials *SO_2* mean or refer to sulfur dioxide.

xc. The initials *SOFA* mean or refer to separated overfire air.

xci. The initials *SRU* mean or refer to sulfur recovery unit.

xcii. The initials *TESCR* mean or refer to tail-end selective catalytic reduction.

xciii. The initials *TCEQ* mean or refer to Texas Commission on Environmental Quality.

xciv. The initials *tpy* mean tons per year.

xcv. The initials *TSD* mean or refer to Technical Support Document.

xcvi. The initials *URP* mean or refer to Uniform Rate of Progress.

xcvii. The initials *VOC* mean or refer to volatile organic compounds.

xcviii. The initials *WA* mean or refer to Wilderness Area.

xcic. The initials *WEP* mean or refer to Weighted Emissions Potential.

c. The initials *WRAP* mean or refer to the Western Regional Air Partnership.

ci. The initials *YELP* mean or refer to Yellowstone Energy Limited Partnership.

I. General Information

The public hearings will provide interested parties the opportunity to present information and opinions to EPA concerning our proposal. Interested parties may also submit written comments, as discussed in the proposal. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at the public hearing. We will not respond to comments during the public hearing. When we publish our final action, we will provide written responses to all oral and written comments received on our proposal.

At the public hearing, the hearing officer may limit the time available for each commenter to address the proposal to 5 minutes or less if the hearing officer determines it to be appropriate. We will not be providing equipment for commenters to show overhead slides or make computerized slide presentations. Any person may provide written or oral comments and data pertaining to our proposal at the public hearing. Verbatim transcripts, in English, of the hearing and written statements will be included in the rulemaking docket.

A. What should I consider as I prepare my comments for EPA?

1. *Submitting CBI.* Do not submit CBI to EPA through *http://www.regulations.gov* or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for Preparing Your Comments.* When submitting comments, remember to:

a. Identify the rulemaking by docket number and other identifying information (subject heading, Federal Register date and page number).

b. Follow directions—The agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

c. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

d. Describe any assumptions and provide any technical information and/or data that you used.

e. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

f. Provide specific examples to illustrate your concerns, and suggest alternatives.

g. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

h. Make sure to submit your comments by the comment period deadline identified.

II. What action is EPA proposing to take?

EPA is proposing a FIP for the State of Montana (State) to address regional haze. In so doing, EPA is proposing to determine that the federal plan along with the change to Montana's visibility plan, submitted on February 17, 2012, that requires BACT as the visibility control measure for open burning satisfy the requirements of 40 CFR 51.308.

III. Background

A. Regional Haze

Regional haze is visibility impairment that is produced by a multitude of sources and activities which are located across a broad geographic area and emit fine particulates ($PM_{2.5}$) (e.g., sulfates, nitrates, organic carbon (OC), elemental carbon (EC), and soil dust), and their precursors (e.g., sulfur dioxide (SO_2), nitrogen oxides (NO_X), and in some cases, ammonia (NH_3) and volatile organic compounds (VOC)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that one can see. $PM_{2.5}$ can also cause serious health effects and mortality in humans and contributes to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the ''Interagency Monitoring of Protected Visual Environments'' (IMPROVE) monitoring network, show that visibility impairment caused by air pollution occurs virtually all the time at most national park (NP) and wilderness areas (WA). The average visual range [1] in many Class I areas (i.e., NPs and memorial parks, WA, and international parks meeting certain size criteria) in the western United States is 100–150

[1] Visual range is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky.

kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In most of the eastern Class I areas of the United States, the average visual range is less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions. 64 FR 35715 (July 1, 1999).

B. Requirements of the CAA and EPA's Regional Haze Rule

In section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the ''prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas [2] which impairment results from manmade air pollution.'' On December 2, 1980, EPA promulgated regulations to address visibility impairment in Class I areas that is ''reasonably attributable'' to a single source or small group of sources, i.e., ''reasonably attributable visibility impairment.'' 45 FR 80084 (December 2, 1980). These regulations represented the first phase in addressing visibility impairment. EPA deferred action on regional haze that emanates from a variety of sources until monitoring, modeling and scientific knowledge about the relationships between pollutants and visibility impairment were improved.

Congress added section 169B to the CAA in 1990 to address regional haze issues. EPA promulgated a rule to address regional haze on July 1, 1999. 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P. The Regional Haze Rule revised the existing visibility regulations to integrate into the regulation provisions addressing regional haze impairment and established a comprehensive visibility protection program for Class I areas. The requirements for regional haze, found at 40 CFR 51.308 and 51.309, are included in EPA's visibility protection regulations at 40 CFR 51.300–309. Some of the main elements of the regional haze requirements are summarized in this section of this preamble. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia and the Virgin Islands.[3] 40 CFR 51.308(b) requires states to submit the first implementation plan addressing regional haze visibility impairment no later than December 17, 2007.[4]

Few states submitted a Regional Haze SIP prior to the December 17, 2007 deadline, and on January 15, 2009, EPA found that 37 states, including Montana and the District of Columbia, and the Virgin Islands, had failed to submit SIPs addressing the regional haze requirements. 74 FR 2392 (January 15, 2009). Once EPA has found that a state has failed to make a required submission, EPA is required to promulgate a FIP within two years unless the state submits a SIP and the Agency approves it within the two year period. CAA § 110(c)(1).

C. Roles of Agencies in Addressing Regional Haze

Successful implementation of the regional haze program will require long-term regional coordination among states, tribal governments and various federal agencies. As noted above, pollution affecting the air quality in Class I areas can be transported over long distances, even hundreds of kilometers. Therefore, to effectively address the problem of visibility impairment in Class I areas, states, or the EPA when implementing a FIP, need to develop strategies in coordination with one another, taking into account the effect of emissions from one jurisdiction on the air quality in another.

Because the pollutants that lead to regional haze can originate from sources located across broad geographic areas, EPA has encouraged the states and tribes across the United States to address visibility impairment from a regional perspective. Five regional planning organizations (RPOs) were developed to address regional haze and related issues. The RPOs first evaluated technical information to better understand how their states and tribes impact Class I areas across the country, and then pursued the development of regional strategies to reduce emissions of particulate matter (PM) and other pollutants leading to regional haze.

The Western Regional Air Partnership (WRAP) RPO is a collaborative effort of state governments, tribal governments, and various federal agencies established to initiate and coordinate activities associated with the management of regional haze, visibility and other air quality issues in the western United States. WRAP member State governments include: Alaska, Arizona, California, Colorado, Idaho, Montana, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. Tribal members include Campo Band of Kumeyaay Indians, Confederated Salish and Kootenai Tribes, Cortina Indian Rancheria, Hopi Tribe, Hualapai Nation of the Grand Canyon, Native Village of Shungnak, Nez Perce Tribe, Northern Cheyenne Tribe, Pueblo of Acoma, Pueblo of San Felipe, and Shoshone-Bannock Tribes of Fort Hall.

IV. Requirements for a Regional Haze FIP

The following is a summary of the requirements of the Regional Haze Rule. See 40 CFR 51.308 for further detail regarding the requirements of the rule.

A. The CAA and the Regional Haze Rule

Regional haze FIPs must assure Reasonable Progress towards the national goal of achieving natural visibility conditions in Class I areas. Section 169A of the CAA and EPA's implementing regulations require states, or EPA when implementing a FIP, to establish long-term strategies for making Reasonable Progress toward meeting this goal. The FIP must also give specific attention to certain stationary sources that were in existence on August 7, 1977, but were not in operation before August 7, 1962, and require these sources, where appropriate, to install BART controls for the purpose of eliminating or reducing visibility impairment. The specific regional haze FIP requirements are discussed in further detail below.

B. EPA's Authority To Promulgate a FIP

On June 19, 2006, Montana submitted a letter to us signifying that the State would be discontinuing its efforts to revise the visibility control plan that would have incorporated provisions of

[2] Areas designated as mandatory Class I Federal areas consist of national parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to ''mandatory Class I Federal areas.'' Each mandatory Class I Federal area is the responsibility of a ''Federal Land Manager.'' 42 U.S.C. 7602(i). When we use the term ''Class I area'' in this action, we mean a ''mandatory Class I Federal area.''

[3] Albuquerque/Bernalillo County in New Mexico must also submit a regional haze SIP to completely satisfy the requirements of section 110(a)(2)(D) of the CAA for the entire State of New Mexico under the New Mexico Air Quality Control Act (section 74–2–4).

[4] EPA's regional haze regulations require subsequent updates to the regional haze SIPs. 40 CFR 51.308(g)–(i).

the Regional Haze Rule.[5] The State acknowledged with this letter that EPA would make a finding of failure to submit and thus promulgate additional federal rules to address the requirements of the Regional Haze Rule, including BART. In response to the State's decision EPA made a finding of SIP inadequacy on January 15, 2009 (74 FR 2392), determining that Montana failed to submit a SIP that addressed any of the required regional haze SIP elements of 40 CFR 51.308.

Under section 110(c) of the Act, whenever we find that a State has failed to make a required submission we are required to promulgate a FIP. Specifically, section 110(c) provides:

''(1) The Administrator shall promulgate a Federal implementation plan at any time within 2 years after the Administrator—

(A) finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under [section 110(k)(1)(A)], or

(B) disapproves a State implementation plan submission in whole or in part, unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan.''

Section 302(y) defines the term ''Federal implementation plan'' in pertinent part, as:

''[A] plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a State implementation plan, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions or emissions allowances) * * *.''

Thus, because the State withdrew their efforts to revise the visibility control plan that would have incorporated provisions of the Regional Haze Rule and we determined the State failed to submit the SIP, we are required to promulgate a FIP.

C. Determination of Baseline, Natural, and Current Visibility Conditions

The Regional Haze Rule establishes the deciview as the principal metric or unit for expressing visibility. *See* 70 FR 39104, 39118 (July 6, 2005). This visibility metric expresses uniform changes in the degree of haze in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions. Visibility expressed in deciviews is determined by using air quality measurements to estimate light extinction and then transforming the value of light extinction using a logarithm function. The deciview is a more useful measure for tracking progress in improving visibility than light extinction itself because each deciview change is an equal incremental change in visibility perceived by the human eye. Most people can detect a change in visibility at one deciview.[6]

The deciview is used in expressing Reasonable Progress Goals (which are interim visibility goals towards meeting the national visibility goal), defining baseline, current, and natural conditions, and tracking changes in visibility. The regional haze FIPs must contain measures that ensure ''reasonable progress'' toward the national goal of preventing and remedying visibility impairment in Class I areas caused by anthropogenic air pollution by reducing anthropogenic emissions that cause regional haze. The national goal is a return to natural conditions, i.e., anthropogenic sources of air pollution would no longer impair visibility in Class I areas.

To track changes in visibility over time at each of the 156 Class I areas covered by the visibility program (40 CFR 81.401–437), and as part of the process for determining Reasonable Progress, states, or EPA when implementing a FIP, must calculate the degree of existing visibility impairment at each Class I area at the time of each regional haze SIP submittal and periodically review progress every five years midway through each 10-year implementation period. To do this, the Regional Haze Rule requires states, or EPA when implementing a FIP, to determine the degree of impairment (in deciviews) for the average of the 20% least impaired (''best'') and 20% most impaired (''worst'') visibility days over a specified time period at each of their Class I areas. In addition, states, or EPA if implementing a FIP, must also develop an estimate of natural visibility conditions for the purpose of comparing progress toward the national goal. Natural visibility is determined by estimating the natural concentrations of pollutants that cause visibility impairment and then calculating total light extinction based on those estimates. We have provided guidance regarding how to calculate baseline, natural and current visibility conditions.[7]

For the first regional haze SIPs that were due by December 17, 2007, ''baseline visibility conditions'' were the starting points for assessing ''current'' visibility impairment. If a state does not submit this SIP, EPA will implement a FIP to cover this requirement. Baseline visibility conditions represent the degree of visibility impairment for the 20% least impaired days and 20% most impaired days for each calendar year from 2000 to 2004. Using monitoring data for 2000 through 2004, states, or EPA if implementing a FIP, are required to calculate the average degree of visibility impairment for each Class I area, based on the average of annual values over the five-year period. The comparison of initial baseline visibility conditions to natural visibility conditions indicates the amount of improvement necessary to attain natural visibility, while the future comparison of baseline conditions to the then current conditions will indicate the amount of progress made. In general, the 2000 to 2004 baseline period is considered the time from which improvement in visibility is measured.

D. Determination of Reasonable Progress Goals (RPGs)

The vehicle for ensuring continuing progress toward achieving the natural visibility goal is the submission of a series of regional haze SIPs from the states that establish two RPGs (*i.e.,* two distinct goals, one for the ''best'' and one for the ''worst'' days) for every Class I area for each (approximately) 10-year implementation period. *See* 40 CFR 51.308(d), (f). However, if a state does not submit a SIP for any of these requirements, then EPA shall implement a FIP. The Regional Haze Rule does not mandate specific milestones or rates of progress, but instead requires EPA to establish goals that provide for ''reasonable progress'' towards achieving natural (*i.e.,* ''background'') visibility conditions. In setting RPGs, EPA must provide for an improvement in visibility for the most

[5] Letter from Richard H. Opper, Director Montana Department of Environmental Quality (further referred to as MDEQ) to Laurel Dygowski, EPA Region Air Program, June 19, 2006.

[6] The preamble to the Regional Haze Rule provides additional details about the deciview. 64 FR 35714, 35725 (July 1, 1999).

[7] *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule,* September 2003, EPA–454/B–03–005, *available* at *http://www.epa.gov/ttncaaa1/t1/memoranda/RegionalHaze_envcurhr_gd.pdf,* (hereinafter referred to as ''our 2003 Natural Visibility Guidance''); and *Guidance for Tracking Progress Under the Regional Haze Rule,* (September 2003, EPA–454/B–03–004, available at *http://www.epa.gov/ttncaaa1/t1/memoranda/rh_tpurhr_gd.pdf,* (hereinafter referred to as our ''2003 Tracking Progress Guidance'').

impaired days over the (approximately) 10-year period of the FIP, and ensure no degradation in visibility for the least impaired days over the same period. *Id.*

In establishing RPGs, states, or EPA if implementing a FIP, are required to consider the following factors established in section 169A of the CAA and in our Regional Haze Rule at 40 CFR 51.308(d)(1)(i)(A): (1) The costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. EPA must demonstrate in our FIP, how these factors are considered when selecting the RPGs for the best and worst days for each applicable Class I area. In setting the RPGs, EPA must also consider the rate of progress needed to reach natural visibility conditions by 2064 (referred to as the ''uniform rate of progress'' or the ''glidepath'') and the emission reduction measures needed to achieve that rate of progress over the 10-year period of the FIP. Uniform progress towards achievement of natural conditions by the year 2064 represents a rate of progress which EPA is to use for analytical comparison to the amount of progress we expect to achieve. In setting RPGs, EPA must also consult with potentially ''contributing states,'' *i.e.,* other nearby states with emission sources that may be affecting visibility impairment at Montana's Class I areas. 40 CFR 51.308(d)(1)(iv). In determining whether EPA's goals for visibility improvement provide for Reasonable Progress toward natural visibility conditions, EPA is required to evaluate the demonstrations developed through our FIP, pursuant to paragraphs 40 CFR 51.308(d)(1)(i) and (d)(1)(ii). 40 CFR 51.308(d)(1)(iii).

E. Best Available Retrofit Technology (BART)

Section 169A of the CAA directs states, or EPA if implementing a FIP, to evaluate the use of retrofit controls at certain larger, often uncontrolled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires EPA to implement a FIP to contain such measures as may be necessary to make Reasonable Progress towards the natural visibility goal, including a requirement that certain categories of existing major stationary sources [8] built between 1962 and 1977 procure, install, and operate the ''Best Available Retrofit Technology'' as determined by EPA. Under the Regional Haze Rule, EPA is directed to conduct BART determinations for such ''BART-eligible'' sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. Rather than requiring source-specific BART controls, EPA also has the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provides greater Reasonable Progress towards improving visibility than BART.

On July 6, 2005, EPA published the *Guidelines for BART Determinations Under the Regional Haze Rule* at appendix Y to 40 CFR part 51 (hereinafter referred to as the ''BART Guidelines'') to assist states, or EPA if implementing a FIP, in determining which of their sources should be subject to the BART requirements and in determining appropriate emission limits for each applicable source. 70 FR 39104 (July 6, 2005). In making a BART determination for a fossil fuel-fired electric generating plant with a total generating capacity in excess of 750 megawatts (MW), EPA must use the approach set forth in the BART Guidelines. EPA is encouraged, but not required, to follow the BART Guidelines in making BART determinations for other types of sources. Regardless of source size or type, EPA must meet the requirements of the CAA and our regulations for selection of BART, and EPA's BART analysis and determination must be reasonable in light of the overarching purpose of the regional haze program.

The process of establishing BART emission limitations can be logically broken down into three steps: first, EPA identifies those sources which meet the definition of ''BART-eligible source'' set forth in 40 CFR 51.301; [9] second, EPA determines which of such sources ''emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area'' (a source which fits this description is ''subject to BART''); and third, for each source subject to BART, EPA then identifies the best available type and level of control for reducing emissions.

States, or EPA if implementing a FIP, must address all visibility-impairing pollutants emitted by a source in the BART determination process. The most significant visibility impairing pollutants are SO_2, NO_X, and PM. EPA has stated that we should use our best judgment in determining whether VOC or NH_3 compounds impair visibility in Class I areas.

Under the BART Guidelines, states, or EPA if implementing a FIP, may select an exemption threshold value for their BART modeling, below which a BART-eligible source would not be expected to cause or contribute to visibility impairment in any Class I area. EPA must document this exemption threshold value in the FIP, and must state the basis for our selection of that value. Any source with emissions that model above the threshold value would be subject to a BART determination review. The BART Guidelines acknowledge varying circumstances affecting different Class I areas. EPA should consider the number of emission sources affecting the Class I areas at issue and the magnitude of the individual sources' impacts. Any exemption threshold set by EPA should not be higher than 0.5 deciviews. 40 CFR part 51, appendix Y, section III.A.1.

A regional haze FIP, must include source-specific BART emission limits and compliance schedules for each source subject to BART. Once EPA has made its BART determination, the BART controls must be installed and in operation as expeditiously as practicable, but no later than five years after the date of the final FIP. CAA section 169(g)(4) and 40 CFR 51.308(e)(1)(iv). In addition to what is required by the Regional Haze Rule, general SIP, or FIP, requirements mandate that the SIP, or FIP, must also include all regulatory requirements related to monitoring, recordkeeping, and reporting for the BART controls on the source. See CAA section 110(a). As noted above, the Regional Haze Rule allows EPA to implement an alternative program in lieu of BART so long as the alternative program can be demonstrated to achieve greater Reasonable Progress toward the national visibility goal than would BART.

F. Long-Term Strategy (LTS)

Consistent with the requirement in section 169A(b) of the CAA that states, or EPA if implementing a FIP, include in the regional haze SIP, or FIP, a 10 to 15 year strategy for making Reasonable Progress, section 51.308(d)(3) of the Regional Haze Rule requires that states, or EPA if implementing a FIP, include a LTS in the regional haze SIP, or FIP. The LTS is the compilation of all control measures that will be used during the implementation period of the FIP to meet applicable RPGs. The LTS must include ''enforceable emissions limitations, compliance schedules, and

[8] The set of ''major stationary sources'' potentially subject to BART is listed in CAA section 169A(g)(7).

[9] BART-eligible sources are those sources that have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were not in operation prior to August 7, 1962, but were in existence on August 7, 1977, and whose operations fall within one or more of 26 specifically listed source categories. 40 CFR 51.301.

other measures as necessary to achieve the reasonable progress goals'' for all Class I areas within, or affected by emissions from, the state of Montana. 40 CFR 51.308(d)(3).

When a state's emissions are reasonably anticipated to cause or contribute to visibility impairment in a Class I area located in another state, the Regional Haze Rule requires the impacted state, or EPA if implementing a FIP, to coordinate with the contributing states in order to develop coordinated emissions management strategies. 40 CFR 51.308(d)(3)(i). In such cases, EPA must demonstrate that it has included in its FIP, all measures necessary to obtain its share of the emission reductions needed to meet the RPGs for the Class I area. *Id.* at (d)(3)(ii). The RPOs have provided forums for significant interstate consultation, but additional consultations between states, or EPA if implementing a FIP, may be required to sufficiently address interstate visibility issues. This is especially true where two states belong to different RPOs.

States, or EPA if implementing a FIP, should consider all types of anthropogenic sources of visibility impairment in developing their LTS, including stationary, minor, mobile, and area sources. At a minimum, EPA must describe how each of the following seven factors listed below are taken into account in developing our LTS: (1) Emission reductions due to ongoing air pollution control programs, including measures to address Reasonably Attributable Visibility Impairment; (2) measures to mitigate the impacts of construction activities; (3) emissions limitations and schedules for compliance to achieve the RPG; (4) source retirement and replacement schedules; (5) smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for these purposes; (6) enforceability of emissions limitations and control measures; and (7) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the LTS. 40 CFR 51.308(d)(3)(v).

G. Coordinating Regional Haze and Reasonably Attributable Visibility Impairment (RAVI)

As part of the Regional Haze Rule, EPA revised 40 CFR 51.306(c) regarding the LTS for RAVI to require that the RAVI plan must provide for a periodic review and SIP revision not less frequently than every three years until the date of submission of the state's first plan addressing regional haze visibility impairment, which was due December 17, 2007, in accordance with 40 CFR 51.308(b) and (c). On or before this date, the state must revise its plan to provide for review and revision of a coordinated LTS for addressing RAVI and regional haze, and the state must submit the first such coordinated LTS with its first regional haze SIP. If the state does not revise its plan in the appropriate amount of time, EPA shall implement a FIP to address this requirement. Future coordinated LTS's, and periodic progress reports evaluating progress towards RPGs, must be submitted consistent with the schedule for SIP submission and periodic progress reports set forth in 40 CFR 51.308(f) and 51.308(g), respectively. The periodic review of a state's LTS must report on both regional haze and RAVI impairment and must be submitted to EPA as a SIP revision. However, if the state does not provide future coordinated LTS and periodic progress reports towards RPGs then EPA will cover this by implementing a FIP.

H. Monitoring Strategy and Other Implementation Plan Requirements

Section 51.308(d)(4) of the Regional Haze Rule includes the requirement for a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all mandatory Class I Federal areas within the state. The strategy must be coordinated with the monitoring strategy required in section 51.305 for RAVI. Compliance with this requirement may be met through ''participation'' in the IMPROVE network, i.e., review and use of monitoring data from the network. The monitoring strategy is due with the first regional haze SIP, and it must be reviewed every five (5) years. The monitoring strategy must also provide for additional monitoring sites if the IMPROVE network is not sufficient to determine whether RPGs will be met.

Under section 51.308(d)(4), the SIP must also provide for the following:

- Procedures for using monitoring data and other information in a state with mandatory Class I areas to determine the contribution of emissions from within the state to regional haze visibility impairment at Class I areas both within and outside the state;
- Procedures for using monitoring data and other information in a state with no mandatory Class I areas to determine the contribution of emissions from within the state to regional haze visibility impairment at Class I areas in other states;
- Reporting of all visibility monitoring data to the Administrator at least annually for each Class I area in the state, and where possible, in electronic format;
- Developing a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any Class I area. The inventory must include emissions for a baseline year, emissions for the most recent year for which data are available, and estimates of future projected emissions. A state must also make a commitment to update the inventory periodically; and
- Other elements, including reporting, recordkeeping, and other measures necessary to assess and report on visibility.

The Regional Haze Rule requires control strategies to cover an initial implementation period extending to the year 2018, with a comprehensive reassessment and revision of those strategies, as appropriate, every 10 years thereafter. Periodic SIP revisions must meet the core requirements of section 51.308(d), with the exception of BART. The requirement to evaluate sources for BART applies only to the first Regional Haze SIP. Facilities subject to BART must continue to comply with the BART provisions of section 51.308(e). Periodic SIP revisions will assure that the statutory requirement of reasonable progress will continue to be met.

I. Consultation with States and Federal Land Managers (FLMs)

The Regional Haze Rule requires that states, or EPA if implementing a FIP, consult with FLMs before adopting and submitting their SIPs, or FIPs. 40 CFR 51.308(i). EPA must provide FLMs an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on the FIP. This consultation must include the opportunity for the FLMs to discuss their assessment of impairment of visibility in any Class I area and to offer recommendations on the development of the RPGs and on the development and implementation of strategies to address visibility impairment. Further, EPA must include in its FIP, a description of how it addressed any comments provided by the FLMs. Finally, a FIP must provide procedures for continuing consultation between EPA and FLMs regarding EPA's FIP, visibility protection program, including development and review of FIP revisions, five-year progress reports, and the implementation of other programs having the potential to contribute to impairment of visibility in Class I areas.

V. EPA's Analysis of Montana's Regional Haze

A. Affected Class I Areas

In accordance with 40 CFR 51.308(d), we have identified 12 Class I areas within Montana: Anaconda-Pintler WA, Bob Marshall WA, Cabinet Mountains WA, Gates of the Mountains WA, Glacier NP, Medicine Lake WA, Mission Mountain WA, Red Rock Lakes WA, Scapegoat WA, Selway-Bitterroot WA, U.L. Bend WA and Yellowstone NP. EPA is responsible for developing RPGs for these 12 Class I areas. EPA has also determined that Montana emissions have or may reasonably be expected to have impacts at Class I areas in other states including: Badlands WA, Bridger WA, Craters of the Moon WA, Fitzpatrick WA, Grand Teton NP, Hells Canyon WA, Lostwood National Wildlife Reserve (NWR), North Absaroka NP, Teton WA, Theodore Roosevelt NP, Washakie WA and Wind Cave NP. This determination was based on Particulate Matter Source Apportionment Technology (PSAT) and Weighted Emissions Potential (WEP) analysis and is further described in Table 150.

EPA worked with the appropriate state air quality agency in each of these states through our involvement with the WRAP. The WRAP is a collaborative effort of tribal governments, state governments and various federal agencies to implement the Grand Canyon Visibility Transport Commission's recommendations and to develop the technical and policy tools needed by western states and tribes to comply with the U.S. EPA's regional haze regulations. Assessment of Montana's contribution to haze in these Class I areas is based on technical analyses developed by WRAP as discussed in this notice.

B. Baseline Visibility, Natural Visibility, and Uniform Rate of Progress

As required by section 51.308(d)(2)(i) of the Regional Haze Rule and in accordance with our 2003 Natural Visibility Guidance, EPA calculated baseline/current and natural visibility conditions for the Montana Class I areas, Anaconda-Pintler WA, Bob Marshall WA, Cabinet Mountains WA, Gates of the Mountains WA, Glacier NP, Medicine Lake WA, Mission Mountain WA, Red Rock Lakes WA, Scapegoat WA, Selway-Bitterroot WA, U.L. Bend WA and Yellowstone NP on the most impaired and least impaired days, as summarized below (and further described in the docket).[10] The natural visibility conditions, baseline visibility conditions, and visibility impact reductions needed to achieve the Uniform Rate of Progress (URP) in 2018 for all Montana Class I areas are presented in Table 1 and further explained in this section.

TABLE 1—VISIBILITY IMPACT REDUCTIONS NEEDED BASED ON BEST AND WORST DAYS BASELINES, NATURAL CONDITIONS, AND UNIFORM RATE OF PROGRESS GOALS FOR MONTANA CLASS I AREAS

Montana class I area	20% Worst days				20% Best days	
	2000–2004 Baseline (deciview)	2018 URP Goal (deciview)	2018 Reduction needed (delta deciview)	2064 Natural conditions (deciview)	2000–2004 Baseline (deciview)	2064 Natural conditions (deciview)
Anaconda-Pintler WA	13.41	12.02	1.39	7.43	2.58	1.12
Bob Marshall WA	14.48	12.91	1.57	7.73	3.85	1.48
Cabinet Mountains WA	14.09	12.56	1.53	7.52	3.62	1.48
Gates of the Mountains WA	11.29	10.15	1.14	6.38	1.71	0.32
Glacier NP	22.26	19.21	3.05	9.18	7.22	2.42
Medicine Lake WA	17.72	15.42	2.30	7.89	7.26	2.96
Mission Mountain WA	14.48	12.91	1.57	7.73	3.85	1.48
Red Rock Lakes WA	11.76	10.52	1.24	6.44	2.58	0.43
Scapegoat WA	14.48	12.91	1.57	7.73	3.85	1.48
Selway-Bitterroot WA	13.41	12.02	1.39	7.43	2.58	1.12
U.L. Bend WA	15.14	13.51	1.63	8.16	4.75	2.45
Yellowstone NP	11.76	10.52	1.24	6.44	2.58	0.43

1. Estimating Natural Visibility Conditions

Natural background visibility, as defined in our 2003 Natural Visibility Guidance, is estimated by calculating the expected light extinction using default estimates of natural concentrations of fine particle components adjusted by site-specific estimates of humidity. This calculation uses the IMPROVE equation, which is a formula for estimating light extinction from the estimated natural concentrations of fine particle components (or from components measured by the IMPROVE monitors). As documented in our 2003 Natural Visibility Guidance, EPA allows the use of ''refined'' or alternative approaches to this guidance to estimate the values that characterize the natural visibility conditions of Class I areas. One alternative approach is to develop and justify the use of alternative estimates of natural concentrations of fine particle components. Another alternative is to use the ''new IMPROVE equation'' that was adopted for use by the IMPROVE Steering Committee in December 2005 and the Natural Conditions II algorithm that was finalized in May 2007.[11] The purpose of this refinement to the ''old IMPROVE equation'' is to provide more

[10] Information presented here was taken from the WRAP TSS (*http://vista.cira.colostate.edu/tss/*). Some of this information was printed and is available in the docket in the document titled Selected Information from the WRAP TSS (''WRAP TSS Information'').

[11] The IMPROVE program is a cooperative measurement effort governed by a steering committee composed of representatives from Federal agencies (including representatives from EPA and the FLMs) and RPOs. The IMPROVE monitoring program was established in 1985 to aid the creation of Federal and State implementation plans for the protection of visibility in Class I areas. One of the objectives of IMPROVE is to identify chemical species and emission sources responsible for existing anthropogenic visibility impairment. The IMPROVE program has also been a key instrument in visibility-related research, including the advancement of monitoring instrumentation, analysis techniques, visibility modeling, policy formulation and source attribution field studies. *http://vista.cira.colostate.edu/improve/Publications/GrayLit/gray_literature.htm.*

accurate estimates of the various factors that affect the calculation of light extinction.

For all 12 Class I Areas in Montana, EPA opted to use WRAP calculations in which the default estimates for the natural conditions (see Table 2) were combined with the ''new IMPROVE equation'' and the Natural Conditions II algorithm (see Table 3). This is an acceptable approach under our 2003 Natural Visibility Guidance. Table 2 shows the default natural visibility values for the 20% worst days and 20% best days.

TABLE 2—DEFAULT NATURAL VISIBILITY VALUES FOR THE 20% BEST DAYS AND 20% WORST DAYS

Class I area	20% Worst days	20% Best days
Anaconda-Pintler WA	7.28	2.16
Bob Marshall WA	7.36	2.24
Cabinet Mountains WA	7.43	2.31
Gates of the Mountains WA	7.22	2.10
Glacier NP	7.56	2.44
Medicine Lake WA	7.30	2.18
Mission Mountain WA	7.39	2.27
Red Rock Lakes WA	7.14	2.02
Scapegoat WA	7.29	2.17
Selway-Bitterroot WA	7.32	2.20
U.L. Bend WA	7.18	2.06
Yellowstone NP	7.12	2.00

EPA also referred to WRAP calculations using the new IMPROVE equation. Table 3 shows the natural visibility values for each Class I Area for the 20% worst days and 20% best days using the new IMPROVE Equation and Natural Conditions II algorithm.

TABLE 3—VISIBILITY VALUES FOR THE 20% BEST DAYS AND 20% WORST DAYS USING THE NEW IMPROVE EQUATION

Class I area	20% Worst days	20% Best days
Anaconda-Pintler WA	7.43	1.12
Bob Marshall WA	7.73	1.48
Cabinet Mountains WA	7.52	1.48
Gates of the Mountains WA	6.38	0.32
Glacier NP	9.18	2.42
Medicine Lake WA	7.89	2.96
Mission Mountain WA	7.73	1.48
Red Rock Lakes WA	6.44	0.43
Scapegoat WA	7.73	1.48
Selway-Bitterroot WA	7.43	1.12
U.L. Bend WA	8.16	2.45
Yellowstone NP	6.44	0.43

The new IMPROVE equation takes into account the most recent review of the science [12] and accounts for the effect of particle size distribution on light extinction efficiency of sulfate, nitrate, and OC. It also adjusts the mass multiplier for OC (particulate organic matter) by increasing it from 1.4 to 1.8. New terms are added to the equation to account for light extinction by sea salt and light absorption by gaseous nitrogen dioxide. Site-specific values are used for Rayleigh scattering (scattering of light due to atmospheric gases) to account for the site-specific effects of elevation and temperature. Separate relative humidity enhancement factors are used for small and large size distributions of ammonium sulfate and ammonium nitrate and for sea salt. The terms for the remaining contributors, EC (light-absorbing carbon), fine soil, and coarse mass terms, do not change between the original and new IMPROVE equations.

2. Estimating Baseline Conditions

As required by section 51.308(d)(2)(i) of the Regional Haze Rule and in accordance with our 2003 Natural Visibility Guidance, EPA calculated baseline visibility conditions for Anaconda-Pintler WA, Bob Marshall WA, Cabinet Mountains WA, Gates of the Mountains WA, Glacier NP, Medicine Lake WA, Mission Mountain WA, Red Rock Lakes WA, Scapegoat WA, Selway-Bitterroot WA, U.L. Bend WA and Yellowstone NP. The baseline condition calculation begins with the calculation of light extinction, using the IMPROVE equation. The IMPROVE equation sums the light extinction [13] resulting from individual pollutants, such as sulfates and nitrates. As with the natural visibility conditions calculation, EPA chose to use the new IMPROVE equation.

The period for establishing baseline visibility conditions is 2000 through 2004, and baseline conditions must be calculated using available monitoring data. 40 CFR 51.308(d)(2). This FIP proposes to use visibility monitoring data collected by IMPROVE monitors located in all Montana Class I areas for the years 2000 through 2004 and the resulting baseline conditions represent an average for 2000 through 2004. Table 4 shows the baseline conditions for each Class I area.

TABLE 4—BASELINE CONDITIONS ON 20% WORST DAYS AND 20% BEST DAYS

Class I area	20% Worst days	20% Best days
Anaconda-Pintler WA	13.41	2.58
Bob Marshall WA	14.48	3.85
Cabinet Mountains WA	14.09	3.62
Gates of the Mountains WA	11.29	1.71
Glacier NP	22.26	7.22
Medicine Lake WA	17.72	7.26
Mission Mountain WA	14.48	3.85
Red Rock Lakes WA	11.76	2.58
Scapegoat WA	14.48	3.85
Selway-Bitterroot WA	13.41	2.58
U.L. Bend WA	15.14	4.75
Yellowstone NP	11.76	2.58

3. Summary of Baseline and Natural Conditions

To address the requirements of 40 CFR 51.308(d)(2)(iv)(A), EPA also calculated the number of deciviews by which baseline conditions exceed natural visibility conditions at each Class I area. Table 5 shows the number of deciviews by which baseline conditions exceed natural visibility conditions at each Class I area.

TABLE 5—NUMBER OF DECIVIEWS BY WHICH BASELINE CONDITIONS EXCEED NATURAL VISIBILITY CONDITIONS

Class I area	20% Worst days	20% Best days
Anaconda-Pintler WA	5.98	1.46
Bob Marshall WA	6.75	2.37
Cabinet Mountains WA	6.57	2.14
Gates of the Mountains WA	4.91	1.39
Glacier NP	13.08	4.8
Medicine Lake WA	9.83	4.3
Mission Mountain WA	6.75	2.37
Red Rock Lakes WA	5.32	2.15
Scapegoat WA	6.75	2.37
Selway-Bitterroot WA	5.98	1.46

[12] The science behind the revised IMPROVE equation is summarized in our technical support document (TSD), in the TSD for Technical Products Prepared by the WRAP in Support of Western Regional Haze Plans (''WRAP TSD''), February 28, 2011, and in numerous published papers. See for example: Hand, J.L., and Malm, W.C., 2006, *Review of the IMPROVE Equation for Estimating Ambient Light Extinction Coefficients—Final Report.* March 2006. Prepared for IMPROVE, Colorado State University, Cooperative Institute for Research in the Atmosphere, Fort Collins, Colorado, *available at http://vista.cira.colostate.edu/improve/publications/GrayLit/016_IMPROVEeqReview/IMPROVEeqReview.htm* and Pitchford, March 2006, *Natural Haze Levels II: Application of the New IMPROVE Algorithm to Natural Species Concentrations Estimates.* Final Report of the Natural Haze Levels II Committee to the RPO Monitoring/Data Analysis Workgroup. September 2006, *available at http://vista.cira.colostate.edu/improve/Publications/GrayLit/029_NaturalCondII/naturalhazelevelsIIreport.ppt.*

[13] The amount of light lost as it travels over one million meters. The haze index, in units of deciviews, is calculated directly from the total light extinction, b_{ext} expressed in inverse megameters (Mm^{-1}), as follows: $HI = 10 \ln(b_{ext}/10)$.

TABLE 5—NUMBER OF DECIVIEWS BY WHICH BASELINE CONDITIONS EXCEED NATURAL VISIBILITY CONDITIONS—Continued

Class I area	20% Worst days	20% Best days
U.L. Bend WA	6.98	2.3
Yellowstone NP	5.32	2.15

4. Uniform Rate of Progress

In setting the RPGs, EPA reviewed and relied on the WRAP analysis to analyze and determine the URP needed to reach natural visibility conditions by the year 2064. In so doing, the analysis compared the baseline visibility conditions in each Class I area to the natural visibility conditions in each Class I area (as described above) and determined the URP needed in order to attain natural visibility conditions by 2064 in all Class I areas. The analysis constructed the URP consistent with the requirements of the Regional Haze Rule and consistent with our 2003 Tracking Progress Guidance by plotting a straight graphical line from the baseline level of visibility impairment for 2000 through 2004 to the level of visibility conditions representing no anthropogenic impairment in 2064 for each Class I area. The URPs are summarized in Table 6. It is clear from Table 6 that there is a large range of baseline and natural visibility conditions across the 12 Class I areas in Montana. The degree of improvement to meet the URP at these sites varies from, 1.24 deciviews at Yellowstone NP to 3.05 deciviews at Glacier NP.

TABLE 6—SUMMARY OF UNIFORM RATE OF PROGRESS FOR 20% WORST DAYS

Class I area	Baseline conditions (deciview)	Natural visibility (deciview)	Total improvement by 2064 (deciview)	URP (deciview/year)	2018 URP target (deciview)	Improvement by 2018 (deciview)
Anaconda-Pintler WA	13.41	7.43	5.98	0.10	12.02	1.39
Bob Marshall WA	14.48	7.73	6.75	0.11	12.91	1.57
Cabinet Mountains WA	14.09	7.52	6.57	0.11	12.56	1.53
Gates of the Mountains WA	11.29	6.38	4.91	0.08	10.15	1.14
Glacier NP	22.26	9.18	13.08	0.22	19.21	3.05
Medicine Lake WA	17.72	7.89	9.83	0.16	15.42	2.3
Mission Mountain WA	14.48	7.73	6.75	0.11	12.91	1.57
Red Rock Lakes WA	11.76	6.44	5.32	0.09	10.52	1.24
Scapegoat WA	14.48	7.73	6.75	0.11	12.91	1.57
Selway-Bitterroot WA	13.41	7.43	5.98	0.10	12.02	1.39
U.L. Bend WA	15.14	8.16	6.98	0.12	13.51	1.63
Yellowstone NP	11.76	6.44	5.32	0.09	10.52	1.24

5. Contribution Assessment According to IMPROVE Monitoring Data

The visibility and pollutant contributions on the 20% worst visibility days for the baseline period (2000–2004) show considerable variation across the 12 Class I areas in Montana. Table 7 shows average data from the IMPROVE monitors for 2000 to 2004.[14] The table shows light extinction from specific pollutants as well as total extinction, as determined by the monitoring data. As stated above, this data provides further detail regarding the considerable variation across the 12 Class I areas in Montana.

TABLE 7—SPECIES-SPECIFIC LIGHT EXTINCTION DETERMINED FROM MONITORING DATA

Class I area	Deciview	Sulfate	Nitrate	Organic carbon	Elemental carbon	Soil	Sea salt	Coarse matter	Total extinction
Anaconda-Pintler WA	13.41	4.83	1.46	20.01	2.52	0.94	0.26	2.49	42.52
Bob Marshall WA	14.48	5.12	1.43	22.29	2.80	1.29	0.03	3.60	46.58
Cabinet Mountains WA	14.09	6.48	2.02	16.95	2.79	1.03	0.10	2.81	42.18
Gates of the Mountains WA	11.29	5.41	1.88	11.26	1.82	0.75	0.06	1.68	31.85
Glacier NP	22.26	11.37	9.36	87.68	11.20	1.40	0.28	5.22	137.50
Medicine Lake WA	17.72	16.96	16.27	9.48	2.34	0.75	0.03	4.46	61.30
Mission Mountains WA	14.48	5.12	1.43	22.29	2.80	1.29	0.03	3.60	46.58
Red Rock Lakes WA	11.76	4.26	1.77	13.48	2.48	0.95	0.02	2.58	34.55
Scapegoat WA	14.48	5.12	1.43	22.29	2.80	1.29	0.03	3.60	46.58
Selway-Bitterroot WA	13.41	4.83	1.46	20.01	2.52	0.94	0.26	2.49	42.52
U.L. Bend WA	15.14	9.78	8.01	12.76	2.08	0.77	0.01	4.01	48.43
Yellowstone NP	11.76	4.26	1.77	13.48	2.48	0.95	0.02	2.58	34.55

The poorest visibility on the 20% worst days was at Glacier NP at 22.26 deciviews, while the best visibility was at Gates of the Mountains WA at 11.26 deciviews. Fire appears to be a major factor contributing to the spatial differences. The five-year average contributions in Table 7 indicate that Glacier NP has significantly higher contributions from organic carbon mass than Gates of the Mountains WA. The daily monitoring data for Glacier NP shows an episode of exceptionally high organic carbon mass during August 2003 that indicates a fire event. This single episode influenced the five-year average values for Glacier NP.

[14] Additional data and information can be found at: *http://views.cira.colostate.edu/web/DataFiles/SummaryDataFiles.aspx.*

C. BART Determinations

BART is an element of EPA's LTS for the first implementation period. As discussed in more detail in section IV.E of this preamble, the BART evaluation process consists of three components: (1) An identification of all the BART-eligible sources; (2) an assessment of whether those BART-eligible sources are in fact subject to BART; and (3) a determination of any BART controls. EPA addressed these steps as follows:

1. BART-Eligible Sources

The first step of a BART evaluation is to identify all the BART-eligible sources within the state's boundaries. While Montana did not submit a SIP, the State did provide some useful information; and as discussed below, we are proposing it as our conclusion.

EPA used some information and analyses developed by Montana as described below.

Montana identified the following 10 sources to be BART-eligible: ASARCO LLC East Helena Plant; Ash Grove Cement Company; Cenex Harvest States Cooperative; Laurel Refinery; PPL Montana, LLC; Colstrip Steam Electric Station Units 1 and 2; Columbia Falls Aluminum Company, LLC; ExxonMobil Refining & Supply Company Billings Refinery; Holcim (US), Inc,; Montana Sulfur & Chemical Company; and Smurfit-Stone Container Enterprises Inc, Missoula Mill.[15] Montana originally identified ASARCO LLC East Helena Plant as BART-eligible; however, the emission units at the facility have since been demolished. Thus, we are proposing that the ASARCO LLC East Helena Plant is not BART-eligible.[16]

The State identified the BART-eligible sources in Montana by utilizing the approach set out in the BART Guidelines (70 FR 39158 (July 6, 2005)); [17] this approach provides three criteria for identifying BART-eligible sources: (1) One or more emission units at the facility fit within one of the 26 categories listed in the BART Guidelines; (2) the emission unit(s) began operation on or after August 6, 1962, and was in existence on August 6, 1977; and (3) potential emissions of any visibility-impairing pollutant from subject units are 250 tons or more per year. Montana initially screened its records to identify facilities that could potentially meet the three criteria in the BART Guidelines (70 FR 39158 (July 6, 2005)). Montana contacted the sources identified through its screening efforts, through a series of letters, to obtain or confirm this information.[18]

The WRAP also reviewed facility information to identify BART-eligible sources. The WRAP used the Preliminary 2002 National Emission Inventory (NEI) to identify all facilities whose actual emissions exceed 100 tons per year (tpy) or more of any visibility-impairing pollutant. The WRAP added sources to this preliminary list if they were identified by the states or tribes; found in various CAA Title V, U.S. Department of Energy, and EPA databases; or found in EPA background documents such as those prepared for New Source Performance Standards (NSPS), maximum achievable control technology standards, and AP–42 emission factors. The WRAP then considered category, date of construction, and PTE information to determine eligibility. The results from this analysis identified facilities as BART-eligible, potentially BART-eligible, not known, or not BART-eligible.[19]

We have reviewed the ''Master List of Montana Sources Reviewed'' in the report titled ''Identification of BART Eligible Sources in the WRAP Region'' dated April 4, 2005. We propose to determine that the following nine facilities identified as BART-eligible by the State and the WRAP are BART-eligible: Ash Grove Cement Company; Cenex Harvest States Cooperative, Laurel Refinery; PPL Montana, LLC, Colstrip Steam Electric Station Units 1 and 2; Columbia Falls Aluminum Company, LLC; ExxonMobil Refining & Supply Company Billings Refinery; Holcim (US); Inc, Montana Sulfur & Chemical Company; and Smurfit-Stone Container Enterprises Inc, Missoula Mill. We propose to determine that the other facilities identified in the WRAP's April 4, 2005 list as ''potentially BART-eligible'', ''not known'', or ''not BART-eligible'' are not BART-eligible.

The BART Guidelines require that we address SO_2, NO_X, and direct PM (including both coarse particulate matter (PM_{10}) and $PM_{2.5}$) emissions as visibility-impairing pollutants and to exercise our ''best judgment to determine whether VOC or ammonia emissions from a source are likely to have an impact on visibility in an area.'' See 70 FR 39160, July 6, 2005. VOCs and NH_3 from point sources are not significant visibility-impairing pollutants at Montana's Class I areas. Point sources contribute less than 1% to Montana's inventory for both NH_3 and VOC emissions.[20] As a result, we have determined that the emissions from these point sources do not merit BART review.

We are proposing that the nine Montana facilities listed in Table 8 are the BART-eligible sources in the State.

TABLE 8—LIST OF BART-ELIGIBLE SOURCES IN MONTANA

BART-eligible source	Location	BART Source category (SC)	Nearest class I area
1. Ash Grove Cement Company	Montana City, western Montana	Portland cement plants	Gates of the Mountains WA 30 km.
2. Cenex Harvest States Cooperatives Laurel Refinery.	Laurel, central Montana	Petroleum refineries	North Absaroka WA 113 km.
3. PPL Montana, LLC Colstrip Steam Electric Station (Unit 1 and Unit 2).	Colstrip, southeastern Montana	Fossil-fuel fired steam electric plants of more than 250 million BTUs per hour heat input.	U.L. Bend WA 200 km.
4. Columbia Falls Aluminum Company, LLC.	Columbia Falls, northwestern Montana.	Primary aluminum ore reduction plants.	Glacier NP 10 km.
5. ExxonMobil Refinery & Supply Company, Billings Refinery.	Billings, central Montana	Petroleum refineries	North Absaroka WA 143 km.

[15] This list can be found in the docket with the title, Montana BART-Eligible Facility List.

[16] Correspondence between ASARCO LLC and EPA can be found in the docket in the file titled ASARCO Correspondence.

[17] The flow charts that Montana used to identify BART-eligible sources are included in the docket in a file titled Montana BART Flow Charts.

[18] Examples of the letters sent to the Montana facilities are included in the docket in a file titled Montana Letters.

[19] The WRAP's work is documented in the document titled, ''Identification of BART-Eligible Sources in the WRAP Region'' dated April 4, 2005. The ''Master List of Montana Sources Reviewed'' in this report is a second document from the one that is referred to in a previous footnote titled, ''Montana BART-Eligible Facility List''.

[20] WRAP TSS Information.

TABLE 8—LIST OF BART-ELIGIBLE SOURCES IN MONTANA—Continued

BART-eligible source	Location	BART Source category (SC)	Nearest class I area
6. Holcim (US), Inc.	Three Forks, western Montana	Portland cement plants	Yellowstone NP 100 km.
7. PPL Montana, LLC—JE Corette Steam Electric Station.	Billings, central Montana	Fossil-fuel fired steam electric plants of more than 250 million BTUs per hour heat input.	North Absaroka WA 137 km.
8. Montana Sulfur & Chemical Company.	Billings, central Montana	Chemical process plants	North Absaroka WA 143 km.
9. Smurfit-Stone Container Enterprises Inc., Missoula Mill.	Missoula, northwestern Montana	Kraft pulp mills and fossil fuel boilers of more than 250 million BTUs per hour heat input.	Selway-Bitterroot WA 32 km.

2. Sources Subject to BART

The second step of the BART evaluation is to identify those BART-eligible sources that may reasonably be anticipated to cause or contribute to any visibility impairment at any Class I area, i.e., those sources that are subject to BART. The BART Guidelines allow us to consider exempting some BART-eligible sources from further BART review because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. Consistent with the BART Guidelines, the WRAP performed dispersion modeling to assess the extent of each BART-eligible source's contribution to visibility impairment at surrounding Class I areas and we propose to use that modeling.

a. Modeling Methodology

The BART Guidelines provide that we may use the CALPUFF [21] modeling system or another appropriate model to predict the visibility impacts from a single source on a Class I area and to, therefore, determine whether an individual source is anticipated to cause or contribute to impairment of visibility in Class I areas, *i.e.,* ''is subject to BART.'' The Guidelines state that we find CALPUFF is the best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment (70 FR 39162 (July 6, 2005)).

The BART Guidelines also recommend that a modeling protocol be developed for making individual source attributions. To determine whether each BART-eligible source has a significant impact on visibility, we propose to use the WRAP's modeling that used the CALPUFF model to estimate daily visibility impacts above estimated natural conditions at each Class I area within 300 kilometers (km) of any BART-eligible facility, based on maximum actual 24-hour emissions over a 3-year period (2000–2002). The modeling followed the WRAP protocol, CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States, August 15, 2006, which was approved by EPA.[22]

b. Contribution Threshold

For the modeling to determine the applicability of BART to single sources, the BART Guidelines note that the first step is to set a contribution threshold to assess whether the impact of a single source is sufficient to cause or contribute to visibility impairment at a Class I area. The BART Guidelines state that, ''[a] single source that is responsible for a 1.0 deciview change or more should be considered to 'cause' visibility impairment.'' 70 FR 39161, July 5, 2005. The BART Guidelines also state that ''the appropriate threshold for determining whether a source contributes to visibility impairment may reasonably differ across states,'' but, ''[a]s 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.'' *Id.* Further, in setting a contribution threshold, states or EPA should ''consider the number of emissions sources affecting the Class I areas at issue and the magnitude of the individual sources' impacts.'' The Guidelines affirm that states and EPA are free to use a lower threshold if they conclude that the location of a large number of BART-eligible sources in proximity to a Class I area justifies this approach.

EPA proposes to use a contribution threshold of 0.5 deciviews for determining which sources are subject to BART. EPA's proposal considered the numerous sources affecting the Class I areas and the magnitude of the individual sources impacts. 70 FR 39121, July 6, 2005. As shown in Table 9, EPA proposes to exempt four of the nine BART-eligible sources in the State from further review under the BART requirements. The visibility impacts attributable to each of these three sources fell well below 0.5 deciviews. Our proposed contribution threshold captures those sources responsible for most of the total visibility impacts, while still excluding other sources with very small impacts. *Id.*

c. Sources Identified by EPA as BART–Eligible and Subject to BART

The results of the CALPUFF modeling are summarized in Table 9. Those facilities listed with demonstrated impacts at all Class I areas less than 0.5 deciviews are proposed by EPA to not be subject to BART; those with impacts greater than 0.5 deciviews are proposed by EPA to be subject to BART.

[21] Note that our reference to CALPUFF encompasses the entire CALPUFF modeling system, which includes the CALMET, CALPUFF, and CALPOST models and other pre and post processors. The different versions of CALPUFF have corresponding versions of CALMET, CALPOST, etc. which may not be compatible with previous versions (e.g., the output from a newer version of CALMET may not be compatible with an older version of CALPUFF). The different versions of the CALPUFF modeling system are available from the model developer at *http://www.src.com/calpuff/calpuff1.htm.*

[22] This approval is described on p. 57 of the WRAP TSD. The WRAP protocol, CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States, August 15, 2006 can be found in the docket.

TABLE 9—INDIVIDUAL BART-ELIGIBLE SOURCE VISIBILITY IMPACTS ON MONTANA CLASS I AREAS

Source and unit	Class I area	Maximum 24-hour 98th percentile visibility impact (deciview)	Subject to BART or exempt
1. Ash Grove Cement Company	Gates of the Mountains WA	2.52	Subject to BART.
	Scapegoat WA	0.42	
	Anaconda-Pintler WA	0.09	
	Bob Marshall WA	0.39	
	Mission Mountains WA	0.06	
	Selway-Bitterroot WA	0.01	
	Yellowstone NP	0.01	
	Red Rock Lakes WA	0.00	
	Theodore Roosevelt NP	0.10	
	North Absaroka WA	0.00	
	Washakie WA	0.00	
	Teton WA	0.00	
2. Cenex Harvest States Cooperatives, Laurel Refinery.	North Absaroka WA	0.04	Exempt.
	Yellowstone NP	0.02	
	Washakie WA	0.03	
	Teton WA	0.01	
	U.L. Bend WA	0.00	
	Red Rocks Lake WA	0.00	
	Gates of the Mountains WA	0.00	
3. PPL Montana, LLC Colstrip Steam Electric Station Units 1 and 1.	U.L. Bend WA	2.52	Subject to BART.
	North Absaroka WA	1.35	
	Theodore Roosevelt NP	2.28	
	Washakie WA	0.69	
	Yellowstone NP	0.86	
4. Columbia Falls Aluminum Company, LLC	Glacier NP	4.54	Subject to BART.
	Bob Marshall WA	0.11	
	Mission Mountains WA	0.08	
	Cabinet Mountains WA	0.12	
	Scapegoat WA	0.05	
	Selway-Bitterroot WA	0.03	
	Gates of the Mountains WA	0.03	
	Anaconda-Pintler WA	0.02	
5. ExxonMobil Refinery & Supply Company, Billings Refinery.[23]	North Absaroka WA	0.27	Exempt.
	Yellowstone NP	0.17	
	Washakie WA	0.22	
	U.L. Bend WA	0.23	
	Teton WA	0.10	
	Gates of the Mountains WA	0.22	
	Red Rock Lakes WA	0.09	
6. Holcim (US), Inc.	Yellowstone NP	0.52	Subject to BART.
	Gates of the Mountains WA	1.02	
	Anaconda-Pintler WA	0.23	
	Red Rock Lakes WA	0.20	
	Scapegoat WA	0.28	
	North Absaroka WA	0.43	
	Bob Marshall WA	0.28	
	Washakie WA	0.11	
	Theodore Roosevelt NP	0.08	
	Selway-Bitterroot WA	0.15	
	Mission Mountains WA	0.12	
	Glacier NP	0.11	
7. PPL Montana, LLC-JE Corette Steam Electric Station.	North Absaroka WA	0.74	Subject to BART.
	Yellowstone NP	0.45	
	Washakie WA	0.53	
	U.L. Bend WA	0.91	
	Teton WA	0.22	
	Gates of the Mountains WA	0.52	
	Red Rock Lakes WA	0.21	
8. Montana Sulfur & Chemical Company	North Absaroka WA	0.22	Exempt.
	Yellowstone NP	0.17	
	Washakie WA	0.16	
	U.L. Bend WA	0.30	
	Teton WA	0.08	
	Gates of the Mountains WA	0.19	

TABLE 9—INDIVIDUAL BART-ELIGIBLE SOURCE VISIBILITY IMPACTS ON MONTANA CLASS I AREAS—Continued

Source and unit	Class I area	Maximum 24-hour 98th percentile visibility impact (deciview)	Subject to BART or exempt
	Red Rock Lakes WA	0.09	
	Selway-Bitterroot WA	0.23	
9. Smurfit-Stone Container Enterprises Inc., Missoula Mill.	Mission Mountains WA	0.36	Exempt.
	Bob Marshall WA	0.23	
	Scapegoat	0.21	
	Anaconda-Pintler WA	0.07	
	Cabinet Mountains WA	0.14	
	Glacier NP	0.19	
	Gates of the Mountains WA	0.11	
	Hells Canyon WA	0.01	
	Eagles Cap Wilderness	0.00	

[23] Exxon Mobil submitted revised modeling dated November 29, 2007 (''Exxon Correspondence''), which is the basis for our analysis and is available in the docket.

3. BART Determinations and Federally Enforceable Limits

The third step of a BART evaluation is to perform the BART analysis. The BART Guidelines (70 FR 39164 (July 6, 2005)) describe the BART analysis as consisting of the following five steps:

- Step 1: Identify All 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; and
- Step 5: Evaluate Visibility Impacts.

In determining BART, the state, or EPA if implementing a FIP, must consider the five statutory factors in section 169A of the CAA: (1) The costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use 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. See also 40 CFR 51.308(e)(1)(ii)(A). The actual visibility impact analysis occurs during steps 4 and 5 of the process.

a. Visibility Improvement Modeling

The fifth factor to consider under EPA's BART Guidelines is the degree of visibility improvement from the BART control options. *See* 59 FR 39170 (August 1, 1994). The BART Guidelines recommend using the CALPUFF air quality dispersion modeling system to estimate the visibility improvements of alternative control technologies at each Class I area, typically those within a 300 km radius of the source, and to compare these to each other and to the impact of the baseline (*i.e.,* current) source configuration. The CALPUFF modeling system is comprised of the CALMET data which is used to pre-process meteorological data; the CALPUFF model which is used to simulate the conversion of pollutant emissions to $PM_{2.5}$ and the transport and fate of $PM_{2.5}$; and the CALPOST processor which is used to calculate visibility impairments at receptors sites.

The BART Guidelines recommend comparing visibility improvements between control options using the 98th percentile of 24-hour delta deciviews, which is equivalent to the facility's 8th highest visibility impact day. The 98th percentile is recommended rather than the maximum value to allow for uncertainty in the modeled impacts and to avoid undue influence from unusual meteorological conditions. The ''delta'' refers to the difference between total deciview impact from the facility plus natural background, and deciviews of natural background alone, so ''delta deciviews'' is the estimate of the facility's impact relative to natural visibility conditions. Visibility is traditionally described in terms of visual range in kilometers or miles. However, the visual range scale does not correspond to how people perceive visibility because how a given increase in visual range is perceived depends on the starting visibility against which it is compared. Thus, an increase in visual range may be perceived to be a big improvement when starting visibility is poor, but a relatively small improvement when starting visibility is good.

The ''deciview'' scale is designed to address this problem. It is linear with respect to perceived visibility changes over its entire range, and is analogous to the decibel scale for sound. This means that a given change in deciviews will be perceived as the same amount of visibility change regardless of the starting visibility. Lower deciview values represent better visibility and greater visual range, while increasing deciview values represent increasingly poor visibility. In the BART Guidelines, EPA determined that ''a 1.0 deciview change or more from an individual source would cause visibility impairment, and a change of 0.5 deciviews would contribute to impairment. Generally, 0.5 deciviews is equivalent to a 5% change in perceived visibility and is the amount of change that will evoke a just noticeable change in most landscapes.'' [24] Converting a 5% change in light extinction to a change in deciviews yields a change of approximately 0.5 deciviews.

Under the BART Guidelines, the improved visibility in deciviews from installing controls is determined by using the CALPUFF air quality model. CALPUFF, generally, simulates the transport and dispersion of emissions, and the conversion of SO_2 to particulate sulfate and NO_X to particulate nitrate, at a rate dependent on meteorological conditions and background ozone concentration. These concentrations are then converted to delta deciviews by the CALPOST post-processor. The CALPUFF modeling system is available and documented at EPA's Model Distribution Web page.[25]

The ''delta deciviews'' for control options estimated by the modeling represents a BART source's impact on visibility at the Class I areas under

[24] BART Guidelines, 70 FR 39120 (July 6, 2005).

[25] EPA's Model Distribution Web page available at: *http://www.epa.gov/ttn/scram/dispersion_prefrec.htm#calpuff.*

different control scenarios. Each modeled day and location in the Class I area will have an associated delta deciviews for each control option. For each day, the model finds the maximum visibility impact of all locations (*i.e.,* receptors) in the Class I area. From among these daily values, the BART Guidelines recommend use of the 98th percentile, for comparing the base case and the effects of various controls.

As part of the FIP development efforts, EPA determined that CALPUFF modeling was needed to evaluate emissions scenarios that would be consistent with the application of controls for Montana sources that were subject to BART.[26] EPA contracted with the University of North Carolina and its subcontractor, Alpine Geophysics, to perform CALPUFF model simulations for BART sources in Montana. The University of North Carolina developed a modeling protocol that EPA approved. The protocol outlines the data sets, models and procedures that were used in the new CALPUFF modeling for BART sources.[27] The evaluated Class I areas that were included in the modeling domain for each BART source are listed in Table 2 of the modeling protocol. The final report from this modeling effort is available in the docket.[28]

The BART determination guidelines recommend that visibility impacts should be estimated in deciviews relative to natural background conditions. CALPOST uses background concentrations of various pollutants to calculate the natural background visibility impact. EPA used background concentrations from Table 2–1 of ''Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule.'' Although the concentration for each pollutant is a single value for the year, this method allows for monthly variation in its visibility impact, which changes with relative humidity.

[26] CALPUFF model simulations had previously been performed for some MT BART sources for certain emissions scenarios using meteorological data sets for the period 2001–2003 that were developed by the WRAP. ''CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States'', available at *http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf.*

The WRAP data sets were developed in 2006 using the CALPUFF model versions and EPA guidance available at that time.

[27] ''Modeling Protocol: Montana Regional Haze Federal Implementation Plan (FIP) Support'', University of North Carolina, Contract EP–D–07–102, November 14, 2011.

[28] Modeling Report: Montana Regional Haze Federal Implementation Plan (FIP) Support, March 16, 2012.

b. BART Five-Factor Determinations and Federally Enforceable Limits

i. Ash Grove Cement

Background

The Ash Grove Cement (Ash Grove) cement plant near Montana City was determined to be subject to the BART requirements as explained in section V.C. As explained in section V.C., the document titled ''Identification of BART Eligible Sources in the WRAP Region'' dated April 4, 2005 provides more details on the specific emission units at each facility. Our analysis focuses on the long wet kiln as the primary source of SO_2 and NO_X emissions.

We requested a five factor BART analysis for Ash Grove Cement and the company submitted that analysis along with updated information.[29] Ash Grove's five factor BART analysis is contained in the docket for this action and we have taken it into consideration in our proposed action.

NO_X

Step 1: Identify All Available Technologies

We identified that the following NO_X control technologies are available for the kiln at Ash Grove: low NO_X burners (LNB), mid-kiln firing of solid fuel (MKF), cement kiln dust (CKD) insufflation, flue gas recirculation (FGR), selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR).

[29] The following information has been submitted by Ash Grove: BART Five Factor Analysis Ash Grove Cement Montana City, Montana, Prepared by Trinity Consultants (''Ash Grove BART Analysis'') (June 2007); Letter to Callie Videtich RE: Ash Grove Cement Montana City Plant, Response to Comments on Best Available Retrofit Technology (''Ash Grove Response to Comments''), (February 28, 2008) (note that no redacted information that was claimed to be CBI by Ash Grove was used from this submittal); Letter to Callie Videtich RE: Ash Grove Cement-Montana City Plant, Response to Comments on Best Available Retrofit Technology (''Ash Grove Additional Response to Comments'') (May 5, 2008); Email to Laurel Dygowski from Bob Vantuyl RE: Ash Grove Cement Montana City BART: Cost Analysis for Ash Grove SNCR (''Ash Grove SNCR Cost'') (December 17, 2008); Email to Laurel Dygowski from Bob Vantuyl RE: Ash Grove Cement Montana City Low NO_X Burner Cost Effectiveness (''Ash Grove LNB Cost'') (January 23, 2009); Letter to Vanessa Hinkle from Thomas R. Wood RE: Substantiation for Confidential Business Information Claim for Information Submitted for Best Available Retrofit Technology Analysis (''Ash Grove Additional Information July 2011'') (July 18, 2011); Letter to Vanessa Hinkle from Thomas R. Wood RE: Response to Request for Additional Information for Montana City BART Determination (''Ash Grove Additional Information October 2011'') (October 5, 2011); Email to Vanessa Hinkle from Thomas R. Wood RE: Ash Grove City Cement Company, Montana City Plant (''Ash Grove Additional Information November 2011'') (November 7, 2011); Email to Vanessa Hinkle from Curtis Lesslie RE: DAA Cost Analysis (''Ash Grove DAA Cost Analysis'') (December 20, 2011); Email to Vanessa Hinkle from Curtis Lesslie RE: Ash Grove Montana City BART Analysis Update (''Ash Grove Update January 2012'') (January 19, 2012); Letter to Vanessa Hinkle from Thomas R. Wood RE: Ash Grove Cement Company Response to Supplemental Information Request (''Ash Grove Update March 2012'') (March 9, 2012).

LNBs use stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame). Staging of combustion air as achieved by such burners is an available control technology for NO_X reduction in cement kilns. In the first stage, fuel combustion is carried out in a high temperature fuel-rich environment and the combustion is completed in the fuel-lean low temperature second stage. By controlling the available oxygen and temperature, LNBs attempt to reduce NO_X formation in the flame zone. LNBs have been used by the cement industry for nearly 30 years and are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. LNBs can be used in combination with SNCR to achieve even greater emissions reduction.

MKF is a form of secondary combustion where a portion of the fuel is fired in a location other than the burning zone. Ash Grove currently uses a mixture of coal and petroleum coke as the primary fuels for the kiln. A common fuel used for mid kiln firing is scrap tires. By adding fuel mid-kiln, MKF changes both the flame temperature and the flame length. This reduces thermal NO_X formation by burning part of the fuel at a lower temperature by creating reducing conditions at the mid-kiln fuel injection point which may destroy some of the NO_X formed upstream in the kiln burning zone.

CKD insufflation is a residual byproduct that can be produced by any of the four basic types of cement kiln systems. As a means of recycling usable CKD to the cement pyroprocess, CKD can be injected or insufflated into the burning zone of the rotary kiln in or near the main flame. The presence of these cold solids within or in close proximity to the flame cools the flame and/or the burning zone thereby reducing the formation of thermal NO_X.

FGR involves the use of oxygen-deficient flue gas from some point in the process as a substitute for primary air in the main burner pipe in the rotary kiln.[30] FGR lowers the peak flame temperature and develops localized reducing conditions in the burning zone by reducing the oxygen content of the primary combustion air. The intended

[30] Ash Grove BART Analysis, p. 5–6.

effect is to decrease both thermal and fuel NO_X formation in the rotary kiln.

In SNCR systems, a reagent such as NH_3 or urea is injected into the flue gas at a suitable temperature zone, typically in the range of 1,800 to 2,000 °F and at an appropriate ratio of reagent to NO_X. SNCR system performance depends on temperature, residence time, turbulence, oxygen content, and other factors specific to the given gas stream. SNCR can be used in combination with LNBs to achieve even greater emissions control.

SCR uses either NH_3 or urea in the presence of a metal based catalyst to selectively reduce NO_X emissions. SCR is used in the electric utility industry to reduce NO_X emissions from boilers and has been used on three cement kilns in Europe. SCR is capable of reducing NO_X emissions by about 80%.

Step 2: Eliminate Technically Infeasible Options

Ash Grove estimated that approximately 1.3 million tires would be required to use MKF at the Montana City kiln.[31] There is not a consistent supply of scrap tires of this volume that would be available for the Montana city kiln; therefore, MKF was not considered further.

CKD insufflation can be used at some cement kilns, but can be problematic for others. The cement making process requires a very hot flame to heat the clinkering raw material to about 2,700 °F in as short a time as possible.[32] Because of the increased requirements for thermal energy in the burning zone when insufflation is employed, and the expected increase in fuel required, it is not an attractive technology for wet kiln systems; therefore, CKD insufflation was not considered further.

FGR is used in the electric utility industry, but is not transferrable to cement kilns. For cement kilns, a hot flame is required to complete the chemical reactions that form the clinker minerals from the raw materials. The long/lazy flame that would be produced by FGR would result in the production of unacceptable quality clinker . Clinkering reactions must take place in an oxidizing atmosphere in the burning zone to generate clinker that can be used to produce acceptable cement. FGR would tend to produce localized or general reducing conditions that also could detrimentally affect clinker quality. Adding FGR to a burner that is already designed for optimum flame shaping and control would distort the thermal profile of the kiln, such that product quality would be unacceptably compromised. For these reasons, FGR was not considered further.

SCR has been used on three kilns in Europe; two are preheater kilns, and one kiln is a Polysius Lepol technology kiln, which is a traveling grate preheater kiln. 73 FR 34079 (June 16, 2008). Although we find that SCR is technically feasible for cement kilns, we have not analyzed it further because of the uncertainty regarding control effectiveness and costs. We note that EPA has acknowledged, in the context of establishing the NSPS for Portland Cement Plants, substantial uncertainty regarding the control effectiveness and costs associated with the use of SCR at such plants. See 75 FR 54995 (September 9, 2010). SCR for cement kilns will be re-evaluated in subsequent reasonable progress (RP) planning periods.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

For LNB on Ash Grove's kiln it is appropriate to assume a control effectiveness of 15%.[33] For SNCR, in evaluating the technology, a control effectiveness of 50% is appropriate, and for LNB+SNCR a control effectiveness of 58% is appropriate.

The following discussion is an explanation of why we consider 50% control effectiveness an appropriate estimate for SNCR at long wet kilns, such as Ash Grove's Montana City kiln. Ash Grove has used SNCR at similar wet kilns in Midlothian, TX. Emissions data submitted by Ash Grove to the Texas Commission on Environmental Quality (TCEQ) show that Ash Grove was able to achieve emission rates in the range of 1.6 to 2.9 lb/ton of clinker from June through August 2008 when using SNCR.[34] The emissions reports submitted to the TCEQ indicate that Ash Grove had been using SNCR in 2007 on one of their kilns at Midlothian; however, since the report doesn't specify the exact timeframe we do not know whether the 2007 data can be compared to the June through August 2008 data. Because the emission report data submitted to the TCEQ for SNCR use in 2007 is from an unknown time, we used 2006 emission data from the same three months as the 2008 data—June through August to assess the performance of the SNCR.[35] Table 10 summarizes emission from the Midlothian kilns using the 2006 and 2008 data.

TABLE 10—NO_X EMISSIONS FOR 2006 AND 2008 FOR ASH GROVE CEMENT

	June through August 2006 emission rate (lb/ton clinker)				June through August 2008 emission rate (lb/ton clinker)				Percentage reduction (%)
	June	July	August	Average	June	July	August	Average	
Kiln 1	5.2	5.0	4.5	4.9	1.7	1.6	2.2	1.8	62.5
Kiln 2	5.0	4.1	3.9	4.4	2.7	2.6	2.8	2.7	37.7
Kiln 3	5.0	4.4	4.2	4.5	2.9	2.6	2.5	2.7	40.5

[31] Ash Grove BART Analysis, p. 5–8.

[32] Ash Grove BART Analysis, p. 5–6.

[33] EPA provided an example of LNB on a long wet kiln with a control effectiveness of 14% in NO_X Control Technologies for the Cement Industry, Final Report, September 2000, p. 61.

[34] See the document received from TCEQ available in the docket: Ash Grove Texas, L.P.—Midlothian Plant 2008 Actual Emission Rate Calculations—Kilns, Ash Grove Texas, L.P.—Midlothian Plant 2008 Actual Emission Rate calculations—Input Data.

[35] See the documents received from TCEQ available in the docket: Ash Grove Texas, L.P.—Midlothian Plant 2006 Actual Emission Rate Calculations—Kilns; Ash Grove Texas, L.P.—Midlothian Plant 2006 Actual Emission Rate Calculations—Input Data; Ash Grove Texas, L.P.—Midlothian Plant 2008 Actual Emission Rate Calculations—Kilns, Ash Grove Texas, L.P.—Midlothian Plant 2008 Actual Emission Rate calculations—Input Data.

When the control effectiveness on all three kilns are averaged together, a 47.5% reduction was achieved. This is within the range of control effectiveness values that have been demonstrated at other kilns.[36] [37] [38]

The concentration of baseline NO_X emissions is one parameter affecting the effectiveness of SNCR. The percentage of control effectiveness is greater when initial NO_X concentrations are greater. The reaction kinetics decrease as the concentration of reactants decreases. This is due to thermodynamic considerations that limit the reduction process at low NO_X concentrations.[39] The baseline NO_X emissions of the Ash Grove Montana City kiln are significantly higher than those at Midlothian,[40] indicating that SNCR on the Montana City kiln would be expected to achieve even greater control effectiveness when compared to SNCR on the Midlothian kilns.

A summary of the emissions projections for the NO_X control options is provided in Table 11.

TABLE 11—SUMMARY OF NO_X BART ANALYSIS CONTROL TECHNOLOGIES FOR ASH GROVE

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
LNB+SNCR	58	1088	803
SNCR	50	946	946
LNB	15	284	1,607
No Controls (Baseline)	0	0	[1] 1,891

[1] Ash Grove LNB Cost.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

LNB

We relied on cost estimates supplied by Ash Grove for capital costs and annual costs associated with LNB. We present the costs for LNB in Table 12 and 13. For our analysis, we used a capital recovery factor (CRF) consistent with 20 years for the useful life of the kiln. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[41] We summarize the cost information for LNB in Tables 12, 13, and 14.

TABLE 12—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR LNB ON ASH GROVE

Description	Cost ($)
Total Capital Investment	[1] 266,309
Capital Recovery	[2] 25,140

[1] Ash Grove LNB Cost.

[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 13—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR LNB ON ASH GROVE

Description	Cost ($)
Total Indirect Annual Cost	[1,2] 65,642
Direct Annual Operating Cost	[2] 92,988
Total Annual Cost	158,630

[1] Includes capital recovery.

[2] Ash Grove LNB Cost.

[36] EPA has stated previously that, ''[o]n average, SNCR achieves approximately a 35 percent reduction in NO_X at a ratio of NH_3-to-NO_X of about 0.5 and a reduction of 63 percent at an NH_3-to-NO_X ratio of 1.0'' in the **Federal Register** notice proposing New Source Performance Standards for Portland cement plants. 73 FR 34078 (June 16, 2008).

[37] The Cadence brochures available at: *http://cadencerecycling.com/sncr.html* and *http://www.cadencerecycling.com/Resources/6–Page Complete.pdf* state that control efficiencies of up to 50% can be achieved on long wet kilns. See also Enhancing SNCR Performance by Induced Mixing, Eric Hansen and Fred Lockwood, December 2006 available at *http://www.cadencerecycling.com/Resources/ICR–Formatted2006.pdf.*

[38] EPA has stated that, ''there are numerous examples of SNCR systems achieving emission reductions greater than 50 percent and as high as 80 percent or more'' in the **Federal Register** notice proposing New Source Performance Standards for Portland cement plants. 73 FR 34079 (June 16, 2008).

[39] EPA's Control Cost Manual (further referred to as CCM) Sixth Edition, January 2002, EPA 452/B–02–001 p. 1–10. The CCM can be found at: *http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf.*

[40] Ash Grove Update March 2012 (Ash Grove's email indicates a mean of 14.4 lbs./ton clinker and a 99th percentile of 18.6 lb NO_X/ton clinker. This is significantly greater than the 2006 emissions shown in Table 10 for the Midlothian kilns.)

[41] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 14—SUMMARY OF NO_X BART COSTS FOR LNB ON ASH GROVE

Control option	Total capital investment ($)	Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
LNB	266,309	158,630	284	559

SNCR

We relied on cost estimates supplied by Ash Grove for capital costs and annual costs, with the exception of the CRF. We present the costs for SNCR in Table 15. For our analysis, we used a CRF consistent with 20 years for the useful life of the kiln. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.[42] In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[43] We summarize the cost information from our SNCR analysis in Tables 15, 16, and 17.

TABLE 15—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SNCR ON ASH GROVE

Description	Cost ($)
Total Capital Investment	[1] 925,324
Capital Recovery	[1,2] 87,351

[1] Ash Grove SNCR Cost.
[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 16—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR SNCR ON ASH GROVE

Description	Cost ($)
Total Indirect Annual Cost	[1,2] 184,063
Direct Annual Operating Cost	[2] 1,896,199
Total Annual Cost	2,080,262

[1] Includes capital recovery
[2] Ash Grove SNCR Cost.

TABLE 17—SUMMARY OF NO_X BART COSTS FOR SNCR ON ASH GROVE

Total capital investment ($)	Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
925,324	2,080,262	946	2,199

LNB + SNCR

We calculated the cost effectiveness of LNB + SNCR by dividing the sum of the annual cost of the two technologies described above by the emissions reduction that would be achieved. We summarize the cost information from our LNB + SNCR analysis in Tables 18 and 19.

TABLE 18—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR LNB + SNCR ON ASH GROVE

Description	Cost ($)
Total Annual Cost LNB	158,630
Total Annual Cost SNCR	2,080,262
Total Annual Cost LNB + SNCR	2,238,892

[42] CRF is 0.0944 and is based on a 7% interest rate and 20 year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

[43] CRF is 0.0944 and is based on a 7% interest rate and 20 year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 19—SUMMARY OF NO_X BART COSTS FOR LNB + SNCR ON ASH GROVE

Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
2,238,892	1,088	2,058

Factor 2: Energy and Non Air Quality Impacts

LNBs are not expected to have energy impacts. SNCR systems require electricity to operate the blowers and pumps. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. While the required electricity will result in emissions, these emissions should be small compared to the reduction in NO_X that would be gained by operating an SNCR system.[44] LNBs are not expected to have any non-air quality environmental impacts. Transporting the chemical reagents for SNCR would use natural resources for fuel and would have associated air quality impacts. The chemical reagents would be stored on site and could result in spills to the environment while being transferred between storage vessels or if containers were to fail during storage or movement. The environmental impacts associated with proper transportation, storage, and/or disposal should not be significant. Therefore, the non-air quality environmental impacts did not warrant eliminating LNB or SNCR.

Factor 3: Any Existing Pollution Control Technology in Use at the Source

Ash Grove currently uses good combustion practices and burner pipe maintenance/position for NO_X control.

Factor 4: Remaining Useful Life

EPA has determined that the remaining useful life of the kiln is at least 20 years. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Ash Grove as described in section V.C.3.a. Table 20 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008.

TABLE 20—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON ASH GROVE

Class I area	Baseline impact (delta deciview)	Improvement from LNB (delta deciview)	Improvement from SNCR (delta deciview)	Improvement from LNB + SNCR (delta deciview)
Anaconda Pintler WA	0.426	0.050	0.116	0.166
Bob Marshall WA	0.604	0.074	0.173	0.247
Gates of the Mountains WA	4.446	0.359	0.856	1.248
Glacier NP	0.193	0.021	0.050	0.069
Mission Mountains WA	0.242	0.024	0.043	0.072
North Absaroka WA	0.215	0.028	0.065	0.092
Red Rock Lakes WA	0.130	0.016	0.038	0.054
Scapegoat WA	1.022	0.131	0.308	0.441
Selway-Bitterroot WA	0.412	0.047	0.110	0.158
Teton WA	0.163	0.021	0.048	0.065
Washakie WA	0.174	0.020	0.046	0.068
Yellowstone NP	0.190	0.028	0.064	0.091

Table 21 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 21—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON ASH GROVE

[Three year total]

Class I area	Baseline (days)	Using LNB	Using SNCR	Using LNB + SNCR
Anaconda Pintler WA	6	6	6	5
Bob Marshall WA	21	18	13	9
Gates of the Mountains WA	361	349	327	296
Glacier NP	2	1	0	0
Mission Mountains WA	8	8	6	5
North Absaroka WA	2	2	0	0
Red Rock Lakes WA	0	0	0	0
Scapegoat WA	37	35	25	18
Selway-Bitterroot WA	7	7	5	4
Teton WA	0	0	0	0
Washakie WA	2	0	0	0

[44] Ash Grove BART Analysis, pp. 5–13, 14.

TABLE 21—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON ASH GROVE—Continued

[Three year total]

Class I area	Baseline (days)	Using LNB	Using SNCR	Using LNB + SNCR
Yellowstone NP	3	1	1	1

Modeling was performed at 35% control effectiveness rather than 50% control effectiveness for SNCR and at 50% control effectiveness rather than 58% control effectiveness for LNB + SNCR. Therefore, visibility improvement from SNCR and LNB + SNCR would be greater than what is shown.

Step 5: Select BART

We propose to find that BART for NO_X is an emission limit of 8.0 lb/ton of clinker (30-day rolling average) based on the use of LNB + SNCR at Ash Grove. Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for NO_X at Ash Grove, we considered LNB, SNCR, and LNB + SNCR. The comparison between our LNB, SNCR, and LNB + SNCR analysis is provided in Table 22.

TABLE 22—SUMMARY OF NO_X BART ANALYSIS COMPARISON OF CONTROL OPTIONS FOR ASH GROVE

Control option	Total capital investment	Total annual cost	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1,2]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 deciview
LNB + SNCR	1,191,632	2,238,893	2,058	1,117	1.248	65
SNCR	925,324	2,080,262	2,199	2,903	0.856	34
LNB	266,309	158,630	559	[3]	0.359	12

[1] The visibility benefit shown is for Gates of the Mountains WA.

[2] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I area that showed the greatest improvement, Gates of the Mountains, WA. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Gates of the Mountains WA.

[3] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that LNB, SNCR, and LNB + SNCR are all cost effective control technologies and that all would provide substantial visibility benefits. LNB has a cost effectiveness value of $559 per ton of NO_X emissions reduced. SNCR is more expensive than LNB, with a cost effectiveness value of $2,199 per ton of NO_X emissions reduced. While LNB + SNCR are more expensive than LNB or SNCR alone, it has a cost effectiveness value of $2,058 per ton of NO_X emissions reduced. This is well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART. We have weighed costs against the anticipated visibility impacts for Ash Grove. Any of the control options would have a positive impact on visibility. As compared to LNB alone, LNB + SNCR would provide an additional visibility benefit of 0.889 deciviews and 53 fewer days above 0.5 deciviews at Gates of the Mountains WA. As compared to SNCR alone, LNB + SNCR would provide an additional visibility benefit of 0.392 deciviews and 31 fewer days above 0.5 deciviews at Gates of the Mountains WA. We consider these impacts to be substantial, especially in light of the fact that this Class I area is not projected to meet the URP. Given the incremental visibility improvement associated with LNB + SNCR, the relatively low incremental cost effectiveness between the options, and the reasonable average cost effectiveness values for LNB + SNCR, we propose that the NO_X BART emission limit for the kiln at Ash Grove should be based on what can be achieved with LNB + SNCR.

As EPA has stated previously, adopting an output-based standard avoids rewarding a source for becoming less efficient, i.e., requiring more feed to produce a unit of product. An output-based standard promotes the most efficient production process. 73 FR 34076, June 16, 2008. Thus, for example, the NSPS for NO_X and National Emission Standards for Hazardous Air Pollutants (NESHAP) for PM are normalized by ton of clinker produced. We have recognized previously that facilities are allowed to measure feed inputs and to use a site-specific feed/clinker ratio to calculate clinker production. 75 FR 54990 (September 9, 2010). For these reasons, we are proposing to establish an emission limit on a lb/ton of clinker basis.

In proposing a BART emission limit of 8.00 lb/ton clinker, we considered the emission rate currently being achieved by Ash Grove.[45] This limit also allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[46] We also are proposing monitoring, recordkeeping, and reporting requirements in regulatory text at the end of this proposal.

As we have noted previously, under section 51.308(e)(1)(iv), ‘‘each source subject to BART [is] 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.’’ We propose a compliance deadline of five (5) years from the date our final FIP becomes effective because of the equipment installation and potential kiln combustion modifications that will be required.

[45] Ash Grove Update, March 2012 (Ash Grove lists the mean 30-day rolling average NO_X emission rate for May 26, 2006 through September 8, 2008, at 14.4 lb/ton clinker. The 99th percentile 30-day rolling average was 18.63 lb/ton clinker. Applying 58% reduction to the 99th percentile figure yields 7.82 lb/ton clinker.)

[46] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

SO_2

Step 1: Identify All Available Technologies

We identified that the following SO_2 control technologies are available: dry absorbent addition (DAA), fuel substitution, raw material substitution, lime spray drying (LSD), semi-wet scrubbing, and wet scrubbing.

In the DAA process, a dry alkaline material such as lime, calcium hydrate, limestone, or soda ash would be added to the process gas stream upstream of the particulate matter control device (PMCD) to react with the SO_2. Ash Grove estimated that they would add a 2:1 molar ratio of lime to SO_2. Solid particles of $CaSO_4$ would be produced, which would be removed from the gas stream along with excess reagent by a PMCD in the process flow. The SO_2 removal efficiency would vary depending on the point of introduction into the process according to the temperature, degree of mixing, and retention time.

Fuel substitution is a control alternative. Ash Grove currently uses a mixture of coal and petroleum coke as the primary fuels for the kiln. In 2008, Ash Grove used 50% petroleum coke, 41% coal and 1% natural gas. The sulfur content of the petroleum coke was 5.2% [47] and the sulfur content of the coal was approximately 0.8%.[48] If sulfur in fuel input to the kiln were reduced by burning a different blend of coal and coke with lower sulfur contents, a reduction in SO_2 emissions would be expected. We considered two different options for fuel switching. Option 1 would use 62% coal with 0.8% sulfur and 38% coke with 5.2% sulfur. Option 2 would use 100% coal that has a lower sulfur content (0.7%), and a higher Btu value.[49]

Raw material substitution would entail using a different source of limestone that contains a lower pyritic sulfur content.

LSD involves injecting an aqueous lime suspension in fine droplets into the flue gas. The lime reacts with SO_2 in the flue gas to create fine particles of $CaSO_3$ or $CaSO_4$. The moisture evaporates from the particles, and the particles are collected in the PMCD.

Semi-wet scrubbers are sometimes referred to as spray dryer absorbers (SDAs). This technology uses lime or limestone to react with SO_2. This technology has been used for SO_2 control on preheater/calciner kilns, but it can be successfully used on long kilns by adding spray nozzles that are made of special materials to prevent nozzle clogging. A semi-wet scrubber can achieve a SO_2 removal efficiency of 30% to 60%. Clogging may not be an issue with semi-wet scrubbers that use lime due to the small size of the lime particles (3–10 microns) which allows the particles to dissolve in water droplets quickly and react with the gaseous SO_2.

Wet scrubbing involves passing flue gas downstream from the main PMCD through a sprayed aqueous suspension of lime or limestone that is contained in a scrubbing device. The SO_2 reacts with the scrubbing reagent to form lime sludge that is collected. The sludge usually is dewatered and disposed of at an offsite landfill.

Step 2: Eliminate Technically Infeasible Options

With regard to raw material substitution, using raw materials with a lower pyritic sulfur content could reduce SO_2 emissions. Because cement plants are built at or near a source of limestone so that shipping costs are minimized, it would be infeasible, however, to obtain raw material with a lower pyritic sulfur content from some other source.

The design of a wet kiln, unlike a preheater/precalciner (PH/PC) kiln, is not amenable to the addition of a LSD. By its design, a PH/PC provides a natural location for a spray dryer type control system to be used between the top of the preheater tower and the PMCD. A wet kiln does not have that attribute. The back end of Ash Grove's wet kiln has a relatively short retention time prior to the PMCD and this would not allow for a spray dryer. For this reason, this alternative was not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

EPA estimates that the appropriate control effectiveness of DAA at Ash Grove is 30%.[50] A literature search indicates that hydrated lime appropriately injected can easily produce a 30% SO_2 control efficiency with a 2.5 to 1 CaO to SO_2 ratio.[51]

For fuel switching, we used a SO_2 control effectiveness of 17% for the purposes of considering fuel switching to 38% coke and 62% coal and SO_2 control effectiveness of 60% for the purposes of considering fuel switching to 100% low-sulfur coal.[52]

The efficiency of semi-wet scrubbing is estimated to be 90%. A 90% SO_2 control effectiveness is the minimum of the range for a semi-wet scrubber with lime absorbent medium.[53] EPA has stated that a well designed and operated wet scrubber can consistently achieve at least 90% control (75 FR 54995, Sept. 9, 2010) and that 95% control efficiency is possible on cement kilns and consistent with other information on the performance of scrubbers for SO_2 removal (73 FR 34080, June 16, 2008).[54] We used 90% control effectiveness for our analysis, which is at the lower end of the range that is possible.

TABLE 23—SUMMARY OF SO_2 BART ANALYSIS CONTROL TECHNOLOGIES FOR ASH GROVE

Control Option	Control effectiveness (%)	Annual emissions reduction (tpy)	Remaining annual emissions (tpy)
Fuel Switching Option 1 (38% coke/62% coal)	[1] 17	200	978
DAA	30	353	825
Fuel Switching Option 2 (lower sulfur coal)	[1] 60	707	471
Semi-wet scrubbing	90	1060	118
Wet scrubbing	90	1060	118
No Controls (Baseline)	0	0	[2] 1,178

[1] Ash Grove Response to Comments, Attachment A.

[47] Ash Grove Additional Response to Comments.

[48] Ash Grove BART Analysis, p. 4–2.

[49] Ash Grove Response to Comments, Attachment A.

[50] Ash Grove January 2012 Update.

[51] Formation and Techniques for Control of Sulfur Oxide and Other Sulfur Compounds in Portland Cement Kiln Systems by F.M. Miller, G.L. Young and M. von Seebach (''Formation and Techniques of Sulfur Oxide and Other Sulfur Compounds'', (PCA R&D Serial No. 2460), p. 43.

[52] Ash Grove BART Analysis, p. 4–11.

[53] Formation and Techniques of Sulfur Oxide and Other Sulfur Compounds, p. 46.

[54] Assessment of Control Technology Options for BART–Eligible Sources, March 2005.

[2] 2008 NEI.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

DAA

We relied on Ash Grove's costs [55] for DAA with the following exceptions. We present the costs for DAA in Table 24. In our estimate, we used a CRF consistent with 20 years of useful life of the kiln and equipment.[56] EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[57] We used 1,178 tpy of SO_2 as was reported to the NEI for 2008.[58] We summarize the cost information for DAA in Tables 24, 25, and 26.

TABLE 24—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR DAA ON ASH GROVE

Description	Cost ($)
Total Capital Investment	[1] 330,620
Capital Recovery	[2] 31,211

[1] Ash Grove Update January 2012.
[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944, which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 25—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR DAA ON ASH GROVE

Description	Cost ($)
Total Indirect Annual Cost	[1] 205,243
Total Annual Operating Cost	[2] 257,839
Total Annual Cost	463,082

[1] Includes capital recovery.
[2] Ash Grove Update January 2012.

TABLE 26—SUMMARY OF SO_2 BART COSTS FOR DAA ON ASH GROVE

Total capital investment ($)	Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
330,620	463,082	323	1,434

We relied on Ash Grove's costs [59] for fuel switching with the following exception. We used 1,178 tpy of SO_2 as was reported to the NEI for 2008. There is no capital cost for fuel switching because there is no equipment to buy or install. However, annual cost will increase due to increased fuel cost. We summarize the cost information for fuel switching in Tables 27 and 28.

TABLE 27—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR FUEL SWITCHING FOR ASH GROVE

Description	Cost ($)
Total Annual Cost Option 1 (38% coke/62% coal)	[1] 487,877
Total Annual Cost Option 2 (lower sulfur coal)	[1] 2,908,170

[1] Ash Grove Response to Comments.

TABLE 28—SUMMARY OF SO_2 BART COSTS FOR FUEL SWITCHING ON ASH GROVE

Control option	Total annual cost ($)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
Fuel Switching Option 1	487,877	200	2,439
Fuel Switching Option 2	2,908,170	707	4,113

[55] Ash Grove Update January 2012.

[56] CRF is 0.0944 and is based on a 7% interest rate and 20 year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

[57] Id.

[58] 2008 NEI.

[59] Ash Grove Response to Comments, Attachment A.

Semi-Wet Scrubbing

We relied on Ash Grove's costs[60] for fuel switching with the following exceptions. We present the costs for semi-wet scrubbing in Table 29. In our estimate, we used a CRF consistent with 20 years for the useful life of the kiln[61] EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[62] We used 1,178 tpy of SO_2 as was reported to the NEI for 2008. We summarize the cost information for semi-wet scrubbing in Tables 29, 30, and 31.

TABLE 29—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR SEMI-WET SCRUBBING ON ASH GROVE

Description	Cost ($)
Total Capital Investment	[1] 11,644,912
Capital Recovery	[1,2] 1,099,280

[1] Ash Grove Additional Information October 2011.
[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 30—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR SEMI-WET SCRUBBING ON ASH GROVE

Description	Cost ($)
Total Indirect Annual Cost	[1,2] 1,689,936
Total Annual Operating Cost	[1] 250,068
Total Annual Cost	1,940,004

[1] Ash Grove Additional Information October 2011.
[2] Includes capital recovery.

TABLE 31—SUMMARY OF SO_2 BART COSTS FOR SEMI-WET SCRUBBING ON ASH GROVE

Total capital investment ($)	Total annual cost ($)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
11,644,912	1,940,004	1,060	1,830

Wet Scrubbing

We relied on costs provided by Ash Grove for wet scrubbing, which we note appear to be more expensive than other cost estimates for wet scrubbing on cement kilns. We present the costs for wet scrubbing in Table 32. In our estimate, we used a CRF consistent with 20 years for the remaining useful life of the kiln[63] EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[64] We used 1,178 tpy of SO_2 as was reported to the NEI for 2008. We summarize the cost information for wet scrubbing in Tables 32, 33, and 34.

TABLE 32—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR WET SCRUBBER ON ASH GROVE

Description	Cost ($)
Total Capital Investment	[1] 30,022,424
Capital Recovery	[1,2] 2,834,117

[1] Ash Grove Additional Information October 2011.
[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 33—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR WET SCRUBBER ON ASH GROVE

Description	Cost ($)
Total Indirect Annual Cost	[1,2] 4,335,284
Total Annual Operating Cost	[2] 759,278

[60] Ash Grove Additional Information October 2011.

[61] CRF is 0.0944 and is based on a 7% interest rate and 20 year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

[62] Id.

[63] *Id.*

[64] *Id.*

TABLE 33—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR WET SCRUBBER ON ASH GROVE—Continued

Description	Cost ($)
Total Annual Cost	5,094,562

[1] Includes capital recovery.
[2] Ash Grove Additional Information October 2011.

TABLE 34—SUMMARY OF SO_2 BART COSTS FOR WET SCRUBBER ON ASH GROVE

Total capital investment ($)	Total annual cost ($)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
30,022,424	5,094,562	1,060	4,806

Factor 2: Energy and Non Air Quality Impacts

We did not identify any energy or non-air quality environmental impacts associated with fuel switching at Ash Grove. Wet scrubbing and semi-wet scrubbing use additional water. Wet scrubbing would consume approximately 38 gallons per minute of water, resulting in approximately 19 million gallons per year. Semi-wet scrubbing would use 3.5 gallons per minute, for an annual usage of 1.75 million gallons per year.[65] DAA would not require additional water. This arid location receives 11.9 inches of rainfall annually.[66] Montana decreased the water rights held by Ash Grove's Montana City plant to match historical use, which resulted in withdrawal of previous water rights.[67] As a result even if Ash Grove were able to obtain water rights, there is no guarantee that Ash Grove would be able to rely on that water right, as in a dryer than normal year a more senior water rights holder could require that Ash Grove cease its water use.[68] The cost analysis for wet scrubbing and semi-wet scrubbing included the costs of obtaining water.[69]

Wet scrubbing, semi-wet scrubbing, and DAA would also generate a waste stream that would need to be transported and disposed. Transporting the waste would use natural resources for fuel and would have associated air quality impacts. The disposal of the solid waste itself would be to a landfill and could possibly result in groundwater or surface water contamination if a landfill's engineering controls were to fail. The environmental impacts associated with proper transportation and/or disposal should not be significant.

Wet scrubbing, semi-wet scrubbing and DAA require additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. The additional energy requirements that would be involved in installation and operation of the evaluated controls are not significant enough to warrant eliminating any of the options evaluated. Note that cost of the additional energy requirements has been included in our calculations.

Factor 3: Any Existing Pollution Control Technology in Use at the Source

The kiln currently uses low sulfur coal as a component of fuel mix and inherent scrubbing for SO_2 control. The kiln inherently acts as an SO_2 scrubber, since some of the sulfur that is oxidized to SO_2 is absorbed by the alkali compounds in the raw material fed to the kiln.[70] Ash Grove currently uses a mixture of petroleum coke with a sulfur content of 5.2% and coal with a sulfur content of 0.8%.[71]

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Ash Grove as described in section V.C.3.a. Table 35 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008.

TABLE 35—DELTA DECIVIEW IMPROVEMENT FOR SO_2 CONTROLS ON ASH GROVE

Class I area	Baseline impact (delta deciview)	Improvement from fuel switching—Option 1 (delta deciview)	Improvement from DAA (delta deciview)	Improvement from fuel wwitching—Option 2 (delta deciview)	Improvement from semi-wet scrubbing (delta deciview)	Improvement from wet scrubbing (delta deciview)
Anaconda Pintler WA	0.426	0.015	0.020	0.050	0.074	0.074
Bob Marshall WA	0.604	0.016	0.023	0.056	0.083	0.083
Gates of the Mountains WA	4.446	0.033	0.049	0.119	0.180	0.180
Glacier NP	0.193	0.009	0.013	0.035	0.048	0.048
Mission Mountains WA	0.242	0.012	0.018	0.039	0.059	0.059
North Absaroka WA	0.215	0.009	0.012	0.018	0.030	0.030
Red Rock Lakes WA	0.130	0.007	0.010	0.015	0.022	0.022
Scapegoat WA	1.022	0.017	0.025	0.060	0.090	0.090
Selway-Bitterroot WA	0.412	0.014	0.020	0.049	0.074	0.074

[65] Ash Grove Additional Information October 2011, p. 14.

[66] Ash Grove Additional Information October 2011, p. 10.

[67] Ash Grove Additional Information October 2011, p. 14.

[68] Ash Grove Additional Information October 2011, p. 10.

[69] Ash Grove Additional Information October 2011, Attachments 1 and 2.

[70] Ash Grove Response to Comments.

[71] Ash Grove BART Analysis, p. 4–2.

TABLE 35—DELTA DECIVIEW IMPROVEMENT FOR SO_2 CONTROLS ON ASH GROVE—Continued

Class I area	Baseline impact (delta deciview)	Improvement from fuel switching—Option 1 (delta deciview)	Improvement from DAA (delta deciview)	Improvement from fuel wwitching—Option 2 (delta deciview)	Improvement from semi-wet scrubbing (delta deciview)	Improvement from wet scrubbing (delta deciview)
Teton WA	0.163	0.008	0.012	0.030	0.044	0.044
Washakie WA	0.174	0.006	0.009	0.021	0.033	0.033
Yellowstone NP	0.190	0.012	0.018	0.042	0.062	0.062

Table 36 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 36—DAYS GREATER THAN 0.5 DECIVIEW FOR SO_2 CONTROLS ON ASH GROVE

[Three year total]

Class I area	Baseline days	Using fuel switching Option 1	Using fuel switching Option 2	Using DSI	Using SDA	Using wet scrubber
Anaconda Pintler WA	6	6	6	6	6	6
Bob Marshall WA	21	21	19	21	18	18
Gates of the Mountains WA	361	359	352	356	349	348
Glacier NP	2	1	1	1	1	1
Mission Mountains WA	8	8	8	8	7	7
North Absaroka WA	2	2	2	2	2	2
Red Rock Lakes WA	0	0	0	0	0	0
Scapegoat WA	37	37	34	36	33	33
Selway-Bitterroot WA	7	7	7	7	6	6
Teton WA	0	0	0	0	0	0
Washakie WA	2	2	0	1	0	0
Yellowstone NP	3	2	2	2	2	2

Modeling was performed at a 25% control effectiveness rather than at a 30% control effectiveness for DAA, and at a control effectiveness of 60% rather than 50% for fuel switching—option 2; however, this should not change the outcome of the analysis because of the relatively small visibility improvement for each of the SO_2 controls considered.

Step 5: Select BART

We propose to find that BART for SO_2 is no additional controls at Ash Grove. We are accordingly proposing a BART emission limit of 11.5 lb/ton clinker (30-day rolling average). Of the five BART factors, visibility was the critical one in our analysis of controls for this source. The low visibility improvement predicted from the use of SO_2 controls did not justify proposing additional controls on this source.

In our BART analysis for SO_2 at Ash Grove, we considered DAA, fuel switching, semi-wet scrubbing and wet scrubbing. The comparison between our DAA, fuel switching, semi-wet scrubbing and wet scrubbing analysis is provided in Table 37.

TABLE 37—SUMMARY OF EPA SO_2 BART ANALYSIS COMPARISON OF DAA, FUEL SWITCHING, SEMI-WET SCRUBBING AND WET SCRUBBING FOR ASH GROVE

Control option	Total capital investment	Total annual cost	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1,2]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 deciview
Wet Scrubbing	30,022,424	5,094,562	4,806	[3]	0.180	12
Semi-wet scrubbing	11,644,912	1,940,004	1,830	2,095	0.180	12
Fuel Switching—Option 2	[4]	2,908,170	4,113	4,773	0.119	9
DAA	330,620	463,082	1,434	[5]	0.049	5
Fuel Switching—Option 1	[4]	487,877	2,439	[6]	0.033	

[1] The visibility benefit shown is for Gates of the Mountains WA.

[2] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I area that showed the greatest improvement, Gates of the Mountains, WA. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Gates of the Mountains WA.

[3] Incremental Cost Effectiveness cannot be calculated because both technologies reduce the same amount of emissions.

[4] Capital cost is not required for fuel switching.

[5] Incremental cost would result in a negative number and therefore was not calculated.

[6] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that DAA, fuel switching, semi-wet scrubbing, and wet scrubbing are all cost effective control technologies, but that they would not provide substantial visibility benefits. Given that the visibility improvement associated with SO_2 controls are relatively small, we propose that the SO_2 BART emission limit for the kiln at Ash Grove should be based on current emissions, while allowing for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[72] As EPA has stated previously, adopting an output-based standard avoids rewarding a source for becoming less efficient, i.e., requiring more feed to produce a unit of product. An output-based standard promotes the most efficient production process. 73 FR 34076, June 16, 2008. The NSPS for NO_X and NESHAP for PM are normalized by ton of clinker produced. We have recognized previously that facilities are allowed to measure feed inputs and to use site-specific feed/clinker ratio to calculate clinker production. 75 FR 54990, Sept. 9, 2010.

Accordingly, we are proposing 11.5 lb/ton clinker as a BART emission limit for SO_2 at Ash Grove Cement. In proposing this limit, we considered the emission rate currently being achieved by Ash Grove Cement in lb/ton clinker.[73] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] 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.'' Because we are not requiring additional controls to be installed, we propose that Ash Grove must comply with this emission limit within 180 days from the date our final FIP becomes effective. This will allow time for monitoring systems to be certified if necessary.

PM

Ash Grove currently has an electrostatic precipitator (ESP) for particulate control from the kiln. An ESP is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The ESP places electrical charges on the particles, causing them to be attracted to oppositely charged metal plates located in the precipitator. The particles are removed from the plates by ''rapping'' and collected in a hopper located below the unit. The removal efficiencies for ESPs are highly variable; however, for very small particles alone, the removal efficiency is about 99%.[74]

Ash Grove Cement must meet a PM_{10} emission rate based on the process weight of the kiln. Pursuant to the regulatory requirement in Montana's EPA approved SIP (Administrative Rule of Montana (ARM) 17.8.310), permit condition A.8 in Ash Grove's Final Title V Operating Permit #OP2005–06 contains the following requirements: if the process weight rate of the kiln is less than or equal to 30 tons per hour, then the emission limit shall be calculated using $E = 4.10p^{0.67}$ where E = rate of emission in pounds per hour and p = process weight rate in tons per hour; however, if the process weight rate of the kiln is greater than 30 tons per hour, then the emission limit shall be calculated using $E = 55.0p^{0.11} - 40$, where E = rate of emission in pounds per hour and P = process weight rate in tons per hour.

Based on our modeling described in section V.C.3.a, PM contribution to the baseline visibility impairment is low. Table 38 shows the maximum baseline visibility impact from PM and percentage contribution to that impact from coarse PM and fine PM.

TABLE 38—ASH GROVE VISIBILITY IMPACT CONTRIBUTION FROM PM

Maximum baseline visibility impact (deciview)	% Contribution coarse PM	% Contribution fine PM
4.446	0.84	4.77

The PM contribution to the baseline visibility impact for Ash Grove is very small; therefore, any visibility improvement that could be achieved with improvements to the existing PM controls would be negligible.

Taking into consideration the above factors we propose a BART emission limit based on use of the current control technology at Ash Grove and the emission limits described above for PM/PM_{10} as BART. We find that the BART emission limit can be achieved through the operation of the existing ESP. Thus, as described in our BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Ash Grove.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] 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.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

ii. Holcim

Background

The Holcim (US) Inc. Trident cement plant near Three Forks, MT was determined to be subject to the BART requirements as explained in section V.C. As explained in section V.C., the document titled ''Identification of BART-Eligible Sources in the WRAP Region'' dated April 4, 2005 provides more details on the specific emission units at each facility. Our analysis focuses on the kiln as the primary source of SO_2 and NO_X emissions. We requested a five factor BART analysis for Holcim's Trident cement plant. The company submitted that analysis on July 6, 2007, with updated information on January 25, 2008, June 9, 2009, August 12, 2009, June 16, 2011, and March 2, 2012.[75] Holcim's five factor

[72] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[73] Response to EPA request for supplemental information on emissions from the Montana City plant, March 9, 2012. Ash Grove lists the mean 30-day rolling average SO_2 emission rate for May 26, 2006 through September 8, 2008, at 7.2 lb/ton clinker. The 99th percentile 30-day rolling average was 11.02 lb/ton clinker.

[74] EPA Air Pollution Control Online Course, description at: *http://www.epa.gov/apti/course422/ce6a1.html.*

[75] BART analysis by Holcim for Trident Cement Plant, Three Forks, MT (''Holcim Initial Response'') (Jul 6, 2007); Responses to EPA comments on BART analysis for Trident Cement Plant (''Holcim 2008 Responses'') (Jan. 25, 2008); BART analysis by Holcim for low NO_X burners for Trident Cement Plant (''Holcim Additional Response, June 2009'') (Jun 9, 2009); Response to EPA letter regarding Confidential Business Information (CBI) claims on BART analysis for Trident Cement Plant (''Holcim

Continued

BART analysis is contained in the docket for this action and we have taken it into consideration in our proposed action.

NO_X

Step 1: Identify All Available Technologies

We identified the following previously described NO_X control technologies are available: LNB, MKF, FGR, SNCR, and SCR.

Step 2: Eliminate Technically Infeasible Options

We did not consider FGR and SCR further for Holcim since Holcim and Ash Grove are similar with regard to the relevant factors.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

For LNB on Holcim's kiln, it is appropriate to assume a control effectiveness of 15%.[76] For MKF, a control effectiveness of 30% is appropriate.[77] For SNCR, in evaluating the technology, a control effectiveness of 50% is appropriate, and for LNB+SNCR a control effectiveness of 58% is appropriate.[78]

As described above in the Ash Grove analysis, we consider 50% control effectiveness appropriate for SNCR at long wet kilns, such as Holcim's kiln.

Concentration of baseline NO_X emissions is one parameter affecting control effectiveness. The percentage of control effectiveness is greater when initial NO_X concentrations are greater. The reaction kinetics decrease as the concentration of reactants decreases. This is due to thermodynamic considerations that limit the reduction process at low NO_X concentrations.[79] The baseline NO_X emissions of the Holcim Trident kiln, in pounds per ton of clinker produced (lb/ton clinker) are significantly higher than those at Ash Grove's Midlothian kilns in Texas (described above in the Ash Grove analysis), indicating that SNCR on the Holcim kiln would be expected to achieve even greater control effectiveness when compared to SNCR on the Midlothian kilns. Information provided to EPA by Holcim on NO_X emissions at the Trident cement plant from 2008 through 2010 indicate that the mean 30-day rolling average emission rate was 9.7 lb/ton clinker,[80] much higher than Midlothian's pre-SNCR emission rate shown in the Ash Grove analysis above, which is between 4.5 and 4.9 lb/ton clinker.

A summary of the emissions projections for the NO_X control options is provided in Table 39.

TABLE 39—SUMMARY OF NO_X BART ANALYSIS CONTROL TECHNOLOGIES FOR HOLCIM

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
LNB + SNCR	58	645	467
SNCR	50	556	556
MKF	30	334	778
LNB	15	167	945
No Controls (Baseline)	0	0	[1] 1,112

[1] Holcim 2012 Response. (Holcim lists NO_X emissions at 998 tons for 2009, 1,175 tons for 2010, and 1164 tons for 2011. The average is 1,112 tons).

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

LNB

We relied on cost estimates supplied by Holcim for capital costs and annual costs,[81] but with two exceptions. We used a capital cost estimate of $4,385,307.[82] Also in our analysis, we used a CRF consistent with 20 years for the useful life of the kiln. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[83]

We calculated the average cost effectiveness from the total annual cost and a 15% reduction from the baseline actual emissions of 1,112 tpy. We summarize the cost information for LNB in Tables 40, 41, and 42.

TABLE 40—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR LNB ON HOLCIM

Description	Cost ($)
Total Capital Investment	[1] 4,385,307
Capital Recovery	[2] 413,972

[1] Holcim Additional Response, June 2009 (revised by EPA to eliminate 1.5 multiplier for "retrofit installation").

Additional Response, August 2009'') (Aug. 12, 2009); Response to EPA request for NO_X and SO_2 emissions data for 2008–2010 (''Holcim 2011 Response'') (Jun. 16, 2011); Response to EPA request for emissions and clinker production for Holcim pursuant to CAA section 114(a) (''Holcim 2012 Response'') (Mar. 2, 2012).

[76] EPA provided an example of LNB on a long wet kiln with a control effectiveness of 14% in NOx Control Technologies for the Cement Industry, Final Report, September 2000, p. 61.

[77] Holcim Initial Response, p. 4–16.

[78] We analyzed only for commercial SNCR at Holcim. In its January 25, 2008 submittal to EPA, Holcim discussed (at pages 11–12) an alternative form of SNCR, which Holcim refers to as ''dust scoops'' SNCR. This version of SNCR would use a solid pelletized form of urea, which could be mechanically introduced into the existing ''dust scoops'' mechanism. In its August 12, 2009 submittal to EPA, Holcim presented cost spreadsheets which estimated substantially less cost for ''dust scoops'' SNCR than for commercial SNCR ($716,800 capital cost versus $1,312,800 capital cost). However, Holcim's 2008 submittal indicated that neither type of SNCR was being considered by Holcim on anything more than a trial basis. Therefore, EPA has chosen to use the commercial SNCR cost estimate in its analysis, rather than the ''dust scoops'' SNCR cost estimate.

[79] CCM, p. 1–10.

[80] Holcim 2012 Response.

[81] Holcim Additional Response, June 2009.

[82] Holcim applied a 1.5 multiplier to the direct installation costs, for ''retrofit installation.'' We did not.

[83] CRF is 0.0944 and is based on a 7% interest rate and 20-year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944 which is based on a 7% interest rate and 20-year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 41—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR LNB ON HOLCIM

Description	Cost ($)
Total Indirect Annual Cost	[1] 413,972
Direct Annual Operating Cost	[2] 300,658
Total Annual Cost	714,629

[1] Includes capital recovery.
[2] Holcim Additional Response, June 2009.

The capital cost estimate of $4,385,307 includes the cost of converting from a direct to an indirect firing system to accommodate LNB, including installation of a baghouse, additional explosion prevention, pulverized coal storage, and dosing equipment.[84]

By comparison, our LNB cost analysis for Ash Grove Cement contains a capital cost estimate of $266,309 and annual cost estimate of $158,630. These figures are much lower than the estimate for Holcim because Ash Grove did not factor in the cost of any kiln modifications to convert from direct to indirect firing.

TABLE 42—SUMMARY OF NO_X BART COSTS FOR LNB ON HOLCIM

Total installed capital cost ($)	Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
4,385,307	714,629	167	4,279

MKF

We relied on cost estimates supplied by Holcim for annual costs.[85] No separate calculation of capital cost was presented by Holcim. Total annual cost of MKF was provided from an EPA publication,[86] for MKF conversion for a 50 tons-per-hour long wet kiln, scaled up by Holcim from 1997 dollars to 2006 dollars, using a 1.25607 Consumer Price Index (CPI) multiplier.[87] We calculated the cost effectiveness, from the total annual cost and a 30% reduction from the baseline actual emissions of 1,112 tpy. We present the costs for MKF in Table 43.

TABLE 43—SUMMARY OF NO_X BART COSTS FOR MKF ON HOLCIM

Total capital investment ($)	Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
Not calculated separately, but included in total annual cost	473,738	334	1,418

As explained in Holcim's BART analysis, the use of tire-derived fuel for MKF cannot be ensured within the five-year timeline required in the BART program. Holcim is not permitted by the State of Montana to use tires as a fuel source in its kiln until the State issues a final air quality permit allowing such use and any legal appeals are concluded.[88] Therefore, MKF is not considered further.

SNCR

We relied on cost estimates supplied by Holcim for capital costs and annual costs, with the exception of the CRF used.[89] For our analysis, we used a CRF consistent with 20 years for the useful life of the kiln. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[90] We calculated the average cost effectiveness from the total annual cost and a 50% reduction from the baseline actual emissions of 1,112 tpy, yielding a 588 tpy reduction. We summarize the cost information from our SNCR analysis in Tables 44, 45, and 46.

[84] Holcim Additional Response, June 2009.

[85] Holcim Initial Response.

[86] NO_X Control Technologies for the Cement Industry: Final Report, September 19, 2000, EPA–457/R–00–002, Table 6–10.

[87] Holcim Initial Response, p. 4–23.

[88] Id., p. 4–25.

[89] Holcim Additional Response, August 2009, Appendix C.

[90] CRF is 0.0944 and is based on a 7% interest rate and 20-year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 44—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SNCR ON HOLCIM

Description	Cost ($)
Total Capital Investment	[1] 1,312,800
Capital Recovery	[2] 123,928

[1] Holcim Additional Response, August, 2009.
[2] Capital Recovery was determined by multiplying the Total Capital Investment by the CRF of 0.0944, which is based on a 7% interest rate and 20-year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 45—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR SNCR ON HOLCIM

Description	Cost ($)
Total Indirect Annual Cost	[1] 123,928
Direct Annual Operating Cost	[2] 147,288
Total Annual Cost	271,216

[1] Includes capital recovery.
[2] Holcim Additional Response, August, 2009.

TABLE 46—SUMMARY OF NO_X BART COSTS FOR SNCR ON HOLCIM

Total capital investment ($)	Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
1,312,800	271,216	556	488

LNB + SNCR

We calculated the cost effectiveness of LNB + SNCR by dividing the sum of the annual cost of the two technologies described above by the 58% emissions reduction that would be achieved. We summarize the cost information from our LNB + SNCR analysis in Tables 47 and 48.

TABLE 47—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR LNB + SNCR ON HOLCIM

Description	Cost ($)
Total Annual Cost LNB	714,629
Total Annual Cost SNCR	271,216
Total Annual Cost LNB + SNCR	985,845

TABLE 48—SUMMARY OF NO_X BART COSTS FOR LNB + SNCR ON HOLCIM

Total annual cost ($)	Annual emissions reductions (tpy)	Average cost effectiveness ($/ton)
985,845	645	1,528

Factor 2: Energy and Non-Air Quality Impacts

LNBs are not expected to have any significant negative energy impacts [91] and are not expected to have any non-air quality environmental impacts. SNCR systems require electricity to operate the blowers and pumps. The generation of the electricity will most likely involve fuel combustion, which will cause emissions. While the required electricity will result in emissions, these emissions should be small compared to the reduction in NO_X that would be gained by operating an SNCR system.[92] Transporting the chemical reagents for SNCR would use natural resources for fuel and would have associated air quality impacts. The chemical reagents would be stored on site and could result in spills to the environment while being transferred between storage vessels or if containers were to fail during storage or movement. The environmental impacts associated with proper transportation, storage, and/or disposal should not be significant. Therefore, the non-air quality environmental impacts did not warrant eliminating LNB or SNCR.

Factor 3: Any Existing Pollution Control Technology in Use at the Source

Holcim currently uses proper kiln design and operation for NO_X control.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without

[91] Holcim Initial Response, p. 4–23.

[92] Holcim Initial Response, p. 5–13, 14.

commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Factor 5: Evaluate Visibility Impacts

We performed modeling as described previously.

We conducted modeling for Holcim as described in section V.C.3.a. Table 49 presents the Visibility Impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 50 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 49—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON HOLCIM

Class I area	Baseline impact (delta deciview)	Improvement from LNB (delta deciview)	Improvement from SNCR (delta deciview)	Improvement from LNB + SNCR (delta deciview)
Gates of the Mountains WA	0.980	0.125	0.295	0.424
Yellowstone NP	0.411	0.051	0.120	0.171

TABLE 50—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON HOLCIM

[Three-year total]

Class I area	Baseline days	Using LNB	Using SNCR	Using LNB + SNCR
Gates of the Mountains WA	46	39	26	19
Yellowstone NP	13	7	4	3

Modeling was performed at 35% control effectiveness rather than 50% control effectiveness for SNCR and at 50% control effectiveness rather than 58% control effectiveness for LNB + SNCR. Therefore, visibility improvement from SNCR and LNB + SNCR would be greater than what is shown.

Step 5: Select BART

We propose to find that BART for NO_X is LNB + SNCR with an emission limit of 5.5 lb/ton of clinker (30-day rolling average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for NO_X at Holcim, we considered LNB, SNCR, and LNB + SNCR. The comparison between our LNB, SNCR, and LNB + SNCR analysis is provided in Table 51.

TABLE 51—SUMMARY OF NO_X BART ANALYSIS COMPARISON OF CONTROL OPTIONS FOR HOLCIM

Control option	Total capital investment	Total annual cost	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1,2]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 deciview
LNB + SNCR	6,271,009	985,845	1,528	8,029	0.424	27
SNCR	1,312,800	271,216	488	[3] −1,140	0.295	20
LNB	4,958,209	714,629	4,279	[4]	0.125	7

[1] The visibility benefit shown is for Gates of the Mountains WA.

[2] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I area that showed the greatest improvement, Gates of the Mountains, WA. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Gates of the Mountains WA.

[3] The incremental cost effectiveness from LNB to SNCR is a negative number because the numerator in dollars is negative (i.e., the total annual cost of SNCR is less than LNB) but the denominator in tons is positive (i.e., SNCR achieves more tons of emission reduction than LNB).

[4] Incremental cost and impact is not applicable to the option that has the lowest emission control effectiveness.

We have concluded that LNB + SNCR is a cost effective control technology and would provide substantial visibility benefits. LNB + SNCR has a cost effectiveness value of $1,528 per ton of NO_X emissions reduced. This is well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART.

We have weighed costs against the anticipated visibility impacts for Holcim. Any of the control options would have a positive impact on visibility. As compared to LNB alone, LNB + SNCR would provide an additional visibility benefit of .299 deciviews and 20 fewer days above 0.5 deciviews at Gates of the Mountains WA. As compared to SNCR alone, LNB + SNCR would provide an additional visibility benefit of 0.129 deciviews and seven fewer days above 0.5 deciviews at Gates of the Mountains WA. Overall improvement from LNB + SNCR is 0.424 deciviews. We consider this impact to be beneficial, especially in light of the fact that this Class I area is not projected to meet the URP. Given the visibility improvement associated with LNB + SNCR and the reasonable average cost effectiveness for LNB + SNCR, we propose that the NO_X BART emission limit for the kiln at Holcim should be based on what can be achieved with LNB + SNCR.

As EPA has explained in earlier in this notice, adopting an output-based standard avoids rewarding a source for becoming less efficient.

In proposing a BART emission limit of 5.5 lb/ton clinker, we considered the emission rate currently being achieved by Holcim in lb/ton clinker, then applied an emission reduction of 58%.[93] This limit allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[94] We also are proposing monitoring, recordkeeping, and reporting requirements in regulatory text at the end of this proposal.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] 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.'' We propose a compliance deadline of five (5) years from the date our final FIP becomes effective because of the equipment installation and potential kiln combustion modifications that will be required.

SO_2

Step 1: Identify All Available Technologies

We identified that the following SO_2 control technologies are available: wet scrubbing, semi-wet scrubbing which for this source is the same as a SDA, fuel switching (lower sulfur fuel), and hot meal injection.

Wet scrubbing involves passing flue gas downstream from the main PMCD through a sprayed aqueous suspension of lime or limestone that is contained in a scrubbing device. The SO_2 reacts with the scrubbing reagent to form calcium sulfate ($CaSO_4$) sludge that is collected. The sludge usually is dewatered and disposed of at an offsite landfill.

SDAs use lime or limestone to react with SO_2. This technology involves injecting an aqueous lime or limestone suspension in fine droplets into the flue gas. The lime reacts with SO_2 in the flue gas to create fine particles of calcium sulfite ($CaSO_3$) or $CaSO_4$. The moisture evaporates from the particles, and the particles are collected in the PMCD. Limestone absorbent scrubbers have been used for SO_2 control on preheater/calciner kilns, but they can be successfully used on long kilns by adding spray nozzles that are made of special materials to prevent nozzle clogging. A SDA can achieve a SO_2 removal efficiency of 30% to 60%. Clogging may not be an issue with SDAs that use lime due to the small size of the lime particles (3–10 microns) which allows the particles to dissolve in water droplets quickly and react with the gaseous SO_2. One manufacturer of these scrubber systems indicates an SO_2 removal efficiency of greater than 90% for SDAs.[95]

Fuel switching is a control alternative. Holcim currently uses a mixture of about 60% low-sulfur coal and 40% petroleum coke as the primary fuels for the kiln. The sulfur content of the petroleum coke is approximately 5.3% and the sulfur content of the coal is approximately 0.8%.[96] If sulfur in fuel input to the kiln were reduced by burning a different blend of coal and coke with lower sulfur contents, a reduction in SO_2 emissions would be expected. We considered two different options for fuel switching. Option 1 would use 75% coal with 0.8% sulfur and 25% coke with 5.3% sulfur. Option 2 would use 100% coal, which has a lower sulfur content (0.8%) than coke.

Hot meal injection is the hot-meal bypass in a PH/PC kiln system, where calcined hot meal produced in the kiln is, in part, discharged in front of the kiln entrance after the precalcining process, so that the hot meal can scrub some of the SO_2 generated from the kiln feed. Achievable SO_2 reduction has been estimated at between 0% and 30%.[97]

Step 2: Eliminate Technically Infeasible Options

As explained above, hot meal is produced in a calcined/preheated kiln. Holcim does not have a PH/PC kiln design from which hot meal can be obtained. Therefore, hot meal injection was not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

EPA has stated that a well designed and operated wet scrubber can consistently achieve at least 90% control (75 FR 54995 (September 9, 2010)) and that 95% control efficiency is possible (73 FR 34080 (June 16, 2008)). Holcim's analysis used 95% control, which is the upper end of the range that is possible.[98] We used 95% control effectiveness for our analysis of wet scrubbing.

As cited above, according to one SDA manufacturer, 90% SO_2 control effectiveness is the minimum of the range for a SDA with lime absorbent medium. Given the extremely low SO_2 emissions from Holcim's kiln (about 50 tpy),[99] we consider 90% control to be optimistic here; nevertheless, relying on information from Holcim's July 6, 2007 submittal, we used 90% control effectiveness for our analysis.

For fuel substitution to 100% coal with 0.8% sulfur content, we relied on Holcim's estimate of 62% control effectiveness. For fuel substitution to 75% coal with 0.8% sulfur content and 25% petroleum coke with 5.3% sulfur content, we relied on Holcim's estimate of 32% control effectiveness.[100] We also evaluated the visibility impact from fuel switching to lower sulfur coal for which we used a control effectiveness of 60%.

TABLE 52—SUMMARY OF SO_2 BART ANALYSIS CONTROL TECHNOLOGIES FOR HOLCIM

Control option	Control effectiveness (%)	Annual emissions reduction (tpy)	Remaining annual emissions (tpy)
Wet scrubbing	95	47.7	2.5
SDA	90	45.2	5.0
Fuel Switching Option 2 (100% lower sulfur coal)	62	19.1	31.1
Fuel Switching Option 1 (25% coke/75% coal)	32	34.1	16.1
No Controls (Baseline)	0	0	50.2

[93] Holcim 2012 Response. (Holcim lists the mean 30-day rolling average NO_X emission rate for 2008–2011 at 9.7 lb/ton clinker. The 99th percentile 30-day rolling average was 12.6 lb/ton clinker. Applying 58% reduction to the 99th percentile figure yields 5.29 lb/ton clinker.)

[94] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[95] Formation and Techniques of Sulfur Oxide and Other Sulfur Compounds, p. 46.

[96] Holcim 2008 Responses, p. 6.

[97] Formation and Techniques of Sulfur Oxide and Other Sulfur Compounds, pp. 31, 44 and 48.

[98] Holcim Initial Response, p. 4–11.

[99] Holcim 2012 Response (Holcim listed the SO_2 emissions at 53.5 tons in 2009, 64.1 tons in 2010, and 33.1 tons in 2011. The average was 50.2 tons).

[100] Holcim 2008 Responses, p. 6.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Wet Scrubbing

We present the costs for wet scrubbing in Table 53. We relied on cost estimates from Holcim,[101] with the exception of the CRF. We used a CRF consistent with 20 years for the remaining useful life of the kiln. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[102] Since Holcim presented the capital costs and annual costs in 2002 dollars, then scaled up the total annual cost to 2007 dollars using a 1.1582 CPI multiplier, we present the costs in the same manner here. We calculated the average cost effectiveness from the total annual cost and a 95% reduction in the baseline actual emissions of 50.2 tpy. We summarize the cost information for wet scrubbing in Tables 53, 54, and 55.

TABLE 53—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR WET SCRUBBER ON HOLCIM

Description	Cost ($)
Total Capital Investment (2002 dollars)	[1] 8,098,489
Capital Recovery (2002 dollars)	[2] 764,497

[1] Holcim Additional Response, August 2009, Appendix B.
[2] Capital Recovery was determined by multiplying the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

TABLE 54—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR WET SCRUBBER ON HOLCIM

Description	Cost ($)
Total Indirect Annual Cost (2002 dollars)	[1] 764,297
Total Annual Operating Cost (2002 dollars)	[2] 3,453,408
Total Annual Cost (2002 dollars)	4,217,905
Total Annual Cost (2007 dollars)	4,885,177

[1] Includes capital recovery.
[2] Holcim Additional Response August 2009, Appendix B.

TABLE 55—SUMMARY OF SO_2 BART COSTS FOR WET SCRUBBER ON HOLCIM

Total capital investment ($)	Total annual cost ($)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
8,098,489 (2002 dollars)	4,885,177 (2007 dollars)	47.7	102,414

SDA

We present the costs for SDA in Table 56. We relied on cost estimates from Holcim,[2] with the exception that we used a CRF consistent with 20 years for the useful life of the kiln. EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. In order to calculate the annualized capital cost, we multiplied the capital cost by the CRF.[103] We calculated the average cost effectiveness from the total annual cost and a 90% reduction in the baseline actual emissions of 50.2 tpy. We summarize the cost information for SDA in Tables 56, 57, and 58.

TABLE 56—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR SDA ON HOLCIM

Description	Cost ($)
Total Capital Investment	[1] 22,597,000
Capital Recovery	[2] 2,133,156

[1] Holcim Initial Response, Appendix C.
[2] Capital Recovery was determined by multiplying the CRF of 0.0944 which is based on a 7% interest rate and 20 year equipment life. The justification for using the CRF of 0.0944 can be found in Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[101] Holcim Additional Response, August 2009, Appendix B.

[102] CRF is 0.0944 and is based on a 7% interest rate and 20 year equipment life. Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[103] *Id.*

TABLE 57—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR SDA ON HOLCIM

Description	Cost ($)
Total Indirect Annual Cost	[1] 2,133,156
Total Annual Operating Cost	[2] 1,186,133
Total Annual Cost	3,319,289

[1] Includes capital recovery.
[2] Holcim Initial Response, Appendix C.

TABLE 58—SUMMARY OF SO_2 BART COSTS FOR SDA ON HOLCIM

Total capital investment ($)	Total annual cost ($)	Emissions reductions (tpy)	Average cost effective-ness ($/ton)
22,597,000	3,319,289	45.2	73.435

Fuel Switching

We relied on Holcim's costs for fuel switching.[104] We calculated the average cost effectiveness from the total annual cost and a 32% reduction in the baseline actual emissions of 50.2 tpy for option 1, or a 62% reduction for option 2. There is no capital cost for fuel switching because there is no equipment to buy or install. However, annual cost will increase due to increased fuel cost. We summarize the cost information for fuel switching in Tables 59 and 60.

TABLE 59—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR FUEL SWITCHING FOR HOLCIM

Description	Cost ($)
Total Annual Cost Option 1 (25% coke/75% coal)	[1] 240,515
Total Annual Cost Option 2 (100% lower sulfur coal)	[1] 659,651

[1] Holcim 2008 Response.

TABLE 60—SUMMARY OF SO_2 BART COSTS FOR FUEL SWITCHING ON HOLCIM

Control option	Total annual cost ($)	Emissions reductions (tpy)	Average cost effective-ness ($/ton)
Fuel Switching Option 1	240,515	[1] 19.1	12,592
Fuel Switching Option 2	659,651	[2] 34.1	19,344

[1] Reflects 32% reduction from 50.2 tpy baseline emissions.
[2] Reflects 62% reduction from 50.2 tpy baseline emissions.

Factor 2: Energy and Non Air Quality Impacts

Fuel Switching Does Not Have Energy or Non Air Quality Environmental Impacts

Wet scrubbing and SDA use additional water and would generate a waste stream that would need to be transported and be disposed. Transporting the waste would use natural resources for fuel and would have associated air quality impacts. The disposal of the solid waste itself would be to a landfill and could possibly result in groundwater or surface water contamination if a landfill's engineering controls were to fail. The environmental impacts associated with proper transportation and/or disposal should not be significant.

Wet scrubbing and SDAs require additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. The additional energy requirements that would be involved in installation and operation of the evaluated controls are not significant enough to warrant eliminating any of the options evaluated. The cost of the additional energy requirements has been included in our calculations.

Factor 3: Any Existing Pollution Control Technology in Use at the Source

The kiln currently uses low sulfur coal as a component of fuel mix and inherent scrubbing for SO_2 control. The kiln inherently acts as an SO_2 scrubber, since some of the sulfur that is oxidized to SO_2 is absorbed by the alkali compounds in the raw material fed to the kiln. Holcim currently uses a mixture of petroleum coke with a sulfur content of 5.3% and coal with a sulfur content of 0.8%.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

[104] Holcim 2008 Responses, p. 6.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Holcim as described in section V.C.3.a. Table 61 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 62 presents the number of days with impacts greater than 0.5 deciviews for each Class I area from 2006 through 2008.

TABLE 61—DELTA DECIVIEW IMPROVEMENT FOR SO_2 CONTROLS ON HOLCIM

Class I area	Baseline impact (delta deciview)	Improvement from fuel switching option 1 (delta deciview)	Improvement from fuel switching option 2 (delta deciview)	Improvement from SDA (delta deciview)	Improvement from wet scrubber (delta deciview)
Gates of the Mountains WA	0.980	0.015	0.024	0.044	0.046
Yellowstone NP	0.411	0.011	0.007	0.020	0.021

TABLE 62—DAYS GREATER THAN 0.5 DECIVIEW FOR SO_2 CONTROLS ON HOLCIM

[Three-year total]

Class I area	Baseline (days)	Using fuel switching option 1	Using fuel switching option 2	Using SDA	Using wet scrubbing
Gates of the Mountains WA	46	45	44	43	43
Yellowstone NP	13	12	12	12	12

Modeling for fuel switching option #2 was performed assuming a 50% reduction rather than a 62% reduction.

Step 5: Select BART

We propose to find that BART for SO_2 is no additional controls at Holcim with an emission limit of 1.3 lb/ton clinker. Of the five BART factors, visibility was the critical one in our analysis of controls for this source. The low visibility improvement did not justify requiring additional SO_2 controls on this source.

In our BART analysis for SO_2 at Holcim, we considered wet scrubbing, SDA and fuel switching. The comparison between our wet scrubbing, SDA and fuel switching analysis is provided in Table 63.

TABLE 63—SUMMARY OF EPA SO_2 BART ANALYSIS COMPARISON OF WET SCRUBBING, SDA AND FUEL SWITCHING FOR HOLCIM

Control option	Total capital investment	Total annual cost	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1,2]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 deciview
Wet Scrubbing	8,098,489	4,217,905	102,414	408,462	0.046	3
SDA	22,597,000	3,319,289	73,435	239,607	0.044	3
Fuel Switching—Option 2	[3]	659,651	19,344	27,942	0.024	2
Fuel Switching—Option 1	[3]	240,515	12,592	[4]	0.015	1

[1] The visibility benefit shown is for Gates of the Mountains WA.
[2] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I area that showed the greatest improvement, Gates of the Mountains WA. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Gates of the Mountains WA.
[3] Capital cost is not required for fuel switching.
[4] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that wet scrubbing, SDA and fuel switching are not cost effective control technologies and would not provide substantial visibility benefits. Given the minimal visibility improvements associated with SO_2 controls, we propose that the SO_2 BART emission limit for the kiln at Holcim should be based on current emissions, while allowing for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[105]

As EPA has explained earlier in this notice, adopting an output-based standard avoids rewarding a source for becoming less efficient. Accordingly, we are proposing 1.3 lb/ton clinker as a BART emission limit for SO_2 at Holcim. In proposing this limit, we considered the emission rate currently being achieved by Holcim in lb/ton clinker.[106] We are also proposing monitoring, recordkeeping, and reporting requirements in regulatory text at the end of this proposal.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the

[105] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[106] Holcim 2012 Response (Holcim lists the mean 30-day rolling average SO_2 emission rate for 2008–2011 at 0.37 lb/ton clinker. The 99th percentile 30-day rolling average was 1.20 lb/ton clinker).

implementation plan revision.'' Because we are not requiring additional controls to be installed, we propose that Holcim must comply with this emission limit within 180 days from the date our final FIP becomes effective. This will allow time for monitoring systems to be certified, if necessary.

PM

Holcim currently has an ESP that uses two fields in series for particulate control from the kiln. A description of an ESP can be found under the PM section of the BART analysis for Ash Grove. The efficiency of the ESP is greater than 99.9%.[107]

Based on our modeling described in section V.C.3.a, PM contribution to the baseline visibility impairment is low. Table 64 shows the maximum baseline visibility impact and percentage contribution to that impact from coarse PM and fine PM.

TABLE 64—HOLCIM VISIBILITY IMPACT CONTRIBUTION FROM PM

Maximum baseline visibility impact (deciview)	% Contribution coarse PM	% Contribution fine PM
0.980	5.79	12.61

The PM contribution to the baseline visibility impact for Holcim is very small; therefore, any visibility improvement that could be achieved with improvements to the existing PM controls would be negligible.

Holcim must meet the filterable PM emission standard of 0.77 lb/ton of clinker in accordance with their Final Title V Operating Permit #OP0982–02. This Title V requirement appears in Permit Condition G.3.; and was included in the permit pursuant to the regulatory requirements in Montana's EPA approved SIP (ARM 17.8.749).

Taking into consideration the above factors we propose basing the BART emission limit on what Holcim is currently meeting. The unit is exceeding a PM control efficiency of 99.9%, and therefore we are proposing that the current control technology and the emission limit of 0.77 lb/ton clinker for PM/PM_{10} as BART. We find that the BART emission limit can be achieved through the operation of the existing ESP. Thus, as described in our BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Holcim.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] 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.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

iii. Columbia Falls Aluminum Company (CFAC)

As described in section V.C., CFAC was determined to be subject to BART. As explained in that section, the document titled ''Identification of BART Eligible Sources in the WRAP Region'' dated April 4, 2005 provides more details on the specific emission units at each facility. We requested a five factor BART analysis for CFAC and the company submitted that analysis along with updated information.[108] CFAC's five factor BART analysis is contained in the docket for this action.

CFAC holds a permit to operate five Vertical Stud Soderberg potlines at the Columbia Falls plant.[109] Each potline has 120 individual cells that produce aluminum by the Hall-Heroult process. Subsequent to CFAC submitting its BART analysis, the CFAC plant closed at the end of October 2009.[110] In a February 19, 2010 report on the CFAC facility, Montana's Department of Environmental Quality (MDEQ) noted witnessing the plant's closure during a January 14, 2010 inspection.[111] The State's report also noted that CFAC's environmental manager was uncertain as to whether and when the plant would resume aluminum production. CFAC's environmental manager stated that the only operating emission units were some natural gas heaters used in conjunction with water treatment at the facility.

CFAC is currently not operating and it is unknown whether and when the Company will resume operations. As explained in the regulatory text for this proposal, if CFAC resumes operations, we will complete a BART determination after notification and revise the FIP as necessary in accordance with regional haze requirements, including the BART provisions in 40 CFR 51.308(e). CFAC will be required to install any controls that are required as soon as practicable, but in no case later than five years following date of the final action of this FIP.

iv. Colstrip

As described in section V.C., Colstrip Units 1 and 2 were determined to be subject to BART. As explained in section V.C., the document titled ''Identification of BART Eligible Sources in the WRAP Region'' dated April 4, 2005 provides more details on the specific emission units at each facility. PPL Montana's (PPL) Colstrip Power Plant (Colstrip), located in Colstrip, Montana, consists of a total of four electric utility steam generating units. Of the four units, only Units 1 and 2 are subject to BART. We previously provided in Section V.C. our reasoning for proposing that these two units are BART-eligible and why they are subject to BART. Units 1 and 2 boilers have a nominal gross capacity of 333 MW each. The boilers began commercial operation in 1975 (Unit 1) and 1976 (Unit 2) and are tangentially fired pulverized coal boilers that burn Powder River Basin (PRB) sub-bituminous coal as their exclusive fuel.

[107] Air Quality Technical Analysis Report, Review of Submittals Supporting the Holcim (US) Inc. Tires Combustion Proposal, Prepared for MDEQ, Prepared by Lorenzen Engineering, Inc., p. 13.

[108] The following information has been submitted by CFAC: Best Available Retrofit Technology (BART) Analysis, Nov. 5, 2007; Letter to Callie Videtich from Harold W. Robbins, RE: CFAC BART Analysis—Response to EPA Comments, June 19, 2008.

[109] See Montana Air Quality Operating Permit (MAQOP) #OP2655–02 (Title V).

[110] See Section V of MDEQ's CFAC Compliance Monitoring Report, p. 10.

[111] See Compliance Monitoring Report Section VII, p. 11.

Our analysis follows EPA's BART Guidelines. For Colstrip Units 1 and 2, the BART Guidelines are mandatory because the combined capacity for all four units at Colstrip is greater than 750 MW.[112]

We requested a five factor BART analysis for Colstrip Units 1 and 2 from PPL and the Company submitted that analysis in August 2007 along with updated information in June 2008 and September 2011. PPL's five factor BART analysis information is contained in the docket for this action and we have taken it into consideration in our proposed action.

(a) Colstrip Unit 1

NO_X

The Colstrip Unit 1 boiler is of tangential-fired design with low-NO_X burners and close-coupled overfire air (CCOFA). Originally, the unit operated with a NO_X emission limit of 0.7 lb/MMBtu. In 1997, EPA approved an early election plan under the acid rain program (ARP) that included a 0.45 lb/MMBtu annual NO_X limit. The early reduction limit expired in 2007 and the new annual limit of 0.40 lb/MMBtu under the ARP became effective in 2008. Normally, the unit operates with an actual annual average NO_X emission rate in the range of 0.30 to 0.35 lb/MMBtu, accomplished with low NO_X burners and CCOFA.[113]

Step 1: Identify All Available Technologies

We identified that the following NO_X control technologies are available: separated overfire air (SOFA), advanced separated overfire air (ASOFA), rotating opposed fire air (ROFA), rich reagent injection (RRI), SNCR, and SCR.

SOFA technology is similar to CCOFA but the air injection point for SOFA is separated some distance above the main burners and can result in improved NO_X removal efficiencies. SOFA in combination with LNB technology provides additional NO_X control by injecting air into the lower temperature combustion zone where NO_X is less likely to form. This allows complete combustion of the fuel while reducing both thermal and chemical NO_X formation.

ASOFA technology is similar to SOFA, but the amount of air staged is in the range of 20 to 30%, and, in some cases, can result in even further improved NO_X removal efficiencies compared to SOFA.

ROFA is a low NO_X system that is somewhat similar to the SOFA. ROFA uses more ports and a significantly bigger fan to accomplish similar results of getting air into the upper portion of the boiler. ROFA uses a rotating opposed fire air process, while the SOFA system uses both horizontal (yaw) and vertical nozzle tip controls.

RRI is similar to SNCR and achieves similar results.

In SNCR systems, a reagent such as NH_3 or urea is injected into the flue gas at a suitable temperature zone, typically in the range of 1,600 to 2,000 °F and at an appropriate ratio of reagent to NO_X.

SCR uses either NH_3 or urea in the presence of a metal based catalyst to selectively reduce NO_X emissions.

Step 2: Eliminate Technically Infeasible Options

Based on our review, all the technologies identified in Step 1 appear to be technically feasible for Colstrip Unit 1. In particular, both SCR and SNCR have been widely employed to control NO_X emissions from coal-fired power plants.[114,115,116]

However, in the BART Guidelines, EPA states that it may be appropriate to eliminate from further consideration technologies that provide similar control levels at higher cost. The guidelines say that, ''a possible outcome of the BART procedures discussed in these guidelines is the evaluation of multiple control technology alternatives which result in essentially equivalent emissions. It is not our intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emissions unit. For example, if two or more control techniques result in control levels that are essentially identical, considering the uncertainties of emissions factors and other parameters pertinent to estimating performance, you may evaluate only the less costly of these options.'' 70 FR 39165 (July 6, 2005). As explained below, we have eliminated ASOFA, ROFA, and RRI from further consideration for this reason. SOFA is the least costly of these options.

Since ASOFA would likely not achieve greater emissions reductions compared to SOFA it is not considered further.

Since ROFA would achieve very similar emissions reductions compared to the SOFA system, ROFA is not considered further.

Since RRI would not achieve greater emissions reductions compared to SNCR, RRI is not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

At tangentially fired boilers firing PRB coal, SOFA in combination with CCOFA and LNB, can typically achieve emission rates below 0.15 lb/MMBtu on an annual basis.[117] However, due to certain issues unique to Colstrip Unit 1, a rate of 0.20 lb/MMBtu is more realistic. Specifically, these issues include: (1) that the furnace is sized smaller than others and therefore runs hotter than similar units, and (2) that the PRB coal used, classified as a borderline sub-bituminous B coal, is less reactive (produces more NO_X) than typical PRB coals.[118] The 0.20 lb/MMBtu rate represents a 34.9% reduction from the current baseline (2008 through 2010) rate of 0.308 lb/MMbtu.

The post-combustion control technologies, SNCR and SCR, have been evaluated in combination with combustion controls. That is, the inlet concentration to the post-combustion controls is assumed to be 0.20 lb/MMBtu. This allows the equipment and operating and maintenance costs of the post-combustion controls to be minimized based on the lower inlet NO_X concentration. Typically, SNCR reduces NO_X an additional 20 to 30% above LNB/combustion controls without excessive NH_3 slip.[119] Assuming that a minimum 25% additional emission reduction is achievable with SNCR, SOFA combined with SNCR can achieve an overall control efficiency of 51.1%. SCR can achieve performance emission rates as low as 0.04 to 0.07 lb/MMBtu

[112] Also, the BART Guidelines establish presumptive NO_X limits for coal-fired Electric Generating Units (EGUs) located at greater than 750 MW power plants that are operating without post-combustion controls. For the tangential-fired boilers burning sub-bituminous coal at Colstrip, that limit is 0.15 lb/MMBtu. 70 FR 39172 (July 6, 2005), Table 1. The guidelines provide that the five factor analysis may result in a limit that is different than the presumptive limit.

[113] Baseline emissions were determined by averaging the annual emissions from 2008 through 2010 as reported to the CAMD database available at *http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.*

[114] Institute of Clean Air Companies (ICAC) White Paper, Selective Catalytic Reduction Controls of NO_X Emissions from Fossil Fuel-Fired Electric Power Plants, May 2009, pp. 7–8.

[115] Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants Northeast States for Coordinated Air Use Management (NESCAUM), March 31, 2011, p. 16.

[116] ICAC White Paper, Selective Non-Catalytic Reduction for Controlling NO_X Emissions, February 2008, pp. 6–7.

[117] Low NO_X Firing Systems and PRB Fuel; Achieving as Low as 0.12 LB NO_X/MMBtu, Jennings, P., ICAC Forum, Feb. 2002.

[118] June 2008 PPL Addendum, p. 5–1.

[119] White Paper, SNCR for Controlling NO_X Emissions, Institute of Clean of Clean Air Companies, pp. 4 and 9, February 2008.

on an annual basis.[120] Assuming that an annual emission rate of 0.05 lb/MMBtu is achievable with SCR, SOFA combined with SCR can achieve an overall control efficiency of 83.8%. A summary of emissions projections for the control options is provided in Table 65.

TABLE 65—SUMMARY OF NO_X BART ANALYSIS CONTROL TECHNOLOGIES FOR COLSTRIP UNIT 1

Control option	Control effectiveness (%)	Annual emission rate (lb/MMBtu)	Emissions reduction (tpy)	Remaining emissions (tpy)
SOFA+SCR	83.5	0.050	425	678
SOFA+SNCR	51.1	0.150	2,097	2,006
SOFA	34.9	0.200	1,432	2,671
No Controls (Baseline) [1]		0.308		4,103

[1] Baseline emissions were determined by averaging the annual emissions from 2008 to 2010 as reported to the CAMD database available at *http://camddataandmaps.epa.gov/gdm/*.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

We relied on a number of resources to assess the cost of compliance for the control technologies under consideration. In accordance with the BART Guidelines (70 FR 39166 (July 6, 2005)), and in order to maintain and improve consistency, in all cases we sought to align our cost methodologies with the EPA's Control Cost Manual (CCM).[121] However, to ensure that our methods also reflect the most recent cost levels seen in the marketplace, we also relied on control costs developed for the Integrated Planning Model (IPM) version 4.10.[122] These IPM control costs are based on databases of actual control project costs and account for project specifics such as coal type, boiler type, and reduction efficiency. The IPM control costs reflect the recent increase in costs in the five years proceeding 2009 that is largely attributed to international competition. Finally, our costs were also informed by cost analyses submitted by the sources, including in some cases vendor data.

Annualization of capital investments was achieved using the CRF as described in the CCM.[123] The CRF was computed using an economic lifetime of 20 years and an annual interest rate of 7%.[124] Unless otherwise noted, all costs presented in this proposal for the PPL BART units have been adjusted to 2010 dollars using the Chemical Engineering Plant Cost Index (CEPCI).[125] EPA's detailed control costs for Colstrip can be found in the docket.

SOFA

We relied on estimates submitted by PPL in 2008 for capital costs and direct annual costs for SOFA.[126] The Capital Cost is listed in Table 66. We then used the CEPCI to adjust capital costs to 2010 dollars. Annual costs were determined by summing the indirect annual cost and the direct annual cost (see Table 67).

TABLE 66—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA ON COLSTRIP UNIT 1

Description	Cost ($)
Total Capital Investment SOFA	4,507,528

TABLE 67—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR SOFA ON COLSTRIP UNIT 1

Description	Cost ($)
Total Indirect Annual Cost	425,511
Total Direct Annual Cost	664,884
Total Annual Cost	1,090,395

TABLE 68—SUMMARY OF NO_X BART COSTS FOR SOFA ON COLSTRIP UNIT 1

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
4.508	1.090	1,432	761

SOFA+SNCR We relied on control costs developed for the IPM for direct capital costs for SNCR.[127] We then used methods provided by the CCM for the remainder of the SOFA+SNCR analysis. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to

[120] Information available at: *http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/NOx%20control%20Lani%20AWMA%200905.pdf*.

[121] EPA's CCM Sixth Edition, January 2002, EPA 452/B–02–001.

[122] Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model, August 2010, EPA #430R10010.

[123] Section 1, Chapter 2, p. 2–21.

[124] Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[125] Chemical Engineering Magazine, p. 56, August 2011. (*http://www.che.com*).

[126] Addendum to PPL Montana's Colstrip BART Report Prepared for PPL Montana, LLC; Prepared by TRC, (''Colstrip Addendum''), June 2008, Table 5.1–1.

[127] IPM, Chapter 5, Appendix 5–2B.

annualize the total capital investment using the CRF, and to sum the total annual costs.

We used a retrofit factor of ''1'' reflecting an SNCR retrofit of typical difficulty in the IPM control costs. As Colstrip Unit 1 burns sub-bituminous PRB coal having a low sulfur content of 0.91 lb/MMBtu (equating to a SO_2 rate of 1.8 lb/MMBtu),[128] it was not necessary to make allowances in the cost calculations to account for equipment modifications or additional maintenance associated with fouling due to the formation of ammonium bisulfate. These are only concerns when the SO_2 rate is above 3 lb/MMBtu.[129] Moreover, ammonium bisulfate formation can be minimized by preventing excessive NH_3 slip. Optimization of the SNCR system can commonly limit NH_3 slip to levels less than the 5 parts per million (ppm) upstream of the pre-air heater.[130] EPA's detailed cost calculations for SOFA+SNCR can be found in the docket.

We used a urea reagent cost estimate of $450 per ton taken from PPL's September 2011 submittal.[131] To estimate the average cost effectiveness (dollars per ton of emissions reductions) we divided the total annual cost by the estimated NO_X emissions reductions. We summarize the costs from our SOFA+SNCR cost analysis in Tables 69, 70, and 71.

TABLE 69—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA+SNCR ON COLSTRIP UNIT 1

Description	Cost ($)
Capital Investment SOFA	4,507,528
Capital Investment SNCR	8,873,145
Total Capital Investment SOFA+SNCR	13,380,673

TABLE 70—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SNCR ON COLSTRIP UNIT 1

Description	Cost ($)
Total Annual Cost SOFA	1,090,395
Total Annual Cost SNCR	2,188,569
Total Annual Cost SOFA+SNCR	3,278,964

TABLE 71—SUMMARY OF NO_X BART COSTS FOR SOFA+SNCR ON COLSTRIP UNIT 1

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
13.381	3.279	2,097	1,564

SOFA+SCR

We relied on control costs developed for the IPM for direct capital costs for SCR.[132] We then used methods in the CCM for the remainder of the SOFA+SCR analysis. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs.

We used a retrofit factor of ''1'' in the IPM control costs, which reflects an SCR retrofit of typical difficulty. We used an aqueous ammonia (29%) cost of $240 per ton,[133] and a catalyst cost of $6,000 per cubic meter.[134] To estimate the average cost effectiveness (dollars per ton of emissions reductions) we divided the total annual cost by the estimated NO_X emissions reductions. We summarize the costs from our SOFA+SCR cost analysis in Tables 72, 73, and 74.

TABLE 72—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA+SCR ON COLSTRIP UNIT 1

Description	Cost ($)
Capital Investment SOFA	4,507,528
Capital Investment SCR	78,264,060
Total Capital Investment SOFA+SCR	82,771,589

TABLE 73—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SCR ON COLSTRIP UNIT 1

Description	Cost ($)
Total Annual Cost SOFA	1,090,395

[128] Cost and Quality of Fuels for Electric Utility Plants 1999 Tables, Energy Information Administration, DOE/EIA–0191(99), June 2000, Table 24.

[129] IPM, Chapter 5, p. 5–9.

[130] ICAC, p. 8.

[131] NO_X Control Update to PPL Montana's Colstrip Generating Station BART Report Prepared for PPL Montana, LLC, by TRC, September 2011, p. 4–1.

[132] IPM, Chapter 5, Appendix 5–2A.

[133] Email communication with Fuel Tech, Inc., March 2, 2012.

[134] Cichanowicz 2010, p. 6–7.

TABLE 73—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SCR ON COLSTRIP UNIT 1—Continued

Description	Cost ($)
Total Annual Cost SCR	9,852,395
Total Annual Cost SOFA+SCR	10,942,766

TABLE 74—SUMMARY OF NO_X BART COSTS FOR SOFA+SCR ON COLSTRIP UNIT 1

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
82.772	10.942	3,425	3,195

Factor 2: Energy Impacts

SNCR reduces the thermal efficiency of a boiler as the reduction reaction uses thermal energy from the boiler.[135] Therefore, additional coal must be burned to make up for the decreases in power generation. Using CCM calculations we determined the additional coal needed for Unit 1 equates to 77,600 MMBtu/yr. For an SCR, the new ductwork and the reactor's catalyst layers decrease the flue gas pressure. As a result, additional fan power is necessary to maintain the flue gas flow rate through the ductwork. SCR systems require additional electric power to meet fan requirements equivalent to approximately 0.3% of the plant's electric output.[136] Both SCR and SNCR require some minimal additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. The additional energy requirements that would be involved in installation and operation of the evaluated controls are not significant enough to warrant eliminating any of the options evaluated. Note that cost of the additional energy requirements has been included in our calculations.

Factor 3: Non-Air Quality Environmental Impacts

SNCR and SCR will increase the quantity of ash that will need to be disposed. Transporting this waste stream for disposal would use natural resources for fuel and would have associated air quality impacts. The disposal of the solid waste itself would be to a landfill and could possibly result in groundwater or surface water contamination if a landfill's engineering controls were to fail. Transporting the chemical reagents and catalysts would use natural resources for fuel and would have associated air quality impacts. The chemical reagents would be stored on site and could result in spills to the environment while being transferred between storage vessels or if containers were to fail during storage or movement. The environmental impacts associated with proper transportation, storage, and/or disposal should not be significant. Therefore, the non-air quality environmental impacts do not warrant eliminating either SNCR or SCR.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. Thus, this factor does not impact our BART determination because the annualized cost was calculated over a 20 year period in accordance with the BART Guidelines.

Factor 5: Evaluate visibility impacts

We conducted modeling for Colstrip Unit 1 as described in section V.C.3.a. Table 75 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 76 presents the number of days with impacts greater than 0.5 deciviews for each Class I area from 2006 through 2008.

TABLE 75—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON COLSTRIP UNIT 1

Class I area	Baseline impact (delta deciview)	Improvement from SOFA+SCR (delta deciview)	Improvement from SOFA+SNCR (delta deciview)	Improvement from SOFA (delta deciview)
North Absaroka WA	0.414	0.181	0.089	0.047
Theodore Roosevelt NP	0.922	0.404	0.264	0.182
UL Bend WA	0.895	0.378	0.249	0.164
Washakie WA	0.410	0.121	0.077	0.052
Yellowstone NP	0.275	0.081	0.059	0.034

TABLE 76—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON COLSTRIP UNIT 1

[Three year total]

Class I area	Baseline (days)	Using SOFA+SCR	Using SOFA+SNCR	Using SOFA
North Absaroka WA	7	5	5	7

[135] CCM, Section 4.2, Chapter 1, p. 1–21.

[136] *Id.*, Section 4.2, Chapter 2, p. 2–28.

TABLE 76—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON COLSTRIP UNIT 1—Continued

[Three year total]

Class I area	Baseline (days)	Using SOFA+SCR	Using SOFA+SNCR	Using SOFA
Theodore Roosevelt NP	52	17	27	33
UL Bend WA	68	29	47	52
Washakie WA	12	5	9	10
Yellowstone NP	4	2	2	2

Step 5: Select BART

We propose to find that BART for NO_X is SOFA+SNCR at Colstrip Unit 1 with an emission limit of 0.15 lb/MMBtu (30-day rolling average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for NO_X at Colstrip Unit 1, we considered SOFA, SOFA+SNCR, and SOFA+SCR. The comparison between our SOFA, SOFA+SNCR, and SOFA+SCR analysis is provided in Table 77.

TABLE 77—SUMMARY OF NO_X BART ANALYSIS COMPARISON OF CONTROL OPTIONS FOR COLSTRIP UNIT 1

Control option	Total capital investment (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1]	
					Visibility improvement (delta deciviews)	Fewer days >0.5 deciview
SOFA+SCR	82.772	10.942	3,195	5,770	0.404 TRNP 0.378 UL Bend	35 TRNP. 39 UL Bend.
SOFA+SNCR	13.380	3.279	1,564	3,291	0.264 TRNP 0.249 UL Bend	25 TRNP. 21 UL Bend.
SOFA	4.508	1.090	761	[2]	0.182 TRNP 0.164 UL Bend	19 TRNP. 16 UL Bend.

TRNP—Theodore Roosevelt National Park.
UL Bend—UL Bend Wilderness Area.
[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I areas in the table.
[2] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that SOFA, SOFA+SNCR, and SOFA+SCR are all cost effective control technologies. SOFA has a cost effectiveness value of $761 per ton of NO_X emissions reduced. SOFA+SNCR is more expensive than SOFA, with a cost effectiveness value of $1,564 per ton of NO_X emissions reduced. SOFA+SCR is more expensive than SOFA or SOFA+SNCR, having a cost effectiveness value of $3,195 per ton of NO_X emissions reduced. This is well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART.

We have weighed costs against the anticipated visibility impacts for Colstrip Unit 1. Any of the control options would have a positive impact on visibility; however, the cost of SOFA+SCR ($3,195/ton) is not justified by the visibility improvement of 0.404 deciviews at TRNP and 0.378 deciviews at UL Bend. The lower cost of SOFA+SNCR ($1,564/ton) is justified when the visibility improvement is considered. SOFA+SNCR would have a visibility improvement of 0.264 deciviews at Theodore Roosevelt NP and 0.249 deciviews at UL Bend WA and it would result in 25 fewer days above 0.5 deciviews at Theodore Roosevelt-NP and 21 fewer days above 0.5 deciviews at UL Bend WA. In addition, application of SOFA+SNCR at both Colstrip Units 1 and 2 would have a combined modeled visibility improvement of 0.501 deciviews at Theodore Roosevelt NP and 0.451 deciviews at UL Bend WA. We consider these improvements to be substantial, especially in light of the fact that Theodore Roosevelt NP and UL Bend WA are not projected to meet the URP. We propose that the NO_X BART emission limit for Colstrip Unit 1 should be based on what can be achieved with SOFA+SNCR.

The proposed BART emission limit of 0.15 lb/MMBtu allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[137] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] 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.'' We propose a compliance deadline of five (5) years from the date our final FIP becomes effective because of the equipment installation and potential combustion modifications that will be required.

SO_2

Colstrip Unit 1 is already controlled by wet venturi scrubbers for simultaneous particulate and SO_2 control. The venturi scrubbers utilize the alkalinity of the fly ash to achieve an estimated SO_2 removal efficiency of 75%.[138] Based on emissions data from the EPA Clean Air Markets Division (CAMD), for the baseline period 2008 through 2010, the average SO_2 emission rate was 0.418 lb/MMBtu and the

[137] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[138] BART Assessment Colstrip Generating Station, prepared for PPL Montana, LLC, by TRC (''Colstrip Initial Response''), August 2007, p. ES–3.

average SO_2 emissions were 5,548 tpy.[139]

Step 1: Identify All Available Technologies

The Colstrip Unit 1 venturi scrubber currently achieves greater than 50% removal of SO_2. For units with preexisting post-combustion SO_2 controls achieving removal efficiencies of at least 50%, the BART Guidelines state that upgrades to the system designed to improve the system's overall removal efficiency should be considered. 70 FR 39171 (July 6, 2005). For wet scrubbers, the BART Guidelines recommend that the following upgrades be considered: (a) Elimination of bypass reheat; (b) installation of liquid distribution rings; (c) installation of perforated trays; (d) use of organic acid additives; (e) improve or upgrade scrubber auxiliary equipment; and (f) redesign spray header or nozzle configuration.

In addition to the upgrades recommended by the BART Guidelines, two other upgrades are available: lime injection and lime injection with an additional scrubber vessel. Some of the upgrades recommended by the BART Guidelines are inherent in lime injection; consequently, they are available technologies only within that context. Specifically, these include options (b), (e), and (f) as listed above.

A venturi scrubber works by increasing the contact between the pollutant-bearing gas stream and the scrubbing liquid. This is achieved in the throat of the venturi scrubber where the gas stream is accelerated, thereby atomizing the scrubber liquid and promoting greater gas-liquid contact.[140] Absorption of SO_2 is further enhanced by use of alkaline reagents. Currently, the venturi scrubbers for Colstrip Unit 1 rely on the alkalinity of the coal ash to reduce SO_2. Adding lime to the water stream for these scrubbers will increase SO_2 removal. However, as the amount of lime is increased, scaling of piping and equipment is also expected to increase and this scaling will have to be removed. The scrubber vessel would not be operational during the descaling process, resulting in downtime. Greater removal efficiencies could be achieved if an additional scrubber vessel is added to the system to reduce downtime for descaling. Therefore, addition of a spare scrubber vessel is an upgrade that can improve the overall SO_2 removal efficiency of the scrubber system by increasing the system's reliability and decreasing its downtime. The additional scrubber vessel is an example of equipment redundancy that will enhance the overall system performance.

Step 2: Eliminate Technically Infeasible Options

Elimination of bypass reheat is not feasible option because Colstrip Unit 1 is designed so that there is no bypass of flue gas. Installation of perforated trays is not a feasible option because the existing scrubber design already includes this technology in the form of wash trays. Finally, the use of organic acid additives is not a feasible option because the reactivity of the lime would neutralize the acids, making the additives ineffective.

Lime injection or lime injection with an additional scrubber vessel are technically feasible control options because lime injection is currently used to control SO_2 emissions at Colstrip Units 3 and 4.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

An annual emission rate of 0.015 lb/MMBtu can be achieved with lime injection without an additional scrubber vessel. PPL stated that this is the lowest emission rate that could be achieved without adding an additional scrubber vessel.[141] An annual emission rate of 0.08 to 0.09 lb/MMBtu can be achieved with lime injection with an additional scrubber vessel. This is the emission rate that is being achieved at Colstrip Units 3 and 4 according to emissions data from CAMD.[142] The control effectiveness of each of the control options was calculated using the controlled emission rates that were provided by PPL.

A summary of control efficiencies, emission rates, and resulting emissions and emission reductions, is provided in Table 78. EPA's detailed emissions calculations can be found in the docket.

TABLE 78—SUMMARY OF BART ANALYSIS CONTROL TECHNOLOGIES FOR SO_2 FOR COLSTRIP UNIT 1

Control option	Control effectiveness (%) [1]	Annual emission rate (lb/MMBtu) [2]	Emissions reduction (tpy)	Remaining emissions (tpy)
Lime Injection with Additional Scrubber Vessel	80.9	0.080	4,486	1,062
Lime Injection	64.1	0.150	3,557	1,991
Existing Controls (Baseline) [3]		0.418		5,548

[1] Control efficiency is provided relative to the emission rate with current controls.
[2] Emission rates are provided on an annual basis.
[3] Baseline emissions for 2008 through 2010 from Clean Air Markets—Data and Maps: *http://camddataandmaps.epa.gov/gdm/.*

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

We relied on capital costs and direct annual costs provided by PPL when determining the cost of compliance for both lime injection and lime injection with an additional scrubber vessel.[143,144] All costs presented here for the Colstrip Unit 1 SO_2 control options are in year 2007 dollars. EPA's cost calculations can be found in the docket.

Lime Injection

We summarize our cost analysis for lime injection in Tables 79, 80, and 81.

[139] Clean Air Markets—Data and Maps: *http://camddataandmaps.epa.gov/gdm/.*

[140] EPA Air Pollution Control Technology Fact Sheet: Venturi Scrubber, EPA–452/F–03–017.

[141] Colstrip Addendum, p. 4–1.

[142] Clean Air Markets—Data and Maps: *http://camddataandmaps.epa.gov/gdm/.*

[143] Colstrip Initial Response, Table A4–6(c).

[144] Colstrip Addendum, Table 4.1–4.

TABLE 79—SUMMARY OF SO_2 CAPITAL COST ANALYSIS FOR LIME INJECTION ON COLSTRIP UNIT 1

Description	Cost ($)
Total Capital Investment	3,000,000

TABLE 80—SUMMARY OF SO_2 BART ANNUAL COST ANALYSIS FOR LIME INJECTION ON COLSTRIP UNIT 1

Description	Cost ($)
Total Direct Annual Cost	1,600,000
Indirect Annual Cost	283,200
Total Annual Cost	1,883,200

TABLE 81—SUMMARY OF SO_2 BART COSTS FOR LIME INJECTION ON COLSTRIP UNIT 1

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
3.000	1.883	3,557	$529

Lime Injection With an Additional Scrubber Vessel

We summarize our cost analysis for lime injection with an additional scrubber vessel cost analysis in Tables 82, 83, and 84.

TABLE 82—SUMMARY OF SO_2 CAPITAL COST ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 1

Description	Cost ($)
Total Capital Investment, Lime Injection	3,000,000
Capital Investment, Scrubber Vessel	25,000,000
Total Capital Investment	28,000,000

TABLE 83—SUMMARY OF SO_2 BART ANNUAL COST ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 1

Description	Cost ($)
Total Direct Annual Cost	1,450,000
Indirect Annual Cost	2,643,200
Total Annual Cost	4,093,200

TABLE 84—SUMMARY OF SO_2 BART COSTS ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 1

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
$28.000	$4.100	4,486	912

Factor 2: Energy Impacts

According to PPL, the pressure drop of the venturi scrubbers is maintained in the range of 17 to 20 inches of water column. The injection of lime will be accompanied by little to no increase in pressure drop, but it will require a small increase in pump power consumption. This is included in the cost analysis in the additional operations and maintenance expenses of $125,000 per year.[145] The additional energy requirements are not significant enough to warrant eliminating either lime injection or lime injection with an additional scrubber vessel.

[145] Colstrip Initial Response, p. 4–16.

Factor 3: Non-Air Quality Environmental Impacts

Adding lime to the scrubbers will require more frequent descaling operations that would increase the quantity of solid waste from descaling operations. Transporting this waste stream for disposal would use natural resources for fuel and would have associated air quality impacts. The disposal of the solid waste itself would be to a landfill and could possibly result in groundwater or surface water contamination if a landfill's engineering controls were to fail. EPA's analysis indicates that the environmental impacts associated with the proper transport and land disposal of the solid waste should not be significant. Therefore, the non-air quality environmental impacts do not warrant eliminating either lime injection addition or lime injection addition with an additional scrubber vessel.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. Because the remaining useful life of the source is equal to that assumed for amortization of control option capital investments, this factor does not impact our BART determination.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Colstrip Unit 1 as described in section V.C.3.a. Table 85 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 86 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 85—DELTA DECIVIEW IMPROVEMENT FOR SO_2 CONTROLS ON COLSTRIP UNIT 1

Class I area	Baseline impact (delta deciview)	Improvement from lime injection + additional scrubber vessel (delta deciview)	Improvement from lime injection (delta deciview)
North Absaroka WA	0.414	0.164	0.146
Theodore Roosevelt NP	0.922	0.350	0.284
UL Bend WA	0.895	0.261	0.234
Washakie WA	0.410	0.154	0.145
Yellowstone NP	0.275	0.115	0.090

TABLE 86—DAYS GREATER THAN 0.5 DECIVIEW FOR SO_2 CONTROLS ON COLSTRIP UNIT 1

[Three-year total]

Class I area	Baseline (days)	Using lime injection + additional scrubber vessel	Using lime injection
North Absaroka WA	7	7	7
Theodore Roosevelt NP	52	29	33
UL Bend WA	68	31	41
Washakie WA	12	6	7
Yellowstone NP	4	2	2

Step 5: Select BART

We propose to find that BART for SO_2 is lime injection with an additional scrubber vessel at Colstrip Unit 1 with an emission limit of 0.08 lb/MMBtu (30-day rolling average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for SO_2 at Colstrip Unit 1, we considered lime injection and lime injection with an additional scrubber vessel. The comparison between our lime injection and lime injection with an additional scrubber vessel analysis is provided in Table 87.

TABLE 87—SUMMARY OF EPA SO_2 BART ANALYSIS COMPARISON OF LIME INJECTION AND LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL FOR COLSTRIP UNIT 1

Control option	Total capital investment (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1]	
					Visibility improvement (delta deciviews)	Fewer days >0.5 deciview
Lime Injection with Additional Scrubber Vessel.	28.000	4.100	912	1,957	0.350 TRNP 0.261 UL Bend	23 TRNP. 37 UL Bend.
Lime Injection	3.000	1.883	529	[2]	0.283 TRNP 0.234 UL Bend	19 TRNP. 27 UL Bend.

TRNP—Theodore Roosevelt National Park.
UL Bend—UL Bend Wilderness Area.
[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I areas in the table.
[2] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that lime injection and lime injection with an additional scrubber vessel are both cost effective control technologies. Lime injection has a cost effectiveness value of $539 per ton of SO_2 emissions reduced. Lime injection with an additional scrubber vessel is more expensive than lime injection, with a cost effectiveness value of $912 per ton of SO_2 emissions reduced. Both of these costs are well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART.

We have weighed costs against the anticipated visibility impacts for Colstrip Unit 1. Either of the control options would have a positive impact on visibility. We have concluded that the cost of lime injection with an additional scrubber vessel ($912/ton) is justified by the visibility improvement of 0.350 deciviews at Theodore Roosevelt NP and 0.261 deciviews at UL Bend WA and it would result in 23 fewer days above 0.5 deciviews at Theodore Roosevelt NP and 37 fewer days above 0.5 deciviews at UL Bend WA. In addition, the application of lime injection with an additional scrubber vessel on both Colstrip Units 1 and 2 would result in a combined modeled visibility improvement of 0.592 deciviews at Theodore Roosevelt NP and 0.384 deciviews at UL Bend WA. We consider these improvements to be substantial, especially in light of the fact that Theodore Roosevelt NP and UL Bend WA are not projected to meet the URP. We propose that the SO_2 BART emission limit for Colstrip Unit 1 should be based on what can be achieved with lime injection with an additional scrubber vessel.

The proposed BART emission limit of 0.08 lb/MMBtu allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[146] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] 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.'' We propose a compliance deadline of five (5) years from the date our final FIP becomes effective because of the equipment installation that will be required.

PM

Colstrip Unit 1 currently has wet venturi scrubbers designed to control PM emissions. Venturi scrubbers use a liquid stream to remove solid particles. In the venturi scrubber, gas laden with PM passes through a short tube with flared ends and a constricted middle. This constriction causes the gas stream to speed up when the pressure is increased. A water spray is directed into the gas stream either prior to or at the constriction in the tube. The difference in velocity and pressure resulting from the constriction causes the particles and water to mix and combine. The reduced velocity at the expanded section of the throat allows the droplets of water containing the particles to drop out of the gas stream. Venturi scrubbers are effective in removing small particles, with removal efficiencies of up to 99%.[147] The venturi scrubbers at Unit 1 are designed to have at least 98% control efficiency and have shown control efficiencies approximating 99.5%.[148] The present filterable particulate emission rate is 0.047 lb/MMBtu.[149]

Based on our modeling described in V.C.3.a., PM contribution to the baseline visibility impairment is low. Table 88 shows the maximum baseline visibility impact and percentage contribution to that impact from coarse PM and fine PM.

TABLE 88—COLSTRIP UNIT 1 VISIBILITY IMPACT CONTRIBUTION FROM PM

Maximum baseline visibility impact (deciview)	% Contribution coarse PM	% Contribution fine PM
0.922	0.73	3.01

The PM contribution to the baseline visibility impact for Colstrip Unit 1 is very small; therefore, any visibility improvement that could be achieved with improvements to the existing PM controls would be negligible.

Colstrip Unit 1 must meet the filterable PM emission standard of 0.1 lb/MMBtu in accordance with their Final Title V Operating Permit #OP0513–06. This requirement appears in Permit Condition B.2.; and was included in the permit pursuant to ARM 17.8.340 and 40 CFR part 60, subpart D.

Taking into consideration the above factors we propose basing the BART emission limit on what Colstrip Unit 1 is currently meeting. The units are exceeding a PM control efficiency of 99%, and therefore we are proposing that the current control technology and the emission limit of 0.1lb/MMBtu for PM/PM_{10} as BART. We find that the BART emission limit can be achieved through the operation of the existing venturi scrubbers. Thus, as described in our BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Colstrip Unit 1.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] 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.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

(b) Colstrip Unit 2

NO_X

The Colstrip Unit 2 boiler is of tangential-fired design with LNB and OFA. Originally, the unit operated with a NO_X emission limit of 0.7 lb/MMBtu. In 1997, EPA approved an early election plan under the ARP that included a 0.45 lb/MMBtu annual NO_X limit. The early reduction limit expired in 2007 and the new annual limit under the ARP (0.40 lb/MMBtu) became effective in 2008. Normally, the unit operates with an actual annual average NO_X emission rate in the range of 0.30 to 0.35 lb/MMBtu, accomplished with the low NO_X burners and CCOFA.[150]

Step 1: Identify All Available Technologies

We identified that the same NO_X control technologies for Colstrip Unit 2

[146] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[147] EPA Air Pollution Control Online Course, description at: *http://www.epa.gov/apti/course422/ce6a3.html.*

[148] Colstrip Addendum, p. 6–1

[149] Colstrip Initial Response, p. 4–8.

[150] Baseline emissions were determined by averaging the annual emissions from 2008 to 2010 as reported to the CAMD database available at *http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.*

as for Colstrip Unit 1; see Step 1 above under Colstrip Unit 1 for a list of proposed controls.

Step 2: Eliminate Technically Infeasible Options

Our analysis for Colstrip Unit 1 explains our reasoning for eliminating some of the technologies that were identified in Step 1. We have retained SOFA, SOFA+SNCR, and SOFA+SCR for evaluation.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

At tangentially fired boilers firing PRB coal, SOFA in combination with CCOFA and LNB, can typically achieve emission rates below 0.15 lb/MMBtu on an annual basis.[151] However, due to certain issues unique to Colstrip Unit 2, a rate of 0.20 lb/MMBtu is more realistic. Specifically, these issues include: (1) That the furnace was sized too small and therefore runs hotter than similar units, and (2) that the PRB coal, classified as a borderline sub-bituminous B coal, is less reactive (produces more NO_X) than typical PRB coals.[152] The 0.20 lb/MMBtu rate represents a 35.3% reduction from the current baseline (2008 through 2010) rate of 0.309 lb/MMbtu.

The post-combustion control technologies, SNCR and SCR, have been evaluated in combination with combustion controls. That is, the inlet concentration to the post-combustion controls is assumed to be 0.20 lb/MMBtu. This allows the equipment and operating and maintenance costs of the post-combustion controls to be minimized based on the lower inlet NO_X concentration. Typically, SNCR reduces NO_X an additional 20 to 30% above LNB/combustion controls without excessive NH_3 slip.[153] Assuming that a minimum 25% additional emission reduction is achievable with SNCR, SOFA combined with SNCR can achieve an overall control efficiency of 51.4%. SCR can achieve performance emission rates as low as 0.04–0.07 lb/MMBtu on an annual basis.[154] Assuming that an annual emission rate of 0.05 lb/MMBtu is achievable with SCR, SOFA combined with SCR can achieve an overall control efficiency of 83.8%. A summary of emissions projections for the control options is provided in Table 89.

TABLE 89—SUMMARY OF NO_X BART ANALYSIS CONTROL TECHNOLOGIES FOR COLSTRIP UNIT 2

Control option	Control effectiveness (%)	Annual emission rate (lb/MMBtu)	Emissions reduction (tpy)	Remaining emissions (tpy)
SOFA+SCR	83.8	0.050	3,376	652
SOFA+SNCR	51.4	0.150	2,072	1,956
SOFA	35.3	0.200	1,420	2,608
No Controls (Baseline) [1]	0	0.309		4,028

[1] Baseline emissions were determined by averaging the annual emissions from 2008 to 2010 as reported to the CAMD database available at *http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.* A summary of this information can be found in our docket.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Refer to the Colstrip Unit 1 section above for general information on how we evaluated the cost of compliance for NO_X controls.

SOFA

We relied on estimates submitted by PPL in 2008 for capital costs and direct annual costs for SOFA.[155] We then used the CEPCI to adjust capital costs to 2010 dollars (see Table 90). Annual costs were determined by summing the indirect annual cost and the direct annual cost (see Table 91).

TABLE 90—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA ON COLSTRIP UNIT 2

Description	Cost ($)
Total Capital Investment SOFA	4,507,528

TABLE 91—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR SOFA ON COLSTRIP UNIT 2

Description	Cost ($)
Total Indirect Annual Cost	425,511
Total Direct Annual Cost	664,884
Total Annual Cost	1,090,395

TABLE 92—SUMMARY OF NO_X BART COSTS FOR SOFA ON COLSTRIP UNIT 2

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
4.508	1.090	1,420	768

[151] *Low NO_X Firing Systems and PRB Fuel; Achieving as Low as 0.12 LB NO_X/MMBtu,* Jennings, P., ICAC Forum, Feb. 2002.

[152] Colstrip Addendum, p. 5–1.

[153] White Paper, SNCR for Controlling NO_X Emissions, Institute of Clean Air Companies, pp. 4 and 9, February 2008.

[154] *http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/NOx%20control%20Lani%20AWMA%200905.pdf.*

[155] Colstrip Addendum, Table 5.1–1.

SOFA+SNCR

We relied on control costs developed for the IPM for direct capital costs for SNCR.[156] We then used methods provided by the CCM for the remainder of the SOFA+SNCR analysis. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs.

We used a retrofit factor of ''1'' reflecting an SNCR retrofit of typical difficulty in the IPM control costs. Colstrip Unit 2 burns sub-bituminous PRB coal having a low sulfur content of 0.91 lb/MMBtu (equating to a SO_2 rate of 1.8 lb/MMBtu).[157] As explained in our analysis for Colstrip Unit 1, it was not necessary to make allowances in the cost calculations to account for equipment modifications or additional maintenance associated with fouling due to the formation of ammonium bisulfate. EPA's detailed cost calculations for SOFA+SNCR can be found in the docket.

We used a urea reagent cost estimate of $450 per ton taken from PPL's September 2011 submittal.[158] To estimate the average cost effectiveness (dollars per ton of emissions reductions) we divided the total annual cost by the estimated NO_X emissions reductions. We summarize the costs from our SOFA+SNCR cost analysis in Tables 93, 94, and 95.

TABLE 93—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA+SNCR ON COLSTRIP UNIT 2

Description	Cost ($)
Capital Investment SOFA	4,507,528
Capital Investment SNCR	8,873,145
Total Capital Investment SOFA+SNCR	13,380,673

TABLE 94—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SNCR ON COLSTRIP UNIT 2

Description	Cost ($)
Total Annual Cost SOFA	1,090,395
Total Annual Cost SNCR	2,165,732
Total Annual Cost SOFA+SNCR	3,256,127

TABLE 95—SUMMARY OF NO_X BART COSTS FOR SOFA+SNCR ON COLSTRIP UNIT 2

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
13.381	3.256	2,072	1,571

SOFA+SCR

We relied on control costs developed for the IPM for direct capital costs for SCR.[159] We then used methods in the CCM for the remainder of the SOFA+SCR analysis. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs.

We used a retrofit factor of ''1'' in the IPM control costs, which reflects an SCR retrofit of typical difficulty. We used an aqueous ammonia (29%) cost of $240 per ton,[160] and a catalyst cost of $6,000 per cubic meter.[161] To estimate the average cost effectiveness (dollars per ton of emissions reductions) we divided the total annual cost by the estimated NO_X emissions reductions. We summarize the costs from our SOFA+SCR cost analysis in Tables 96, 97, and 98.

TABLE 96—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA+SCR ON COLSTRIP UNIT 2

Description	Cost ($)
Capital Investment SOFA	4,507,528
Capital Investment SCR	78,263,720
Total capital Investment SOFA + SCR	82,771,248

TABLE 97—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SCR ON COLSTRIP UNIT 2

Description	Cost ($)
Total Annual Cost SOFA	1,090,395

[156] IPM, Chapter 5, Appendix 5–2B.

[157] Cost and Quality of Fuels for Electric Utility Plants 1999 Tables, Energy Information Administration, DOE/EIA–0191(99), June 2000, Table 24.

[158] NO_X Control Update to PPL Montana's Colstrip Generating Station BART Report Prepared for PPL Montana, LLC, by TRC, September 2011, p. 4–1.

[159] IPM, Chapter 5, Appendix 5–2A.

[160] Email communication with Fuel Tech, Inc., March 2, 2012.

[161] Cichanowicz 2010, p. 6–7.

TABLE 97—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SCR ON COLSTRIP UNIT 2—Continued

Description	Cost ($)
Total Annual Cost SCR	9,830,104
Total Annual Cost SOFA+SCR	10,920,499

TABLE 98—SUMMARY OF NO_X BART COSTS FOR SOFA+SCR ON COLSTRIP UNIT 2

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tons/yr)	Average cost effectiveness ($/ton)
82.771	10.920	3,376	3,235

Factor 2: Energy Impacts

An SNCR process reduces the thermal efficiency of a boiler as the reduction reaction uses thermal energy from the boiler.[162] Therefore, additional coal must be burned to make up for the decreases in power generation. Using CCM calculations we determined the additional coal needed for Unit 2 equates to 75,800 MMBtu/yr. For an SCR, the new ductwork and the reactor's catalyst layers decrease the flue gas pressure. As a result, additional fan power is necessary to maintain the flue gas flow rate through the ductwork. SCR systems require additional electric power to meet fan requirements equivalent to approximately 0.3% of the plant's electric output.[163] Both SCR and SNCR require some minimal additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. The additional energy requirements that would be involved in installation and operation of the evaluated controls are not significant enough to warrant eliminating any of the options evaluated. Note that cost of the additional energy requirements has been included in our calculations.

Factor 3: Non-Air Quality Environmental Impacts

The non-air quality environmental impacts for Colstrip Unit 2 are the same as for Colstrip Unit 1, see previous discussion for Colstrip Unit 1.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. Thus, this factor does not impact our BART determination because the annualized cost was calculated over a 20 year period in accordance with the BART Guidelines.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Colstrip Unit 2 as described in section V.C.3.a. Table 99 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 100 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 99—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON COLSTRIP UNIT 2

Class I area	Baseline impact (delta deciview)	Improvement from SOFA+SCR (delta deciview)	Improvement from SOFA+SNCR (delta deciview)	Improvement from SOFA (delta deciview)
North Absaroka WA	0.402	0.185	0.083	0.055
Theodore Roosevelt NP	0.895	0.423	0.269	0.190
UL Bend WA	0.889	0.406	0.269	0.185
Washakie WA	0.392	0.143	0.089	0.063
Yellowstone NP	0.289	0.091	0.071	0.063

TABLE 100—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON COLSTRIP UNIT 2

[Three year total]

Class I Area	Baseline (days)	Using SOFA+SCR	Using SOFA+SNCR	Using SOFA
North Absaroka WA	8	5	5	7
Theodore Roosevelt NP	54	14	25	35
UL Bend WA	66	17	41	46
Washakie WA	12	5	8	11
Yellowstone NP	4	2	2	2

[162] CCM, Section 4.2, Chapter 1, p. 1–21.

[163] CCM, Section 4.2, Chapter 2, p. 2–28.

Step 5: Select BART

We propose to find that BART for NO_X is SOFA+SNCR at Colstrip Unit 2 with an emission limit of 0.15 lb/MMBtu (30-day rolling average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for NO_X at Colstrip Unit 2, we considered SOFA, SOFA+SNCR, and SOFA+SCR. The comparison between our SOFA, SOFA+SNCR, and SOFA+SCR analysis is provided in Table 101.

TABLE 101—SUMMARY OF NO_X BART ANALYSIS COMPARISON OF CONTROL OPTIONS FOR COLSTRIP UNIT 2

Control option	Total capital investment (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility Impacts [1]	
					Visibility Improvement (delta deciviews)	Fewer days > 0.5 deciview
SOFA+SCR	82.771	10.920	3,235	5,877	0.423 TRNP 0.406 UL Bend	40 TRNP 49 UL Bend
SOFA+SNCR	13.380	3.256	1,571	3,322	0.269 TRNP 0.269 UL Bend	29 TRNP 25 UL Bend
SOFA	4.508	1.090	768	[2]	0.190 TRNP 0.185 UL Bend	19 TRNP 20 UL Bend

TRNP—Theodore Roosevelt National Park.
UL Bend—UL Bend Wilderness Area.
[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I areas in the table.
[2] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that SOFA, SOFA+SNCR, and SOFA+SCR are all cost effective control technologies. SOFA has a cost effectiveness value of $768 per ton of NO_X emissions reduced. SOFA+SNCR is more expensive than SOFA, with a cost effectiveness value of $1,571 per ton of NO_X emissions reduced. SOFA+SCR is more expensive than SOFA or SOFA+SNCR, having a cost effectiveness value of $3,235 per ton of NO_X emissions reduced. This is well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART.

We have weighed costs against the anticipated visibility impacts for Colstrip Unit 2. Any of the control options would have a positive impact on visibility; however, the cost of SOFA+SCR ($3,322) is not justified by the visibility improvement of 0.423 deciviews at TRNP and 0.404 deciviews at UL Bend. The lower cost of SOFA+SNCR ($1,571/ton) is justified when the visibility improvement is considered. SOFA+SNCR would have a visibility improvement of 0.269 deciviews at Theodore Roosevelt NP and 0.269 deciviews at UL Bend WA and it would result in 29 fewer days above 0.5 deciviews at Theodore Roosevelt NP and 25 fewer days above 0.5 deciviews at UL Bend WA. In addition, application of SOFA+SNCR at both Colstrip Units 1 and 2 would have a combined modeled visibility improvement of 0.501 deciviews at Theodore Roosevelt NP and 0.451 deciviews at UL Bend WA. We consider these improvements to be substantial, especially in light of the fact that Theodore Roosevelt NP and UL Bend WA are not projected to meet the URP. We propose that the NO_X BART emission limit for Colstrip Unit 2 should be based on what can be achieved with SOFA + SNCR.

The proposed BART emission limit of 0.15 lb/MMBtu allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[164] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] 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.'' We propose a compliance deadline of five (5) years from the date our final FIP becomes effective because of the equipment installation and potential combustion modifications that will be required.

SO_2

Colstrip Unit 2 is already controlled by wet venturi scrubbers, which are identical to Colstrip Unit 1 scrubbers, for simultaneous particulate and SO_2 control. The venturi scrubbers utilize the alkalinity of the fly ash to achieve an estimated SO_2 removal efficiency of 75%.[165] Based on emissions data from CAMD, for the baseline period 2008 through 2010, the average SO_2 emission rate was 0.418 lb/MMBtu and the average SO_2 emissions were 5,548 tpy.[166]

Step 1: Identify All Available Technologies

The Colstrip Unit 2 venturi scrubber currently achieves greater than 50% removal of SO_2. The available technologies for Colstrip Unit 2 are the same as those for Colstrip Unit 1; see Step 1 analysis for Colstrip Unit 1.

Step 2: Eliminate Technically Infeasible Options

Elimination of bypass reheat is not a feasible option because Colstrip Unit 2 is designed so that there is no bypass of flue gas. Installation of perforated trays is not a feasible option because the existing scrubber design already includes this technology in the form of wash trays. Finally, the use of organic acid additives is not a feasible option because the reactivity of the lime would neutralize the acids, making the additives ineffective.

Lime injection or lime injection with an additional scrubber vessel are technically feasible control options because lime injection is currently used to control SO_2 emissions at Colstrip Units 3 and 4.

[164] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[165] Colstrip Initial Response, p. ES–3.

[166] Clean Air Markets—Data and Maps: *http://camddataandmaps.epa.gov/gdm.*

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

An annual emission rate of 0.015 lb/MMBtu can be achieved with lime injection without an additional scrubber vessel. PPL stated that this is the lowest emission rate that could be achieved without adding an additional scrubber vessel.[167] An annual emission rate of 0.08–0.09 lb/MMBtu can be achieved with lime injection with an additional scrubber vessel. This is the emission rate that is being achieved at Colstrip Units 3 and 4 according to emissions data from CAMD.[168] The control effectiveness of each of the control options was calculated using the controlled emission rates that were provided by PPL.

A summary of control efficiencies, emission rates, and resulting emissions and emission reductions, is provided in Table 102. EPA's detailed emissions calculations for Colstrip 2 can be found in the docket.

TABLE 102—SUMMARY OF BART ANALYSIS CONTROL TECHNOLOGIES FOR SO_2 FOR COLSTRIP UNIT 2

Control option	Control effectiveness (%) [1]	Annual emission rate (lb/MMBtu) [2]	Emissions reduction (tpy)	Remaining emissions (tpy)
Lime Injection with Additional Scrubber Vessel	79.7	0.080	4,129	1,049
Lime Injection	62.0	0.150	3,212	1,966
Existing Controls (Baseline) [3]		0.395		5,178

[1] Control efficiency is provided relative to the emission rate with current controls.
[2] Emission rates are provided on an annual basis.
[3] Baseline emissions for 2008 through 2010 from Clean Air Markets—Data and Maps: *http://camddataandmaps.epa.gov/gdm/.*

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

We relied on capital costs and direct annual costs provided by PPL when determining the cost of compliance for both lime injection and lime injection with an additional scrubber vessel.[169] [170] All costs presented here for the Colstrip Unit 2 SO_2 control options are in year 2007 dollars. EPA's cost calculations for Colstrip 2 can be found in the docket.

Lime Injection

We summarize our cost analysis for lime injection in Tables 103, 104, and 105.

TABLE 103—SUMMARY OF SO_2 CAPITAL COST ANALYSIS FOR LIME INJECTION ON COLSTRIP UNIT 2

Description	Cost ($)
Total Capital Investment	3,000,000

TABLE 104—SUMMARY OF SO_2 BART ANNUAL COST ANALYSIS FOR LIME INJECTION ON COLSTRIP UNIT 2

Description	Cost ($)
Total Direct Annual Cost	1,600,000
Indirect Annual Cost	283,200
Total Annual Cost	1,883,200

TABLE 105—SUMMARY OF SO_2 BART COSTS FOR LIME INJECTION ON COLSTRIP UNIT 2

Total Capital Investment (MM$)	Total Annual Cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
3.000	1.883	3,212	586

Lime Injection With an Additional Scrubber Vessel

We summarize our cost analysis for lime injection with an additional scrubber vessel cost analysis in Tables 106, 107, and 108.

TABLE 106—SUMMARY OF SO_2 CAPITAL COST ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 2

Description	Cost ($)
Total Capital Investment, Lime Injection	3,000,000

[167] Colstrip Addendum, p. 4–1.

[168] Clean Air Markets—Data and Maps: *http://camddataandmaps.epa.gov/gdm/.*

[169] Colstrip Initial Response, Table A4–6(c).

[170] Colstrip Addendum, Table 4.1–4.

TABLE 106—SUMMARY OF SO_2 CAPITAL COST ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 2—Continued

Description	Cost ($)
Capital Investment, Scrubber Vessel	25,000,000
Total Capital Investment	28,000,000

TABLE 107—SUMMARY OF SO_2 BART ANNUAL COST ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 2

Description	Cost ($)
Total Direct Annual Cost	1,450,000
Indirect Annual Cost	2,643,200
Total Annual Cost	4,093,200

TABLE 108—SUMMARY OF SO_2 BART COSTS ANALYSIS FOR LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL ON COLSTRIP UNIT 2

Total installed capital cost (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
$28.000	$4.093	4,129	991

Factor 2: Energy Impacts

According to PPL, the pressure drop of the venturi scrubbers is maintained in the range of 17 to 20 inches of water column. The injection of lime will be accompanied by little to no increase in pressure drop, but it will require a small increase in pump power consumption. This is included in the cost analysis in the additional operations and maintenance expenses of $125,000 per year.[171] The additional energy requirements are not significant enough to warrant eliminating either lime injection or lime injection with an additional scrubber vessel.

Factor 3: Non-Air Quality Environmental Impacts

Adding lime to the scrubbers will require more frequent descaling operations that would increase the quantity of solid waste from descaling operations. Transporting this waste stream for disposal would use natural resources for fuel and would have associated air quality impacts. The disposal of the solid waste itself would be to a landfill and could possibly result in groundwater or surface water contamination if a landfill's engineering controls were to fail. EPA's analysis indicates that the environmental impacts associated with the proper transport and land disposal of the solid waste should not be significant. Therefore, the non-air quality environmental impacts do not warrant eliminating either lime injection addition or lime injection addition with an additional scrubber vessel.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. Because the remaining useful life of the source is equal to that assumed for amortization of control option capital investments, this factor does not impact our BART determination.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Colstrip Unit 2 as described in section V.C.3.a. Table 109 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 110 presents the number of days with impacts greater than 0.5 deciviews for each Class I area from 2006 through 2008.

TABLE 109—DELTA DECIVIEW IMPROVEMENT FOR SO_2 CONTROLS ON COLSTRIP 2

Class I area	Baseline impact (delta deciview)	Improvement from lime injection + additional scrubber vessel (delta deciview)	Improvement from lime injection (delta deciview)
North Absaroka WA	0.402	0.140	0.111
Theodore Roosevelt NP	0.895	0.280	0.225
UL Bend WA	0.889	0.179	0.143
Washakie WA	0.392	0.141	0.119
Yellowstone NP	0.289	0.090	0.067

[171] Colstrip Initial Response, p. 4–16.

TABLE 110—DAYS GREATER THAN 0.5 DECIVIEW FOR SO_2 CONTROLS ON COLSTRIP 2

[Three year total]

Class I area	Baseline (days)	Using lime injection + additional scrubber vessel	Using lime injection
North Absaroka WA	7	7	7
Theodore Roosevelt NP	52	33	37
UL Bend WA	68	39	44
Washakie WA	12	7	8
Yellowstone NP	4	2	3

Step 5: Select BART

We propose to find that BART for SO_2 is lime injection with an additional scrubber vessel at Colstrip Unit 2 with an emission limit of 0.08 lb/MMBtu (30-day rolling average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for SO_2 at Colstrip Unit 2, we considered lime injection and lime injection with an additional scrubber vessel. The comparison between our lime injection and lime injection with an additional scrubber vessel analysis is provided in Table 111.

TABLE 111—SUMMARY OF EPA SO_2 BART ANALYSIS COMPARISON OF LIME INJECTION AND LIME INJECTION WITH AN ADDITIONAL SCRUBBER VESSEL FOR COLSTRIP UNIT 2

Control option	Total capital investment (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 deciview
Lime Injection with Additional Scrubber Vessel.	28.000	4.093	991	2,410	0.280 TRNP 0.179 UL Bend	7 TRNP 8 UL Bend
Lime Injection	3.000	1.883	586	[2]	0.225 TRNP 0.143 UL Bend	6 TRNP 7 UL Bend

TRNP—Theodore Roosevelt National Park.
UL Bend—UL Bend Wilderness Area.
[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) at the Class I areas in the table.
[2] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that lime injection and lime injection with an additional scrubber vessel are both cost effective control technologies. Lime injection has a cost effectiveness value of $586 per ton of SO_2 emissions reduced. Lime injection with an additional scrubber vessel is more expensive than lime injection, with a cost effectiveness value of $919 per ton of SO_2 emissions reduced. Both of these costs are well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART.

We have weighed costs against the anticipated visibility impacts at Colstrip Unit 2. Either of the control options would have a positive impact on visibility. We have concluded that the cost of lime injection with an additional scrubber vessel ($991/ton) is justified by the visibility improvement of 0.280 deciviews at Theodore Roosevelt NP and 0.179 deciviews at UL Bend WA and it would result in seven fewer days above 0.5 deciviews at Theodore Roosevelt NP and eight fewer days above 0.5 deciviews at UL Bend WA. In addition, the application of lime injection with an additional scrubber vessel on both Colstrip Units 1 and 2 would result in a combined modeled visibility improvement of 0.592 deciviews at Theodore Roosevelt NP and 0.384 deciviews at UL Bend WA. We consider these improvements to be substantial, especially in light of the fact that Theodore Roosevelt NP and UL Bend WA are not projected to meet the URP. We propose that the SO_2 BART emission limit for Colstrip Unit 2 should be based on what can be achieved with lime injection with an additional scrubber vessel.

The proposed BART emission limit of 0.08 lb/MMBtu allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[172] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] 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.'' We propose a compliance deadline of five (5) years from the date our final FIP becomes effective because of the equipment installation that will be required.

PM

Colstrip Unit 2 currently has venturi scrubbers designed to control PM emissions. A description of a venturi scrubber can be found under the PM section of the BART analysis for Colstrip Unit 1. The venturi scrubbers at Colstrip unit 2 are designed to have at least 98% control efficiency and have shown control efficiencies approximating 99.5%. The present emission rate is 0.0525 lb/MMBtu.[173]

[172] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[173] Colstrip Addendum, p. 6–1.

Based on our modeling described in section V.C.3.a. PM contribution to the baseline visibility impairment is low. Table 112 shows the maximum baseline visibility impact and percentage contribution to that impact from coarse PM and fine PM.

TABLE 112—COLSTRIP UNIT 2 VISIBILITY IMPACT CONTRIBUTION FROM PM

Maximum baseline visibility impact (deciview)	% Contribution coarse PM	% Contribution fine PM
0.895	0.95	3.88

The PM contribution to the baseline visibility impact for Colstrip Unit 2 is very small; therefore, any visibility improvement that could be achieved with improvements to the existing PM controls would be negligible. We are proposing that the existing PM control device represents BART.

Colstrip Unit 2 must meet the filterable PM emission standard of 0.1lb/MMBtu in accordance with its Final Title V Operating Permit #OP0513–06. This requirement appears in Permit Condition B.2.; and was included in the permit pursuant to ARM 17.8.340 and 40 CFR part 60, subpart D.

Taking into consideration the above factors we propose basing the BART emission limit on what Colstrip Unit 2 is currently meeting. The units are exceeding a PM control efficiency of 99%, and therefore we are proposing that the current control technology and the emission limit of 0.1lb/MMBtu for PM/PM_{10} as BART. We find that the BART emission limit can be achieved through the operation of the existing venturi scrubbers. Thus, as described in our BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Colstrip Unit 2.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] 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.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

v. Corette

Background

PPL Montana's Corette Power Plant (Corette), located in Billings, Montana, consists of one electric utility steam generating unit. We previously provided in Section V.C. our reasoning for proposing that this unit is BART-eligible and why it is subject to BART. As explained in section V.C., the document titled ''Identification of BART Eligible Sources in the WRAP Region'' dated April 4, 2005 provides more details on the specific emission units at each facility. Corette's boiler has a nominal gross capacity of 162 MW. The boiler began commercial operation in 1968 and is a tangentially fired pulverized coal boiler that burns PRB sub-bituminous coal as their exclusive fuel.

Although the gross capacity of Corette is below the 750 MW cutoff for which use of the BART Guidelines is mandatory, we have nonetheless followed the guidelines as they ''provide useful advice in implementing the BART provisions of the regional haze rule.'' [174]

We requested a five factor BART analysis for Corette from PPL and the Company submitted that analysis in August 2007 along with updated information in June 2008 and September 2011. PPL's five factor BART analysis information is contained in the docket for this action and we have taken it into consideration in our proposed action.

NO_X

The Corette boiler is a tangential-fired unit with existing low-NO_X burners and CCOFA. The unit is subject to an annual NO_X emission limit of 0.4 lb/MMBtu.

Step 1: Identify All Available Technologies

We identified the following NO_X control technologies are available: SOFA, SNCR, and SCR. Descriptions for each of these NO_X control technologies can be found in the Colstrip 1 evaluation above.

Step 2: Eliminate Technically Infeasible Options

Based on our review all the technologies identified in Step 1 appear to be technically feasible for Corette. In particular, both SCR and SNCR have been widely employed to control NO_X emissions from coal-fired power plants.[175 176 177]

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

At tangentially fired boilers firing sub-bituminous coal, SOFA in combination with CCOFA and LNB, can typically achieve emission rates below 0.15 lb/MMBtu on an annual basis.[178] However, due to certain issues unique to Corette, a rate of 0.20 lb/MMBtu is more realistic. Specifically, these issues include: (1) That the furnace is undersized, has a high heat rate, and therefore runs hotter than newer units designed for low NO_X emissions; and (2) the nature of the particular PRB coal burned. The 0.20 lb/MMBtu rate represents a 26.8% reduction from the current baseline (2008 through 2010) rate of 0.274 lb/MMbtu.

The post-combustion control technologies, SNCR and SCR, have been evaluated in combination with combustion controls. That is, the inlet concentration to the post-combustion controls is assumed to be 0.20 lb/MMBtu. This allows the equipment and operating and maintenance costs of the post-combustion controls to be minimized based on the lower inlet NO_X concentration. Typically, SNCR reduces NO_X an additional 20 to 30% above LNB/combustion controls without excessive NH_3 slip.[179] Assuming that a minimum 25% additional emission reduction is achievable with SNCR, SOFA combined with SNCR can achieve an overall control efficiency of 44.9%. SCR can achieve performance emission rates as low as 0.04–0.07 lb/MMBtu on an annual basis.[180] Assuming that an annual emission rate of 0.05 lb/MMBtu is achievable with SOFA+SCR, this equates to an overall control efficiency of 81.2%. A summary of control

[174] 70 FR 39108 (July 6, 2005).

[175] Institute of Clean Air Companies (ICAC) White Paper, SCR Controls of NO_X Emissions from Fossil Fuel-Fired Electric Power Plants, May 2009, pp. 7–8.

[176] Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants, Northeast States for Coordinated Air Use Management (NESCAUM), March 31, 2011, p. 16.

[177] ICAC White Paper, SNCR for Controlling NO_X Emissions, February 2008, pp. 6–7.

[178] Low NO_X Firing Systems and PRB Fuel; Achieving as Low as 0.12 LB NO_X/MMBtu, Jennings, P., ICAC Forum, Feb. 2002.

[179] White Paper, SNCR for Controlling NO_X Emissions, Institute of Clean Air Companies, pp. 4 and 9, February 2008.

[180] Srivastava, R., Hall, R., Khan, S., Lani, B., and Culligan, K., ''Nitrogen oxides emission control options for coal-fired utility boilers,'' Journal of Air and Waste Management Association 55(9):1367–88 (2005). Available at: *http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/NOx%20control%20Lani%20AWMA%200905.pdf.*

efficiencies, emission rates, and resulting emission reductions for the control options under consideration are provided in Table 113. EPA's detailed emissions calculations for Corette can be found in the docket.

TABLE 113—SUMMARY OF NO_X BART ANALYSIS CONTROL TECHNOLOGIES FOR CORETTE

Control option	Control effectiveness (%)	Annual emission rate (lb/MMBtu)	Emissions reduction (tpy)	Remaining emissions (tpy)
SOFA+SCR	81.2	0.050	1,320	305
SOFA+SNCR	44.9	0.150	730	895
SOFA	26.9	0.200	435	1,190
No Controls (Baseline) [1]		0.274		1,625

[1] Baseline emissions were determined by averaging the annual emissions from 2008 to 2010 as reported to the CAMD database available at *http://camddataandmaps.epa.gov/gdm/.*

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Refer to the Colstrip Unit 1 section above for general information on how we evaluated the cost of compliance for NO_X controls. EPA's cost calculations for NO_X controls at Corette can be found in the docket.

SOFA

We relied on estimates submitted by PPL in 2008 for capital costs and direct annual costs for SOFA.[181] We then used the CEPCI to adjust capital costs to 2010 dollars (see Table 114). Annual costs were determined by summing the indirect annual cost and the direct annual cost (see Table 115).

TABLE 114—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA ON CORETTE

Description	Cost ($)
Total Capital Investment SOFA	3,350,365

TABLE 115—SUMMARY OF NO_X BART ANNUAL COST ANALYSIS FOR SOFA ON CORETTE

Description	Cost ($)
Total Indirect Annual Cost	330,375
Total Direct Annual Cost	315,754
Total Annual Cost	646,129

TABLE 116—SUMMARY OF NO_X BART COSTS FOR SOFA ON CORETTE

Total installed capital cost (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
3.351	0.646	435	1,487

SOFA+SNCR

We relied on control costs developed for the IPM for direct capital costs for SNCR.[182] We then used methods provided by the CCM for the remainder of the SOFA+SNCR analysis. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs.

We used a retrofit factor of ''1'' reflecting an SNCR retrofit of typical difficulty in the IPM control costs. Corette burns sub-bituminous PRB coal having a low sulfur content of 0.24 lb/MMBtu.[183] As explained in our analysis for Colstrip Unit 1, it was not necessary to make allowances in the cost calculations to account for equipment modifications or additional maintenance associated with fouling due to the formation of ammonium bisulfate. EPA's detailed cost calculations for SOFA+SNCR can be found in the docket.

We used a urea reagent cost estimate of $450 per ton taken from PPL's September 2011 submittal.[184] To estimate the average cost effectiveness (dollars per ton of emissions reductions) we divided the total annual cost by the estimated NO_X emissions reductions. We summarize the costs from our SPFA+SNCR cost analysis in Tables 117, 118, and 119.

[181] Addendum to PPL Montana's J.E. Corette Generating Station BART Report Prepared for PPL Montana, LLC; Prepared by TRC (''Corette Addendum''), June 2008, Table 5.1–3.

[182] IPM, Chapter 5, Appendix 5–2B.

[183] Cost and Quality of Fuels for Electric Utility Plants 1999 Tables, Energy Information Administration, DOE/EIA–0191(99), June 2000, Table 24.

[184] NO_X Control Update to PPL Montana's J.E. Corette Generating Station BART Report, September 2011, Prepared for PPL Montana, LLC by TRC, p. 8.

TABLE 117—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA+SNCR ON CORETTE

Description	Cost ($)
Capital Investment SOFA	3,350,365
Capital Investment SNCR	6,464,691
Total Capital Investment SOFA + SNCR	9,815,056

TABLE 118—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SNCR ON CORETTE

Description	Cost ($)
Total Annual Cost SOFA	646,129
Total Annual Cost SNCR	1,248,062
Total Annual Cost SOFA+SNCR	1,894,191

TABLE 119—SUMMARY OF NO_X BART COSTS FOR SOFA+SNCR ON CORETTE

Total installed capital cost (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
9.815	1.894	730	2,596

SOFA+SCR

We relied on control costs developed for the IPM for direct capital costs for SCR.[185] We then used methods in the CCM for the remainder of the SOFA+SCR analysis. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs.

We used a retrofit factor of ''1'' in the IPM control costs, which reflects an SCR retrofit of typical difficulty. We used an aqueous ammonia (29%) cost of $240 per ton,[186] and a catalyst cost of $6,000 per cubic meter.[187] To estimate the average cost effectiveness (dollars per ton of emissions reductions) we divided the total annual cost by the estimated NO_X emissions reductions. We summarize the costs from our SOFA+SCR cost analysis in Tables 120, 121, and 122.

TABLE 120—SUMMARY OF NO_X BART CAPITAL COST ANALYSIS FOR SOFA+SCR ON CORETTE

Description	Cost ($)
Capital Investment SOFA	3.350,365
Capital Investment SCR	42,958,390
Total Capital Investment SOFA+SCR	46,308,755

TABLE 121—SUMMARY OF NO_X BART TOTAL ANNUAL COST ANALYSIS FOR SOFA+SCR ON CORETTE

Description	Cost ($)
Total Annual Cost SOFA	646,129
Total Annual Cost SCR	5,281,486
Total Annual Cost SOFA+SCR	5,927,615

TABLE 122—SUMMARY OF NO_X BART COSTS FOR SOFA+SCR ON CORETTE

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
46.309	5.927	1,320	4,491

Factor 2: Energy Impacts

SNCR reduces the thermal efficiency of a boiler as the reduction reaction uses thermal energy from the boiler.[188] Therefore, additional coal must be burned to make up for the decrease in power generation. Using CCM calculations we determined the additional coal needed for Corette equates to 34,319 MMBtu/yr. For SCR, the new ductwork and the reactor's catalyst layers decrease the flue gas

[185] IPM, Chapter 5, Appendix 5–2A.

[186] Email communication with Fuel Tech, Inc., March 2, 2012.

[187] Cichanowicz 2010, p. 6–7.

[188] CCM, Section 4.2, Chapter 1, p. 1–21.

pressure. As a result, additional fan power is necessary to maintain the flue gas flow rate through the ductwork. SCR systems require additional electric power to meet fan requirements equivalent to approximately 0.3% of the plant's electric output.[189] Both SCR and SNCR require some minimal additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. The additional energy requirements that would be involved with operation of the evaluated controls are not significant enough to warrant eliminating any of the options evaluated. Note that the cost of the additional energy requirements has been included in our calculations.

Factor 3: Non-Air Quality Environmental Impacts

The non-air quality environmental impacts for Corette are the same as for Colstrip Unit 1, see previous discussion for Colstrip Unit 1.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. Thus, this factor does not impact our BART determination because the annualized cost was calculated over a 20 year period in accordance with the BART Guidelines.

Factor 5: Evaluate Visibility Impacts

We conducted modeling for Corette as described in section V.C.3.a. Table 123 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 124 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 123—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON CORETTE

Class I area	Baseline impact (delta deciview)	SOFA+SCR (delta deciview)	SOFA+SNCR (delta deciview)	SOFA (delta deciview)
Gates of the Mountains WA	0.295	0.093	0.049	0.028
North Absaroka WA	0.497	0.184	0.103	0.062
Red Rock Lakes WA	0.090	0.029	0.016	0.010
Teton WA	0.298	0.118	0.062	0.042
UL Bend WA	0.462	0.158	0.091	0.057
Washakie WA	0.667	0.264	0.146	0.087
Yellowstone NP	0.325	0.093	0.053	0.033

TABLE 124—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON CORETTE

[Three Year Total]

Class I area	Baseline (days)	Using SOFA+SCR	Using SOFA+SNCR	Using SOFA
Gates of the Mountains WA	4	2	3	3
North Absaroka WA	11	7	9	10
Red Rock Lakes WA	0	0	0	0
Teton WA	7	2	6	7
UL Bend WA	14	2	5	8
Washakie WA	20	7	13	13
Yellowstone NP	7	2	3	4

Step 5. Select BART

We propose to find that BART for NO_X is the existing tangential firing design of the boilers and existing low-NO_X burners with close coupled over fire air at Corette with an emission limit of 0.40 lb/MMBtu (annual average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for NO_X at Corette, we considered SOFA, SOFA+SNCR, and SOFA+SCR. The comparison between our SOFA, SOFA+SNCR, and SOFA+SCR analysis is provided in Table 125.

TABLE 125—SUMMARY OF NO_X BART ANALYSIS COMPARISON OF CONTROL OPTIONS FOR CORETTE

Control option	Total capital investment (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 deciview
SOFA+SCR	46.309	5.927	4,491	6,836	0.264	13
SOFA+SNCR	9.815	1.894	2,596	4,231	0.146	9
SOFA	3.350	0.646	1,487	[2]	0.087	7

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) is for Washakie WA, the Class I area with the greatest change, except that the fewer days >0.5 deciview for SOFA+SNCR is for UL Bend WA.

[2] Incremental cost is not applicable to the option that has the lowest effectiveness.

[189] Id., Section 4.2, Chapter 2, p. 2–28.

We have concluded that SOFA, SOFA+SNCR, and SOFA+SCR are all cost effective control technologies. SOFA has a cost effectiveness value of $1,487 per ton of NO_X emissions reduced. SOFA+SNCR is more expensive than SOFA, with a cost effectiveness value of $2,596 per ton of NO_X emissions reduced. SOFA+SCR is more expensive than SOFA or SOFA+SNCR, having a cost effectiveness value of $4,491 per ton of NO_X emissions reduced. This is well within the range of values we have considered reasonable for BART and that states have considered reasonable for BART.

We have weighed costs against the anticipated visibility impacts for Corette. Any of the control options would have a positive impact on visibility; however, the cost of controls is not justified by the visibility improvement.

In proposing a BART emission limit of 0.40 lb/MMBtu, we evaluated the existing emissions from the facility and determined this rate to allow for a sufficient margin of compliance for a 30-day rolling average limit that that would apply at all times, including startup, shutdown, and malfunction.[190] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] 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.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

SO_2

The Corette boiler currently burns very low-sulfur PRB sub-bituminous coal with a sulfur content of 0.3% by weight.[191] The boiler is subject to a fuel sulfur limit of 1 lb/MMBtu (as fired) on a continuous basis and an annual emission limit of 9,990,00 lbs/calendar year.[192]

[190] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[191] BART Assessment J.E. Corette Generating Station, prepared for PPL Montana, LLC, by TRC, (''Corette Initial Response''), August 2007, p. 4–9.

[192] MDEQ, Final Operating Permit #OP2953–05, for PPL Montana, LLC, JE Corette Steam Electric Station, 9.25/09.

Step 1: Identify All Available Technologies

We identified that three flue gas desulfurization (FGD or ''scrubbing'') technologies as available control technologies for consideration at Corette. Two of these options, dry sorbent injection (DSI) and semi-dry scrubbing (sometimes referred to as LSD), are dry scrubbing technologies. The third option is a wet scrubbing technology known as limestone forced oxidation (LSFO). We did not consider fuel-switching options as Corette already burns very low-sulfur coal.

DSI is the injection of dry sorbent reagents that react with SO_2 and other acid gases, with a downstream PM control device (ESP or baghouse) to capture the reaction products. Unlike wet or semi-dry scrubbing, a reaction chamber is not necessary and reagents are introduced directly into the existing ductwork. Trona, a naturally occurring mixture of sodium carbonate and sodium bicarbonate mined in some western states, is commonly used as a reagent in DSI systems.[193] DSI is typically more attractive for smaller boilers.

In a LSD system, the polluted gas stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer absorber. The term ''dry'' refers to the fact that, although water is added to the flue gas, the amount of water added is only just enough to maintain the gas above the saturation (dew point) temperature. In most cases, the reaction products and any unreacted lime from the LSD process are captured in a downstream fabric filter (baghouse), which helps provide additional capture of SO_2.[194]

In LSFO, the polluted gas stream is brought into contact with a liquid alkaline sorbent (typically limestone) by forcing it through a pool of the liquid slurry or by spraying it with the liquid. In the absorber, the gas is cooled to below the saturation temperature, resulting in a wet gas stream and high rates of capture. Because a wet FGD system operates at low temperatures, it is usually the last pollution control device before the stack. The wet FGD absorber is typically located downstream of the PM control device (most often an ESP) and immediately upstream of the stack.[195]

There are several variations of the scrubbing systems described above. However, as discussed in the NO_X control evaluation, the BART Guidelines do not require that all variations be evaluated. The particular variations that we have identified here—DSI with trona, LSD, and LSFO—represent designs that have been successfully applied in a cost-effective manner at numerous utility boilers.

[193] Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants, NESCAUM, March 31, 2011, p. 13.

[194] *Id.,* p. 11.

[195] *Id.,* p. 10.

Step 2: Eliminate Technically Infeasible Options

Based on our review, all the technologies identified in Step 1 appear to be technically feasible for Corette. Using these technologies, over 480 power plant boilers, representing nearly two-thirds of the electric generating capacity in the United States, are scrubbed or are projected to be scrubbed in the near future.[196]

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

The control effectiveness of DSI, when located upstream of an ESP (as would be the case at Corette), is in the range of 30 to 60%.[197] For the purposes of our BART analysis for Corette, we assumed a SO_2 removal target for DSI of 50%, which is at the upper end of this range. Higher control efficiencies can be achieved with DSI in conjunction with a baghouse. However, as described under the PM control evaluation, replacement of the existing ESP with a new baghouse is not warranted under BART.

The control effectiveness of LSD or LSFO is dependent on the sulfur content of the coal burned, with greater removal efficiencies being achieved with higher sulfur coals. LSD, which is more commonly applied to lower sulfur coals, can achieve control efficiencies of 70 to 95%, while LSFO can routinely achieve control efficiencies of 95% when applied to higher sulfur coals.[198] Because the control efficiency varies significantly with the inlet sulfur concentration, we evaluated the control effectiveness of LSD and LSFO based on the performance rate that can be achieved. Specifically, we aligned the performance rate with the ''floor'' assumed for retrofits in the IPM control cost methodology.[199] On an annual basis, these rates are 0.065 lb/MMBtu and 0.060 lb/MMBtu for LSD and LSFO, respectively.

A summary of control efficiencies, emission rates, and resulting emission reductions for the control options under consideration are provided in Table 126.

[196] *Id.,* p. 10.

[197] *Id.,* p. 13.

[198] ICAC, Acid Gas/SO_2 Control Technologies, *http://www.icac.com/i4a/pages/index.cfm?pageid=3401.*

[199] Documentation for IPM v. 4.1, Table 5–2.

TABLE 126—SUMMARY OF SO_2 BART ANALYSIS CONTROL TECHNOLOGIES FOR CORETTE

Control option	Control effectiveness (%)	Annual emission rate (lb/MMBtu)	Emissions reduction (tpy)	Remaining emissions (tpy)
LSFO	87.0	0.060	2,369	354
LSD	85.9	0.065	2,339	384
DSI	50.0	0.232	1,362	1,361
No Controls (Baseline) [1]	NA	0.461		2,723

[1] Baseline emissions were determined by averaging the annual emissions from 2008 to 2010 as reported to the CAMD database available at *http://camddataandmaps.epa.gov/gdm/*. A summary of this information can be found in our docket.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of compliance

In accordance with the BART Guidelines (70 FR 39166 (July 6, 2005)), and in order to maintain and improve consistency, we sought to align our cost analysis for SO_2 controls with the CCM. In a manner similar to our evaluation of costs for NO_X controls as described above, we relied on the cost methods developed for IPM version 4.10. However, unlike our evaluation of costs for NO_X controls, we relied on the IPM cost methods for both the capital costs and operating and maintenance costs (*i.e.,* direct annual costs). The IPM cost methods for both capital and operation and maintenance costs for SO_2 controls are more appropriate to utility boilers than the methods for industrial processes found in the CCM. Our costs were also informed by cost analyses submitted by PPL. EPA's detailed cost calculations for each of the SO_2 control options can be found in the docket.

Annualization of capital investments was achieved using the CRF as described in the CCM.[200] Unless noted otherwise, the CRF was computed using an economic lifetime of 20 years and an annual interest rate of 7%.[201] All costs presented in this proposal are adjusted to 2010 dollars using the CEPCI.[202] EPA's detailed cost calculations can be found in the docket.

DSI

The specific methods that we relied upon for evaluating costs for DSI are found in Appendix 5–4 to the IPM v.4.1 documentation. Our costs are based on utilization of the existing ESP to handle the increased particulate loading associated with injection of dry sorbent. This is consistent with the SO_2 control efficiency of 50% that we assumed for DSI in conjunction with ESP. We used a retrofit factor of ''1'' reflecting a DSI retrofit of typical difficulty in the IPM control costs. We used a reagent cost of $145/ton of trona, consistent with the assumption in the IPM cost methods. We summarize the costs from our DSI cost analysis in Tables 127, 128, and 129.

TABLE 127—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR DSI ON CORETTE

Description	Cost ($)
Total Capital Investment	10,311,531

TABLE 128—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR DSI ON CORETTE

Description	Cost ($)
Total Indirect Annual Cost	973,409
Total Direct Annual Cost	4,390,487
Total Annual Cost	5,363,896

TABLE 129—SUMMARY OF SO_2 BART COSTS FOR DSI ON CORETTE

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
10.311	5.364	1,361	3,940

Semi-dry Scrubbing with LSD

The specific methods that we relied upon for evaluating costs for LSD can be found in Appendix 5–1B to the IPM v.4.1 documentation. We used a retrofit factor of ''1'' reflecting a LSD retrofit of typical difficulty in the IPM control costs. We summarize the costs from our LSD cost analysis in Tables 130, 131, and 132.

[200] CCM, Section 1, Chapter 2, p. 2–21.

[201] Office of Management and Budget, Circular A–4, Regulatory Analysis, *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

[202] Chemical Engineering Magazine, p. 56, August 2011. (*http://www.che.com*).

TABLE 130—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR LSD ON CORETTE

Description	Cost ($)
Total Capital Investment	93,175,857

TABLE 131—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR LSD ON CORETTE

Description	Cost ($)
Total Indirect Annual Cost	8,795,801
Total Direct Annual Cost	3,932,763
Total Annual Cost	12,728,564

TABLE 132—SUMMARY OF SO_2 BART COSTS FOR LSD ON CORETTE

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tons/yr)	Average cost effectiveness ($/ton)
93.175	12.728	2,339	5,442

Wet Scrubbing With LSFO

The specific methods that we relied upon for evaluating costs for LSFO can be found in Appendix 5–1A to the IPM v.4.1 documentation. We used a retrofit factor of ''1'' reflecting a LSFO retrofit of typical difficulty in the IPM control costs. We summarize the costs from our LSFO cost analysis in Tables 133, 134, and 135.

TABLE 133—SUMMARY OF SO_2 BART CAPITAL COST ANALYSIS FOR LSFO ON CORETTE

Description	Cost ($)
Total Capital Investment	98,352,945

TABLE 134—SUMMARY OF EPA SO_2 BART ANNUAL COST ANALYSIS FOR LSFO ON CORETTE

Description	Cost ($)
Total Indirect Annual Cost	9,284,518
Total Direct Annual Cost	5,792,020
Total Annual Cost	15,076,538

TABLE 135—SUMMARY OF SO_2 BART COSTS FOR LSFO ON CORETTE

Total capital investment (MM$)	Total annual cost (MM$)	Emissions reductions (tpy)	Average cost effectiveness ($/ton)
98.352	15.076	2,369	6,365

Factor 2: Energy Impacts

Auxiliary power requirements were calculated consistent with the methods found in the IPM cost model for variable operating and maintenance costs. DSI requires additional power of 0.19% of the plant's electrical output for air blowers for the injection system, drying equipment for the transport air, and in-line trona milling equipment. LSD and LSFO require additional power of 1.64% and 1.42% of the plant's electrical output, respectively, to meet power requirements primarily associated with increased fan power to overcome the pressure drop of the FGD system. The average annual gross output of the Corette facility between 2008 and 2010 was 1,084,455 MW-hours (MWh). The additional annual power needs associated with DSI, LSD, and LSFO equate to 2,060 MWh, 17,785 MWh, and 15,399 MWh, respectively. We find that the additional energy requirements are not significant enough to warrant elimination of any of the SO_2 control options under consideration.

Factor 3: Non-air Quality Environmental Impacts

Non-air quality environmental impacts for the SO_2 control options under consideration for Corette include increased waste disposal, and with the exception of DSI, water usage.

Waste disposal rates were calculated consistent with the methods found in the IPM cost model for variable operation and maintenance costs; PPL currently sells the fly ash generated at Corette. However, with the addition of a sodium sorbent used in DSI, any fly ash produced must be landfilled.

Therefore, the total waste disposal rate includes waste associated with both fly ash and sorbent. The hourly waste generation rate for DSI is 9.51 tons/hr. For both LSD and LSFO, the waste generation rate is directly proportional to the reagent usage and is estimated based on 10% moisture in the by-product. The hourly waste generation rates for LSD and LSFO are 1.41 tons/hr and 1.42 tons/hr, respectively. The average annual hours of operation at the Corette facility between 2008 and 2010 were 7,513 hours. The annual waste generation rates associated with DSI, LSD, and LSFO equate to 71,448 tons/yr, 10,593 tons/yr, and 10,668 tons/yr, respectively.

Makeup water rates were calculated consistent with the methods found in the IPM cost model for variable operation and maintenance costs. The makeup water rates for LSD and LSFO are a function of gross unit size (actual gas flow rate) and sulfur feed rate. The hourly makeup water rates for LSD and LSFO are 11,290 gallons/hr and 15,380 gallons/hr, respectively. These rates equate to an increase of annual consumption of 85,024,990 gallons/yr and 115,813,373 gallons/yr, respectively.

With the exception of water use explained above, we find that the non-air quality environmental impacts are not significant enough to warrant elimination of any of the SO_2 control options under consideration.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis. Thus, this factor does not impact our BART determination because the annualized cost was calculated over a 20 year period in accordance with the BART Guidelines.

Factor 5: Evaluate Visibility Impacts.

We conducted modeling for Corette as described in section V.C.3.a. Table 136 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 137 presents the number of days with impacts greater than 0.5 deciviews for each Class area from 2006 through 2008.

TABLE 136—DELTA DECIVIEW IMPROVEMENT FOR SO_2 CONTROLS ON CORETTE

Class I area	Baseline impact (Delta deciview)	LSFO (Delta deciview)	LSD (Delta deciview)	DSI (Delta deciview)
Gates of the Mountains WA	0.295	0.147	0.145	0.090
North Absaroka WA	0.497	0.148	0.147	0.093
Red Rock Lakes WA	0.090	0.044	0.043	0.025
Teton WA	0.298	0.114	0.112	0.065
UL Bend WA	0.462	0.168	0.168	0.101
Washakie WA	0.667	0.256	0.253	0.176
Yellowstone NP	0.325	0.135	0.134	0.097

TABLE 137—DAYS GREATER THAN 0.5 DECIVIEW FOR SO_2 CONTROLS ON CORETTE (THREE YEAR TOTAL)

Class I area	Baseline (days)	Using LSFO	Using LSD	Using DSI
Gates of the Mountains WA	4	2	2	3
North Absaroka WA	11	8	8	9
Red Rock Lakes WA	0	0	0	0
Teton WA	7	4	4	5
UL Bend WA	14	4	4	6
Washakie WA	20	8	8	12
Yellowstone NP	7	3	3	4

Step 5: Select BART.

We propose to find that BART for SO_2 is the existing operation at Corette with an emission limit of 0.70 lb/MMBtu (annual average). Of the five BART factors, cost and visibility improvement were the critical ones in our analysis of controls for this source.

In our BART analysis for SO_2 at Corette, we considered DSI, LSD, and LSFO. The comparison between our DSI, LSD, and LSFO analysis is provided in Table 138.

TABLE 138—SUMMARY OF EPA SO_2 BART ANALYSIS COMPARISON OF DSI, LSD, AND LSFO FOR CORETTE

Control option	Total capital investment (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effective-ness ($/ton)	Visibility Impacts[1]	
					Visibility im-provement (delta deciviews)	Fewer days > 0.5 deciview
LSFO	98.352	15.076	6,365	78,266	0.256	12
LSD	93.175	12.728	5,442	7,530	0.253	12
DSI	10.312	5.364	3,940	[2]	0.176	8

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2006 through 2008) is for Washakie WA, the Class I area with the greatest change.

[2] Incremental cost is not applicable to the option that has the lowest effectiveness.

We have concluded that DSI is a cost effective control technology. DSI has a cost effectiveness value of $3,940 per ton of NO_X emissions reduced. This is within the range of values we have considered reasonable for BART and that states have considered reasonable for BART. We have concluded that LSD and LSFO are not cost effective. LSD has a cost effectiveness of $5,442 per ton of SO_2 emissions reduced and LSFO has a cost effectiveness of $6,365 per ton of SO_2 emissions reduced.

We have weighed costs against the anticipated visibility impacts at Corette. Any of the control options would have a positive impact on visibility; however, the cost of controls is not justified by the visibility improvement.

In proposing a BART emission limit of 0.70 lb/MMBtu, we evaluated the existing emissions from the facility and determined this rate to allow for a sufficient margin of compliance for an annual average limit that would apply at all times, including startup, shutdown, and malfunction.[203] We are also proposing monitoring, recordkeeping, and reporting requirements as described in our proposed regulatory text for 40 CFR 52.1395.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] 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.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

PM

Corette currently has an ESP for particulate control. ESP is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The ESP places electrical charges on the particles, causing them to be attracted to oppositely charged metal plates located in the precipitator. The particles are removed from the plates by ''rapping'' and collected in a hopper located below the unit. The removal efficiencies for ESPs are highly variable; however, for very small particles alone, the removal efficiency is about 99%.[204] The ESP at Corette is designed to achieve a 96% control efficiency, but is currently operating at 98.5%.[205] The present emission annual average filterable particulate emission rate is 0.082 lb/MMBtu.[206]

Based on our modeling described in section V.C.3.a., PM contribution to the baseline visibility impairment is low. Table 139 shows the maximum baseline visibility impact and percentage contribution to that impact from coarse PM and fine PM.

TABLE 139—CORETTE VISIBILITY IMPACT CONTRIBUTION FROM PM

Maximum baseline visibility impact (deciview)	% Contribution coarse PM	% Contribution fine PM
0.497	1.97	2.42

The PM contribution to the baseline visibility impact for Corette is very small; therefore, any visibility improvement that could be achieved with improvements to the existing PM controls would be negligible.

Corette must meet the filterable PM emission standard of 0.26 lb/MMBtu in accordance with its Final Title V Operating Permit #OP2953–05. This Title V requirement appears in Permit Condition H.4.; and was included in the permit pursuant to the regulatory requirements in Montana's EPA approved SIP (ARM 17.8.749).

Taking into consideration the above factors we propose basing the BART emission limit on what Corette is currently meeting. The units are exceeding a PM control efficiency of 99%, and therefore we are proposing that the current control technology and the emission limit of 0.10 lb/MMBtu for PM/PM_{10} as BART. We find that the BART emission limit can be achieved through the operation of the existing ESP. Thus, as described in our BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Corette.

As we have noted previously, under section 51.308(e)(1)(iv), ''each source subject to BART [is] 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.'' Since we propose a BART emission limit that represents current operations and no installation is necessary, we propose a compliance deadline of 30 days from the date our final FIP becomes effective.

D. Long-Term Strategy/Strategies

1. Emissions Inventories

40 CFR 51.308(d)(3)(iii) requires that EPA document the technical basis, including modeling, monitoring, and emissions information, on which it relied to determine its apportionment of emission reduction obligations necessary for achieving Reasonable Progress in each mandatory Class I Federal area Montana affects. EPA must identify the baseline emissions inventory on which its strategies for Montana are based. 40 CFR 51.308(d)(3)(iv) requires that EPA identify all anthropogenic (human-caused) sources of visibility impairment it considered in developing Montana's LTS. This includes major and minor stationary sources, mobile sources, and area sources. In its efforts to meet these requirements, EPA relied on technical analyses developed by WRAP and approved by all state participants, as described below.

Emissions within Montana are both naturally occurring and man-made. Two primary sources of naturally occurring emissions include wildfires and windblown dust. In Montana, the primary sources of anthropogenic emissions include electric utility steam generating units, energy production and processing sources, agricultural production and processing sources, prescribed burning, and fugitive dust sources. The Montana inventory includes emissions of SO_2, NO_X, $PM_{2.5}$, PM_{10}, OC, EC, VOCs, and NH_3.

An emissions inventory for each pollutant was developed by WRAP for Montana for the baseline year 2002 and for 2018, which is the first RP milestone. The 2018 emissions inventory was developed by projecting 2002 emissions and applying reductions expected from federal and state regulations. The emission inventories developed by WRAP were calculated using approved EPA methods.

[203] As discussed in the BART Guidelines, section V (70 FR 39172, July 6, 2005), and Section 302(k) of the CAA, emissions limits such as BART are required to be met on a continuous basis.

[204] EPA Air Pollution Control Online Course, description at *http://www.epa.gov/apti/course422/ce6a1.html.*

[205] Corette Addendum, p. 6–1.

[206] *Id.*

There are ten different emission inventory source categories identified: Point, area, area oil and gas, on-road, off-road, all fire, biogenic, road dust, fugitive dust, and windblown dust. Tables 140 through 145 show the 2002 baseline emissions, the 2018 projected emissions, and net changes of emissions for SO_2, NO_X, OC, EC, $PM_{2.5}$, and PM_{10} by source category in Montana. The methods that WRAP used to develop these emission inventories are described in more detail in the WRAP documents included in the docket.[207]

SO_2 emissions in Montana, shown in Table 140, come mostly from point sources with smaller amounts coming from fire, area, mobile and the oil and gas industry. WRAP assumed more than 6,000 tpy of SO_2 would be reduced at Colstrip due to controls required by the Regional Haze program. Overall, a 12% statewide reduction in SO_2 emissions is expected by 2018.

TABLE 140—MONTANA SO_2 EMISSION INVENTORY—2002 AND 2018

Montana statewide SO_2 emissions [tons/year]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	36,888	36,749	−138	−0.4
All Fire	5,134	4,912	−222	−4.3
Biogenic	0	0	0	0
Area	3,236	3,580	344	11
Area Oil and Gas	225	6	−219	−97
On-Road Mobile	1,863	234	−1629	−87
Off-Road Mobile	4,552	282	−4270	−94
Road Dust	11	13	2	20
Fugitive Dust	13	17	4	32.8
Wind Blown Dust	0	0	0	0
Total	51,923	45,794	−6,128	−12

NO_X emissions in Montana, shown in Table 141, are expected to decline 26% by 2018. Off-road and on-road vehicle NO_X emissions are estimated to decline by more than 50,000 tpy from the base case emissions total of approximately 104,000 tpy. WRAP assumed more than 23,000 tpy of NO_X would be reduced at Colstrip by 2018 due to an enforcement action and additional controls required as a result of the regional haze requirements. NO_X emissions from oil and gas sources are projected to increase by 84% (6000 tons). Overall, a 26% statewide reduction in NO_X emissions is expected by 2018.

TABLE 141—MONTANA NO_X EMISSION INVENTORY—2002 AND 2018

Montana statewide NO_X emissions [tons/year]

Source Category	Baseline 2002	Future 2018	Net change	Percent change
Point	53,416	33,508	−19,909	−37
All Fire	15,283	14,632	−652	−4
Biogenic	58,354	58,354	0	0
Area	4,292	5,535	1,244	29
Area Oil and Gas	7,557	13,880	6,323	84
On-Road Mobile	53,597	22,036	−31,560	−59
Off-Road Mobile	50,604	32,054	−18,550	−37
Road Dust	25	29	4	17
Fugitive Dust	14	15	1	11
Wind Blown Dust	0	0	0	0
Total	243,142	180,043	−63,099	−26

Most of the PM OC emissions in Montana are from fires as shown in Table 142. In 2002, natural (non-anthropogenic) wildfire accounted for 38,324 tons of OC emissions while anthropogenic fire accounted for 3,745 tons of OC emission. Anthropogenic fire (human-caused), includes such activities as forestry prescribed burning, agricultural field burning, and outdoor residential burning. Overall, OC emissions are estimated to decline by 3% by 2018.

[207] The WRAP 2002 Plan02d and WRAP 2018 PRP18b inventories cited in Tables 73–78 can be found at *http://vista.cira.colostate.edu/tss/Results/HazePlanning.aspx.*

TABLE 142—MONTANA PARTICULATE MATTER ORGANIC CARBON EMISSION INVENTORY—2002 AND 2018

Montana statewide organic carbon emissions
[tons/year]

Source category	Baseline 2002	Future 2018	Net change	Percent Change
Point	101	267	167	165
All Fire	42,069	40,162	−1,907	−5
Biogenic	0	0	0	0
Area [1]	2788	2974	187	7
On-Road Mobile	455	469	14	3
Off-Road Mobile	718	382	−336	−47
Road Dust	1,271	1,487	216	17
Fugitive Dust	687	760	73	11
Wind Blown Dust	0	0	0	0
Total	48,089	46,502	−1,587	−3

[1] Area Source Oil and Gas emissions are included in Area Source total for OC, EC, and PM.

The primary source of EC is fire as shown in Table 143. In 2002, natural (non-anthropogenic) wildfire accounted for 7,743 tons of EC emissions while anthropogenic fire accounted for 759 tons of OC emissions. Other emissions of note are off-road mobile and on-road mobile sources, particularly those associated with diesel engines. EC emissions are estimated to decrease by 17% by 2018 due mostly to new federal mobile source regulations.

TABLE 143—MONTANA ELEMENTAL CARBON EMISSION INVENTORY—2002 AND 2018

Montana statewide elemental carbon emissions
[tons/year]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	17	25	8	49
All Fire	8,502	8,116	−386	−5
Biogenic	0	0	0	0
Area [1]	413	447	34	8
On-Road Mobile	519	159	−361	−69
Off-Road Mobile	2,288	1,001	−1287	−56
Road Dust	87	102	15	17
Fugitive Dust	47	52	5	11
Wind Blown Dust	0	0	0	0
Total	11,873	9,901	−1,971	−17

[1] Area Source Oil and Gas emissions are included in Area Source total for OC, EC, and PM.

As detailed in Tables 144 and 145, the primary sources of PM (both PM_{10} and $PM_{2.5}$) are road, fugitive, and windblown dust (agriculture, mining, construction, and unpaved and paved roads). Overall, PM shows an increase of 8–9% by 2018.

TABLE 144—MONTANA FINE PARTICULATE MATTER EMISSION INVENTORY—2002 AND 2018

Montana statewide $PM_{2.5}$ emissions
[tons/year]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	182	294	112	62
All Fire	3,190	3,047	−142	−5
Biogenic	0	0	0	0
Area [1]	2,472	2,754	281	11
On-Road Mobile	0	0	0	0
Off-Road Mobile	0	0	0	0
Road Dust	21,671	25,294	3,623	17
Fugitive Dust	13,276	15,209	1,933	15
Wind Blown Dust	36,448	36,448	0	0
Total	77,239	83,047	5,807	8

[1] Area Source Oil and Gas emissions are included in Area Source total for OC, EC, and PM.

TABLE 145—MONTANA COARSE PARTICULATE MATTER EMISSION INVENTORY—2002 AND 2018

Montana statewide coarse particulate matter emissions [tons/year]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	7,818	11,384	3,566	46
All Fire	9,210	8,808	−401	−4
Biogenic	0	0	0	0
Area [1]	706	790	84	12
On-Road Mobile	270	329	59	22
Off-Road Mobile	0	0	0	0
Road Dust	206,863	241,329	34,467	17
Fugitive Dust	68,373	85,309	16,936	25
Wind Blown Dust	328,036	328,036	0	0
Total	621,276	675,985	54,709	9

[1] Area Source Oil and Gas emissions are included in Area Source total for OC, EC, and PM.

See the WRAP documents included in the docket for details on how the 2018 emissions inventory was constructed. WRAP used this inventory and other states' 2018 emission inventories to construct visibility projection modeling for 2018.

The reduction in point and area emissions shown in Tables 140 through 145 is explained in the WRAP's 2018 point and area source projection on Reasonable Progress inventory (version 2018 PRP 18b, *http://www.wrapair.org/forums/ssjf/pivot.html*). The factors contributing to the reductions included emission reductions due to known controls in place on the emission sources, consent decrees, SIP control measures, and other relevant regulations that have gone into effect since 2002, or will go into effect before the end of 2018. This includes estimates made in 2007 for controls for BART sources. These controls do not include impacts from any future control scenarios that had not been defined by 2007. The reduction in emissions due to the retirement of older equipment was estimated using annual retirement rates and based on expected equipment lifetimes. Unit lifetimes were examined for natural gas-fired electrical generating units (EGU) but no retirements were assumed for coal-fired EGU. The permit limits for a source having a limit were considered in the cases where the projected emissions may have inadvertently exceeded an enforceable emission limit i.e., emissions were adjusted downward to the permit limit.

2. Sources of Visibility Impairment in Montana Class I Areas

In order to determine the significant sources contributing to haze in Montana's Class I areas, EPA relied upon two source apportionment analysis techniques developed by WRAP. The first technique was regional modeling using the Comprehensive Air Quality Model (CAMx) and the PSAT tool, used for the attribution of sulfate and nitrate sources only. The second technique was the WEP tool, used for attribution of sources of OC, EC, $PM_{2.5}$, and PM_{10}. The WEP tool is based on emissions and residence time, not modeling.

PSAT uses the CAMx air quality model to show nitrate-sulfate-ammonia chemistry and apply this chemistry to a system of tracers or ''tags'' to track the chemical transformations, transport, and removal of NO_X and SO_2. These two pollutants are important because they tend to originate from anthropogenic sources. Therefore, the results from this analysis can be useful in determining contributing sources that may be controllable, both in-state and in neighboring states.

WEP is a screening tool that helps to identify source regions that have the potential to contribute to haze formation at specific Class I areas. Unlike PSAT, this method does not account for chemistry or deposition. The WEP combines emissions inventories, wind patterns, and residence times of air masses over each area where emissions occur, to estimate the percent contribution of different pollutants. Like PSAT, the WEP tool compares baseline values (2000 through 2004) to 2018 values, to show the improvement expected by 2018, for sulfate, nitrate, OC, EC, $PM_{2.5}$, and PM_{10}. More information on WRAP modeling methodologies is available in the docket.[208] Note that the PSAT analyses used the earlier 2002 Plan 02c and 2018 Base 18b inventories, rather than the 2002 Plan 02d and 2018 PRP 18b inventories that are listed in the tables here. The 2018 Base 18b inventory does not assume BART controls.

The contributions of sulfate and nitrate are based on PSAT while the contributions of OC, EC, $PM_{2.5}$, PM_{10}, and Sea Salt are based on WEP. The PSAT and WEP results presented in Tables 146, 147, and 148 were derived from WRAP analysis. Table 147 shows the contribution of different pollutant species from Montana sources.

TABLE 146—MT SOURCES EXTINCTION CONTRIBUTION 2000–2004 FOR 20% WORST DAYS

Class I area	Pollutant species	Extinction (Mm^{-1})	Species contribution to total extinction (%)	MT sources contribution to species extinction (%)[1]
	Sulfate	4.83	11	4
	Nitrate	1.46	3	18
	OC	20.01	47	5

[208] WRAP TSD.

TABLE 146—MT SOURCES EXTINCTION CONTRIBUTION 2000–2004 FOR 20% WORST DAYS—Continued

Class I area	Pollutant species	Extinction (Mm^{-1})	Species contribution to total extinction (%)	MT sources contribution to species extinction (%)[1]
Anaconda-Pintler WA	EC	2.52	6	6
	$PM_{2.5}$	0.94	2	21
	PM_{10}	2.49	6	21
	Sea Salt	0.26	1	[2]
	Sulfate	5.12	11	6
	Nitrate	1.43	3	31
Bob Marshall WA	OC	22.29	48	33
	EC	2.8	6	36
	$PM_{2.5}$	1.29	3	49
	PM_{10}	3.6	8	60
	Sea Salt	0.03	0	[2]
Cabinet Mountains WA.	Sulfate	6.48	15	3
	Nitrate	2.02	5	14
	OC	16.95	40	25
	EC	2.79	7	25
	$PM_{2.5}$	1.03	2	13
	PM_{10}	2.81	7	16
	Sea Salt	0.1	0	[2]
	Sulfate	5.41	17	8
	Nitrate	1.88	6	30
Gates of the Mountains WA	OC	11.26	35	35
	EC	1.82	6	38
	$PM_{2.5}$	0.75	2	73
	PM_{10}	1.68	5	82
	Sea Salt	0.06	0	[2]
	Sulfate	11.37	8	10
	Nitrate	9.36	7	23
Glacier National Park	OC	87.68	64	44
	EC	11.2	8	45
	$PM_{2.5}$	1.4	1	36
	PM_{10}	5.22	4	42
	Sea Salt	0.28	0	[2]
	Sulfate	16.96	28	3
	Nitrate	16.27	27	16
	OC	9.48	15	40
Medicine Lake WA.				
	EC	2.34	4	40
	$PM_{2.5}$	0.75	1	45
	PM_{10}	4.46	7	51
	Sea Salt	0.03	0	[2]
	Sulfate	5.12	11	6
	Nitrate	1.43	3	31
Mission Mountain WA	OC	22.29	48	33
	EC	2.8	6	36
	$PM_{2.5}$	1.29	3	49
	PM_{10}	3.6	8	60
	Sea Salt	0.03	0	[2]
	Sulfate	4.26	12	1
	Nitrate	1.77	5	1
Red Rock Lakes WA	OC	13.48	39	2
	EC	2.48	7	3
	$PM_{2.5}$	0.95	3	18
	PM_{10}	2.58	7	26
	Sea Salt	0.02	0	[2]
	Sulfate	5.12	11	6
	Nitrate	1.43	3	31
	OC	22.29	48	33
Scapegoat WA	EC	2.8	6	36
	$PM_{2.5}$	1.29	3	49
	PM_{10}	3.6	8	60
	Sea Salt	0.03	0	[2]
	Sulfate	4.83	11	4
	Nitrate	1.46	3	1

TABLE 146—MT SOURCES EXTINCTION CONTRIBUTION 2000–2004 FOR 20% WORST DAYS—Continued

Class I area	Pollutant species	Extinction (Mm^{-1})	Species contribution to total extinction (%)	MT sources contribution to species extinction (%)[1]
Selway-Bitterroot WA	OC	20.01	47	5
	EC	2.52	6	6
	$PM_{2.5}$	0.94	2	21
	PM_{10}	2.49	6	21
	Sea Salt	0.26	1	[2]
	Sulfate	9.78	20	5
	Nitrate	8.01	17	18
	OC	12.76	26	52
U.L. Bend WA	EC	2.08	4	51
	$PM_{2.5}$	0.77	2	75
	PM_{10}	4.01	8	81
	Sea Salt	0.01	0	[2]
	Sulfate	4.26	12	1
	Nitrate	1.77	5	1
	OC	13.48	39	2
Yellowstone NP	EC	2.48	7	3
	$PM_{2.5}$	0.95	3	18
	PM_{10}	2.58	7	26
	Sea Salt	0.02	0	[2]

[1] Contribution of sulfate and nitrate based on PSAT; OC, EC, $PM_{2.5}$, PM_{10}, and Sea Salt contribution based on WEP.
[2] MT sources contribution to sea salt was not included in the WRAP results.

Tables 147 and 148 show influences from sources both inside and outside of Montana.

TABLE 147—SOURCE REGION APPORTIONMENT FOR SO_4 FOR 20% WORST DAYS

[Percentage]

	Montana	Canada	Idaho	Washington	Oregon	Outside domain
Anaconda-Pintler WA	4	14	13	10	7	45
Bob Marshall WA	6	14	5	6	4	47
Cabinet Mountains WA	3	17	7	14	5	48
Gates of the Mountains WA	8	1	4	6	3	48
Glacier NP	10	24	2	6	5	51
Medicine Lake WA	3	50	0	2	1	23
Mission Mountain WA	6	14	5	6	4	47
Red Rock Lakes WA	1	5	8	4	4	46
Scapegoat WA	6	14	5	6	4	47
Selway-Bitterroot WA	4	14	13	10	7	45
U.L. Bend WA	5	34	1	2	1	37
Yellowstone NP	1	5	8	4	4	46

TABLE 148—SOURCE REGION APPORTIONMENT FOR NO_3 FOR 20% WORST DAYS

[Percentage]

	Montana	Canada	Idaho	Washington	Oregon	Outside domain
Anaconda-Pintler WA	18	9	13	15	5	23
Bob Marshall WA	31	11	7	9	3	25
Cabinet Mountains WA	14	9	14	32	7	14
Gates of the Mountains WA	29	13	6	9	2	26
Glacier NP	23	22	9	13	6	23
Medicine Lake WA	16	47	1	6	3	18
Mission Mountain WA	31	11	7	9	3	25
Red Rock Lakes WA	2	1	24	8	6	27
Scapegoat WA	31	11	7	9	3	25
Selway-Bitterroot WA	18	9	13	15	5	23
U.L. Bend WA	18	38	2	5	3	21
Yellowstone NP	2	1	24	8	6	27

3. Other States' Class I Areas Affected by Montana Emissions

Table 149 shows the impact Montana sources have on Class I areas in adjacent states.[209]

TABLE 149—MT SOURCES EXTINCTION CONTRIBUTION 2000–2004, 20% WORST DAYS

Class I area	Pollutant species	Extinction (Mm $^{-1}$)	Species contribution to particle extinction (%)	MT sources contribution to species extinction (%) [1]
Badlands WA	Sulfate	18.85	41	2
	Nitrate	5.85	13	7
	OC	11.78	26	18
	EC	2.59	6	12
	$PM_{2.5}$	0.98	2	4
	PM_{10}	5.94	13	5
	Sea Salt	0.19	0	
Bridger WA	Sulfate	4.99	22	2
	Nitrate	1.43	6	3
	OC	10.55	47	2
	EC	1.99	9	2
	$PM_{2.5}$	1.1	5	8
	PM_{10}	2.51	11	13
	Sea Salt	0.04	0	
Craters of the Moon WA	Sulfate	5.69	18	1
	Nitrate	11.35	35	3
	OC	9.06	28	1
	EC	1.92	6	1
	$PM_{2.5}$	1.04	3	4
	PM_{10}	2.95	9	5
	Sea Salt	0.03	0	
Fitzpatrick WA	Sulfate	4.99	22	2
	Nitrate	1.43	6	3
	OC	10.55	47	2
	EC	1.99	9	2
	$PM_{2.5}$	1.1	5	8
	PM_{10}	2.51	11	13
	Sea Salt	0.04	0	
Grand Teton NP	Sulfate	4.26	17	0
	Nitrate	1.77	7	0
	OC	13.48	53	2
	EC	2.48	10	3
	$PM_{2.5}$	0.95	4	18
	PM_{10}	2.58	10	26
	Sea Salt	0.02	0	
Hells Canyon WA	Sulfate	8.37	14	1
	Nitrate	28.47	49	1
	OC	15.6	27	1
	EC	3.06	5	1
	$PM_{2.5}$	0.66	1	2
	PM_{10}	1.93	3	3
	Sea Salt	0.05	0	
Lostwood NWR	Sulfate	21.4	34	2
	Nitrate	22.94	36	9
	OC	11.05	18	17
	EC	2.84	5	12
	$PM_{2.5}$	0.62	1	7
	PM_{10}	3.93	6	11
	Sea Salt	0.26	0	
North Absaroka NP	Sulfate	4.87	21	7
	Nitrate	1.61	7	16
	OC	11.64	49	15
	EC	1.86	8	15
	$PM_{2.5}$	0.85	4	45
	PM_{10}	2.91	12	56
	Sea Salt	0.01	0	
Teton WA	Sulfate	4.26	17	0
	Nitrate	1.77	7	0
	OC	13.48	53	2
	EC	2.48	10	3

[209] WRAP TSD.

TABLE 149—MT SOURCES EXTINCTION CONTRIBUTION 2000–2004, 20% WORST DAYS—Continued

Class I area	Pollutant species	Extinction (Mm^{-1})	Species contribution to particle extinction (%)	MT sources contribution to species extinction (%) [1]
	$PM_{2.5}$	0.95	4	18
	PM_{10}	2.58	10	26
	Sea Salt	0.02	0	
Theodore Roosevelt NP	Sulfate	17.53	35	3
	Nitrate	13.74	27	15
	OC	10.82	21	49
	EC	2.75	5	33
	$PM_{2.5}$	0.9	2	22
	PM_{10}	4.82	10	25
	Sea Salt	0.07	0	
Washakie WA	Sulfate	4.87	21	7
	Nitrate	1.61	7	16
	OC	11.64	49	15
	EC	1.86	8	15
	$PM_{2.5}$	0.85	4	45
	PM_{10}	2.91	12	56
	Sea Salt	0.01	0	
Wind Cave NP	Sulfate	13.2	32	2
	Nitrate	6.98	17	0
	OC	13.22	32	21
	EC	2.92	7	15
	$PM_{2.5}$	0.85	2	11
	PM_{10}	3.52	9	13
	Sea Salt	0.03	0	

[1] Contribution of sulfate and nitrate based on PSAT; OC, EC, $PM_{2.5}$, PM_{10}, and Sea Salt contribution based on WEP.

4. Visibility Projection Modeling

The Regional Modeling Center (RMC) at the University of California Riverside, under the oversight of the WRAP Modeling Forum, performed modeling for the regional haze LTS for the WRAP member states, including Montana. The modeling analysis is a complex technical evaluation that began with selection of the modeling system. RMC primarily used the Community Multi-Scale Air Quality (CMAQ) photochemical grid model to estimate 2018 visibility conditions in Montana and all western Class I areas, based on application of the regional haze strategies in the various state plans, including some assumed controls on BART sources.

The RMC developed air quality modeling inputs, including annual meteorology and emissions inventories for: (1) A 2002 actual emissions base case; (2) a planning case to represent the 2000–2004 regional haze baseline period using averages for key emissions categories; and (3) a 2018 base case of projected emissions determined using factors known at the end of 2007. All emission inventories were spatially and temporally allocated using the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system. Each of these inventories underwent a number of revisions throughout the development process to arrive at the final versions used in CMAQ modeling. The WRAP states' modeling was developed in accordance with our guidance.[210] A more detailed description of the CMAQ modeling performed for the WRAP can be found in the docket.[211]

The photochemical modeling of regional haze for the WRAP states for 2002 and 2018 was conducted on the 36-km resolution national regional planning organization domain that covered the continental United States, portions of Canada and Mexico, and portions of the Atlantic and Pacific Oceans along the east and west coasts. The RMC examined the model performance of the regional modeling for the areas of interest before determining whether the CMAQ model results were suitable for use in the regional haze assessment of the LTS and for use in the modeling assessment. The 2002 modeling efforts were used to evaluate air quality/visibility modeling for a historical episode—in this case, for calendar year 2002—to demonstrate the suitability of the modeling systems for subsequent planning, sensitivity, and emissions control strategy modeling. Model performance evaluation compares output from model simulations with ambient air quality data for the same time period to determine whether model performance is sufficiently accurate to justify using the model to simulate future conditions. Once the RMC determined that model performance was acceptable, it used the model to determine the 2018 RPGs using the current and future year air quality modeling predictions, and compared the RPGs to the URP.

5. Consultation and Emissions Reduction for Other States' Class I Areas

40 CFR 51.308(d)(3)(i) requires that EPA consult with another state if Montana's emissions are reasonably anticipated to contribute to visibility impairment at that state's Class I area(s), and that EPA consult with other states if those other states' emissions are reasonably anticipated to contribute to visibility impairment at Montana's Class I areas. EPA worked with other states and tribes through the WRAP process. EPA also accepts and incorporates the WRAP-developed visibility modeling

[210] Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze, (EPA–454/B–07–002), April 2007, located at *http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf;* Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations, August 2005, updated November 2005 ("Our Modeling Guidance"), located at *http://www.epa.gov/ttnchie1/eidocs/eiguid/index.html,* EPA–454/R–05–001.

[211] WRAP TSD and "Air Quality Modeling," available at: *http://vista.cira.colostate.edu/docs/WRAP/Modeling/AirQualityModeling.doc.*

into the Regional Haze FIP for Montana.[212]

This proposal contains the necessary measures to meet Montana's share of the reasonable progress goals for the other state's Class I areas.

Table 149 above shows Montana's contribution to Class I areas in neighboring states. None of the neighboring states with Class I areas have indicated to EPA that specific reductions are necessary for this FIP. Therefore, EPA proposes that this FIP meets Montana's share of the reasonable progress goals for the other state's Class I areas.

6. EPA's Reasonable Progress Goals for Montana

In order to establish RPGs for the Class I areas in Montana and to determine the controls needed for the LTS, we followed the process established in the Regional Haze Rule. First, we identified the anticipated visibility improvement in 2018 in all Montana Class I areas accounting for all existing enforceable federal and state regulations already in place and anticipated BART controls. The WRAP CMAQ modeling results were used to identify the extent of visibility improvement from the baseline by pollutant for each Class I area.

a. EPA's Use of WRAP Visibility Modeling

We are relying on modeling performed by WRAP. The primary tool WRAP relied upon for modeling regional haze improvements by 2018, and for estimating Montana's RPGs, was the CMAQ model. The CMAQ model was used to estimate 2018 visibility conditions in Montana and all western Class I areas, based on application of anticipated regional haze strategies in the various states' regional haze plans, including assumed controls on BART sources.

The RMC at the University of California Riverside conducted the CMAQ modeling under the oversight of the WRAP Modeling Forum. The RMC developed air quality modeling inputs including annual meteorology and emissions inventories for: (1) A 2002 actual emissions base case; (2) a planning case to represent the 2000–2004 regional haze baseline period using averages for key emissions categories; and (3) a 2018 base case of projected emissions determined using factors known at the end of 2007. A more detailed description of the inventories can be found in the following documents that are included in the docket.[213] All emission inventories were spatially and temporally allocated using the SMOKE modeling system. Each of these inventories underwent a number of revisions throughout the development process to arrive at the final versions used in CMAQ modeling.[214]

b. EPA's Reasonable Progress ''Four-Factor'' Analysis

In determining the measures necessary to make reasonable progress and in selecting RPGs for mandatory Class I areas within Montana, we must take into account the following four factors and demonstrate how they were taken into consideration:

- Costs of Compliance;
- Time Necessary for Compliance;
- Energy and Non-air Quality Environmental Impacts of Compliance; and
- Remaining Useful Life of any Potentially Affected Sources.

CAA § 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A).

As the purpose of the reasonable progress analysis is to evaluate the potential of controlling certain sources or source categories for addressing visibility from manmade sources, our four-factor analysis addresses only anthropogenic sources, on the assumption that the focus should be on sources that can be ''controlled.''

As explained previously, WRAP developed emission inventories for 11 source categories and we are proposing to use this analysis to identify sources that should be evaluated for further control. Specifically, we identified those source categories that, based on the inventories, contribute the most to emissions of visibility impairing pollutants and for which there are not adequate controls. The visibility impairing pollutants we considered are primary organic aerosol, EC, $PM_{2.5}$, PM_{10}, SO_2, and NO_X.

Tables 150 through 154 provide the statewide 2002 baseline primary organic aerosol, EC, $PM_{2.5}$ and PM_{10} emissions and percentage contribution from the eleven source categories evaluated by WRAP.

TABLE 150—MONTANA PRIMARY ORGANIC AEROSOL EMISSION INVENTORY—2002

Source category	Baseline 2002 (tpy)	Percentage of total
Point	101	<1
Anthropogenic Fire	3,745	8
Natural Fire	38,324	80
Biogenic	0	0
Area	2,788	6
Area Oil and Gas	0	0
On-Road Mobile	455	1
Off-Road Mobile	718	2
Road Dust	1,271	3
Fugitive Dust	687	1
Wind Blown Dust	0	0
Total	48,089	

[212] See ''Air Quality Modeling,'' available at: *http://vista.cira.colostate.edu/docs/WRAP/Modeling/AirQualityModeling.doc.*

[213] WRAP TSD; WRAP PRP 18b Emissions Inventory—Revised Point and Area Sources Projections, Final dated October 16, 2009; Development of 2000–04 Baseline period and 2018 Projection Year Emission Inventories, Final, dated May 2007; Final Report, WRAP Mobile Source Emission Inventories Updated, dated May 2006; Emissions Overview, for which WRAP did not include a date; 2002 Planning Simulation Version D Specification Sheet for which WRAP did not include a date; 2018 Preliminary Reasonable Progress Simulation Version B Specification Sheet for which WRAP did not include a date. The actual inventories can be found in the docket in the spreadsheets with the following titles: 02d Point Source Inventory; 02d Area Source Inventory; PRP18b Point Source Inventory; PRP 18b Area Source Inventory.

[214] A more detailed description of the CMAQ modeling performed by WRAP can be found in WRAP's TSD dated February 29, 2011, and also in the document in the docket titled Air Quality Modeling for which the WRAP did not include a date.

TABLE 151—MONTANA ELEMENTAL CARBON EMISSION INVENTORY—2002

Source category	Baseline 2002 (tpy)	Percentage of total
Point	17	<1
Anthropogenic Fire	759	6
Natural Fire	7,743	65
Biogenic	0	0
Area	413	3
Area Oil and Gas	0	0
On-Road Mobile	519	4
Off-Road Mobile	2,288	19
Road Dust	89	<1
Fugitive Dust	47	<1
Wind Blown Dust	0	0
Total	11,873	

TABLE 152—MONTANA FINE PARTICULATE MATTER EMISSION INVENTORY—2002

Source category	Baseline 2002 (tpy)	Percentage of total
Point	182	<1
Anthropogenic Fire	279	<1
Natural Fire	2,911	4
Biogenic	0	0
Area	2,472	3
Area Oil and Gas	0	0
On-Road Mobile	0	0
Off-Road Mobile	0	0
Road Dust	21,671	28
Fugitive Dust	13,276	17
Wind Blown Dust	36,448	47
Total	77,239	

TABLE 153—MONTANA COARSE PARTICULATE MATTER EMISSION INVENTORY—2002

Source category	Baseline 2002 (tpy)	Percentage of total
Point	7,818	1
Anthropogenic Fire	713	<1
Natural Fire	8,496	1
Biogenic	0	0
Area	706	<1
Area Oil and Gas	0	0
On-Road Mobile	270	<1
Off-Road Mobile	0	0
Road Dust	206,863	33
Fugitive Dust	68,373	11
Wind Blown Dust	328,036	53
Total	621,276	

As indicated, point sources contribute less than 1% to primary organic aerosol emissions, less than 1% to EC emissions, less than 1% to fine particulate, and 1% to coarse particulate emissions. Also, BART modeling that we conducted tends to indicate that PM emissions from point sources have the potential to contribute only a minimal amount to the visibility impairment in the Montana Class I areas. Since the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} is very small, and modeling tends to show that PM emissions from point sources do not have a very large impact, we are proposing that additional controls on point sources for primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} are not necessary for this planning period. We next consider other sources of these pollutants.

Anthropogenic fire contributes 8% to primary organic aerosol emissions, 6% to EC emissions, less than 1% to $PM_{2.5}$ emissions and less than 1% to PM_{10} emissions. Anthropogenic fire emissions are controlled through Montana's visibility SIP, which we propose for approval as addressing one of the required LTS factors, Agricultural and Forestry Smoke Management Techniques, in section V.D.6.f.v . Natural fire contributes 80% to primary organic aerosol emissions, 65% to EC emissions, 4% to $PM_{2.5}$ emissions, and 1% to PM_{10} emissions. Natural fires are considered uncontrollable. In summary, we are proposing that additional controls for primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} from anthropogenic fire are not necessary for this planning period. We also are proposing that natural fires do not need to be addressed because they are not man-made.

Area sources contribute only 6% to primary organic aerosol emissions, 3% to EC emissions, 3% to $PM_{2.5}$ emissions, and less than 1% to PM_{10} emissions. We are proposing that because area sources have such a small contribution to the emissions inventory, additional controls for primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} from area sources are not necessary for this planning period.

On-road mobile sources contribute only 1% to primary organic aerosol emissions, 4% to EC emissions, and less than 1% to PM_{10} emissions. Off-road mobile sources contribute 2% to primary organic aerosol emissions and 19% to EC emissions. Both on-road and off-road mobile sources will benefit from fleet turnover to cleaner vehicles resulting from more stringent federal emission standards. Since emissions are expected to decrease as newer vehicles replace older ones, we are proposing that additional controls for primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} from on-road and off-road vehicles are not necessary during this planning period.

Emissions from road dust contribute 3% to primary organic aerosol emissions, less than 1% to EC emissions, 28% to $PM_{2.5}$ emissions and 33% to PM_{10} emissions. Wind-blown dust contributes 47% to fine particulate emissions and 53% to PM_{10} emissions. Road dust and wind-blown dust are regulated by the State's ARM 17.8.308, Particulate Matter, Airborne. This regulation, which is approved into Montana's SIP, establishes an opacity limit of 20% and also requires reasonable precautions to be taken to control emissions of airborne PM from the production, handling, transportation, or storage of any material. It also requires reasonable precautions to be taken to control emissions of airborne PM from streets, roads, and parking lots. In addition, in any nonattainment area, this regulation requires Reasonable Available Control Technology for existing sources, BACT for new sources with a potential to emit less than 100 tpy, and Lowest Achievable Emission Rates for new sources that have the potential to emit more than 100 tpy. Finally, this regulation requires operators of a construction site to take reasonable precautions to control emissions of airborne PM at construction and demolition sites and it establishes a 20% opacity limit for emissions of airborne pollutants at these sites. The measures to mitigate the impact of construction activities are included as one of the required LTS factors in section V.D.6.f.ii. We are proposing that the existing rules at ARM 17.8.308 are sufficient to control emissions of OC, EC, $PM_{2.5}$ and PM_{10} and that additional controls for primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} from road dust, fugitive dust, and windblown dust are not necessary for this planning period.

Table 154 provides the Statewide baseline SO_2 emissions and percentage contribution to the total SO_2 emissions in Montana.

TABLE 154—MONTANA SO_2 EMISSION INVENTORY—2002

Source category	Baseline 2002 (tpy)	Percentage of total
Point	36,887	71
Anthropogenic Fire	500	1
Natural Fire	4,634	9
Biogenic	0	0
Area	3,236	6
Area Oil and Gas	225	<1
On-Road Mobile	1,836	4
Off-Road Mobile	4,552	9
Road Dust	11	<1
Fugitive Dust	13	<1
Wind Blown Dust	0	0
Total	51,923	

As indicated, 71% of total Statewide SO_2 emissions are from point sources, 6% are from area sources and less than 1% are from area oil and gas sources. Emissions from anthropogenic fire contribute 1% and emissions from natural fire contribute 9% to Statewide SO_2 emissions. Anthropogenic fire emissions are controlled through Montana's Visibility SIP, which is further described as one of the required LTS factors, Agricultural and Forestry Smoke Management Techniques, in V.D.6.f.v. SO_2 emissions from natural fires (9%) are considered uncontrollable. On-road mobile sources contribute 4% and off-road sources contribute 9% to Statewide SO_2 emissions. Both off-road and on-road mobile sources are subject to federal ultra-low sulfur diesel fuel requirements that limit sulfur content to 15 ppm (0.0015%), which was in widespread use after June 2010 for off-road mobile and June 2006 for on-road mobile. Road dust, fugitive dust and windblown dust comprise less than 1% of Statewide emissions. We are proposing that point sources are the dominant source of emissions and, for this planning period, the only category necessary to evaluate further under reasonable progress for SO_2.

Table 155 provides the Statewide baseline NO_X emissions and percentage contribution to the total NO_X emissions in Montana.

TABLE 155—MONTANA NO_X EMISSION INVENTORY—2002

Source category	Baseline 2002 (tpy)	Percentage of total
Point	53,416	22
Anthropogenic Fire	1,513	<1
Natural Fire	13,770	6

TABLE 155—MONTANA NO_X EMISSION INVENTORY—2002—Continued

Source category	Baseline 2002 (tpy)	Percentage of total
Biogenic	58,353	24
Area	4,292	2
Area Oil and Gas	7,557	3
On-Road Mobile	53,597	22
Off-Road Mobile	50,604	21
Road Dust	25	<1
Fugitive Dust	14	<1
Wind Blown Dust	0	0
Total	24,314	

As indicated, 22% of total Statewide NO_X emissions are from point sources. Emissions from anthropogenic fire contribute less than 1% and emissions from natural fire contribute 6% to Statewide NO_X emissions. Agricultural and Forestry smoke management techniques are discussed in section V.D.6.f.v as one of the mandatory LTS factors required to be considered. Emissions from natural fires are considered uncontrollable. Emissions from biogenic sources contribute 24% and also are considered uncontrollable. Emissions from area sources contribute only 2% and emissions from area oil and gas sources contribute only 3% of statewide emissions. Emissions from on-road mobile sources contribute 22% and emissions from off-road mobile sources contribute 21% to Statewide NO_X emissions. Both on-road and off-road mobile sources will benefit from fleet turnover to cleaner vehicles resulting from more stringent federal emission standards. We are proposing that point sources are the dominant source of emissions not already being addressed and, for this planning period, the only category necessary to evaluate further under reasonable progress for NO_X.

To identify the point sources in Montana that potentially affect visibility in Class I areas, we started with the list of sources included in the 2002 NEI, except that for Colstrip Units 3 and 4 we used data from 2010. For Colstrip, we included only the emissions for Units 3 and 4 because Units 1 and 2 are subject to BART. Also, a consent decree signed in 2007 required upgraded combustion controls on Units 3 and 4. The year 2010 was the first full year that the upgraded combustions controls were operational for both units.

We divided the actual emissions (Q) in tpy from each source in the inventory by their distance (D) in kilometers to the nearest Class I Federal area. We are proposing to use a Q/D value of 10 as our threshold for further evaluation for RP controls. We chose this value based on the FLMs' Air Quality Related Values Work Group guidance amendments for initial screening criteria, as well as statements in EPA's BART Guidelines.[215] A comprehensive list of the sources we reviewed is included in the docket as a spreadsheet titled, ''Montana Q Over D Analysis.'' The sources with Q/D results greater than 10 are listed below in Table 156.

TABLE 156—MONTANA Q/D ANALYSIS SOURCES WITH RESULTS GREATER THAN 10

Source	SO_2 + NO_X emissions (tons)	Distance to nearest class I area (km)	Q/D (tons/km)
PPL Montana, LLC Colstrip Steam Electric Station (Units 3 and 4)	15,754	193	82
Plum Creek Manufacturing	1,067	13	82
Ash Grove Cement Company	2,060	31	66
Columbia Falls Aluminum Company, LLC	591	10	59
ExxonMobil Refinery & Supply Company, Billings Refinery	6,313	161	39
PPL Montana, LLC—JE Corette Steam Electric Station	4,838	136	36
Smurfit Stone Container Enterprises Inc., Missoula Mill	1,315	41	32
Montana-Dakota Utilities Company Lewis and Clark Station	1,576	54	29
Cenex Harvest States Cooperatives Laurel Refinery	3,038	161	19
Holcim (US), Inc.	1,783	97	18
Montana Sulphur and Chemical	2,408	161	15
Yellowstone Energy Limited Partnership	1,928	141	14
Roseburg Forest Products	518	44	12
Devon Energy Production Company, LP, Blaine County #1 Compressor Station	1,155	107	11
Colstrip Energy Limited Partnership	1,242	117	11
Montana Refining	774	77	10
Conoco Phillips	1,323	136	10

[215] The relevant language in our BART Guidelines reads, ''Based on our analyses, we believe that a State that has established 0.5 deciviews as a contribution threshold could reasonably exempt from the BART review process sources that emit less than 500 tpy of NO_X or SO_2 (or combined NO_X and SO_2), as long as these sources are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tpy of NO_X or SO_2 (or combined NO_X and SO_2) that are located more than 100 kilometers from any Class I area.'' (See 40 CFR part 51, appendix Y, section III, How to Identify Sources ''Subject to BART.'') The values described equate to a Q/D of 10.

For the reasons described below, we eliminated from further consideration several sources that met the Q/D criteria.

We are eliminating the four refineries from further consideration as a result of consent decrees entered into by the owners. Under these consent decrees, emissions have been reduced sufficiently after the 2002 baseline so that the Q/D for each facility is below 10. Specifically, ExxonMobil's emissions in 2008 of NO_X and SO_2 were 1,019 tpy, resulting in a Q/D of 6. Cenex's emissions in 2008 of NO_X and SO_2 were 727 tpy, resulting in a Q/D of 5. Conoco's emissions in 2008 of NO_X and SO_2 were 1,087 tpy, resulting in a Q/D of 8. Montana Refining's emissions in 2008 of NO_X and SO_2 were 122 tpy, resulting in a Q/D of 2. The consent decrees are available in the docket.

We eliminated from further discussion the following sources because they were evaluated under BART: Colstrip Units 1 and 2, Ash Grove Cement, CFAC, PPL Montana JE Corette, and Holcim US Incorporated, Trident Plant. As the BART analysis is based, in part, on an assessment of many of the same factors that are addressed under RP or RPGs, we propose that the BART control requirements for these facilities also satisfy the requirements for reasonable progress for the facilities for this planning period.

We undertook a more detailed analysis of the remaining sources that exceeded a Q/D of 10. These sources are shown below in Table 157.

TABLE 157—SOURCES FOR REASONABLE PROGRESS FOUR-FACTOR ANALYSES

Source	SO_2 + NO_X Emissions (tons)	Distance to nearest class I area (km)	Q/D (tons/km)
PPL Montana, LLC Colstrip Steam Electric Station (Units 3 and 4)	15,754	193	82
Plum Creek Manufacturing	1,067	13	82
Smurfit Stone Container Enterprises Inc., Missoula Mill	1,315	41	32
Montana Dakota Utilities Company Lewis and Clark Station	1,576	54	29
Montana Sulphur and Chemical	2,408	161	15
Yellowstone Energy Limited Partnership	1,928	141	14
Roseburg Forest Products	518	44	12
Devon Energy Production Company, LP Blaine County #1 Compressor Station	1,155	107	11
Colstrip Energy Limited Partnership	1,242	117	11

c. Four Factor Analyses for Point Sources

The BART Guidelines recommend that states utilize a five-step process for determining BART for sources that meet specific criteria. In proposing a FIP we are considering this recommendation applicable to us as it would be applicable to a state. Although this five-step process is not required for making RP determinations, we have elected to largely follow it in our RP analysis because there is some overlap in the statutory BART and RP factors and because it provides a reasonable structure for evaluating potential control options.

We requested a four factor analysis from each RP source and our analysis has taken that information into consideration.

i. Colstrip Energy Limited Partnership

Colstrip Energy Limited Partnership (CELP) submitted analysis and supporting information on March 11, 2009 and February 24, 2011.[216]

CELP in partnership with Rosebud Energy Corporation, owns the Rosebud Power Plant, operated by Rosebud Operating Services. The plant is rated at 43 MWs gross output (38 MWs net). The primary source of emissions consists of a single circulating fluidized bed (CFB) boiler, fired on waste coal. The boiler and emission controls were installed in 1989–90.

PM emissions are controlled by a fabric filter baghouse that is designed to achieve greater than 99% control of particulates.[217] As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

SO_2

The current SO_2 control consists of limestone injection with waste coal prior to its combustion in the boiler.

Step 1: Identify All Available Technologies

We identified that the following technologies are available: limestone injection process upgrade, SDA, DSI, a circulating dry scrubber (CDS), hydrated ash reinjection (HAR), a wet lime scrubber, a wet limestone scrubber, and/or a dual alkali scrubber.

CELP currently controls SO_2 emissions using limestone injection. Crushed limestone is injected with the waste coal prior to its combustion in the boiler, becoming the solid medium in which coal combustion takes place. When limestone is heated to 1550°F, it releases CO_2 and forms lime, which subsequently reacts with acid gases released from the burning coal, to form calcium sulfates and calcium sulfites. The calcium compounds are removed as PM by the baghouse. Depending on the fuel fired in the boiler and the total heat input, this process currently removes 70% to 90% of SO_2 emissions, on average about 80%. Increasing the limestone injection rate beyond current levels could theoretically result in a modest increase in SO_2 control.[218]

SDAs use lime slurry and water injected into a tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry in order to produce a relatively dry by-product. The process equipment associated with an SDA typically includes an alkaline storage tank, mixing and feed tanks, atomizer, spray chamber, particulate

[216] Response to Request for Information for the Colstrip Energy Limited Partnership Facility Pursuant to Section 114(a) of the Clean Air Act (42 U.S.C. Section 7414(A) (''CELP Initial Response''), Rosebud Energy Corp. (Mar. 11, 2009); Response to Additional Reasonable Progress Information for the Colstrip Energy Limited Partnership Facility Pursuant to Section 114(a) of the Clean Air Act (42 U.S.C. Section 7414(A)) (''CELP Additional Response''), Rosebud Energy Corp., Prepared by Bison Engineering Inc (Feb. 24, 2011).

[217] CELP Additional Response, p. 2–1.

[218] CELP Additional Response, p. 2–2.

control device, and recycle system. The recycle system collects solid reaction product and recycles it back to the spray dryer feed system to reduce alkaline sorbent use. SDAs are the commonly used dry scrubbing method in large industrial and utility boiler applications. SDAs have demonstrated the ability to achieve 90% to 94% SO_2 reduction. SDA plus limestone injection can achieve between 98% and 99% SO_2 reduction.[219]

DSI was previously described in our evaluation for Corette. SO_2 control efficiencies for DSI systems by themselves (not downstream of limestone injection systems) are approximately 50%, but if the sorbent is hydrated lime, then 80% or greater removal can be achieved. These systems are commonly called lime spray dryers.

A CDS uses a fluidized bed of dry hydrated lime reagent to remove SO_2. Flue gas passes through a venturi at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime where SO_2 is removed. The dry by-product produced by this system is routed with the flue gas to the particulate removal system. A CDS can achieve removal efficiency similar to that achieved by SDA on CFB boilers.[220]

The HAR process is a modified dry FGD process developed to increase the use of unreacted lime in the CFB ash and any free lime left from the furnace burning process. HAR will further reduce the SO_2 concentration in the flue gas. The actual design of an HAR system is vendor-specific, but in general, a portion of the collected ash and lime is hydrated and re-introduced into a reaction vessel located ahead of the fabric filter inlet. In conventional boiler applications, additional lime may be added to the ash to increase the mixture's alkalinity. For CFB applications, sufficient residual lime is available in the ash and additional lime is not required. HAR downstream of a CFB boiler that utilizes limestone injection can reduce the remaining SO_2 by about 80%.[221]

The wet lime scrubbing process uses alkaline slurry made by adding CaO to water. The alkaline slurry is sprayed into the exhaust stream and reacts with the SO_2 in the flue gas. Insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts are formed in the chemical reaction that occurs in the scrubber. The salts are removed as a solid waste by-product.

Wet lime and wet limestone scrubbers involve spraying alkaline slurry into the exhaust gas to react with SO_2 in the flue gas. The reaction in the scrubber forms insoluble salts that are removed as a solid waste by-product. Wet lime and limestone scrubbers are very similar, but the type of additive used differs (lime or limestone). Using limestone ($CaCO_3$) instead of lime requires different feed preparation equipment and a higher liquid-to-gas ratio. The higher liquid-to-gas ratio typically requires a larger absorbing unit. The limestone slurry process also requires a ball mill to crush the limestone feed. Wet lime and limestone scrubbers have been demonstrated to achieve greater than 99% control efficiency.[222]

Dual-alkali scrubbers use a sodium-based alkali solution to remove SO_2 from the combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The sodium-based reagents absorb SO_2 from the exhaust gas, and the calcium-based solution (lime or limestone) regenerates the spent liquor. Calcium sulfites and sulfates are precipitated and discarded as sludge, and the regenerated sodium solution is returned to the absorber loop. The dual-alkali process requires lower liquid-to-gas ratios than scrubbing with lime or limestone. The reduced liquid-to-gas ratios generally mean smaller reaction units; however, additional regeneration and sludge processing equipment is necessary.

A sodium-based scrubbing solution, typically consisting of a mixture of sodium hydroxide, sodium carbonates, and sodium sulfite, is an efficient SO_2 control reagent. However, the process generates a sludge that can create material handling and disposal issues. The control efficiency is similar to the wet lime/limestone scrubbers at approximately 95% or greater.

Step 2: Eliminate Technically Infeasible Options

The current limestone injection system is operating at or near its maximum capacity. The boiler feed rates are approximately 770 tons/day of waste coal and 91 tons/day of limestone. Increasing limestone injection beyond the current levels would result in plugging of the injection lines, and increased bed ash production, which can reduce combustion efficiency, and increased particulate loading to the baghouses. Therefore, increasing limestone injection beyond its current level would require major upgrades to the limestone feeding system and the baghouses.[223] Only modest increases in SO_2 removal efficiency, if any, are expected with this scenario, compared to add-on SO_2 control systems discussed below. Therefore, a limestone injection process upgrade is eliminated from further consideration.

CDS systems result in high particulate loading to the unit's particulate control device. Because of the high particulate loading, the pressure drop across a fabric filter would be unacceptable; therefore, ESPs are generally used for particulate control. CELP has a high efficiency fabric filter (baghouse) in place. Based on limited technical data from non-comparable applications and engineering judgment, we are determining that CDS is not technically feasible for this baghouse-equipped facility.[224] Therefore, CDS is eliminated from further consideration.

A DSI system is not practical for use in a CFB boiler such as CELP, where limestone injection is already being used upstream in the boiler for SO_2 control. With limestone injection, the CFB boiler flue gas already contains excess unreacted lime. Fly ash containing this unreacted lime is reinjected back into the CFB boiler combustion bed, as part of the boiler operating design. A DSI system would simply add additional unreacted lime to the flue gas and would achieve little, if any, additional SO_2 control.[225] If used instead of limestone injection (the only practical way it might be used), DSI would achieve less control efficiency (50%) than the limestone injection system already being used (70% to 90%). Therefore, DSI is eliminated from further consideration.

Regarding wet scrubbing, there is limited area to install additional SO_2 controls that would require high quantities of water and dewatering ponds. The wet FGD scrubber systems with the higher water requirements (wet lime scrubber, wet limestone scrubber, dual alkali wet scrubber) would require an on-site dewatering pond or an additional landfill to dispose of scrubber sludge. Due to the limited available space, its proximity to the East Armels Creek to the east of the plant, an unnamed creek to the south of the plant, and limited water availability for these

[219] US EPA Region 8, Final Statement of Basis, PSD Permit to Construct, Deseret Power Elec. Coop., Bonanza Power Plant (''Deseret Bonanza SOB''), p. 92 (Aug. 30, 2007), available at *http://www.epa.gov/region8/air/pdf/FinalStatementOfBasis.pdf.*

[220] *Id.*

[221] *Id.,* p. 93.

[222] *Id.,* p. 94 (for proposed CFB boiler, indicating that a wet FGD scrubber plus limestone injection can achieve 99.1% control efficiency).

[223] CELP Additional Response, p. 2–2.

[224] Deseret Bonanza SOB, p. 92 (indicating that CDS systems have thus far not been used on CFB boilers).

[225] Id., p. 93.

controls,[226] we consider these technologies technically infeasible and do not evaluate them further.

The remaining technically feasible SO_2 control options for CELP are SDA and HAR.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline SO_2 emissions from CELP are 1141 tpy. A summary of emissions projections for the various control options is provided in Table 158. Since limestone injection is already in use at the CELP facility, the control efficiencies and emissions reductions shown below are those that might be achieved beyond the control already being achieved by the existing limestone injection system.

TABLE 158—SUMMARY OF CELP SO_2 REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction tpy	Remaining emissions tpy
SDA	80	913	228
HAR	50	571	570

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Table 159 provides a summary of estimated annual costs for the various control options.

TABLE 159—SUMMARY OF CELP SO_2 REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
SDA with baghouse replacement	4,419,472	4,840
SDA without baghouse replacement	3,138,450	3,437
HAR with baghouse replacement	3,384,565	5,927
HAR without baghouse replacement	2,103,543	3,684

We are relying on the control costs provided by CELP,[227] with two exceptions. First, we calculated the annual cost of capital using a 7% annual interest rate and a 20-year equipment life (which yields a capital CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[228] Second, we calculated the cost of SDA and HAR in two ways: (1) With baghouse replacement, and (2) without baghouse replacement.

Factor 2: Time Necessary for Compliance

We have relied on CELP's estimates that the time necessary to complete the modifications to the boiler to accommodate SDA or HAR, without baghouse replacement, would be approximately four to six months and that a boiler outage of approximate two to three months would be necessary to perform the installation of either system. As noted previously, CELP states that complete replacement or major modifications to the existing baghouse would be necessary; however, the company does not explain why the existing baghouse would need to be replaced or modified to accommodate SDA or HAR.[229]

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

Wet FGD systems are estimated to consume 1% to 2.5% of the total electric generation of the plant and can consume approximately 40% more than dry FGD systems (SDA). Electricity requirements for a HAR system are less than FGD systems. DSI systems are estimated to consume 0.1% to 0.5% of the total plant generation.[230] For reasons explained above, wet FGD systems and DSI systems have already been eliminated as technically infeasible.

SO_2 controls would result in increased ash production at the CELP facility. Boiler ash is currently either sent to a landfill or sold for beneficial use, such as oil well reclamation. Changes in ash properties due to increased calcium sulfates and calcium sulfites could result in the ash being no longer suitable to be sold for beneficial uses. If the ash properties were to change such that the ash could no longer be sold for beneficial use, the loss of this market would cost approximately $1,020,000 per year at the current ash value and production rates (approximately 100,000 tons of ash per year). The loss of this market could also result in the company having to dispose of the ash at its current landfill, which is adjacent to the plant. The cost to dispose of the ash would be approximately $62,000 per year. The total cost from the loss of the beneficial use market and the increase in ash disposal costs would be a total of $1,082,000 per year.[231] This potential cost has not been included in the cost described above, as it is only speculative, being based on an undetermined potential future change in ash properties.

As described above, wet FGD scrubber systems with the higher water requirements (wet lime scrubber, wet limestone scrubber, dual alkali wet scrubber) would require an on-site dewatering pond or an additional landfill to dispose of scrubber sludge.

[226] CELP Additional Response, p. 2–5.

[227] CELP Additional Response, Appendix A, pp. 17–24.

[228] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[229] CELP Additional Response, p. 3–1.

[230] *Id.*, p. 4–1.

[231] *Id.*

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: the cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the source. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Given the cost of $3,437 per ton of SO_2 (at a minimum) for the most cost-effective option (SDA), the relatively small size of CELP, and the small baseline Q/D of 11, we find it reasonable to not impose any of the SO_2 control options. We therefore propose to not require additional SO_2 controls for this planning period.

NO_X

Currently, there are no NO_X controls at the CELP facility.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available: SCR, SNCR, low excess air (LEA), FGR, OFA, LNB, non-thermal plasma reactor, and carbon injection into the combustion chamber.

SCR uses either NH_3 or urea in the presence of a metal-based catalyst to selectively reduce NO_X emissions. Technical factors that impact the effectiveness of SCR include the catalyst reactor design, operating temperature, type of fuel fired, sulfur content of the fuel, design of the NH_3 injection system, and the potential for catalyst poisoning.

SCR has been demonstrated to achieve high levels of NO_X reduction in the range of 80% to 90% control, for a wide range of industrial combustion sources, including PC and stoker coal-fired boilers and natural gas-fired boilers and turbines. Typically, installation of the SCR is upstream of the particulate control device (e.g., baghouse). However, calcium oxide (from a dry scrubber) in the exhaust stream can cause the SCR catalyst to plug and foul, which would lead to an ineffective catalyst.

SCRs are classified as low dust SCR (LDSCR) or high dust SCR (HDSCR). LDSCR is usually applied to natural gas combustion units or after a particulate control device. HDSCR units can be installed on solid fuel combustion units before the particulate control device, but they have their limitations. Installation of SCR in a low dust flue gas stream is often not practical, especially on an existing boiler. The reason is that the low dust portion of a flue gas stream is located after a baghouse or precipitator. The temperature of the flue gas stream is too low in these areas for proper operation of SCR. The temperature range for proper operation of SCR is between 480 °F and 800 °F. Many of the CFBs in the United States have baghouses for particulate control. The normal maximum allowable temperature for a baghouse is 400 °F.

Therefore, on some installations, regenerative SCR (RSCR) is installed. RSCRs are expensive to install and expensive to operate, because an RSCR requires the use of burners to heat up the flue gas stream in order for the NO_X capture to occur. This is often an efficiency decrease for the boiler, significant increase in operating cost, and often not a practical solution. For this reason, RSCR was not evaluated as a control option for CELP. Instead, HDSCR was evaluated.

In SNCR systems, a reagent such as NH_3 or urea is injected into the flue gas at a suitable temperature zone, typically in the range of 1,600 to 2,000 °F and at an appropriate ratio of reagent to NO_X.

LEA operation involves lowering the amount of combustion air to the minimum level compatible with efficient and complete combustion. Limiting the amount of air fed to the furnace reduces the availability of oxygen for the formation of fuel NO_X and lowers the peak flame temperature, which inhibits thermal NO_X formation. Emissions reductions achieved by LEA are limited by the need to have sufficient oxygen present for flame stability and to ensure complete combustion. As excess air levels decrease, emissions of carbon monoxide (CO), hydrocarbons (HC) and unburned carbon increase, resulting in lower boiler efficiency. Other impediments to LEA operation are the possibility of increased corrosion and slagging in the upper boiler because of the reducing atmosphere created at low oxygen levels.

FGR is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizers or the air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through absorption of the combustion heat by relatively cooler flue gas. FGR also serves to reduce the oxygen concentration in the combustion zone.

OFA allows staged combustion by supplying less than the stoichiometric amount of air theoretically required for complete combustion through the burners. The remaining necessary combustion air is injected into the furnace through overfire air ports. Having an oxygen-deficient primary combustion zone in the furnace lowers the formation of fuel NO_X. In this atmosphere, most of the fuel nitrogen compounds are driven into the gas phase. Having combustion occur over a larger portion of the furnace lowers peak flame temperatures. Use of a cooler, less intense flame limits thermal NO_X formation.

Poorly controlled OFA may result in increased CO and hydrocarbon emissions, as well as unburned carbon in the fly ash. These products of incomplete combustion result from a decrease in boiler efficiency. OFA may also lead to reducing conditions in the lower furnace that in turn may lead to corrosion of the boiler.

LNBs use stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame).

The non-thermal plasma technique involves using methane and hexane as reducing agents. Non-thermal plasma is shown to remove NO_X in a laboratory setting with a reactor duct only two feet long. The reducing agents were ionized by a transient high voltage that created a non-thermal plasma. The ionized reducing agents reacted with NO_X achieving a 94% destruction efficiency, and there are indications that an even higher destruction efficiency can be achieved. A successful commercial vendor uses NH_3 as a reducing agent to react with NO_X in an electron beam generated plasma.[232] Such a short reactor can meet available space requirements for virtually any plant. The non-thermal plasma reactor can also be used without a reducing agent to generate ozone and use that ozone to raise the valence of nitrogen for subsequent absorption as nitric acid. This control technology may have practical potential for application to coal-fired CFB boilers as a technology transfer option.

A version of sorbent injection uses carbon injected into the air flow to finish the capture of NO_X. The carbon is captured in either the baghouse or the ESP, just like other sorbents.[233]

[232] Deseret Bonanza SOB, p. 46.

[233] US EPA, Office of Air Quality Planning and Standards, Technical Bulletin: Nitrogen Oxides (NO_X), Why and How They Are Controlled, EPA–456/F–99–006R, p. 19 (Nov. 1999), available at *http://www.epa.gov/ttn/catc/dir1/fnoxdoc.pdf.*

Step 2: Eliminate Technically Infeasible Options

LEA, FGR, and OFA are typically used on Pulverized Coal (PC) units and cannot be used on CFB boilers due to air needed to fluidize the bed.[234] While LEA may have substantial effect on NO_X emissions at PC boilers, it has much less effect on NO_X emissions at combustion sources such as CFBs that operate at low combustion temperatures. FGR reduces NO_X formation by reducing peak flame temperature and is ineffective on combustion sources such as CFBs that already operate at low combustion temperatures. For these reasons, LEA, FGR and OFA are eliminated from further consideration.

LNBs are typically used on PC units and cannot be used on CFB boilers because the combustion occurs within the fluidized bed.[235] CFB boilers do not use burners during normal operation. Therefore, LNBs are eliminated from further consideration.

While a non-thermal plasma reactor may have practical potential for application to coal-fired CFB boilers as a technology transfer option at Step 1 of the analysis, it is not known to be commercially available for CFB boilers.[236] Therefore, a non-thermal plasma reactor is eliminated from further consideration.

Although carbon injection is an emerging technology used to reduce mercury emissions, it has not been used anywhere to control NO_X. Therefore, it is eliminated from further consideration.

The remaining technically feasible NO_X control options for CELP are HDSCR and SNCR.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions from CELP are 768 tpy. A summary of emissions projections for the various control options is provided in Table 160.

TABLE 160—SUMMARY OF CELP NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions reduction (tpy)
HDSCR	80	614	154
SNCR	50	384	384

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Table 161 provides a summary of estimated annual costs for the various control options.

TABLE 161—SUMMARY OF CELP NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
HDSCR	2,102,189	3,423
SNCR	584,717	1,523

We are relying on all the NO_X control costs provided by CELP,[237] with one exception. We calculated the annual cost of capital using a 7% annual interest rate and 20-year equipment life (which yields a capital CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[238]

Factor 2: Time Necessary for Compliance

We are relaying on CELP's estimates that SCR would take approximately 26 months to install and that SNCR would take 16 to 24 weeks to install.[239]

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

The energy impacts from SNCR are expected to be minimal. SNCR is not expected to cause a loss of power output from the facility. SCR, however, could cause significant backpressure on the boiler, leading to lost boiler efficiency and, thus, a loss of power production. If LDSCR was to be installed instead of HDSCR, CELP would be subject to the additional cost of reheating the exhaust gas.

Regarding other non-air quality environmental impacts of compliance, SCRs can contribute to airheater fouling from the formation of ammonium sulfate. Airheater fouling could reduce unit efficiency, increase flue gas velocities in the airheater, cause corrosion, and erosion. Catalyst replacement can lengthen boiler outages, especially in retrofit installations, where space and access is limited. This is a retrofit installation in a high dust environment, thus fouling is likely, which could lead to unplanned outages or less time between planned outages. On some installations, catalyst life is short and SCRs have fouled in high dust environments. For both SCR and SNCR, the storage of on-site NH_3 could pose a risk from potential releases to the environment. An additional concern is the loss of NH_3, or ''slip'' into the emissions stream from the facility.

[234] CELP Additional Response, pp. 2–7, 2–8.

[235] CELP Additional Response, p. 2–8.

[236] Deseret Bonanza SOB, pp. 46, 48.

[237] CELP Additional Response.

[238] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

[239] CELP Additional Response, p. 3–1.

This ''slip'' contributes another pollutant to the environment, which has been implicated as a precursor to $PM_{2.5}$ formation.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: the cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Based on costs of compliance, the relatively small size of CELP, and the relatively small baseline Q/D, we propose to eliminate the more expensive control option (SCR). The more cost-effective control option (SNCR) would result in a fairly small total reduction in emissions (384 tpy). This would constitute an approximately 20% reduction in overall emissions of SO_2 + NO_X for the facility and a reduction of the facility's Q/D from 11 to 9. Based on the cost of compliance, the relatively small size of CELP, and the reduction in Q/D for SNCR, we find it reasonable to not require SNCR. We therefore propose to not require additional NO_X controls for this planning period.

ii. Colstrip Unit 3

PPL Montana's Colstrip Power Plant (Colstrip), located in Colstrip, Montana, consists of a total of four electric utility steam generating unit; however, only Units 3 and 4 are being analyzed for control options to meet RP requirements under the Regional Haze Rule. All information found within this section is located in the docket. Unit 3, a tangentially fired CE boiler which burns low sulfur, sub-bituminous northern PRB coal, is rated at 805 MW gross output. The boiler started operation in 1984.

PM emissions are controlled by using a wet particulate scrubber that is designed to achieve approximately 99.8% particulate control efficiency.[240] As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

Colstrip Unit 3 burns low-sulfur (0.7%) coal and has a wet particulate scrubber that achieves 95% SO_2 control. Emissions for the last five years have averaged 0.08 lb/MMBtu. The scrubber has no provisions for bypass and the system includes a spare vessel for the unit which is available for use while servicing the other vessels. Other upgrades to the scrubber are infeasible for the same reasons as described in the BART determinations for Colstrip Units 1 and 2. For these reasons, additional controls for SO_2 will not be considered or required in this planning period. We now consider controls for NO_X.

Currently, Colstrip Unit 3 has installed LNB with SOFA and a Digital Process Control System (DPCS). These controls reduce NO_X emissions by 81%.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available for Colstrip Unit 3: SCR and SNCR. These technologies have been described in the BART determinations for Colstrip Unit 1.

Step 2: Eliminate Technically Infeasible Options

We are not eliminating either SCR or SNCR as technically infeasible. Thus, the technically feasible NO_X control options for Colstrip Unit 3 are SCR and SNCR.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions from Colstrip Unit 3 are 5,428 tpy. A summary of emissions projections for the various control options is provided in Table 162.

TABLE 162—SUMMARY OF COLSTRIP UNIT 3 NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions reduction (tpy)
SCR	70.2	3,810	1,618
SNCR	25.0	1,356	4,072

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Refer to the Colstrip Unit 1 section above for general information on how we evaluated the cost of compliance for NO_X controls. EPA's control costs can be found in the docket.

Table 163 provides a summary of estimated annual costs for the various control options.

TABLE 163—SUMMARY OF COLSTRIP UNIT 3 NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
SCR	17,425,444	4,574
SNCR	3,755,238	2,769

[240] Letter from James Parker to Vanessa Hinkle regarding Request for Additional Reasonable Progress Information—Colstrip Steam Electric Station Units 3 & 4 (''Colstrip 3 & 4 Additional Response''), Attachment 2, p. 2 (Jan. 31, 2011).

We relied on control costs developed for the IPM for direct capital costs for SCR and SNCR.[241] We then used methods provided by the CCM for the remainder of SCR and SNCR calculations. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs. We used a retrofit factor of ''1,'' reflecting an SCR and SNCR retrofit of typical difficulty in the IPM control costs.

As Colstrip Unit 3 burns sub-bituminous PRB coal having a low sulfur content of 0.91 lb/MMBtu (equating to a SO_2 rate of 1.8 lb/MMBtu),[242] it was not necessary to make allowances in the control costs to account for equipment modifications or additional maintenance associated with fouling due to the formation of ammonium bisulfate. These are only concerns when the rate of SO_2 is above 3 lb/MMBtu.[243] Moreover, ammonium bisulfate formation can be minimized by preventing excessive NH_3 slip. Optimization of the SNCR system can commonly limit NH_3 slip to levels less than the 5 ppm upstream of the pre-air heater.[244] EPA's detailed cost calculations for SNCR can be found in the docket.

For SNCR we used a urea reagent cost estimate of $450 per ton, taken from PPL's September 2011 submittal for Colstrip Units 1 and 2.[245] For SCR, we used an aqueous ammonia (29%) cost of $240 per ton,[246] and a catalyst cost of $6,000 per cubic meter.[247] To estimate the average cost effectiveness (dollars per ton of emissions reductions), we divided the total annual cost by the estimated NO_X emissions reductions.

Factor 2: Time Necessary for Compliance

We estimate that SCR and SNCR can be installed within this planning period.

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

An SNCR process reduces the thermal efficiency of a boiler as the reduction reaction uses thermal energy from the boiler.[248] Therefore, additional coal must be burned to make up for the decreases in power generation. Using CCM calculations, we determined the additional coal needed for Unit 3 equates to 176,800 MMBtu/yr. For an SCR, the new ductwork and the reactor's catalyst layers decrease the flue gas pressure. As a result, additional fan power is necessary to maintain the flue gas flow rate through the ductwork. SCR systems require additional electric power to meet fan requirements equivalent to approximately 0.3% of the plant's electric output.[249] Both SCR and SNCR require some minimal additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. Note that cost of the additional energy requirements has been included in our calculations.

Non-air quality environmental impacts of SNCR and SCR were described in our BART analysis for Colstrip Unit 1.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Optional Factor: Modeled Visibility Impacts

We conducted modeling for Colstrip Unit 3 as described in section V.C.3.a. Table 164 presents the visibility impacts and benefits of SCR and SNCR at the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 165 presents the number of days with impacts greater than 0.5 deciviews for each Class I area from 2006 through 2008.

TABLE 164—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON COLSTRIP UNIT 3

Class I area	Baseline impact (delta deciview)	Improvement from SCR (delta deciview)	Improvement from SNCR (delta deciview)
North Absaroka WA	0.200	0.109	0.036
Theodore Roosevelt NP	0.498	0.273	0.099
UL Bend WA	0.471	0.261	0.084
Washakie WA	0.223	0.105	0.044
Yellowstone NP	0.151	0.063	0.032

TABLE 165—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON COLSTRIP UNIT 3

[Three Year Total]

Class I area	Baseline (days)	Using SCR	Using SNCR
North Absaroka WA	2	0	2
Theodore Roosevelt NP	14	2	8
UL Bend WA	15	0	10
Washakie WA	2	0	2
Yellowstone NP	1	0	1

[241] IPM, Chapter 5, Appendix 5–2A and 5–2B.

[242] U.S. DOE, Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1999 Tables, DOE/EIA–0191(99), Table 24 (June 2000).

[243] IPM, Chapter 5, p. 5–9.

[244] ICAC, p. 8.

[245] NO_X Control Update to PPL Montana's Colstrip Generating Station BART Report, September 2011, p. 8.

[246] Email communication with Fuel Tech, Inc. (Mar. 2, 2012).

[247] Cichanowicz 2010, p. 6–7.

[248] CCM, Section 4.2, Chapter 1, p. 1–21.

[249] CCM, Section 4.2, Chapter 2, p. 2–28.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We have also considered an additional factor: The modeled visibility benefits of controls. We evaluated this factor for Colstrip Units 3 and 4, due to the size of Colstrip Units 3 and 4 in comparison with the other RP sources. For the more cost-effective option (SNCR), the modeled visibility benefits are relatively modest. For the more expensive option (SCR), the modeled visibility benefits, although more substantial, are not sufficient for us to consider it reasonable to impose this option in this planning period. Therefore, we are proposing that no additional NO_X controls will be required for this planning period on Colstrip Unit 3.

iii. Colstrip Unit 4

All information found within this section is located in the docket. Unit 4, a tangentially fired CE boiler which burns low sulfur, sub-bituminous northern PRB coal, is rated at 805 MW gross output. The boiler started operation in 1984.

PM emissions are controlled by using a wet particulate scrubber that is designed to achieve approximately 99.8% particulate control efficiency.[250] As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

Colstrip Unit 4 burns low-sulfur (0.7%) coal and has a wet particulate scrubber that achieves 95% SO_2 control. Emissions for the last five years have averaged 0.08 lb/MMBtu. The scrubber has no provisions for bypass and the system includes a spare vessel for the unit which is available for use while servicing the other vessels.[251] Other upgrades to the scrubber are infeasible for the same reasons as described in the BART determinations for Colstrip Units 1 and 2. For these reasons, additional controls for SO_2 will not be considered or required in this planning period.

Currently, Colstrip Unit 4 has installed LNB with SOFA and a DPCS. These controls reduce NO_X emissions by 81%.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available for Colstrip Unit 4: SCR and SNCR. These technologies have been described in the BART determinations for Colstrip Unit 1.

Step 2: Eliminate Technically Infeasible Options

We are not eliminating any options as technically infeasible. Thus, the technically feasible NO_X control options for Colstrip Unit 4 are SCR and SNCR.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions from Colstrip Unit 4 are 5,347 tpy. A summary of emissions projections for the various control options is provided in Table 166.

TABLE 166—SUMMARY OF COLSTRIP UNIT 4 NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
SCR	70.7	3,780	1,567
SNCR	25.0	1,336	4,011

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Refer to the Colstrip Unit 1 section above for general information on how we evaluated the cost of compliance for NO_X controls. EPA's cost calculations can be found in the docket.

Table 167 provides a summary of estimated annual costs for the various control options.

TABLE 167—SUMMARY OF COLSTRIP UNIT 4 NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
SCR	17,441,422	4,607
SNCR	3,682,750	2,757

We relied on control costs developed for the IPM for direct capital costs for SCR and SNCR.[252] We then used methods provided by the CCM for the remainder of the SCR and SNCR. Specifically, we used the methods in the CCM to calculate total capital investment, annual costs associated with operation and maintenance, to annualize the total capital investment using the CRF, and to sum the total annual costs. We used a retrofit factor of ''1,'' reflecting an SCR and SNCR retrofit of typical difficulty in the IPM control costs.

As Colstrip Unit 4 burns sub-bituminous PRB coal having a low sulfur content of 0.91 lb/MMBtu (equating to a SO_2 rate of 1.8 lb/MMBtu),[253] it was not necessary to make allowances in the cost calculations to account for equipment modifications or additional

[250] Colstrip 3 & 4 Additional Response, Attachment 2, p. 2.

[251] *Id.*

[252] IPM, Chapter 5, Appendix 5–2A and 5–2B.

[253] U.S. DOE, Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1999 Tables, DOE/EIA–0191(99), Table 24 (June 2000).

maintenance associated with fouling due to the formation of ammonium bisulfate. These are only concerns when the rate of SO_2 is above 3 lb/MMBtu.[254] Moreover, ammonium bisulfate formation can be minimized by preventing excessive NH_3 slip. Optimization of the SNCR system can commonly limit NH_3 slip to levels less than the 5 ppm upstream of the pre-air heater.[255] EPA's detailed cost calculations for SNCR can be in the docket.

For SNCR we used a urea reagent cost estimate of $450 per ton taken from PPL's September 2011 submittal for Colstrip Units 1 and 2.[256] For SCR, we used an aqueous ammonia (29%) cost of $240 per ton,[257] and a catalyst cost of $6,000 per cubic meter.[258]

Factor 2: Time Necessary for Compliance

We estimate that SCR and SNCR can be installed within this planning period.

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

An SNCR process reduces the thermal efficiency of a boiler as the reduction reaction uses thermal energy from the boiler.[259] Therefore, additional coal must be burned to make up for the decreases in power generation. Using CCM calculations we determined the additional coal needed for Unit 4 equates to 172,200 MMBtu/yr. For an SCR, the new ductwork and the reactor's catalyst layers decrease the flue gas pressure. As a result, additional fan power is necessary to maintain the flue gas flow rate through the ductwork. SCR systems require additional electric power to meet fan requirements equivalent to approximately 0.3% of the plant's electric output.[260] Both SCR and SNCR require some minimal additional electricity to service pretreatment and injection equipment, pumps, compressors, and control systems. Note that cost of the additional energy requirements has been included in our calculations.

Non-air quality environmental impacts of SNCR and SCR were described in our BART analysis for Colstrip Unit 1.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Optional Factor: Modeled Visibility Impacts

We conducted modeling for Colstrip Unit 4 as described in section V.C.3.a. Table 168 presents the visibility impacts and benefits of SCR and SNCR at the 98th percentile of daily maxima for each Class I area from 2006 through 2008. Table 169 presents the number of days with impacts greater than 0.5 deciviews for each Class I area from 2006 through 2008.

TABLE 168—DELTA DECIVIEW IMPROVEMENT FOR NO_X CONTROLS ON COLSTRIP UNIT 4

Class I area	Baseline impact (delta deciview)	Improvement from SCR (delta deciview)	Improvement from SNCR (delta deciview)
North Absaroka WA	0.168	0.077	0.030
Theodore Roosevelt NP	0.485	0.260	0.091
UL Bend WA	0.468	0.249	0.081
Washakie WA	0.223	0.101	0.043
Yellowstone NP	0.148	0.057	0.026

TABLE 169—DAYS GREATER THAN 0.5 DECIVIEW FOR NO_X CONTROLS ON COLSTRIP UNIT 4
[Three Year Total]

Class I area	Baseline (days)	Using SCR	Using SNCR
North Absaroka WA	2	0	1
Theodore Roosevelt NP	14	2	8
UL Bend WA	14	0	11
Washakie WA	2	0	1
Yellowstone NP	1	0	1

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We have also considered an additional factor: The modeled visibility benefits of controls. We evaluated this factor for Colstrip Units 3 and 4, due to the size of Colstrip Units 3 and 4 in comparison with the other RP sources. For the more cost-effective option (SNCR), the modeled visibility benefits are relatively modest. For the more expensive option (SCR), the modeled visibility benefits, although more substantial, are not sufficient for us to consider it reasonable to impose this option in this planning period. Therefore, we are proposing that no additional NO_X controls will be required for this planning period on Colstrip Unit 4.

[254] IPM, Chapter 5, p. 5–9.

[255] ICAC, p. 8.

[256] NO_X Control Update to PPL Montana's Colstrip Generating Station BART Report, September 2011, p. 8.

[257] Email communication with Fuel Tech, Inc., March 2, 2012.

[258] Cichanowicz 2010, p. 6–7.

[259] CCM, Section 4.2, Chapter 1, p. 1–21.

[260] CCM, Section 4.2, Chapter 2, p. 2–28.

iv. Devon Energy Blaine County #1 Compressor Station

Devon Energy Blaine County #1 Compressor Station (Devon) operates two 5,500-hp Ingersoll Rand 616 natural gas compressor engines at its Blaine County #1 Compressor Station. The engines began operation in 1972 and combust natural gas. Emissions exit through a 45-foot stack. Additional information to support this four factor analysis can be found in the docket.[261]

PM and SO_2 emissions are relatively small (0.32 tpy of PM and 0.02 tpy of SO_2 per engine). Thus, SO_2 and PM emissions from these two engines are not significant contributors to regional haze and our determination only considers NO_X. Additional controls for SO_2 and PM will not be considered or required in this planning period.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available for the compressor station: A continuous exhaust monitoring system (CEMS) with upgraded ignition system and air-fuel ratio control, a Dresser-Rand (D–R) mixing kit, a D–R mixing kit with screw-in prechambers, SCR, and non-selective catalytic reduction (NSCR). Both engines are already equipped with electronic air/fuel controllers, as well as electronic fuel valves and ignition. Emissions are adjusted through manual setpoint control of the air-to-fuel (A/F) ratio.

The CEMS involves continuous monitoring of the exhaust stack gases and making the necessary automatic adjustments to the ignition timing and air-fuel ratio to ensure optimization of the combustion cycle within the power cylinders. Load changes on the engine are compensated for in real time as opposed to the manual adjustments that currently take place. It is estimated that this system could achieve a 12% reduction in NO_X from the baseline case. This technology has been used in the past on similar engines.

A D–R mixing kit system, supplied by the engine manufacturer, improves the fuel delivery system to enhance fuel/air mixing, which improves exhaust NO_X levels and combustion stability. Dresser-Rand estimates that this system could achieve a 14% reduction in NO_X from the baseline case.

The D–R mixing kit with screw-in prechambers adds a new turbocharger and cooling system to the hardware of the mixing kit. This system further leans out the combustion of the existing engine to improve NO_X emissions performance. Dresser-Rand estimates that this system could achieve a 78% reduction in NO_X from the baseline case.

SCR has been described in general terms in the above BART determinations. SCR is considered feasible for this source. However, typical compressor engines operate at variable loads, thereby creating technical difficulties for SCR operation leading to periods of NH_3 slip or periods of insufficient NH_3 injection. It is estimated that this system could achieve a 75% reduction in NO_X from the baseline case. This technology is available from Catalytic Combustion, Inc and has been used in the past on similar engines.

NSCR is an add-on NO_X control technology for exhaust streams with low O_2 content. NSCR uses a catalyst reaction to simultaneously reduce NO_X, CO, and HC to water, carbon dioxide, and nitrogen. The catalyst is usually a noble metal.

One type of NSCR system injects a reducing agent into the exhaust gas stream prior to the catalyst reactor to reduce the NO_X. Another type of NSCR system has an afterburner and two catalytic reactors (one reduction catalyst and one oxidation catalyst). In this system, natural gas is injected into the afterburner to combust unburned HC (at a minimum temperature of 1700 °F). The gas stream is cooled prior to entering the first catalytic reactor where CO and NO_X are reduced. A second heat exchanger cools the gas stream (to reduce any NO_X reformation) before the second catalytic reactor where remaining CO is converted to carbon dioxide.

The control efficiency achieved by NSCR for NO_X ranges from 80 to 90%. The NO_X reduction efficiency is controlled by similar factors as for SCR, including the catalyst material and condition, the space velocity, and the catalyst bed operating temperature. Other factors include the A/F ratio, the exhaust gas temperature, and the presence of masking or poisoning agents. The operating temperature for an NSCR system ranges from approximately 700 °F to 1500 °F, depending on the catalyst.[262]

Step 2: Eliminate Technically Infeasible Options

We are not eliminating any of the control options as being technically infeasible.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions are 372 tpy for each engine. A summary of emissions projections for the various control options is provided in Table 170.

TABLE 170—SUMMARY OF DEVON NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)	Emissions reduction (tpy)	Remaining emissions (tpy)
		Unit 1		Unit 2	
NSCR	90	335	37	335	37
Mixing kit plus screw-in prechambers	78	290	82	290	82
SCR	75	279	93	279	93
Mixing kit	14	52	320	52	320
CEMS with upgraded ignition system and air-fuel ratio control	12	45	327	45	327

CAM Technical Guidance Document, Appendix B–16, Non-Selective Catalytic Reduction (Apr. 2002), available at: *www.epa.gov/ttnchie1/mkb/documents/B_16a.pdf.*

[261] Letter to Laurel Dygowski from Tracy Carter, no subject (June 18, 2009); Memo to Laurel Dygowski from Brad Nelson, RE: Four-Factor Analysis of Control Options for Devon Energy-Blaine County #1 Compressor Station—Chinook, Montana (July 17, 2009); Letter to Vanessa Hinkle from Tracy Carter, no subject, (Feb. 25, 2011); APMM Unit Recommendations/Considerations for AQP Unit Reasonable Progress Determination for Devon Energy Blaine County #1 Compressor Station, Prepared by Claudia Smith (Dec. 5, 2011); Email to Vanessa Hinkle from Alden West RE: Regional Haze RP Analysis (Oct. 26, 2011).

[262] CAM Technical Guidance Document, Appendix B–16, Non-Selective Catalytic Reduction (Apr. 2002), available at: *www.epa.gov/ttnchie1/mkb/documents/B_16a.pdf.*

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

We are adopting cost figures provided by Devon, except for the costs of NSCR. For NSCR, we estimated the annual cost to be $105,000 based on information used to support the 2002 NESHAP for Reciprocating Internal Combustion Engines (RICE).[263]

Table 171 provides a summary of estimated annual costs for the various control options.

TABLE 171—SUMMARY OF DEVON NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($) (same for both units)	Cost effectiveness ($/ton)	Cost effectiveness ($/ton)
		Unit 1	Unit 2
NSCR	105,000	282	282
Mixing kit plus screw-in prechambers	261,000	897	897
SCR	308,822	1,108	1,108
Mixing kit	110,500	2,079	2,079
CEMS with Upgraded ignition system and air-fuel ratio control	29,100	652	652

Factor 2: Time Necessary for Compliance

Installation of a CEMS would take approximately nine weeks, installation of the mixing kit would take between 17 to 22 weeks, installation of a mixing kit plus screw-in prechambers would take 20 to 26 weeks, installation of SCR would take approximately 25 weeks, and installation of NSCR could take up to one year.

Factor 3: Energy and Non-Air Quality Environmental Impacts

A CEMS with an upgraded ignition system and air-fuel ratio control would actually improve fuel consumption. Installation of SCR would cause backpressure on the engine exhausts which would lead to a reduction of available power and an increase in engine fuel use. NSCR can potentially require up to a 5% increase in fuel consumption and up to a 2% reduction in power output.

A CEMS with an integrated ignition system and air-fuel ratio control, D–R mixing kit, or D–R mixing kit with screw-in prechambers would not have direct environmental impacts. Some manufacturers accept the return of spent catalyst that would be used by NSCR and SCR. If the catalyst could not be returned to the manufacturer, it would need to be disposed. In addition, SCR uses NH_3, which would have the possibility of being released if not properly managed.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Based primarily on the low cost of $282 per ton of NO_X removed, we propose to find NSCR is a reasonable control to address reasonable progress for the initial planning period, with an emission limit of 21.8 lb/hr (30-day rolling average).

We have eliminated lower performing options—upgraded ignition system and air-fuel ratio control, D–R mixing kit, SCR, and D–R mixing kit with screw-in prechambers because their cost effectiveness values are higher and/or the emission reductions are lower than NSCR. We are proposing an emission limit of 21.8 lbs/hr (30-day rolling average) based on a predicted control efficiency of 90%. The emission limit would apply on a continuous basis, including during startup, shutdown, and malfunction. We propose to require that Devon start meeting our proposed emission limit at Blaine County #1 Compressor Station as expeditiously as practicable, but no later than July 31, 2018. This is consistent with the requirement that the FIP cover an initial planning period that ends July 31, 2018. We propose this compliance deadline because of the equipment installation that is required.

In order to ensure the effectiveness of the NSCR, we are proposing to require the following work practices and operational requirements. We are proposing that Devon install a temperature-sensing device (*i.e.,* thermocouple or resistance temperature detectors) before the catalyst in order to monitor the inlet temperatures of the catalyst for each engine and that Devon maintain the engine at a minimum of at least 750 °F and no more than 1250 °F in accordance with manufacturer's specifications. Also, we are proposing that Devon install gauges before and after the catalyst for each engine in order to monitor pressure drop across the catalyst, and that Devon maintain the pressure drop within ±2″ water at 100% load plus or minus 10% from the pressure drop across the catalyst measured during the initial performance test. We are proposing to require Devon to follow the manufacturer's recommended maintenance schedule and procedures for each engine and its respective catalyst. We are proposing that Devon only fire each engine with natural gas that is of pipeline-quality in all respects except that the CO_2 concentration in the gas shall not be required to be within pipeline-quality.

We are proposing the following monitoring, recordkeeping, and reporting requirements for Devon:

• Devon shall measure NO_X emissions from each engine at least semi-annually or once every six month period to demonstrate compliance with the emission limits. To meet this requirement, we are proposing that Devon measure NO_X emissions from the

[263] US EPA, Office of Air Quality Planning and Standards, Regulatory Impact Analysis of the Proposed Reciprocating Internal Combustion Engines NESHAP, Final Report (Nov. 2002), available at *http://www.epa.gov/ttn/atw/rice/riceria.pdf.*

engines using a portable analyzer and a monitoring protocol approved by EPA.

• Devon shall submit the analyzer specifications and monitoring protocol to EPA for approval within 45 calendar days prior to installation of the NSCR unit.

• Monitoring for NO_X emissions shall commence during the first complete calendar quarter following Devon's submittal of the initial performance test results for NO_X to EPA.

• Devon shall measure the engine exhaust temperature at the inlet to the oxidation catalyst at least once per week and shall measure the pressure drop across the oxidation catalyst monthly.

• Each temperature-sensing device shall be accurate to within plus or minus 0.75% of span and that the pressure sensing devices be accurate to within plus or minus 0.1 inches of water.

• Devon shall keep records of all temperature and pressure measurements; vendor specifications for the thermocouples and pressure gauges; vendor specifications for the NSCR catalyst and the A/F ratio controller on each engine.

• Devon shall keep records sufficient to demonstrate that the fuel for the engines is pipeline-quality natural gas in all respects, with the exception of the CO_2 concentration in the natural gas.

• Devon shall keep records of all required testing and monitoring that include: the date, place, and time of sampling or measurements; the date(s) analyses were performed; the company or entity that performed the analyses; the analytical techniques or methods used; the results of such analyses or measurements; and the operating conditions as existing at the time of sampling or measurement.

• Devon shall maintain records of all required monitoring data and support information (e.g. all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required) for a period of at least five years from the date of the monitoring sample, measurement, or report and that these records be made available upon request by EPA.

Devon shall submit a written report of the results of the required performance tests to EPA within 90 calendar days of the date of testing completion.

v. Montana-Dakota Utilities Lewis & Clark Station

Montana-Dakota Utilities Company (MDU) submitted analyses and supporting information on March 17, 2009, February 2011 (Revised June 2011), June 14, 2011, February 10, 2012, and February 27, 2012.[264]

MDU owns and operates an electric utility power plant in Sidney, Montana, known as the L&C Station. The plant is rated at 52 MWs gross output (48 MWs net output) and consists of a single dry bottom, tangentially fired boiler, fueled with lignite coal. The boiler was installed in 1958.

PM emissions are controlled by a multi-cyclone dust collector, installed in 1957, with design control of 75–80%, as well as a flooded disc wet scrubber installed in 1975, designed for 98% PM control, with a nominal SO_2 control efficiency of approximately 15%, but which has achieved up to 60% control during certain operating conditions, mainly by the presence of calcium in the coal, but also by MDU's addition of lime to the existing scrubber system when the coal has lower calcium and higher sulfur content. Current NO_X controls consist of LNBs and a CCOFA system, installed in 1996. Estimated level of control is 33%.[265]

As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

SO_2

Current SO_2 controls consist of a wet scrubbing system (flooded disc wet scrubber, with lime addition as needed, depending on coal quality) with an estimated control efficiency of up to 60%.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available for emissions reductions beyond those achieved by the current control configuration: Wet lime scrubbing/optimization of existing wet PM scrubber, lime SDA and baghouse, DSI and baghouse, and fuel switching to either PRB coal or to natural gas.

Wet lime scrubbing involves scrubbing the exhaust gas stream with slurry comprised of lime (CaO) in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. The SO_2 in the gas stream reacts with the lime to form $CaSO_3 \bullet 2H_2O$ and $CaSO_4$. This control option is functionally equivalent to ''in terms of concept and control efficiency. Forced oxidation is used in wet scrubbing systems to convert calcium sulfite to calcium sulfate (gypsum). Air is blown through spent lime reagent to accomplish this reaction. This often takes place in the bottom of the wet scrubber. Calcium sulfite is a watery compound and cannot be de-watered. It is typically disposed in ash ponds. Calcium sulfate is a solid. Wet scrubber blowdown containing calcium sulfate can be run through a filter press for calcium sulfate recovery. After filtration, calcium sulfate can be disposed of as a solid waste or it can be sold as a raw material for drywall production. The use of forced oxidation has an impact on the method of scrubber waste disposal, but does not appreciably impact SO_2 removal.

This wet scrubbing option at L&C Station would involve modification to the existing PM wet scrubber to increase SO_2 removal efficiency. The modification would primarily involve upgrade and optimization of the lime injection system. Expected total SO_2 emissions reduction would be approximately 70% on an annual basis, versus the estimated 60% control currently being achieved (about a 10% improvement). The scrubber lime injection system would be upgraded to achieve this additional removal.[266]

Lime SDA is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO_2 is absorbed by the droplets. Once absorbed, the SO_2 reacts with lime to form $CaSO_3 \bullet 2H_2O$ and $CaSO_4$ within the droplets. The SDA temperature must be hot enough to ensure that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder, which is carried out with the gas and collected

[264] Response to Reasonable Progress Request for Information, Montana-Dakota Utilities Co. (''L&C Initial Response'') (Mar. 17, 2009); Emissions Control Analysis for Lewis & Clark Station Unit 1, Prepared for Montana-Dakota Utilities Co. by Barr Consultants (''L&C Emissions Control Analysis'') (Feb. 2011, rev'd June 2011); Revised Emissions Control Analysis for Lewis & Clark Station, in Response to EPA Request of November 5, 2010, Montana-Dakota Utilities Co. (''L&C Revised Emissions Control Analysis'') (June 14, 2011); Response to EPA Questions of January 19, 2012, Regarding Fuel Switch to Natural Gas, Basis for SCR Cost Calculation, and SDA Efficiency, Montana-Dakota Utilities Co. (''L&C Feb. 10, 2012 Response'') (Feb. 10, 2012); Response to EPA Questions of February 15, 2012, Regarding Cost of Fuel Switch to Natural Gas, Montana-Dakota Utilities Co. (''L&C Feb. 27, 2012 Response'') (Feb. 27, 2012).

[265] L&C Initial Response, pp. 3–5; L&C Emissions Control Analysis, p. 4.

[266] L&C Emissions Control Analysis, pp. 13–17.

with a fabric filter baghouse. Spray dryer absorption control efficiency is typically in the 70% to 90% range, but can be as high as 95%.[267] We used 95% control for this analysis. To accommodate the SDA control option, the existing particulate scrubber at L&C Station would need to be abandoned in place and replaced with a baghouse.[268] This is necessary to ensure the required system residence time for a dry control option; otherwise, the achievable control efficiency would be significantly decreased.[269]

DSI involves the injection of a lime or limestone powder into the exhaust gas duct work. The stream is then passed through a baghouse or ESP to remove the sorbent and entrained SO_2. The process was developed as a lower cost FGD option because the mixing occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time allowed in the system and gas duct temperature, sorbent injection control efficiency is typically between 50% and 70%. Based on the particulate loading of the existing control system, DSI is expected to achieve removal efficiencies of less than the design range in combination with existing controls. We used 70% control for this analysis. To accommodate the DSI control option, the existing particulate scrubber at L&C Station would need to be abandoned in place and replaced with a new baghouse. Again, this is necessary to ensure the required system residence time for a dry control option; otherwise, the achievable control efficiency would be significantly decreased.[270]

Fuel switching is a control technology option. Blending of subbituminous PRB coal is already employed at L&C Station, in instances where relatively poor quality lignite coal is provided to the plant. MDU's boiler is currently permitted to blend PRB coal with the primary lignite fuel.[271] Therefore, we consider a fuel switch to PRB coal as primary fuel to be an available SO_2 control option, although, since there is no appreciable difference in the sulfur content (weight percent) of PRB coal versus lignite coal, this option might yield only marginal SO_2 reductions.[272] Also, since MDU has provided data indicating natural gas is used to some extent (about 0.37% of total heat input to the boiler in 2002, by our calculations, based on information supplied by MDU),[273] we consider a fuel switch to natural gas as primary fuel to be another available control option for SO_2. Since pipeline-quality natural gas has negligible sulfur content, we would expect a greater than 99% reduction in SO_2. To supply sufficient natural gas to serve as primary fuel for the boiler, a new 22-mile pipeline from the nearest connection point to L&C Station would have to be constructed.[274]

Step 2: Eliminate Technically Infeasible Options

Although switching to coals with lower sulfur content and higher Btu content represents a viable pre-combustion method of reducing SO_2 emissions, there are limitations to achievable blending. Switching to any fuel with an appreciably different composition and energy content would require boiler surface and other design changes. Previous test burns of PRB coal at the boiler confirm that the high flue gas temperatures, resulting from the use of PRB coal, cause significant fouling to boiler walls and other boiler surfaces. Due to the physical properties of PRB coal, coal mills and coal piping to the boiler would also need to be replaced, along with the addition of a railcar unloading system. A re-design of the existing boiler does not constitute a feasible retrofit control option. Further, there is no appreciable difference in the sulfur content (weight percent) of the subbituminous coal supplement, and reduced calcium/magnesium concentrations present in the subbituminous coal would also result in less inherent SO_2 control. Finally, the on-site coal inventory is fairly limited (generally 2–3 days' supply of lignite), due primarily to lack of property to safely store additional inventory.[275] Therefore, a switch to PRB coal as primary fuel is not considered further in this evaluation.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

A summary of emissions projections for the various control options is provided in Table 172. For all options, we relied on the estimated control efficiencies, estimated emissions reductions, and emissions baseline provided by MDU. The emissions baseline of 1,002.1 tpy used in our analysis reflects an estimated 60% level of control already being achieved by the existing scrubber system. The control efficiencies listed in the table below are the degree of control that is expected to be achieved on baseline SO_2 emissions (1,002 tpy).

TABLE 172—SUMMARY OF MDU LEWIS AND CLARK SO_2 REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
Fuel switch to natural gas	99+	1,002	Negligible
SDA with baghouse	85	850.3	151.8
DSI with baghouse	10	100.2	901.9
Existing scrubber mod.	10	100.2	901.9

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Table 173 provides a summary of estimated annual costs for the various control options.

[267] L&C Feb. 10, 2012 Response, p. 3.

[268] L&C Emissions Control Analysis, p. 15.

[269] *Id.*

[270] *Id.*, pp. 13, 15.

[271] *Id.*, pp. 8–10.

[272] *Id.*

[273] L&C Initial Response, p. 7.

[274] L&C Feb. 10, 2012 Response, p. 2.

[275] L&C Emissions Control Analysis, p. 8–10.

TABLE 173—SUMMARY OF MDU LEWIS & CLARK REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
Fuel switch to natural gas	21,919,094	21,875
SDA with baghouse	10,055,056	11,825
DSI with baghouse	2,840,734	28,350
Existing scrubber mod.	138,637	1,383

We have relied on costs provide by MDU for these control options. The high annual cost of a fuel switch is due partly to the need to construct a new 22-mile natural gas pipeline, and partly to the large difference in cost of natural gas versus lignite coal. Natural gas would cost about five times as much as lignite coal to fuel the boiler.

Factor 2: Time Necessary for Compliance

For the option involving a fuel switch to natural gas as primary fuel, we estimate several years would be needed to secure the necessary rights-of-way and install a new 22-mile pipeline that MDU has stated would be needed to provide a sufficient supply of natural gas.[276] For the SDA-with-baghouse and DSI-with-baghouse control options, we relied on an estimate from the Institute of Clean Air Companies (ICAC) that approximately 30 months is required to design, build and install SO_2 scrubbing technology.[277] For the option involving modification to the existing scrubbing system, we relied on MDU's estimate of 6 to 12 months to conduct an optimization study to evaluate scrubber capabilities and identify operational constraints.[278]

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

A fuel switch to natural gas as primary fuel could significantly increase the demand for natural gas in the region and could increase natural gas prices for other consumers of natural gas in the region, as well as create impacts associated with more production of natural gas in the region. For the SDA-with-baghouse control option, as well as for the DSI-with-baghouse control option, energy impacts would include a blower requiring increased energy use and an associated indirect CO_2 emissions increase. For the option of modifying the existing wet scrubber system, no appreciable energy impacts are expected. There is, however, a potential for additional water consumption and wastewater generation.[279]

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. The costs per ton of pollutant reduced are excessive for the three most expensive options. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Based on costs of compliance, the small size of MDU L&C, and the relatively small baseline Q/D, we propose to eliminate the more expensive control options (fuel switch to natural gas, SDA with baghouse, and DSI with baghouse). The most cost-effective control option (scrubber modifications) would reduce SO_2 emissions by 100 tpy, which equates to a 5.5% reduction in overall emissions of SO_2 + NO_X for this facility, or a reduction of Q/D from 29 to 27. Based on the costs of compliance, the relatively small size of MDU L&C, the baseline Q/D, and the modest reduction in Q/D, we find it reasonable to eliminate this option. We therefore propose to not require additional SO_2 controls for this planning period.

NO_X

Current NO_X controls consist of LNBs and a CCOFA system, with estimated control efficiency of 33%.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available for emissions reductions beyond those achieved by the current control configuration: Fuel switching to PRB coal or to natural gas, SCR + SOFA/LNB, SNCR, SOFA/LNB, and SNCR with SOFA/LNB.

We consider fuel switching to PRB coal or to natural gas, as primary fuel for the boiler, as an available control for NO_X, for the same reasons as described in our SO_2 analysis. With regard to a potential switch to PRB coal, higher heat content of coal can yield lower NO_X emissions in lb/MMBtu. The lignite coal used at L&C Station has an average heating value of 6,435 Btu/lb.[280] PRB coal typically ranges from 8,000 to 8,500 Btu/lb and therefore could be expected to have lower NO_X emissions than lignite coal, per ton of coal fired. Similarly, natural gas could be expected to produce lower NO_X emissions than lignite coal. We used a 65% reduction in our analysis.[281]

SCR was generally described in our BART analysis for CELP. SCR has been demonstrated to achieve high levels of NO_X reduction in the range of 80% to 90% (or higher) control, for a wide range of industrial combustion sources, including PC, cyclone, and stoker coal-fired boilers and natural gas-fired boilers and turbines. For our SCR analysis, we included SOFA and LNB upstream of the SCR controls, on the basis that these controls are much less expensive than SCR and would enable the SCR system to use less reagent. Our calculations reveal that a control system consisting of SCR + SOFA/LNB would be more cost-effective than SCR alone

[276] L&C Feb. 10, 2012 Response, p. 2.

[277] Report from Bradley Nelson, EC/R Inc. to Laurel Dygowski of EPA, Four-factor Analysis of Control Options for MDU L&C Station, p. 5 (July 3, 2009).

[278] L&C Emissions Control Analysis, p. 17.

[279] L&C Emissions Control Analysis, p. 16.

[280] L&C Feb. 27, 2012 Response. MDU cited typical heat content of 6,435 Btu/lb for lignite coal, based on 2009–2011 average from FERC Form 1/EIA 923 reports.

[281] The AP–42 emission factor for natural gas is 170 lb/MMSCF. MDU's February 27, 2012 letter to EPA states that annual natural gas consumption, if natural gas is used as primary fuel, would be 3,283 MMSCF. This yields 279 tpy of NO_X emissions. Baseline NO_X emissions used by MDU in its June 2011 analysis, with lignite coal as primary fuel, are 802 tpy. Switching to natural gas would therefore represent a potential 65% reduction in NO_X emissions.

and would also achieve a higher level of control than SCR alone. We have used 87.5% control as our estimate for the combined SCR + SOFA/LNB system.[282]

A description of SNCR was provided in our BART analysis for CELP. We used 38% control effectiveness for SNCR alone, and 50% control effectiveness for the control option of SNCR with SOFA/LNB.

L&C Station is a member of Midwest Independent Transmission System Operator (MISO) and, as such, is operated as called upon based on energy demand and price. Generally, combustion systems on boilers are not optimized for low load operation, including associated NO_X emissions. This is important because the efficiency of many air emission controls cannot be guaranteed at low load operating conditions. This is especially true for SNCR. Therefore, to reflect actual emission reductions on cost per ton basis, an SNCR scenario at low load operation is also presented in our analysis, using 23 MW capacity as the low load operational case. Based on a preliminary SNCR engineering assessment that includes the temperature, residence time, and the current level of NO_X control, an emissions reduction of approximately 15% to 30% would be expected at low load conditions. We used 16% for our analysis.

SOFA was described in our BART analysis for Colstrip Unit 1. LNB was described in our analysis for CELP. SOFA technology is compatible with the existing LNB.

LNBs typically achieve NO_X emission reductions of 25% to 50% as compared to uncontrolled emissions. LNBs are currently used at L&C Station. Based on the currently achieved emission rates, a combined reduction in the range of 30% to 40% is expected at L&C Station with the addition of SOFA and new LNB. We used 38% for our analysis.

Step 2: Eliminate Technically Infeasible Options

We consider fuel switching to PRB coal to be technically infeasible, for reasons already described in Step 2 of our SO_2 analysis.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

A summary of emissions projections for the various control options is provided in Table 174. We relied on information from MDU for estimated control efficiencies, expected emission reductions, and baseline emissions, with the exception of HDSCR + SOFA/LNB, for which we performed our own analysis. The control efficiencies listed in the table below, other than for the SNCR low-load scenario, are the degree of reduction that is expected to be achieved on actual controlled baseline NO_X emissions of 802 tpy. Similarly, the emission reductions in tpy in the table are reductions from the baseline emissions. For the SNCR low-load scenario, the baseline emissions, control efficiency and emissions reduction are those that correspond to low load operation (23 MW).

TABLE 174—SUMMARY OF MDU LEWIS & CLARK NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
HDSCR + SOFA/LNB	87.5	693	109
Fuel switch to natural gas	65	523	279
SNCR with SOFA/LNB	50	401	401
SOFA/LNB	38	301	501
SNCR	38	301	501
SNCR (low load) [1]	16	57.6	298

[1] Baseline emissions for the low load scenario are 356 tpy.

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Table 175 provides a summary of estimated annual costs for the various control options. We relied on MDU's cost figures, with the exception of HDSCR + SOFA/LNB, for which we performed our own cost calculations, using a combination of EPA's OAQPS CCM and control costs from EPA's IPM.

TABLE 175—SUMMARY OF MDU LEWIS & CLARK NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
HDSCR + SOFA/LNB	3,361,965	4,853
Fuel switch to natural gas	21,919,094	41,934
SNCR with SOFA/LNB	1,093,962	2,729
SOFA/LNB	364,546	1,213
SNCR	761,654	2,533
SNCR (low load)	565,673	9,817

[282] MDU NO_X control cost analysis by US EPA Region 8 for SCR, SOFA/LNB, and SCR + SOFA/LNB, Summary Spreadsheet (Mar. 7, 2012).

Factor 2: Time Necessary for Compliance

For combustion modifications such as SOFA and/or LNB, furnace penetration would be required and, as such, will need to align with a major outage. The next planned outage is spring of 2018.[283] Therefore, it might not be possible to ensure that SOFA or LNB could be installed within the first planning period for regional haze requirements under the CAA. If HDSCR + SOFA/LNB is the chosen control option, the construction schedule could extend into many months. If SNCR is the chosen control option, installation would likely be much quicker. For the option involving a fuel switch to natural gas as primary fuel, several years might be needed to secure the necessary rights-of-way and install a new 22-mile pipeline that MDU has stated would be needed to provide a sufficient supply of natural gas.[284]

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

A fuel switch to natural gas as primary fuel could significantly increase the demand for natural gas in the region and could increase natural gas prices for other consumers of natural gas in the region, as well as create impacts associated with more production of natural gas in the region. Other control options, however, would have minimal energy impacts.

Depending on HDSCR installation in relation to existing controls, NH_3 slip can generally cause additional NH_3 to be emitted to air or water. As NH_3 is both a visibility impairing air pollutant and a wastewater regulated pollutant, air emissions and water discharges can be impacted. This is also a potential SNCR impact. Also, spent catalyst from SCR produces an increase in solid waste. Finally, for combustion modifications (SOFA and/or LNB), there is a potential for increased CO emissions from the boiler. During normal operation at L&C Station, CO levels are currently on the order of 20 ppm. Generally, CO performance guarantees are in the 100 ppm to 200 ppm range for LNBs.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

[283] L&C Emissions Control Analysis, p. 26.

[284] L&C Feb. 10, 2012 Response, p. 2.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: the cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Based on costs of compliance, the small size of the facility, and the relatively small baseline Q/D, we propose to eliminate the more expensive control options (fuel switching to natural gas and HDSCR + SOFA/LNB). For similar reasons, taking into account costs in the low load scenario, we propose to eliminate SNCR and SNCR + SOFA/LNB. Finally, for the most cost effective option (SOFA/LNB), emissions reductions would be fairly small (300 tpy), which would result in approximately 16.6% reduction in overall emissions of $SO_2 + NO_X$ for this facility, or a reduction of Q/D from 29 to 24. Based on the costs of compliance, the relatively small size of MDU L&C, and the modest reduction in Q/D, we find it reasonable to eliminate this option. We therefore propose to not require NO_X controls for this planning period.

vi. Montana Sulphur and Chemical

Montana Sulphur and Chemical Company (MSCC) is a sulfur recovery source located in Billings, Montana. Additional information to support this four factor analysis can be found in the docket.[285]

MSCC converts the raw sulfur compound from fuel gases, acid gases and other materials to create marketable products, including: low sulfur fuel gas, elemental sulfur, dry fertilizers, hydrogen gas, hydrogen sulfide, and carbon and sodium sulfates. MSCC receives sulfur-containing fuel gases from the ExxonMobil refinery, desulfurizes these gases in its amine unit, and returns low-sulfur fuels back to the refinery. This process reduces sulfur oxide emissions that might otherwise be emitted to the atmosphere at the oil refinery site.

At MSCC, acid gases are processed in a multistage Claus process and tail gas incinerator. In 1998, MSCC installed a SuperClaus Process, which further desulfurizes Claus tail gases by selective partial oxidation and controls emissions of SO_2. In 2008, a second SuperClaus unit was installed in parallel to the first unit, so that sulfur and fuel gas processing can continue during periods of repair and maintenance.

[285] Reasonable Progress (RP) Four-Factor Analysis of Control Options for Montana Sulphur & Chemical Company in Billings Montana; Response to Request for Information, Reasonable Progress for Montana Sulphur & Chemical Co, pursuant to Section 114(A) of the Federal Clean Air (Feb. 6, 2012).

The sulfur recovery process and its related stack is the preponderant source of SO_2 emissions from the facility and is the only emissions unit included in our analysis.

PM emissions from the sulfur recovery process are estimated to be only 1 tpy. As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

NO_X emissions also are relatively small, at 3 tpy. Thus, NO_X emissions from the unit are not significant contributors to regional haze. Additional controls for NO_X will not be considered or required in this planning period. We are therefore considering controls only for SO_2 for this planning period.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available: extending the Claus reaction into a lower temperature liquid phase (the Sulfured® process) and tail gas scrubbing (Wellman-Lord, SCOT, and traditional FGD processes).

In the Sulfured® process, the Claus reaction is extended at low temperatures (260 to 300°F) to recover SO_2 and H_2S in the tail gas. Tail gas passes through one of three reactors on line at a given time. Two reactors are on either heating or cooling cycles while the third is on the gas stream. Gas flow is switched from the reactors and is determined by the sulfur-holding capacity of each catalyst bed in the reactors. Sulfur is vaporized by using inert gas from a blower, resulting in the regeneration of the catalyst bed. The inert gas is then cooled in a condenser, where the liquid sulfur is removed. The hot regenerated catalyst bed must be cooled before going back on the gas stream.

The Wellman-Lord is an oxidation tail gas scrubber that uses sodium sulfite (Na_2SO_3) and sodium bisulfate ($NaHSO_3$) to react with SO_2 gas from the Claus incinerator to form bisulfate. The incinerator gases must be cooled and quenched before scrubbing, subjected to misting after scrubbing, and reheated afterwards. The bisulfate solution is regenerated to sodium sulfite in a steam-energized evaporator. The concentrated wet SO_2 gas stream from the evaporator is partially condensed and some of the liquid water is used to dissolve sulfite crystals. The remaining enriched SO_2 gas stream is recycled back to the Claus plant and used to recover additional sulfur by reaction with the incoming hydrogen sulfide.

The Shell Claus Off-Gas Treatment (SCOT) process is another example of reduction tail gas scrubbing. In the SCOT process, and numerous variants, tail gas from the sulfur recovery unit (SRU) is re-heated and mixed with a hydrogen-rich reducing gas stream. Heated tail gas is treated using a catalytic reactor where the free sulfur, SO_2, and reduced sulfur compounds are substantially reconverted to H_2S. The H_2S-rich gas stream is then routed to a cooling/quench system where the gases are cooled. Excess condensed water from the quench system is routed to a separate sour water system for treatment and disposal. The cooled quench system gas effluent is then fed to an absorber section where the acidic gas comes in contact with a selective amine solution and is absorbed into solution; the amine must selectively reject carbon dioxide gas to avoid problems in the following steps, and must not be exposed to unreduced gases or oxygen (e.g., unconverted SO_2 or sulfur) that may arise during malfunctions. The rich solution is separately regenerated using steam, cooled and returned to the scrubber/absorber. The H_2S-rich gas released at the regenerator is reprocessed by the SRU.

Other traditional FGD technologies include: Wet lime scrubbers, wet limestone scrubbers, dual alkali wet scrubbers, spray dry absorbers, DSI, and CDS. All of these technologies were described in previous sections (see the BART analysis for Corette and the four factor analyses for CELP, YELP, and MDU, L&C Station).

Step 2: Eliminate Technically Infeasible Options

The Wellman-Lord scrubber is infeasible for MSCC. This system can require significant space, especially in retrofit applications. There is limited space at MSCC. Also, the purge system required by this process would generate excess acid water that would require onsite management and onsite or offsite disposal. For these reasons, the Wellman Lord system was not considered further.

SDA and DSI are not technically feasible because the flue gas SO_2 concentrations at MSCC are too high. These technologies cannot be used when concentrations are greater than 2000 ppm. The average concentration of SO_2 in the flue gas at MSCC ranges from 2,100 to 6,000 ppm. For this reason, SDA and DSI were not considered further.

MSCC has very limited space to install wet systems or to manage the waste streams generated by wet systems (wet lime scrubbers, wet limestone scrubbers, and dual alkali wet scrubbers). These systems can require significant space, especially in retrofit applications. There is limited space at MSCC. Also, these processes would generate excess water that would require onsite management and onsite or offsite disposal. Wet systems would require an onsite dewatering pond and landfill to process and dispose of scrubber sludge. For these reasons, the wet systems were not considered further.

CDS cannot be used at MSCC because it would result in high particulate loading. It would be necessary to control those particulates. Because of the high particulate loading, the pressure drop across a fabric filter would be unacceptable; therefore, ESPs are generally used for particulate control for power plants. Either type of particulate control device would require substantial space, which is not available at MSCC. Based on limited technical data from non-comparable applications and our engineering judgment, we have determined that CDS is not technically feasible for this facility. For this reason, CDS was not considered further.

Both the SCOT and Sulfured® processes are feasible; however, in the BART Guidelines, EPA states that it may be appropriate to eliminate from further consideration technologies that provide similar control levels at higher cost. See 70 FR 39165 (July 6, 2005). We think it appropriate to do the same for RP determinations. In this case, Sulfured® systems reportedly can achieve 98% to 99.5% sulfur recovery efficiency while SCOT can reportedly achieve sulfur recovery as high as 99.8% to 99.9%. The cost is higher for the Sulfured® system when compared to the SCOT process. Because the SCOT process is more effective and costs less than the Sulfured® system, the Sulfured® system was not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Baseline SO_2 emissions from MSCC are 1,452 tpy. A summary of emissions projections for the SCOT process, the only remaining control technology, is provided in Table 176.

TABLE 176—SUMMARY OF MSCC SO_2 REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY CONTROL EFFECTIVENESS

Control option	Control effectiveness [1] (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
SCOT	99.9	871	581

[1] Overall control efficiency is shown. Incremental control efficiency, over the current Superclaus™ Process is 60%.

Factor 1: Costs of Compliance

Table 177 provides a summary of estimated annual costs and cost effectiveness for the SCOT process.

TABLE 177—SUMMARY OF MSCC SO_2 REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
SCOT	7,705,000	5,441

We are adopting cost figures provided by MSCC, except that we annualized the capital cost using a 7% interest rate and 20-year equipment life (which yields a CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[286] The capital cost is annualized by multiplying the total capital investment by the CRF (0.0944). We also used a control efficiency of 99.9% for the SCOT process.

Factor 2: Time Necessary for Compliance

The SCOT process could be installed in 18 to 36 months.

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

The SCOT process requires substantial additional energy for operation. The tail gas from the Claus unit would need to be heated prior to entering a reducing reactor and/or heating recycled gas for regeneration requirements. Low-temperature based systems such as the SCOT system would also require additional fuel for reheat of the final tail gas for incineration prior to discharge. SCOT systems also require substantial electricity to operate numerous pumps, coolers and a condenser. Additional power is required to provide relatively large amounts of cooling water. Additional fuel and power energy (and equipment) is required for processing of the new sour water waste that is continuously produced in the quench process necessary for scrubbing. Additional details of the energy requirements for the SCOT process are described in the docket.

The quench system in the SCOT system produces a sour water effluent that requires treatment prior to disposal. This effluent contains hydrogen sulfide, and may contain other troublesome species as well, particularly during upset conditions. An engineered facility needs to be installed at MSCC to manage this waste stream.

Factor 4: Remaining useful life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Based on costs of compliance for the only control option (SCOT), the relatively small size of the facility, and the relatively small baseline Q/D, we propose to eliminate this option. Therefore, we are proposing that no additional controls for SO_2 will be required for this planning period.

vii. Plum Creek Manufacturing

Plum Creek Manufacturing's Columbia Falls Operation, in Columbia Falls, Montana consists of a sawmill, a planner, and plywood and medium density fiberboard (MDF) processes. Additional information to support this four-factor analysis can be found in the docket.[287] This RP analysis focuses on four emitting units at the Columbia Falls Operation: the Riley Union hog fuel boiler (Riley Union boiler), two Line 1 MDF dryer sander dust burners (Line 1 sander dust burners), and the Line 2 MDF dryer sander dust burner (Line 2 sander dust burner). The Riley Union boiler is used as a load-following steam generator for the dry kilns, plywood press, log vats, and MDF platen press. Downstream from the spreader-stoker grate, there are sander dust burners that are capable of supplementing 10% of the heat rate capacity of the boiler. These burners are normally fired with sander dust, but have the ability to fire natural gas during sander dust shortages and startup.

The Line 1 MDF dryers include two direct-contact dryers, a core fiber dryer, and a face fiber dryer. One Cone sander dust burner supplies heat to each dryer. The Line 1 fireboxes are one-quarter the size of the Line 2 firebox.

The Line 2 MDF dryers are direct-contact dryers. The flue gas from the combustion chamber provides heat for the first- and second-stage dryer lines. The design of the Line 2 burner employs staged combustion, with a rich zone followed by a lean zone reducing peak flame temperature, thereby reducing thermal NO_X emissions.

The Riley Union boiler exhausts to a dry ESP that was installed in 1993. The Line 1 dryer exhausts combine with the Line 1 press vents and metering bin baghouse exhausts before being controlled by a wet ESP that was installed in 1995. They emit to the atmosphere through two 80-foot stacks. The Line 2 dryer exhausts to a Venturi scrubber (installed in 2001) before emitting to the atmosphere through three 40-foot stacks. As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

SO_2 emissions are relatively small (18 tpy for all units combined). Thus, SO_2 emissions from these units are not significant contributors to regional haze, and additional controls for SO_2 will not be considered or required in this planning period. We are therefore only considering controls for NO_X for this planning period.

Riley Union Boiler

Step 1: Identify All Available Technologies

The Riley Union Boiler does not currently have post-combustion or low NO_X combustion technology. We identified that the following technologies to be available: SCR, RSCR, SNCR, SNCR/SCR hybrid, staged combustion, fuel staging, LNB, OFA, LEA, and FGR.

SCR, SNCR, LNB, OFA, LEA and FGR were described in our analysis for CELP.

RSCR uses a regenerative thermal oxidizer (or waste heat transfer system) to bring cool exhaust gas back up to the

[286] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

[287] Letter from Thomas Ray to Vanessa Hinkle (Feb. 28, 2011); Reasonable Progress (RP) Four-Factor Analysis of Control Options for Plum Creek Manufacturing/Columbia Falls Operations.

temperature required for the SCR catalyst to be effective at reducing NO_X to nitrogen and water. RSCR is a good option for an exhaust gas that has constituents requiring removal prior to introduction into the catalyst (to prevent fouling or plugging), such as high PM concentrations.

The SNCR/SCR hybrid approach involves injecting the reagent (NH_3 or urea) into the combustion chamber, which is a higher temperature zone than traditional SCR injection. This provides an initial reaction that is similar to SNCR. A catalyst is placed in the downstream flue gas to further reduce NO_X and any reagent that remains.

Staged combustion can be achieved through a wide variety of methods and techniques, but in general creates a fuel-rich zone followed by a fuel lean zone. This reduces the peak flame temperature and the generation of thermal NO_X.

Fuel staging is a technique that uses 10% to 20% of the total fuel input downstream from the primary combustion zone. The fuel in the downstream secondary zone acts as a reducing agent to reduce NO emissions to N_2. Natural gas or distillate oil usually are used in the secondary combustion zone.

Step 2: Eliminate Technically Infeasible Options

SCR catalysts may be fouled or plugged by exhaust gas that contains high concentrations of PM, as is the case with the combustion of wood, biomass, or hog fuel. To prevent the premature failure of the catalyst, the PM must be removed from the exhaust stream prior to SCR. At this facility, the exhaust from the boiler's ESP will not meet the minimum temperature required for SCR (without reheat). Since the PM loading is too high for high dust SCR prior to PM controls; and the gas is too cool after the PM control equipment for a low dust SCR (downstream of the ESP). For these reasons, SCR was not considered further.

Since the PM concentrations in the exhaust of the Riley Union boiler would require the PM controls to precede the catalyst section of the hybrid system, reheat would be required. RSCR is considered to be feasible without firebox/SNCR injection, therefore SNCR/SCR Hybrid systems were not considered further.

Further staged combustion is not possible for the Riley Union boiler. The boiler is a stoker boiler with sander dust burners downstream from the stoker. In order to create a further staged combustion process (and lower flame temperature), the energy density must be reduced in the combustion fuel. This means that more volume would be required to accommodate the current heat rate. In addition to the space constraint, as with OFA, it is unlikely that the current design could further stratify the rich and lean combustion zones (either through decreased under-fire air, or increased OFA), due to the minimum air flow needed to cool the stoker grate and maintain an even heat release rate. For these reasons, staged combustion was not considered further.

The Riley Union boiler already employs fuel staging by having a stoker grate for a majority of the heat input followed by sander dust burners downstream of the grate. Further fuel staging is infeasible for the boiler. For this reason, fuel staging was not considered further.

LNBs are not feasible for spreader-stoker boilers, as they do not use burners for a majority (90% in this case) of the heat input. Sander dust burners are located downstream from the stoker grate; however, their small size may restrict the ability to create conditions necessary for a LNB. For LNB technology to be effective, the rich zone must precede the lean zone. In this case, the secondary combustion zone burners would not have sufficient space to accommodate a larger flame front characterized by LNB technology. In addition, lowering the flame temperature at that location may negatively affect the function of the secondary combustion zone, which could result in increased emissions of some pollutants. For these reasons, LNB technology was not considered further.

In order to implement OFA on the boiler, further modifications would be required to add OFA ports. The OFA ports would need to be installed at the same location as the current sander dust burners. In addition, installation of OFA ports will increase the size/volume of the flame front, in turn, increasing flame impingement on the boiler walls, which may lead to tube failure. Flame impingement may also increase quenching of the flame thereby increasing emissions associated with incomplete combustion. The reducing atmosphere of the rich primary zone also may result in accelerated corrosion of the furnace, and grate corrosion and overheating may occur in stokers as primary air flow is diverted to OFA ports. Some level of staged combustion is already achieved through fuel staging (by use of the downstream sander dust burners). Further staging of the combustion process through OFA (or other techniques) is technically infeasible without increasing the boiler volume or decreasing the heat input rate. For these reasons, OFA was not considered further.

LEA is not compatible with the design of the boiler. The boiler is a stoker boiler that operates on the principle of creating an even release of heat across the entire grate. In order to achieve optimal conditions, sufficient air flow is required from beneath the grate. In addition sufficient air flow is needed to keep the grate and parts exposed to combustion material below their maximum operating temperatures. For these reasons, LEA is not considered further.

Similarly, FGR creates a LEA condition, but may not affect the under fire air needed to properly operate the stoker grate system. In order to prevent high loss on ignition and increased emissions associated with incomplete combustion (and the LEA condition) the volume of the boiler's combustion chamber would likely need to be increased to maintain the current steam rate and overall heat release rate, and thus is not compatible with the design of the boiler. FGR is a technique with multiple mechanisms for reducing NO_X, including reducing the available oxygen, since some exhaust gas replaces oxygen rich ambient air. For this reason, FGR is not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Baseline NO_X emissions from the boiler are 587 tpy. A summary of emissions projections for RSCR and SNCR, the only remaining control technologies, are provided in Table 178. Further information can be found in the docket.

TABLE 178—SUMMARY OF BOILER NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
SNCR	35	205	382

TABLE 178—SUMMARY OF BOILER NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY—Continued

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
RSCR	75	440	147

Factor 1: Costs of Compliance

Table 179 provides a summary of estimated annual costs and cost effectiveness for SNCR and RSCR.

TABLE 179—SUMMARY OF BOILER NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
SNCR	$294,377	$1,436
[1] RSCR	748,097	1,700

[1] Further information on our cost calculation can be found in the docket in the document titled Reasonable Progress (RP) Four-Factor Analysis of Control Options for Roseburg Forest Products Co./Missoula Particleboard (a similar type source to Plum Creek's boiler).

For SNCR, we are adopting cost figures provided by Plum Creek,[288] except that we annualized the capital cost by multiplying the capital cost by a CRF that corresponds to a 7% interest rate and 20-year equipment life (which yields a CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[289] For RSCR, we are adopting the total annual cost for RSCR for the SolaGen sander dust burner at Roseburg Forest Products. This is likely an underestimation of the cost for the boiler dryers at Plum Creek, because the boiler at Plum Creek is larger than the SolaGen sander dust burner at Roseburg.

Factor 2: Time Necessary for Compliance

RSCR systems can be operational within eight months to one year. Because RSCR includes much of the equipment needed for SNCR, with additional equipment (the catalyst for instance), we have assumed that SNCR could be installed within a similar timeframe to that quoted for RSCR. Therefore, SNCR also can be installed and operational within eight months to one year.

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

RSCR requires the reheat of the flue gas, either through a heat exchanger that uses plant waste heat, and/or through direct reheat of the flue gas by additional combustion or electrically powered heating elements. Although specific estimates of resources needed to operate RSCR on the Columbia Falls boiler were not available, we have examined estimates presented for a similar source (Roseburg Forest Products) to illustrate the approximate quantity of resources needed to run a RSCR system. Table 180 provides estimates of these additional resources that are necessary for RSCR.

TABLE 180—ADDITIONAL AMMONIA, NATURAL GAS, ELECTRICITY, AND STEAM REQUIRED FOR RSCR

	Ammonia (NH_3)	Natural gas	Electricity	Steam
RSCR usage per system	300,000 to 400,000 gal/year.	2 million scf/year to 9.7 million scf/year.	930,000–5.4 million kWh/year.	42.5–125 lb/hr or 186–548 tpy.

Additionally, the RSCR catalyst may have the potential to emit NH_3 (as NH_3 slip) and generate nitrous oxide if not operated optimally. Catalysts must be disposed of, presenting a cost; however, many catalyst manufacturers provide a system to regenerate or recycle the catalyst reducing the impacts associated with spent catalysts. In addition to these considerations, there are issues associated with the production, transport, storage, and use of NH_3. However, regular handling of NH_3 has reduced the risks associated with its transport, storage, and use.

As with RSCR, there are issues associated with NH_3, electricity, and compressed air for SNCR. Although specific estimates of resources needed to operate SNCR on the Columbia Falls boiler were not available, we have examined estimates presented for a similar source (Roseburg Forest Products) to illustrate the approximate quantity of resources needed to run a SNCR system. Table 181 provides estimates for additional reagent, electricity and steam use.

[288] Plum Creek Revised Response, Table C–4 (Mar. 13, 2012).

[289] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

TABLE 181—ADDITIONAL REAGENT, ELECTRICITY AND STEAM REQUIRED FOR SNCR

	Reagent (Urea)	Electricity	Steam
Boiler SNCR System	165 tpy or 69,740 gallons Urea solution/year.	204,108 kWh/year	51.4 lb/hr or 225 tpy.

As with RSCR, some level of NH_3 slip will be present, which is dependent on the amount of reagent injected and the level of control that is desired. Higher levels of control are associated with greater NH_3 slip. Whether urea or NH_3 is used, there are impacts associated with the production, transport, storage, and use of these chemicals. If urea is used, there will be GHG emissions associated with its hydrolysis prior to its use as a NO_X reagent.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. We propose to eliminate the most expensive option (RSCR), based on costs of compliance and the relatively small size of this facility. The less expensive option (SNCR) would reduce emissions by 205 tpy, which equates to approximately an 18.5% reduction in overall emissions of SO_2 + NO_X from the facility, or a reduction of Q/D from 82 to 67. Based on the relatively small size of this facility, the baseline Q/D, and the reduction in Q/D, we propose to find it reasonable to eliminate this option. Therefore, we are proposing to not require any NO_X controls for this planning period.

Line 1 Sander Dust Burners

Step 1: Identify All Available Technologies

The Line 1 sander dust burners do not currently have post-combustion or low NO_X combustion technology. We identified the following technologies to be available: SCR, RSCR, SNCR, SNCR/SCR hybrid, staged combustion, fuel staging, LNB, OFA, LEA, and FGR. SCR, SNCR, LNB, OFA, LEA and FGR were described in our analysis for CELP. RSCR, SNCR/SCR hybrid, staged combustion, and fuel staging were described in our analysis for Plum Creek's Riley Union boiler.

Step 2: Eliminate Technically Infeasible Options

For the Line 1 sander dust burners, PM loadings are too high for a hot/high dust SCR, and temperatures are too cool following the PMCD unless reheat is used. In addition to these issues, the dryer burners are direct contact dryers. Therefore, any NH_3 in the gas stream from a hot/high dust SCR would have the potential to stain or darken the wood product. For these reasons, SCR was not considered further.

The exhaust from the Line 1 sander dust burners acts as a direct contact heat source for the drying processes at the facility. The use of SNCR would require injection of the reagent prior to the dryers introducing NH_3 to the product lines. Contact with NH_3 may result in reduced product quality. NH_3 darkens wood, which would not be acceptable for Plum Creek's light colored stains. Additionally, NH_3 may affect the curing of any formaldehyde-based resins used in the wood products. High levels of NH_3 reduce the cellulosic structure of the wood, allowing it to be permanently shaped; however compressive strength is reduced, which is an important factor for product quality. Space constraints also are a consideration because there is not sufficient residence time at the required temperatures in the exhaust stream prior to the location where the exhaust comes into contact with the wood products; therefore, there is a likelihood that the conversion of the NH_3 reagent may not be sufficiently completed before the exhaust enters the dryers, making product quality a concern (as stated above). For these reasons, SNCR was not considered further.

Because the PM concentrations in the exhaust of the sander dust burners would require the PM controls to precede the catalyst section of the hybrid system, reheat would be required. RSCR is considered to be feasible without firebox/SNCR injection, therefore SNCR/SCR hybrid systems were not considered further.

Fuel staging is not feasible for the Line 1 sander dust burners. The Line 1 sander dust burners have a combustion chamber that is too small to accommodate fuel staging; therefore, fuel staging was not considered further.

Staged combustion is not compatible with the Line 1 sander dust burners. The Line 1 sander dust burners have a combustion chamber that is one-quarter the volume of the Line 2 sander dust burner. Staged combustion techniques increase the volume (or size) of the flame front for a given heat input rate; therefore it would be necessary to reduce the overall heat input of the burners to achieve lower flame temperatures and thereby realize the NO_X reduction achievable with staged combustion techniques. A reduction in the heat rate to the Line 1 sander dust burners would result in insufficient heat being sent into the drying process.

As stated above in the Step 2 discussion of staged combustion, there is insufficient combustion chamber volume to implement LNB design for the Line 1 sander dust burners; therefore, LNB are considered to be technically infeasible for the Line 1 sander dust burners without increasing combustion chamber volume or decreasing the heat input rate (which would affect Plum Creek's ability to successfully operate the wood product dryers). For this reason, LNB was not considered further.

As also discussed above, there is insufficient combustion chamber volume to implement OFA on the Line 1 burners without decreasing the heat input rate. The reduced heat input rate would prevent the dryers from operating as designed. For this reason, OFA was not considered further.

LEA is considered to be technically infeasible for the Line 1 sander dust burners because sander dust suspension burners require high levels of air in order to fluidize the solid fuel. Poor operation of the burners would result with LEA since high excess air conditions are necessary to sustain stable combustion. The Line 1 dryers are all suspension burners, and therefore LEA is considered technically infeasible for these sources.

Because FGR depends on the same conditions as LEA and LEA is considered technically infeasible for the Line 1 sander dust burners, FGR is also considered infeasible for the Line 1 sander dust burners. Additionally, FGR may require additional combustion chamber volume to accommodate the same heat input while maintaining a reduced flame temperature. For these reasons, FGR was not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Baseline NO_X emissions from the Line 1 sander dust burners are 319 tpy. A summary of emissions projections for RSCR, the only remaining control technology, is provided in Table 182. Further information can be found in the docket.

TABLE 182—SUMMARY OF LINE 1 NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
RSCR	75	240	79

Factor 1: Costs of Compliance

Table 183 provides a summary of estimated annual costs and cost effectiveness for RSCR.

TABLE 183—SUMMARY OF LINE 1 NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
[1] RSCR	748,097	3,117

[1] Further information on our cost calculation can be found in the docket in the document titled Reasonable Progress (RP) Four-Factor Analysis of Control Options for Roseburg Forest Products Co./Missoula Particleboard (a similar type source to Plum Creek).

For RSCR, we are adopting the total annual cost for RSCR for the SolaGen sander dust burner at Roseburg Forest Products. This is likely an underestimation of the cost for the Line 1 sander dust burners at Plum Creek, because the Line 1 sander dust burners are smaller than the SolaGen sander dust burner at Roseburg.

Factor 2: Time Necessary for Compliance

RSCR systems for the Line 1 sander dust burners could be operational within eight months to one year.

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air quality environmental impacts from RSCR were discussed in the analysis for the boiler. Specific reagent, electricity and steam requirements were not calculated for the Line 1 sander dust burners but are expected to be less than what would be needed for the boiler.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. The emissions reductions from the only feasible option (RSCR) would be fairly small (240 tpy), which would result in approximately 21.7% reduction in overall emissions of SO_2 + NO_X for this facility, or a reduction of Q/D from 82 to 64. Based on the costs of compliance, the relatively small size of the facility, and the reduction in Q/D, we think it reasonable to not impose RSCR for this facility. Therefore, we are proposing to not require any NO_X controls on this unit for this planning period.

Line 2 Sander Dust Burner

Step 1: Identify All Available Technologies

The line 2 sander dust burner uses staged combustion to control NO_X. We identified the following technologies to be available: SCR, RSCR, SNCR, SNCR/SCR hybrid, staged combustion, fuel staging, LNB, OFA, LEA, and FGR. SCR, SNCR, LNB, OFA, LEA and FGR were described in our analysis for CELP. RSCR, SNCR/SCR hybrid, staged combustion, and fuel staging were described in our analysis for Plum Creek's boiler.

Step 2: Eliminate Technically Infeasible Options

All of the sander dust burners have the same issues associated with the implementation of SCR as the boiler. PM loadings are too high for a hot/high dust SCR, and temperatures are too cool following PM control unless reheat is used. In addition to these issues, the dryer burners are all direct contact dryers. Therefore, any NH_3 in the gas stream from a hot/high dust SCR would have the potential to stain or darken the wood product. For these reasons, SCR was not considered further.

The exhaust from the Line 2 sander dust burner acts as a direct contact heat source for the drying processes at the facility. Using SNCR on the Line 2 sander dust burner would cause the same product quality issues that were explained in the analysis for the Line 1 sander dust burners. Space constraints are also an issue as explained for the Line 1 sander dust burners. For these reasons, SNCR was not considered further.

As explained in the analysis for the Line 1 sander dust burners, the PM concentrations in the exhaust of the sander dust burners would require the

PM controls to precede the catalyst section of the hybrid system, and so reheat would be required. RSCR is considered to be feasible without firebox/SNCR injection; therefore SNCR/SCR Hybrid systems were not considered further.

Fuel staging is not feasible for the Line 2 sander dust burner. The Line 2 sander dust burner uses staged combustion. Further modification of the combustion chamber would be required to use fuel staging; however, space constraints would make the expansion infeasible. Also, additional NO_X reductions would not likely be realized because the staged combustion design has already reduced thermal NO_X to the extent possible. For these reasons, fuel staging is not considered further.

The Line 2 sander dust burner already uses staged combustion, therefore further staging would not be technically feasible without complete replacement.

LNB (or staged combustion) is a technique that was designed into the Line 2 sander dust burner; therefore, further staging, or LNB configuration was not considered further.

The Line 2 sander dust burner uses staged combustion. Further modification of the combustion chamber would be required to use fuel staging; however, space constraints would make the expansion infeasible. Also, further NO_X reductions would not likely be realized because the staged combustion design has already reduced thermal NO_X to the extent possible. For these reasons, fuel staging is not considered further.

The Line 2 sander dust burner already employs staged combustion; therefore, further staging through the use of OFA is technically infeasible. For this reason, OFA was not considered further.

LEA is considered to be technically infeasible for the Line 2 sander dust burner because sander dust suspension burners require high levels of air in order to fluidize the solid fuel. Poor operation of the burners would result with LEA since high excess air conditions are found under the conditions necessary to sustain stable combustion. The Line 2 dryers are all suspension burners, and therefore LEA is considered technically infeasible for these sources. For these reasons, LEA was not considered further.

FGR is not technically feasible for the Line 2 sander dust burner for the same reasons as were described under the analysis for the Line 1 sander dust burners. Because FGR causes a LEA condition and LEA is considered technically infeasible for the Line 2 sander dust burner, FGR has also been considered to be infeasible for the Line 2 sander dust burner. Also, FGR may require additional combustion chamber volume to accommodate the same heat input while maintaining a reduced flame temperature. For these reasons, FGR was not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Baseline NO_X emissions from the Line 2 sander dust burner are 200 tpy. A summary of emissions projections for RSCR, the only remaining control technology, is provided in Table 184.

TABLE 184—SUMMARY OF LINE 2 NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
RSCR	75	150	50

Factor 1: Costs of Compliance

Table 185 provides a summary of estimated annual costs and cost effectiveness for RSCR.

TABLE 185—SUMMARY OF LINE 2 NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
[1] RSCR	748,000	4,987

[1] Further information on our cost calculation can be found in the docket in the document titled Reasonable Progress (RP) Four-Factor Analysis of Control Options for Roseburg Forest Products Co./Missoula Particleboard (a similar type source to Plum Creek's boiler).

For RSCR, we are adopting the total annual cost for RSCR for the SolaGen sander dust burner at Roseburg Forest Products. This is likely an underestimation of the cost for the Line 2 sander dust burner because the line 2 sander dust burner at Plum Creek is larger than the SolaGen sander dust burner at Roseburg.

Factor 2: Time Necessary for Compliance

RSCR systems for the Line 2 sander dust burner could be operational within eight months to one year.

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air quality environmental impacts from RSCR were discussed in the analysis for the boiler. Specific reagent, electricity and steam requirements were not calculated for the Line 2 sander dust burner, but are expected to be less than what would be needed for the boiler.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/

D of the facility, and the potential reduction in Q/D from the controls. Based on the costs of compliance and the relatively small size of this facility, we find it reasonable to eliminate the only control option (RSCR). Therefore, we are proposing that no additional controls will be required for this planning period.

viii. Roseburg Forest Products

Roseburg Forest Products Company owns and operates a particleboard manufacturing facility in Missoula, Montana. Additional information to support this four factor analysis can be found in the docket.[290] The facility has two production lines, one with a multi-platen batch press (Line 1) and one with a continuous press (Line 2). A pre-dryer is used to reduce the moisture of green wood materials received at the facility. Heat for the pre-dryer is provided by exhaust from a 45 MMBtu/hr SolaGen sander dust burner. There are four final dryers associated with Line 1 and two final dryers associated with Line 2 that produce dried wood furnish for face and core material in the particleboard. Heat input for all six of the final dryers is provided by the combined exhaust of a 50 MMBtu/hr ROEMMC sander dust burner and 55 MMBtu/hr sander dust-fired Babcock & Wilcox boiler, which also provides steam for facility processes.

The Babcock & Wilcox boiler is the oldest of the three sander dust-fired sources at the facility. It is a stoker-type boiler that was installed in 1969. Unlike the other sander dust burners at the facility, the boiler serves the function of producing steam for facility processes in addition to providing heat input to the final dryers. The ROEMMC burner was installed in 1979, although it is a 1978 model burner. The sole purpose of this burner is to provide heat input for the final dryers. The SolaGen sander dust burner was installed in 2006, although it is a 2005 model. The sole purpose of this burner is to provide heat input to the pre-dryer.

PM emissions from the Babcock & Wilcox boiler, ROEMMC burner, and Line 1 and 2 final dryers are controlled by multi-clones at the dryer outlets. PM emissions from the SolaGen burner and pre-dryer are controlled by a cyclone, a wet ESP, and a regenerative thermal oxidizer. As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ and PM_{10} at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

SO_2 emissions are relatively small (6 tpy of SO_2 for all units combined). Thus, SO_2 emissions from these units are not significant contributors to regional haze and our analysis only considers NO_X. Additional controls for SO_2 will not be considered or required in this planning period. We are therefore considering controls only for NO_X for this planning period.

Babcock & Wilcox Boiler

Step 1: Identify All Available Technologies

The Babcock & Wilcox boiler does not currently have post-combustion controls or low NO_X combustion technology. We identified that the following technologies to be available: SCR, RSCR, SNCR, SNCR/SCR hybrid, staged combustion, fuel staging, LNB, OFA, LEA, and FGR. SCR, SNCR, LNB, OFA, LEA and FGR were described in our analysis for CELP. RSCR, SNCR/SCR hybrid, staged combustion, and fuel staging were described in our analysis for the boiler at Plum Creek Manufacturing.

Step 2: Eliminate Technically Infeasible Options

SCR catalysts may be fouled or plugged by exhaust gas that contains high concentrations of PM, as is the case with the combustion of wood, biomass, or hog fuel. To prevent the premature failure of the catalyst, the PM must be removed from the exhaust stream prior to the SCR. In this case, the exhaust from the PM control equipment will not meet the minimum temperature required for SCR to be effective. In addition to these issues, there is insufficient space prior to the dryers to add both PM controls and SCR. Even if there were space to add both systems, the exhaust from PM controls and SCR would be at a lower temperature, resulting in insufficient heat being sent to the dryers. For these reasons, SCR was not considered further.

The exhaust from all of the units act as direct contact heat sources for the drying processes at the facility. The use of SNCR would require injection of the reagent prior to the dryers, which would introduce NH_3 to the product lines. Roseburg has stated that contact with NH_3 may reduce product quality. For this reason, SNCR was not considered further.

A SNCR/SCR hybrid system also uses a catalyst and thus would experience similar technical difficulties related to catalyst plugging and/or fouling, as described for SCR. If PM controls were retrofitted prior to the dryers to allow the SCR to be operated without reheat, the exhaust from the PM controls would be significantly reduced, resulting in insufficient heat being sent to the dryers. Space constraints and product quality concerns are also issues. For these reasons, a SNCR/SCR hybrid system was not considered further.

Two stable zones of combustion are required for fuel staging. If there is insufficient space, the secondary fuel and combustion zone will impinge on the primary zone having the effect of raising the peak flame temperature and, in turn, increasing NO_X emissions. There is not sufficient room within the boiler to achieve fuel staging while maintaining the necessary heat input to the dryers. The creation of a larger combustion zone within the boiler also has the possibility of causing greater flame impingement on the boiler wall and tubes, which may compromise their integrity and cause premature failure. For these reasons, fuel staging was not considered further.

Staged combustion is considered feasible for the boiler in the form of a new SolaGen-type LNB; however, staged combustion in the form of OFA is considered technically infeasible for the boiler. Suspension burners such as the boiler need high air flow through the fuel-feed auger and burner to suspend and fluidize the solid fuel. Splitting the combustion air to OFA ports would result in poor and perhaps unstable combustion at the burner tip. For this reason, OFA was not considered further.

As with OFA, suspension-type burners, such as the boiler, require high levels of air in order to fluidize the solid fuel. The burners would operate poorly with LEA. For this reason, LEA was not considered further.

FGR is a technique with multiple mechanisms for reducing NO_X, including reducing the available oxygen, since some exhaust gas replaces oxygen rich ambient air. As with LEA, some combustion air must be reduced to accommodate the recirculating flue gas, which may cause the suspension burner to operate improperly. FGR may be applied in some situations, but in order to maintain the necessary heat input in this situation, additional combustion chamber volume would be required to accommodate the volume of the flue gas introduced into the combustion

[290] Reasonable Progress Analysis, Roseburg Forest Products, Missoula Particleboard, Submitted for Roseburg Forest Products by Golder Associates, Inc. (Feb. 2, 2011); Reasonable Progress (RP) Four-Factor Analysis of Control Options for Roseburg Forest Products Co., Missoula Particleboard.

chamber. For these reasons, FGR was not considered further.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

A summary of emissions projections for LNB and RSCR, the only remaining control technologies, are provided in Table 186. At this facility, RSCR would be placed downstream of the wood particle dryers and as a result would control emissions from both the boiler and the ROEMMC sander dust burner. Baseline NO_X emissions from the boiler are 134 tpy. Baseline NO_X emissions from the Line 1 dryers would be from the boiler and ROEMMC sander dust burner combined and are 202 tpy. Baseline NO_X emissions from the Line 2 dryers would be from the boiler and ROEMMC sander dust burner combined and are 92 tpy.

TABLE 186—SUMMARY OF ROSEBURG NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
LNB	22.2	30	104
RSCR Line 1	75	[1] 151	[1] 51
RSCR Line 2	75	[1] 69	[1] 23

[1] RSCR on the dryers would control emissions from the boiler and the ROEMMC.

LNBs are a form of staged combustion and may be able to achieve 50–70% reductions in NO_X emissions when firing coal, depending on the design or generation of the burner. However, NO_X reductions are highly dependent on the specifics of the burner design, fuel fired, and the operational setting. Roseburg presented a control efficiency for LNB applicable to the boiler of approximately 20%, which was based on information from the LNB vendor. This is not unreasonable considering that biomass produces primarily fuel NO_X rather than thermal NO_X, and LNB primarily reduce the generation of thermal NO_X.

Factor 1: Costs of Compliance

Table 187 provides a summary of estimated annual costs and cost effectiveness for LNB and RSCR.

TABLE 187—SUMMARY OF ROSEBURG NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
LNB	70,624	2,354
RSCR Line 1	2,261,273	14,975
RSCR Line 2	1,234,469	17,891

For LNB, we are adopting cost figures provided by Roseburg, except that we annualized the capital cost by multiplying the capital cost by a CRF that corresponds to a 7% interest rate and 20-year equipment life (which yields a CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[291]

Factor 2: Time Necessary for Compliance

EPA found cases in which boilers have been retrofitted with LNB in less than six months. However, this does not take into account variables that affect the ability of a company to have equipment off-line, such as seasonal variations in business that may require Roseburg to postpone retrofit until such time as is appropriate. In this case, we would expect that the LNB can be installed within a maximum of 12 months.

RSCR systems can be operational within eight months to one year.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

LNB would reduce the heat rate that could be sent to the units without increasing the volume of the combustion chamber. That would have the effect of reducing the mass flow rate and heat flux through the dryers. In order to make up for the lost heat it may be possible to add an additional heat source; however, that would use additional fuel, increasing natural resource use. It may be possible to reduce the amount of ambient air mixed into the exhaust prior to the dryers, but this is unlikely because there must be sufficient air flow, in addition to heat, to reduce the moisture content of the product.

RSCR requires the reheat of the flue gas, either through a heat exchanger that utilizes plant waste heat, and/or through direct reheat of the flue gas by additional combustion or electrically powered heating elements. The flue gas at the boiler exhaust is approximately 572 °F, and the temperature of the exhaust of the ROEMMC varies between 700 °F and 1050 °F. These two gas streams then mix with additional ambient air and pass through the Line 1 and Line 2 dryers, further reducing the exhaust gas temperature to 130 °F to 155 °F. In order to reheat the gas stream and operate the RSCR system it is anticipated that the following resources described in Table 188 would be required or consumed.

[291] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

TABLE 188—ADDITIONAL AMMONIA, NATURAL GAS, ELECTRICITY AND COMPRESSED AIR FOR RSCR

	Ammonia (NH_3)	Natural gas	Electricity	Compressed air
Line 1 RSCR	433,000 gal/year	9.7 million scf/year	3.6 million kWh/year	7.2 million scf/year
Line 2 RSCR	433,000 gal/year	4.7 million scf/year	1.7 million kWh/year	3.8 million scf/year

Additionally, the RSCR catalyst may have the potential to emit NH_3 (as NH_3 slip) and generate nitrous oxide if not operated optimally. Catalysts must be disposed of, presenting a cost; however, many catalyst manufacturers provide a system to regenerate or recycle the catalyst reducing the impacts associated with spent catalysts. In addition to these considerations, there are issues associated with the production, transport, storage, and use of NH_3. However, regular handling of NH_3 has reduced the risks associated with its transport, storage, and use.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. We propose to eliminate the most expensive options (RSCR on line 1 and line 2), based on costs of compliance and the relatively small size of this facility. The most cost-effective option (LNB) would reduce emissions by only 34 tpy, which equates to approximately a 9.2% reduction in overall emissions of SO_2 + NO_X from the facility, or a reduction of Q/D from 12 to 11. Based on this benefit, the baseline Q/D, and the reduction in Q/D, we find it reasonable to eliminate this option. Therefore, we are proposing to not require any NO_X controls on this unit for this planning period.

ROEMMC Sander Dust Burner

Step 1: Identify All Available Technologies

The ROEMMC sander dust burner does not currently have post combustion controls or low NO_X combustion technology. We identified that the following technologies to be available: SCR, RSCR, SNCR, SNCR/SCR hybrid, staged combustion, fuel staging, LNB, OFA, LEA, and FGR. SCR, SNCR, and LNB, OFA, LEA and FGR were described in our analysis for CELP. RSCR, SNCR/SCR hybrid, staged combustion, and fuel staging were described in our analysis for the boiler at Plum Creek Manufacturing.

Step 2: Eliminate Technically Infeasible Options

SCR was not considered further for the ROEMMC sander dust burner for the same reasons provided for the boiler: Insufficient space for both PM controls (necessary to avoid fouling and plugging) and the SCR catalyst, and insufficient heat from the exhaust to operate the dryers.

RSCRs would be placed downstream of the wood particle dryers. The RSCRs would control emissions from the ROEMMC sander dust burner in addition to the Babcock & Wilcox boiler. This technology was described in the analysis for the boiler; for the same reasons it was considered feasible there, it is considered feasible here.

SNCR was not considered further for the ROEMMC sander dust burner for the same reason provided for the boiler: reduced product quality due to contact with NH_3. A SNCR/SCR hybrid system was also not considered further for the ROEMMC sander dust burner for the same reasons provided for the boiler: lower temperature exhaust from PM controls and the SCR/SNCR hybrid system would provide insufficient heat for the dryers.

Staged combustion techniques increase the volume of the flame front for a given heat input rate. The ROEMMC sander dust burner is small, making it necessary to reduce the overall heat input to levels below what is needed to operate the dryers to achieve staged combustion. For this reason, staged combustion was not considered further.

Fuel staging was not considered further for the same reasons provided for the boiler: Insufficient space to achieve fuel staging while maintaining the necessary heat input the dryers.

LNB designs increase the length of the flame front. In order for the ROEMMC sander dust burner to operate as designed (with a rich and lean zone), the heat input to the burner would need to be decreased so that a smaller, yet longer flame could be created within the same physical space available with the current combustion chamber. The reduced firing rate would have the effect of reducing the necessary heat input below acceptable levels for operating the dryers. For these reasons, LNB was not considered further.

The ROEMMC sander dust burner does not have sufficient space to install OFA ports. In addition to space constraints, suspension burners such as the ROEMMC need high air flow through the fuel feed auger and burner to suspend and fluidize the solid fuel. Splitting the combustion air to OFA ports would result in poor and perhaps unstable combustion at the burner tip. For these reasons, OFA was not considered further.

LEA was not considered further for the ROEMMC sander dust burner for the same reasons provided for the boiler. Suspension-type burners, such as the ROEMMC sander dust burner, require high levels of air in order to fluidize the solid fuel. The burners would operate poorly with LEA.

FGR was not considered further for the ROEMMC sander dust burner for the same reasons provided for the boiler. FGR reduces the available oxygen, since some exhaust gas replaces oxygen rich ambient air. Additionally, FGR may require increased combustion chamber volume to accommodate the same heat input while maintaining a reduced flame temperature. For these reasons, FGR was not considered further.

All technologies identified in Step 1 were eliminated in Step 2; therefore, our analysis for the ROEMMC sander dust burner is complete. We have determined that no additional controls should be imposed on this unit in this planning period.

SolaGen Sander Dust Burner

Step 1: Identify All Available Technologies

The SolaGen sander dust burner currently uses LNB and FGR to control NO_X. We identified that the following technologies to be available: SCR, RSCR, SNCR, SNCR/SCR hybrid, staged combustion, fuel staging, OFA, and LEA. SCR, SNCR, LNB, OFA, LEA and FGR were described in our analysis for

CELP. RSCR, SNCR/SCR hybrid, staged combustion, and fuel staging were described in our analysis for the boiler at Plum Creek Manufacturing.

Step 2: Eliminate Technically Infeasible Options

SCR was not considered further for the SolaGen sander dust burner for the same reasons provided for the boiler. There is insufficient space prior to the pre-dryer to add both PM controls and SCR, and the exhaust from PM controls and SCR would be at a lower temperature resulting in insufficient heat being sent to the pre-dryer.

SNCR was not considered further for the SolaGen sander dust burner for the same reason provided for the boiler: reduced product quality from contact with NH_3. A SNCR/SCR hybrid system was not considered further for the SolaGen sander dust burner for the same reasons provided for the boiler: lower temperature exhaust from PM controls and the SCR/SNCR hybrid system would provide insufficient heat for the pre-dryer.

The SolaGen sander dust burner is a LNB, which is a form of staged combustion; further staging would not be technically feasible for the SolaGen. For this reason, staged combustion was not considered further.

Fuel staging was not considered further for the same reasons provided for the boiler. There is not sufficient room to achieve fuel staging while maintaining the necessary heat input for the pre-dryer.

The SolaGen sander dust burner already utilizes a LNB design, making further excess air infeasible to support stable combustion. For this reason, OFA was not considered further.

LEA was not considered further for the SolaGen sander dust burner for the same reasons provided for the boiler. Suspension-type burners, such as the SolaGen sander dust burner, require high levels of air in order to fluidize the solid fuel. The burners would operate poorly with LEA.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions from the SolaGen sander dust burner are 58 tpy. A summary of emissions projections for RSCR, the only remaining control technology, is provided in Table 189.

TABLE 189—SUMMARY OF ROSEBURG NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGY

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
RSCR	75	43	15

Factor 1: Costs of Compliance

Table 190 provides a summary of estimated annual costs for RSCR.

TABLE 190—SUMMARY OF ROSEBURG RSCR REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
RSCR	748,097	17,398

We are adopting cost figures provided by Roseburg, except that we annualized the capital cost by multiplying the capital cost by a CRF that corresponds to a 7% interest rate and 20-year equipment life (which yields a CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[292]

Factor 2: Time Necessary for Compliance

RSCR systems can be operational within eight months to one year.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

RSCR requires the reheat of the flue gas, either through a heat exchanger that utilizes plant waste heat, and/or through direct reheat of the flue gas by additional combustion or electrically powered heating elements. In order to reheat the gas stream and operate the RSCR system, the following resources described in Table 191 would be consumed.

TABLE 191—ADDITIONAL AMMONIA, NATURAL GAS, ELECTRICITY AND COMPRESSED AIR REQUIRED FOR RSCR

Ammonia (NH_3)	Natural gas	Electricity	Compressed air
304,000 gal/year	2 million scf/year	700,000 kWh/year	1.3 million scf/year

Environmental impacts were described in the analysis for the boiler.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: the cost of compliance; the time necessary for compliance; the

[292] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. We find it reasonable to eliminate the only feasible option, RSCR, on the basis of the costs of compliance and the relatively small size of this facility. Therefore, we are proposing that no additional NO_X controls will be required for this planning period.

ix. Smurfit Stone Container

Smurfit Stone Container Enterprises Inc., Missoula Mill (purchased and renamed M2Green Redevelopment LLC Missoula Site on 5/3/11) [293] was determined to be below the threshold of sources subject to BART, but above the threshold for sources subject to further evaluation for RP controls. According to an emissions report from M2Green Redevelopment LLC, the mill was permanently shut down on January 12, 2010 and is no longer operating.[294]

While the current owners have permanently shut down the mill at M2Green Redevelopment LLC, Missoula Site, and it is uncertain whether the mill will resume operations, should the mill resume operations we will revise the FIP as necessary in accordance with regional haze requirements, including the ''reasonable progress'' provisions in 40 CFR 51.308(d)(1).

x. Yellowstone Energy Limited Partnership

Yellowstone Energy Limited Partnership (YELP), in partnership with Billings Generation Incorporated, owns an electric power plant in Billings, Montana.[295] The plant is rated at 65 MW gross output and includes two identical CFB boilers that are fired on petroleum coke and cooker gas; exhaust exits through a common stack. The boilers and emission controls were installed in 1995.

PM emissions are controlled by two fabric filter baghouses at the common stack that is designed to achieve greater than 99% control of particulates.[296] As discussed previously in Section V.D.6.b., the contribution from point sources to primary organic aerosols, EC, $PM_{2.5}$ at Montana Class I areas is very small, and modeling tends to confirm that PM emissions from point sources do not have a very large impact. Therefore, we are proposing that additional controls for PM are not necessary for this planning period.

SO_2

Step 1: Identify All Available Technologies

We identified that the following technologies to be available: limestone injection process upgrade, a SDA, DSI, a CDS, HAR, a wet lime scrubber, a wet limestone scrubber, and/or a dual alkali scrubber.

YELP currently controls SO_2 emissions using limestone injection. Crushed limestone is injected with the petroleum coke prior to its combustion in the two CFB boilers. When limestone is heated to 1550 °F, it releases CO_2 and forms lime (CaO), which subsequently reacts with the SO_2 in the combustion gas to form calcium sulfates and calcium sulfites. The calcium compounds are removed as PM by the baghouse. Depending on the fuel fired in the boilers and the total heat input, YELP must achieve, under a Montana operating permit, 70% to 90% reduction of SO_2 emissions. YELP states that, during 2008 through 2009, SO_2 reduction averaged 95%. Increasing the limestone injection rate beyond current levels could theoretically result in a modest increase in SO_2 control.

SDAs were described in our analysis for CELP. SDAs have demonstrated the ability to achieve 90% to 94% SO_2 reduction. SDA plus limestone injection can achieve between 98% and 99% SO_2 reduction.[297] Due to the high degree of SO_2 control efficiency already achieved by limestone injection at this facility (95%), we have used 80% control efficiency for SDA in this analysis, downstream of limestone injection.

DSI was described in our BART analysis for Corette. SO_2 control efficiencies for DSI systems by themselves (not downstream of limestone injection systems) are approximately 50%, but if the sorbent is hydrated lime, then 80% or greater removal can be achieved. These systems are commonly called lime spray dryers.

A description of a CDS was provided in our analysis for CELP. A CDS can achieve removal efficiency similar to that achieved by SDA on CFB boilers.[298]

The HAR process was described in our analysis for CELP. HAR downstream of a CFB boiler that utilizes limestone injection can reduce the remaining SO_2 by about 80%.[299]

A general description of wet lime scrubbing was provided in our BART analysis for Ash Grove.

Wet lime and wet limestone scrubbers involve spraying alkaline slurry into the exhaust gas to react with SO_2 in the flue gas. Insoluble salts are formed in the chemical reaction that occurs in the scrubber and the salts are removed as a solid waste by-product. Wet lime and limestone scrubbers are very similar, but the type of additive used differs (lime or limestone). The use of limestone ($CaCO_3$) instead of lime requires different feed preparation equipment and a higher liquid-to-gas ratio. The higher liquid-to-gas ratio typically requires a larger absorbing unit. The limestone slurry process also requires a ball mill to crush the limestone feed. Wet lime and limestone scrubbers have been demonstrated to achieve greater than 99% control efficiency.[300]

Dual-alkali scrubbers use a sodium-based alkali solution to remove SO_2 from the combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The sodium-based reagents absorb SO_2 from the exhaust gas, and the calcium-based solution (lime or limestone) regenerates the spent liquor. Calcium sulfites and sulfates are precipitated and discarded as sludge, and the regenerated sodium solution is returned to the absorber loop. The dual-alkali process requires lower liquid-to-gas ratios than scrubbing with lime or limestone. The reduced liquid-to-gas ratios generally mean smaller reaction units; however, additional regeneration and sludge processing equipment is necessary. A sodium-based scrubbing solution, typically consisting of a mixture of sodium hydroxide, sodium carbonates, and sodium sulfite, is an efficient SO_2 control reagent. However, the process generates a sludge that can create material handling and disposal issues. The control efficiency is similar to the wet lime/limestone scrubbers at approximately 95% or greater.

Step 2: Eliminate Technically Infeasible Options

The current limestone injection system is operating at or near its maximum capacity. The boiler feed rates are approximately 740 tons/day of petroleum coke and 415 tons/day of limestone. Increasing limestone injection beyond the current levels would result in plugging of the injection

[293] See *http://www.greeninvgroup.com/news/news-release-missoula-announcement.html.*

[294] M2Green Redevelopment LLC Quarterly Excess Emissions Report—Third Quarter 2011 (11/1/2011).

[295] All information found within this section can be found in the corresponding report in the docket.

[296] Response to Additional Reasonable Progress Information for the Yellowstone Energy Limited Partnership Facility Pursuant to Section 114(a) of the CAA (42 U.S.C. Section 7414(A)) Prepared for Billings Generation, Inc. (''YELP Additional Response''), p. 2–1 February 24, 2011.

[297] Deseret Bonanza SOB, p. 92.

[298] *Id.*

[299] *Id.,* p. 93.

[300] Deseret Bonanza SOB, p. 94.

lines, and increased bed ash production, which can reduce combustion efficiency, and increased particulate loading to the baghouses. Therefore, increasing limestone injection beyond its current level would require major upgrades to the limestone feeding system and the baghouses.[301] Only modest increases in SO_2 removal efficiency, if any, would be expected with this scenario, compared to add-on SO_2 control systems discussed below. Therefore, a limestone injection process upgrade is eliminated from further consideration.

CDS systems result in high particulate loading to the unit's particulate control device. Because of the high particulate loading, the pressure drop across a fabric filter would be unacceptable; therefore, ESPs are generally used for particulate control. YELP has two high efficiency fabric filters (baghouses) in place. Based on limited technical data from non-comparable applications and engineering judgment, we are determining that CDS is not technically feasible for this facility.[302] Therefore, CDS is eliminated from further consideration.

A DSI system is not practical for use in a CFB boiler such as YELP, where limestone injection is already being used upstream in the boiler for SO_2 control. With limestone injection, the CFB boiler flue gas already contains excess unreacted lime. Fly ash containing this unreacted lime is reinjected back into the CFB boiler combustion bed, as part of the boiler operating design. A DSI system would simply add additional unreacted lime to the flue gas and would achieve little, if any, additional SO_2 control.[303] If used instead of limestone injection (the only practical way it might be used), DSI would achieve less control efficiency (50%) than the limestone injection system already being used (70 to 90%). Therefore, DSI is eliminated from further consideration.

Regarding wet scrubbing, there is limited area to install additional SO_2 controls that would require high quantities of water and dewatering ponds. The wet FGD scrubber systems with the higher water requirements (wet lime scrubber, wet limestone scrubber, and dual alkali wet scrubber) would require an on-site dewatering pond or an additional landfill to dispose of scrubber sludge. Due to the limited available space, its proximity to the Yellowstone River and limited water availability for these controls,[304] we consider these technologies technically infeasible and do not evaluate them further.

The remaining technically feasible SO_2 control options for YELP are SDA and HAR.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions from YELP are 1,826 tpy. A summary of emissions projections for the various control options is provided in Table 192. Since limestone injection is already in use at the YELP facility, the control efficiencies and emissions reductions shown below are those that might be achieved beyond the control already being achieved by the existing limestone injection system.

TABLE 192—SUMMARY OF YELP SO_2 REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
SDA	80	1,461	365
HAR	50	913	913

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of compliance

Table 193 provides a summary of estimated annual costs for the various control options. All costs shown are for the two boilers combined.

TABLE 193—SUMMARY OF YELP SO_2 REASONABLE PROGRESS COST ANALYSIS AS RECALCULATED BY EPA

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
SDA with baghouse replacement	6,237,065	4,211
SDA without baghouse replacement	4,709,504	3,182
HAR with baghouse replacement	4,660,376	5,104
HAR without baghouse replacement	3,132,815	3,431

We have relied on the control costs provided by YELP,[305] with two exceptions. First, we calculated the annual cost of capital using 7% annual interest rate and a 20-year equipment life (which yields a CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4 Regulatory Analysis.[306] Second, we calculated the cost of SDA and HAR in two ways: (1) With baghouse replacement, and (2) without baghouse replacement, see Table 193 above.

Factor 2: Time Necessary for Compliance

We have relied on YELP's estimates that the time necessary to complete the modifications to the two boilers to accommodate SDA or HAR, without replacing the baghouses, would be

[301] YELP Additional Response, p. 2–2.

[302] Deseret Bonanza SOB, p. 92.

[303] *Id.*, p. 93.

[304] YELP Additional Response, p. 2–5.

[305] *Id.*, p. 7–3.

[306] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/*.

approximately one year and that a boiler outage of approximate two to three months per boiler would be necessary to perform the installation of either system. The installation of the controls would need to be staggered to allow one boiler to remain in operation while the retrofits are applied to the other boiler. YELP states that complete replacement or major modifications to the existing baghouses would be necessary, however, the company does not explain why the existing baghouses would need to be replaced or modified to accommodate SDA or HAR.[307]

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

Wet FGD systems are estimated to consume 1% to 2.5% of the total electric generation of the plant and can consume approximately 40% more than dry FGD systems (SDA). Electricity requirements for a HAR system are less than FGD systems. DSI systems are estimated to consume 0.1% to 0.5% of the total plant generation.[308] For reasons explained above, wet FGD systems and DSI systems have already been eliminated as technically infeasible.

SO_2 controls would result in increased ash production at the YELP facility. Boiler ash is currently either sent to a landfill or sold for beneficial use, such as oil well reclamation. Changes in ash properties due to increased calcium sulfates and calcium sulfites could result in the ash being no longer suitable to be sold for beneficial uses. If the ash properties were to change such that the ash could no longer be sold for beneficial use, the loss of this market would cost approximately $2,300,000 per year at the current ash value and production rates (approximately 170,000 tons of ash per year). The loss of this market could also result in the company having to dispose of the ash at its current landfill, which is approximately 80 miles from the plant. The cost to dispose of the ash would be approximately $96,000 per year. The total cost from the loss of the beneficial use market and the increase in ash disposal costs would be a total of $2,400,000 per year.[309] This potential cost has not been included in the cost described above, as it is only speculative, being based on an undetermined potential future change in ash properties.

As described above, wet FGD scrubber systems with the higher water requirements (Wet Lime Scrubber, Wet Limestone Scrubber, and Dual Alkali Wet Scrubber) would require construction of an on-site dewatering pond or an additional landfill to dispose of scrubber sludge.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: the cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the sources. We are also taking into account the size of the facility, the baseline Q/D of the facility, and the potential reduction in Q/D from the controls. Given the cost of $3,182 per ton of SO_2 (at a minimum) for the most cost-effective option (SDA), the relatively small size of YELP, and the small baseline Q/D of 14, we find it reasonable to not impose any of the SO_2 control options. Therefore, we are proposing that no additional controls will be required for this planning period.

NO_X

Currently, there are no NO_X controls at the YELP facility.

Step 1: Identify All Available Technologies

We identified that the following technologies to be available: SCR, SNCR, LEA, FGR, OFA, LNB, non-thermal plasma reactor, and carbon injection into the combustion chamber.

SCR, SNCR, LNB, LEA, OFA, FGR, non-thermal plasma reactor, and carbon injection into the combustion chamber were described in our analysis for CELP.

The temperature range for proper operation of an SCR is between 480 °F and 800 °F. Many of the CFBs in the United States have baghouses for particulate control. The normal maximum allowable temperature for a baghouse is 400 °F.

Therefore, on some installations, RSCR is installed. RSCRs are expensive to install and expensive to operate, because an RSCR requires the use of burners to heat up the flue gas stream in order for the NO_X capture to occur. This is often an efficiency decrease for the boiler, significant increase in operating cost, and often not a practical solution. For this reason, RSCR was not evaluated as a control option for YELP. Instead, high dust SCR was evaluated.

Step 2: Eliminate Technically Infeasible Options

LEA, FGR, and OFA are typically used on Pulverized Coal (PC) units and cannot be used on CFB boilers due to air needed to fluidize the bed.[310] While LEA may have substantial effect on NO_X emissions at PC boilers, it has much less effect on NO_X emissions at combustion sources such as CFBs that operate at low combustion temperatures. FGR reduces NO_X formation by reducing peak flame temperature and is ineffective on combustion sources such as CFBs that already operate at low combustion temperatures. For these reasons, LEA, FGR and OFA are eliminated from further consideration.

LNBs are typically used on PC units and cannot be used on CFB boilers because the combustion occurs within the fluidized bed.[311] CFB boilers do not use burners during normal operation. Therefore, LNBs are eliminated from further consideration.

While a non-thermal plasma reactor may have practical potential for application to coal-fired CFB boilers as a technology transfer option at Step 1 of the analysis, it is not known to be commercially available for CFB boilers.[312] Therefore, a non-thermal plasma reactor is eliminated from further consideration.

Although carbon injection is an emerging technology used to reduce mercury emissions, it has not been used anywhere to control NO_X. Therefore, it is eliminated from further consideration.

The remaining technically feasible NO_X control options for YELP are HDSCR and SNCR.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology

Baseline NO_X emissions from YELP are 396 tpy. A summary of emissions projections for the various control options is provided in Table 194.

[307] YELP Additional Response, p. 3–1.

[308] *Id.,* p. 4–2.

[309] *Id.*

[310] *Id.*

[311] *Id.*

[312] Deseret Bonanza SOB, pp. 46, 48.

TABLE 194—SUMMARY OF YELP NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES

Control option	Control effectiveness (%)	Emissions reduction (tpy)	Remaining emissions (tpy)
HDSCR	80	317	79
SNCR	50	198	198

Step 4: Evaluate Impacts and Document Results

Factor 1: Costs of Compliance

Table 195 provides a summary of estimated annual costs for the various control options.

TABLE 195—SUMMARY OF YELP NO_X REASONABLE PROGRESS COST ANALYSIS

Control option	Total annual cost ($)	Cost effectiveness ($/ton)
HDSCR	3,883,020	12,249
SNCR	529,810	2,689

We have relied on the NO_X control costs provided by YELP,[313] with one exception. We calculated the annual cost of capital using a 7% annual interest rate and 20-year equipment life (which yields a CRF of 0.0944), as specified in the Office of Management and Budget's Circular A–4, Regulatory Analysis.[314]

Factor 2: Time Necessary for Compliance

We have relied on YELP's estimates that HDSCR would take approximately 26 months to install and that SNCR would take 24 to 30 weeks to install.[315]

Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

The energy impacts from SNCR are expected to be minimal. SNCR is not expected to cause a loss of power output from the facility. SCR, however, could cause significant backpressure on the boiler, leading to lost boiler efficiency and, thus, a loss of power production. If LDSCR was to be installed instead of HDSCR, YELP would be subject to the additional cost of reheating the exhaust gas.

Regarding other non-air quality environmental impacts of compliance, SCRs can contribute to airheater fouling from the formation of ammonium sulfate. Airheater fouling could reduce unit efficiency, increase flue gas velocities in the airheater, cause corrosion, and erosion. Catalyst replacement can lengthen boiler outages, especially in retrofit installations, where space and access is limited. This is a retrofit installation in a high dust environment, thus fouling is likely, which could lead to unplanned outages or less time between planned outages. On some installations, catalyst life is short and SCRs have fouled in high dust environments. For both SCR and SNCR, the storage of on-site NH_3 could pose a risk from potential releases to the environment. An additional concern is the loss of NH_3, or ''slip'' into the emissions stream from the facility. This ''slip'' contributes another pollutant to the environment, which has been implicated as a precursor to $PM_{2.5}$ formation.

Factor 4: Remaining Useful Life

EPA has determined that the default 20-year amortization period is most appropriate to use as the remaining useful life of the facility. Without commitments for an early shut down, EPA cannot consider a shorter amortization period in our analysis.

Step 5: Select Reasonable Progress Controls

We have considered the following four factors: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of the source. For the more expensive option (SCR), we have concluded that the costs per ton of pollutant reduced are excessive for this facility. The less expensive option (SNCR) would reduce emissions by 198 tpy, which equates to approximately an 8.9% reduction in overall emissions of $SO_2 + NO_X$ from this facility, or a reduction of Q/D from 14 to 13. Given the small size of the facility, the baseline Q/D, and the potential reduction in Q/D, we find it reasonable to eliminate this option. Therefore, we are proposing to not require any NO_X controls on this unit for this planning period.

d. Establishment of the Reasonable Progress Goal

40 CFR 51.308(d)(1) of the Regional Haze Rule requires states to ''establish goals (in deciviews) that provide for Reasonable Progress towards achieving natural visibility conditions'' for each Class I area of the state. These RPGs are interim goals that must provide for incremental visibility improvement for the most impaired visibility days, and ensure no degradation for the least impaired visibility days. The RPGs for the first planning period are goals for the year 2018.

Based on (1) the results of the WRAP CMAQ modeling, and (2) the results of the four-factor analysis of Montana point sources, we established RPGs for the most impaired days for all of Montana's Class I areas, as identified in Table 196 below. Also shown in Table 197 is a comparison of the RPGs to the URP for Montana Class I areas. The RPGs for the 20% worst days fall short

[313] YELP Additional Response, Appendix A.

[314] Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4/.*

[315] YELP Additional Response, p. 3–1.

of the URP by the amounts shown in the table.

TABLE 196—COMPARISON OF REASONABLE PROGRESS GOALS TO UNIFORM RATE OF PROGRESS ON MOST IMPAIRED DAYS FOR MONTANA CLASS I AREAS

Montana class I area	Visibility conditions on 20% worst days (deciview)			Percentage of URP achieved (%)
	Average for 20% worst days (baseline 2000–2004)	2018 URP goal	RPG (WRAP projection)	
Anaconda-Pintler WA	13.41	12.02	12.94	34
Bob Marshall WA	14.48	12.91	13.83	41
Cabinet Mountains WA	14.09	12.56	13.31	51
Gates of the Mountains WA	11.29	10.15	10.82	41
Glacier NP	22.26	19.21	21.48	26
Medicine Lake WA	17.72	15.42	17.36	16
Mission Mountain WA	14.48	12.91	13.83	41
Red Rock Lakes WA	11.76	10.52	11.23	43
Scapegoat WA	14.48	12.91	13.83	41
Selway-Bitterroot WA	13.41	12.02	12.94	34
U.L. Bend WA	15.14	13.51	14.85	18
Yellowstone NP	11.76	10.52	11.23	43

Our RPGs for each Class I area for 2018 for the 20% worst days represents the improvement shown in Table 197. Our RPGs establish a slower rate of progress than the URP. The number of years necessary to attain natural conditions was calculated by dividing the amount of improvement needed by the rate of progress established by the RPGs. Table 197 shows the number of years it would take to attain natural conditions if visibility improvement continues at the rate of progress established by the RPGs.

TABLE 197—NUMBER OF YEARS TO REACH NATURAL CONDITIONS FOR MONTANA CLASS I AREAS

Montana class I area	2064 natural conditions (deciview)	Average for 20% worst days (Baseline 2000–2004)	Improvement needed (deciview)	RPG Rate of improvement (deciview/year)	Number of years to reach natural conditions
Anaconda-Pintler WA	7.43	13.41	5.98	0.03	204
Bob Marshall WA	7.73	14.48	6.75	0.04	166
Cabinet Mountains WA	7.52	14.09	6.57	0.05	135
Gates of the Mountains WA	6.38	11.29	4.91	0.03	167
Glacier NP	9.18	22.26	13.08	0.05	268
Medicine Lake WA	7.89	17.72	9.83	0.02	437
Mission Mountain WA	7.73	14.48	6.75	0.04	166
Red Rock Lakes WA	6.44	11.76	5.32	0.03	161
Scapegoat WA	7.73	14.48	6.75	0.04	166
Selway-Bitterroot WA	7.43	13.41	5.98	0.03	204
U.L. Bend WA	8.16	15.14	6.98	0.02	385
Yellowstone NP	6.44	11.76	5.32	0.03	161

Table 198 provides a comparison of our RPGs for Montana to baseline conditions on the least impaired days. This comparison demonstrates that our RPGs will result in no degradation in visibility conditions in the first planning period.

TABLE 198—COMPARISON OF REASONABLE PROGRESS GOALS TO BASELINE CONDITIONS ON LEAST IMPAIRED DAYS FOR MONTANA CLASS I AREAS

Montana class I area	Visibility conditions on 20% best days (deciview)		Achieved "No degradation" (Y/N)
	Average for 20% best days (Baseline 2000–2004)	RPG (WRAP projection)	
Anaconda-Pintler WA	2.58	2.48	Y
Bob Marshall WA	3.85	3.60	Y
Cabinet Mountains WA	3.62	3.27	Y
Gates of the Mountains WA	1.71	1.54	Y

TABLE 198—COMPARISON OF REASONABLE PROGRESS GOALS TO BASELINE CONDITIONS ON LEAST IMPAIRED DAYS FOR MONTANA CLASS I AREAS—Continued

Montana class I area	Visibility conditions on 20% best days (deciview)		Achieved "No degradation" (Y/N)
	Average for 20% best days (Baseline 2000–2004)	RPG (WRAP projection)	
Glacier NP	7.22	6.92	Y
Medicine Lake WA	7.26	7.11	Y
Mission Mountain WA	3.85	3.60	Y
Red Rock Lakes WA	2.58	2.36	Y
Scapegoat WA	3.85	3.60	Y
Selway-Bitterroot WA	2.58	2.48	Y
U.L. Bend WA	4.75	4.57	Y
Yellowstone NP	2.58	2.36	Y

The Regional Haze Rule states that if we establish a RPG that provides for a slower rate of improvement in visibility than the rate that would be needed to attain natural conditions by 2064, we must demonstrate that the rate of progress for the implementation plan to attain natural conditions by 2064 is not reasonable; and that the progress goal we adopt is reasonable. 40 CFR 51.308(d)(1)(B)(ii).

We are proposing that the RPGs we established for the Montana Class I areas are reasonable, and that it is not reasonable to achieve the glide path in 2018, for the following reasons:

1. Findings from our four-factor analyses resulted in limited opportunities for reasonable controls for point sources.

2. As described previously in section V.D.2., significant visibility impairment is caused by non-anthropogenic sources in and outside Montana.

We could not re-run the WRAP modeling, but anticipate that the additional controls would result in an increase in visibility improvement during the 20% worst days and the 20% best days. As noted in our analyses, many of our proposed controls would result in significant incremental visibility benefits when modeled against natural background. We anticipate that this would translate into some measurable improvement if modeled on the 20% worst days as well. We are confident that this improvement would not be sufficient to achieve the URP at Montana Class I areas.

For purposes of this action, we are proposing RPGs that are consistent with the additional controls we are proposing. While we would prefer to quantify the RPGs, we note that the RPGs themselves are not enforceable values. The more critical elements of our FIP are the enforceable emissions limits we are proposing.

e. Reasonable Progress Consultation

In accordance with 40 CFR 51.308(d)(3)(i) and (ii), each state that causes or contributes to impairment in a Class I area in another state or states is required to consult with other states and demonstrate that it has included in its SIP all measures necessary to obtain its share of the emission reductions needed to meet the progress goals for the Class I area. If the state has participated in a regional planning process, the state must ensure it has included all measures needed to achieve its apportionment of emission reduction obligations agreed upon through that process.

In this case, where EPA is promulgating a FIP, we take on the responsibilities of the state. We propose that we have met the requirement for consultation with other states through our participation in the WRAP process. Through this processes, we worked with neighboring states, and relied on the technical tools, policy documents, and other products that all western states used to develop their regional haze plans. The WRAP Implementation Work Group was one of the primary collaboration mechanisms. Discussions with neighboring states included the review of major contributing sources of air pollution, as documented in numerous WRAP reports and projects. The focus of this review process was interstate transport of emissions, major sources believed to be contributing, and whether any mitigation measures were needed. All the states relied upon similar emission inventories, results from source apportionment studies and BART modeling, review of IMPROVE monitoring data, existing state smoke management programs, and other information in assessing the extent to which each state contributes to visibility impairment other states' Class I areas.

The Regional Haze Rule at 40 CFR 51.308(d)(3)(ii) requires a state to demonstrate that its regional haze plan includes all measures necessary to obtain its fair share of emission reductions needed to meet RPGs. Based on the consultation described above, we identified no major contributions that supported developing new interstate strategies, mitigation measures, or emission reduction obligations. Both EPA and neighboring states agreed that the implementation of BART and other existing measures in state regional haze plans were sufficient for the states to meet the RPGs for their Class I areas, and that future consultation would address any new strategies or measures needed.

f. Mandatory Long-Term Strategy Requirements

40 CFR 51.308(d)(3)(v) requires that we, at a minimum, consider certain factors in developing our LTS (the LTS factors). These are: (a) Emission reductions due to ongoing air pollution control programs, including measures to address RAVI; (b) measures to mitigate the impacts of construction activities; (c) emissions limitations and schedules for compliance to achieve the RPG; (d) source retirement and replacement schedules; (e) smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for these purposes; (f) enforceability of emissions limitations and control measures; and (g) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the LTS.

i. Reductions Due to Ongoing Air Pollution Programs

In addition to our BART determinations, our LTS incorporates emission reductions due to a number of ongoing air pollution control programs.

a. Prevention of Significant Deterioration/New Source Review Rules

The two primary regulatory tools for addressing visibility impairment from industrial sources are BART and the PSD New Source Review rules. The PSD rules protect visibility in Class I areas from new industrial sources and major changes to existing sources. Title 17, Chapter 8 of the ARM contain requirements for visibility impact assessment and mitigation associated with emissions from new and modified major stationary sources. A primary responsibility of Montana under these rules is visibility protection. ARM 17.8.1106 requires an owner or operator of a major source or major modification to demonstrate that the emissions will not cause or contribute to adverse impact on a Class I area or the Department shall not issue a permit. ARM 17.8.1107 describes the modeling methods.

b. Montana's Phase I Visibility Protection Program

Montana's Visibility SIP was approved as meeting the requirements of 40 CFR 51.305 (Monitoring for RAVI) and 40 CFR 51.307 (New Source Review) on June 6, 1986 (51 FR 20646). On February 17, 2012, Montana submitted a revised Visibility SIP, which as explained in the submittal, includes administrative updates to rule citations, board affiliation, and grammar/punctuation edits to these sections.

EPA will act on the revisions to the sections addressing monitoring for RAVI, new source review, and other sections in a future action.

c. On-going Implementation of State and Federal Mobile Source Regulations

Mobile source NO_X and SO_2 emissions are expected to decrease in Montana from 2002 to 2018.[316] This reduction will result from numerous ''on the books'' federal mobile source regulations described below. This trend is expected to provide significant visibility benefits. Beginning in 2006, EPA mandated new standards for on-road (highway) diesel fuel, known as ultra-low sulfur diesel. This regulation dropped the sulfur content of diesel fuel from 500 ppm to 15 ppm. Ultra-low sulfur diesel fuel enables the use of cleaner technology diesel engines and vehicles with advanced emissions control devices, resulting in significantly lower emissions.

Diesel fuel intended for locomotive, marine, and non-road (farming and construction) engines and equipment was required to meet a low sulfur diesel fuel maximum specification of 500 ppm sulfur in 2007 (down from 5000 ppm). By 2010, the ultra-low sulfur diesel fuel standard of 15 ppm sulfur applied to all non-road diesel fuel. Locomotive and marine diesel fuel will be required to meet the ultra-low sulfur diesel standard beginning in 2012, resulting in further reductions of diesel emissions.

ii. Measures to Mitigate the Impacts of Construction Activities

In developing our LTS, we have considered the impact of construction activities. Based on our general knowledge of construction activity in the State, and without conducting extensive research on the contribution of emissions from construction activities to visibility impairment in Montana Class I areas, we propose to find that current State regulations adequately address construction activities because the regulations already require controls for these sources. Current rules addressing impacts from construction activities in Montana include ARM 17.8.308, which regulates fugitive dust emissions. The rule requires that ''no person shall operate a construction site or demolition project unless reasonable precautions are taken to control emissions of airborne particulate matter.'' The SIP rule also requires that ''[s]uch emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over six consecutive minutes.'' Additionally, emissions from vehicles at construction site are expected to decrease due to on-going implementation of federal mobile source regulations. ARM 18.8.743 requires permits for asphalt concrete plants, mineral crushers, and mineral screens that have a potential to emit that is greater than 15 tpy.

iii. Emission Limitations and Schedules for Compliance

For those sources subject to BART: Ash Grove Cement Company; PPL Montana, LLC Colstrip Steam Electric Station (Unit 1 and Unit 2); Holcim (US), Inc.; and PPL Montana, LLC JE Corette Steam Electric Station, we have included proposed emission limits and schedules of compliance in regulatory text at the end of this proposal.

As described earlier in Section V.C.3.b.iii, we are proposing that we make a BART determination in the future for CFAC if the sources at that facility begin operating. Additionally, we also are proposing that those sources at CFAC will be required to implement that determination within five years of our final FIP for this action.

For the source that is subject to additional controls for RP requirements, Devon, we have included proposed emission limits and schedules of compliance in regulatory text at the end of this proposal.

We are proposing to determine whether additional controls will be required for Green Investment Group, Inc. (previously owned by Smurfit Stone Container Enterprises Inc.) if the sources at that facility begin operating. We also are proposing that those sources will be required to implement any additional controls that are required by those determinations within this planning period. The proposed schedules for implementation of additional controls for this source is identified within the four factor analyses for this source.

iv. Sources Retirement and Replacement Schedules

Even though the sources at CFAC and Green Investment Group Inc. are not currently operating, we are not relying on those source retirements or replacements in the LTS. Replacement of existing facilities will be managed according to Montana's existing PSD program. The 2018 modeling that WRAP conducted included one new power plant in Montana that is unlikely to be built.[317] Construction of new power plants or replacement of existing plants prior to 2018 is unlikely.

v. Agricultural and Forestry Smoke Management Techniques

We are proposing to use the WRAP's estimates of fire emissions in our analysis for Montana. Table 199, below, shows WRAP's estimate of emissions from fire in Montana for the 2000–2004 baseline period.

[316] WRAP TSD. and Final Report, WRAP Mobile Source Emission Inventories Updated, dated May 2006.

[317] Email from Debbie Skibicki to Vanessa Hinkle dated January 4, 2012 regarding Roundup Power.

TABLE 199—ANNUAL AVERAGE EMISSIONS FROM FIRE (2000–2004) (TONS/YEAR)

Source	$PM_{2.5}$	PM_{10}	NO_X	SO_2	OC	EC
Natural	2,911	8,496	13,770	4,634	38,324	7,743
Anthropogenic	279	713	1,513	500	3,745	759
Total	3,190	9,209	15,283	5,134	42,069	8,502

A more detailed description of the inventories can be found in the docket.[318] 40 CFR 308(d)(3)(v)(E) of the Regional Haze Rule requires the LTS to address smoke management techniques for agricultural and forestry burning. These two sources generally have a very small contribution to visibility impairment in Montana Class I areas. Much of these fire emissions are from wildfires, which fluctuate significantly from year to year. The following paragraph summarizes source apportionment analyses conducted by the WRAP.

As described previously in Sections V.D.6.b., most of the emissions from fire are from wildfires which fluctuate significantly from year to year. Anthropogenic fire contributes 8% to primary organic aerosol emissions, 6% to EC emissions, less than 1% to $PM_{2.5}$ emissions, less than 1% to PM_{10} emissions, 1% to SO_2 emissions, and less than 1% to NO_X emissions. Natural fire contributes 80% to primary organic aerosol emissions, 65% to EC emissions, 4% to $PM_{2.5}$ emissions, 1% to PM_{10} emissions, 9% to SO_2 emissions, and 6% to NO_X emissions. As described previously in Section V.D.2., OC contributes 15% to 64%, EC contributes 4% to 8%, fine particulate contributes 1% to 7%, coarse particulate contributes 4% to 8%, SO_2 contributes 8% to 28%, and NO_X contributes 3% to 27% of the total light extinction to Montana Class I areas.

40 CFR 308(d)(3)(v)(E) of the Regional Haze Rule requires states to consider smoke management techniques for agricultural and forestry burning in their LTS. We are proposing to approve amendments to Montana's existing smoking management program that will ensure that the State's program meets the Regional Haze Rule requirement.

Montana's existing smoke management program regulates major and minor sources of open burning; and the State operates a year round open burning program as well as issues air quality open burning permits for specific types of open burning.[319] On February 17, 2012, Montana submitted a revised Montana Visibility Plan (Plan) that contained revisions to the smoke management program. As described in Montana's ''Explanation of Proposed Action'' the revised Plan ''includes a reference to BACT as the current visibility mitigation measure for open burning administered through the Department's open burning permit program''. The revised Plan requires Montana to consider the visibility impact of smoke on the mandatory federal class I areas when developing, issuing or conditioning permits and when making dispersion forecast recommendations through the implementation of Title 17, Chapter 8, Subchapter 6, Open Burning. These revisions appear in the paragraph of the Plan titled ''Smoke Management''.[320] We are proposing that to approve the revisions to this paragraph titled ''Smoke Management'' as meeting the requirement in 40 CFR 308(d)(3)(v)(E) because the Plan controls emissions from these sources by requiring BACT and takes into consideration the visibility impacts on the mandatory class I areas. We will take action in a future notice on the additional revisions in the Montana Visibility Plan, which as explained in the State's February 17, 2012 submittal include administrative updates to rule citations, board affiliation, and grammar/punctuation edits.

vi. Enforceability of Montana's Measures

40 CFR 51.308(d)(3)(v)(F) of the Regional Haze Rule requires us to ensure that emission limitations and control measures used to meet RPGs are enforceable. In addition to what is required by the Regional Haze Rule, general FIP requirements mandate that the FIP must also include adequate monitoring, recordkeeping, and reporting requirements for the regional haze emission limits and requirements. See CAA section 110(a). As noted, we are proposing specific BART and other emission limits and compliance schedules. For SO_2 and NO_X limits, we are proposing to require the use of CEMS that must be operated and maintained in accordance with relevant EPA regulations, in particular, 40 CFR part 75. For PM limits, we are requiring regular testing. We are proposing to require that relevant records be kept for five years, and that sources report excess emissions on a quarterly basis.

In addition to these requirements, various requirements that are relevant to regional haze are codified in Montana's regulations, including Montana's PSD and other provisions mentioned above.

vii. Anticipated Net Effect on Visibility Due to Projected Changes

The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during this planning period is addressed in section V.D.4 above.

E. Coordination of RAVI and Regional Haze Requirements

Our visibility regulations direct states to coordinate their RAVI LTS and monitoring provisions with those for regional haze, as explained in section IV.G, above. Under our RAVI regulations, the RAVI portion of a state SIP must address any integral vistas identified by the FLMs pursuant to 40 CFR 51.304. See 40 CFR 51.302. An *integral vista* is defined in 40 CFR 51.301 as a ''view perceived from within the mandatory Class I federal area of a specific landmark or panorama located outside the boundary of the mandatory Class I federal area.'' Visibility in any mandatory Class I Federal area includes any integral vista associated with that

[318] WRAP TSD; Development of 2000–04 Baseline Period and 2018 Projection Year Emission Inventories, FINAL dated May 2007; Emissions Overview, for which WRAP did not include a date; 2002 Planning Simulation Version D Specification Sheet for which WRAP did not include a date; 1996 Fire Emission Inventory dated December 2002. The actual inventories can be found in the docket in the spreadsheets with the following title: 02d Area Source Inventory.

[319] There are several key elements of Montana's existing smoke management program, which include: (1) Smoke is monitored in Montana (*http://www.satguard.com/usfs4/realtime/MT.asp*); (2) the open burning SIP regulations require best available control technology (BACT) as the visibility mitigation measure for open burning administered through MDEQ's open burning permit program; and (3) the State participates in Montana State Airshed Group, which implements an enhanced smoke management plan (information on the Montana State Airshed Group can be found at *http://www.smokemu.org/about.cfm*).

[320] State of Montana Air Quality Control Implementation Plan, Volume I, Chapter 9, p. 9.6(8) (Dec. 2, 2011).

area. The FLMs did not identify any integral vistas in Montana. In addition, there have been no certifications of RAVI in the Montana Class I areas, nor are any Montana sources affected by the RAVI provisions. We commit to coordinate the Montana regional haze LTS with our RAVI FIP LTS. We propose to find that the Regional Haze FIP appropriately supplements and augments the EPA FIP for RAVI visibility provisions by updating the monitoring and LTS provisions to address regional haze. We discuss the relevant monitoring provisions further below.

F. Monitoring Strategy and Other Implementation Plan Requirements

40 CFR 51.308(d)(4) requires that the FIP contain a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment that is representative of all mandatory Class I Federal areas within the state. This monitoring strategy must be coordinated with the monitoring strategy required in 40 CFR 51.305 for RAVI. As 40 CFR 51.308(d)(4) notes, compliance with this requirement may be met through participation in the IMPROVE network. 40 CFR 51.308(d)(4)(i) further requires the establishment of any additional monitoring sites or equipment needed to assess whether RPGs to address regional haze for all mandatory Class I Federal areas within the state are being achieved. Consistent with EPA's monitoring regulations for RAVI and regional haze, EPA will rely on the IMPROVE network for compliance purposes, in addition to any RAVI monitoring that may be needed in the future. Further information on monitoring methods and monitor locations can be found in the docket.[321] [322] The most recent report also can be found in the docket.[323] Therefore, we propose to find that we have satisfied the requirements of 40 CFR 51.308(d)(4) enumerated in this paragraph.

40 CFR 51.308(d)(4)(ii) requires that EPA establish procedures by which monitoring data and other information are used in determining the contribution of emissions from within Montana to regional haze visibility impairment at mandatory Class I Federal areas both within and outside the State. The IMPROVE monitoring program is national in scope, and other states have similar monitoring and data reporting procedures, ensuring a consistent and robust monitoring data collection system. As 40 CFR 51.308(d)(4) indicates, participation in the IMPROVE program constitutes compliance with this requirement.

40 CFR 51.308(d)(4)(iv) requires that the FIP provide for the reporting of all visibility monitoring data to the Administrator at least annually for each mandatory Class I Federal area in the state. To the extent possible, EPA should report visibility monitoring data electronically. 40 CFR 51.308(d)(4)(vi) also requires that the FIP provide for other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility. We propose that EPA's participation in the IMPROVE network ensures that the monitoring data is reported at least annually and is easily accessible; therefore, such participation complies with this requirement.

40 CFR 51.308(d)(4)(v) requires that EPA maintain a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area. The inventory must include emissions for a baseline year, emissions for the most recent year for which data are available, and estimates of future projected emissions. EPA must also include a commitment to update the inventory periodically. Please refer to section V.D.1, above, where we discuss EPA's emission inventory for Montana. EPA proposes that we will update statewide emissions inventories periodically and review periodic emissions information from other states and future emissions projections. Additionally, during the next planning period EPA intends to review and consider emissions from oil and gas activities, as well as from other sources. Therefore, we propose that this satisfies the requirement.

G. Coordination With FLMs

The Forest Service manages Anaconda-Pintler WA, Bob Marshall WA, Cabinet Mountains WA, Gates of the Mountains WA, Mission Mountains WA, Scapegoat WA, and Selway-Bitterroot WA. The Fish and Wildlife Service manages the Medicine Lake WA, Red Rocks Lake WA, and U.L. Bend WA. The National Park Service manages Glacier NP and Yellowstone NP. Although the FLMs are very active in participating in the RPOs, the Regional Haze Rule grants the FLMs a special role in the review of regional haze FIPs, summarized in section IV.H, above.

Initially, MDEQ met the requirement of 40 CFR 51.308(i)(1) by sending letters to the FLMs dated November 5, 1999. The letters included the title of the official to which the FLM of any mandatory Class I Federal area could submit any recommendations on the implementation of the regional haze rule including the identification of impairment of visibility in any mandatory Class I Federal area(s) and the identification of elements for inclusion in the visibility monitoring strategy required by 40 CFR 51.305 and the regional haze rule.

Under 40 CFR 51.308(i)(2), we were obligated to provide the Forest Service, the Fish and Wildlife Service, and the National Park Service with an opportunity for consultation, in person and at least 60 days prior to holding a public hearing on the Regional Haze FIP. We sent a draft of our Regional Haze FIP to the Forest Service, the Fish and Wildlife Service, and the National Park Service on February 16, 2012 and March 5, 2012. We notified the FLMs of our public hearings (as initially scheduled) on March 14, 2012. 40 CFR 51.308(i)(3) requires that we provide in our Regional Haze FIP a description of how we addressed any comments provided by the FLMs. We revised our proposed Regional Haze FIP to incorporate comments received by the FLMs.

Lastly, 40 CFR 51.308(i)(4) specifies the regional haze FIP must provide procedures for continuing consultation with the FLMs on the implementation of the visibility protection program required by 40 CFR 51.308, including development and review of implementation plan revisions and 5-year progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas. We commit to continue to coordinate and consult with the FLMs as required by 40 CFR 51.308(i)(4). We intend to consult the FLMs in the development and review of implementation plan revisions; review of progress reports; and development and implementation of other programs that may contribute to impairment of visibility at Montana and other Class I areas.

We are proposing that we have complied with the requirements of 40 CFR 51.308(i).

[321] *Visibility Monitoring Guidance,* EPA–454/R–99–003, June 1999, *http://www.epa.gov/ttn/amtic/files/ambient/visible/r-99-003.pdf.*

[322] Guidance for Tracking Progress Under the Regional Haze Rule, EPA–454/B–03–004, September 2003, available at *http://www.epa.gov/ttncaaa1/t1/memoranda/rh_tpurhr_gd.pdf.* Figure 1–2 shows the monitoring network on a map, while Table A–2 lists Class I areas and corresponding monitors.

[323] *Spatial and Seasonal Patterns and Temporal Variability of Haze and its Constituents in the United States,* Report V, ISSN 0737–5352–87, June 2011.

H. Periodic FIP Revisions and Five-Year Progress Reports

Consistent with 40 CFR 51.308(g), we are committing to prepare a progress report in the form of a FIP revision, every five years following the final FIP. The FIP revision will evaluate progress towards the RPG for each mandatory Class I Federal area located within Montana and in each mandatory Class I Federal area located outside Montana that may be affected by emissions from within Montana. The FIP revision will include all the activities in 40 CFR 51.308(g).

VI. Proposed Action

A. Montana Visibility SIP

B. We are proposing to approve the changes to one of the sections of Montana's Visibility SIP that were submitted on February 17, 2012 that includes amendments to the ''Smoke Management'' section, which adds a reference to BACT as the visibility control measure for open burning as currently administered through the State's air quality permit program.

Montana Regional Haze FIP

We are proposing the promulgation of a FIP to address Regional Haze for Montana that we have identified in this proposal. The proposed FIP includes the following elements:

- For Ash Grove Cement:
  - A NO_X BART determination and emission limit of 8 lb/ton clinker that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this NO_X BART limit within five (5) years of the effective date of our final rule.
  - A SO_2 BART determination and emission limit of 11.5 lb/ton clinker that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this SO_2 BART limit within 180 days of the effective date of our final rule.
  - The following PM BART determination and emission limit: if the process weight rate of the kiln is less than or equal to 30 tons per hour, then the emission limit shall be calculated using $E=4.10p^{0.67}$ where E = rate of emission in pounds per hour and p = process weight rate in tons per hour; however, if the process weight rate of the kiln is greater than 30 tons per hour, then the emission limit shall be calculated using $E = 55.0p^{0.11} - 40$, where E = rate of emission in pounds per hour and P = process weight rate in tons per hour. This limit applies on a 30-day rolling average, and a requirement that the owners/operators comply with this PM BART limit within 30 days of the effective date of our final rule.
- For Colstrip Units 1 and 2:
  - NO_X BART determinations and emission limits of 0.15 lb/MMBtu that apply singly to each of these units on a 30-day rolling average, and a requirement that the owners/operators comply with these NO_X BART limits within five (5) years of the effective date of our final rule.
  - SO_2 BART determinations and emission limits of 0.08 lb/MMBtu that apply singly to each of these units on a 30-day rolling average, and a requirement that the owners/operators comply with these SO_2 BART limits within five (5) years of the effective date of our final rule.
  - PM BART determinations and emission limits of 0.10 lb/MMBtu that apply singly to each of these units on a 30-day rolling average, and a requirement that the owners/operators comply with these PM BART limits within 30 days of the effective date of our final rule.
- For Holcim:
  - A NO_X BART determination and emission limit of 5.5 lbs/ton clinker produced that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this NO_X BART limit within five (5) years of the effective date of our final rule.
  - A SO_2 BART determination and emission limit of 1.3 lbs/ton clinker produced that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this SO_2 BART limit within 180 days of the effective date of our final rule.
  - A PM BART determination and emission limit of 0.77 lb/ton clinker produced that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this PM BART limit within 30 days of the effective date of our final rule.
- For Corette:
  - A NO_X BART determination and emission limit of .40 lb/MMBtu that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this NO_X BART limit within 30 days of the effective date of our final rule.
  - A SO_2 BART determination and emission limit of 0.70 lb/MMBtu that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this SO_2 BART limit within 30 days of the effective date of our final rule.
  - A PM BART determination and emission limit of 0.10 lb/MMBtu that applies on a 30-day rolling average, and a requirement that the owners/operators comply with this PM BART limit within 30 days of the effective date of our final rule.
- For Devon Energy Blaine County #1 Compressor Station, a NO_X emission limit of 21.8 lb/hr that applies on a 30-day rolling average, and a requirement, as described in our proposed regulatory text for 40 CFR § 52.1395, that the owners/operators comply with this limit as expeditiously as practicable, but no later than July 31, 2018.
- For CFAC, CFAC must notify EPA 60 days in advance of resuming operation. Once CFAC notifies EPA that it intends to resume operation, EPA will initiate and complete a BART determination after notification and revise the FIP as necessary in accordance with regional haze requirements, including the BART provisions in 40 CFR 51.308(e). CFAC will be required to install any controls that are required as soon as practicable, but in no case later than five years following the effective date of this action.
- For the M2Green Redevelopment LLC, Missoula Site, M2Green Redevelopment LLC must notify EPA 60 days in advance of resuming operation. Once M2 Green Redevelopment LLC notifies EPA that it intends to resume operation, EPA will initiate and complete a four factor analysis after notification and revise the FIP as necessary in accordance with regional haze requirements including the ''reasonable progress'' provisions in 40 CFR 51.308(d)(1). M2 Green Redevelopment LLC will be required to install any controls that are required as soon as practicable, but in no case later than July 31, 2018.
- Monitoring, recordkeeping, and reporting requirements for the above six units to ensure compliance with these emission limitations.
- RPGs consistent with the proposed FIP limits.
- LTS elements that reflect the other aspects of the proposed FIP.

VII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

This proposed action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011). As discussed in detail in section C below, the proposed FIP applies to only six sources. It is therefore not a rule of general applicability.

B. Paperwork Reduction Act

This proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* Under the Paperwork Reduction Act, a ''collection of information'' is defined as a requirement for ''answers to * * * identical reporting or recordkeeping requirements imposed on ten or more persons * * *.'' 44 U.S.C. 3502(3)(A). Because the proposed FIP applies to just six facilities, the Paperwork Reduction Act does not apply. *See* 5 CFR 1320(c).

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid Office of Management and Budget (OMB) control number. The OMB control numbers for our regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's proposed rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed action on small entities, I certify that this proposed action will not have a significant economic impact on a substantial number of small entities. EPA's proposal consists of the proposed partial approval of Montana's Regional Haze SIP submission and the proposed Regional Haze FIP by EPA that adds additional controls to certain sources. The Regional Haze FIP that EPA is proposing for purposes of the regional haze program consists of imposing federal controls to meet the BART requirement for PM, NO_X and SO_2 emissions on specific units at five sources in Montana, and imposing controls to meet the RP requirement for NO_X emissions at one additional source in Montana. The net result of the FIP action is that EPA is proposing direct emission controls on selected units at six sources. The sources in question are two large electric generating plants, two cement plants, and one gas compressor station, and none of these sources are not owned by small entities, and therefore are not small entities. The proposed partial approval of the SIP, if finalized, merely approves state law as meeting federal requirements and imposes no additional requirements beyond those imposed by state law. *See Mid-Tex Electric Cooperative, Inc.* v. *FERC,* 773 F.2d 327 (D.C. Cir. 1985)

D. Unfunded Mandates Reform Act (UMRA)

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more (adjusted for inflation) in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 of UMRA do not apply when they are inconsistent with applicable law. Moreover, section 205 of UMRA allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Under Title II of UMRA, EPA has determined that this proposed rule does not contain a federal mandate that may result in expenditures that exceed the inflation-adjusted UMRA threshold of $100 million by State, local, or Tribal governments or the private sector in any one year. In addition, this proposed rule does not contain a significant federal intergovernmental mandate as described by section 203 of UMRA nor does it contain any regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

Federalism (64 FR 43255, August 10, 1999) revokes and replaces Executive Orders 12612 (Federalism) and 12875 (Enhancing the Intergovernmental Partnership). Executive Order 13132 requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.'' Under Executive Order 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the proposed regulation. EPA also may not issue a regulation that has federalism implications and that preempts State law unless the Agency consults with State and local officials early in the process of developing the proposed regulation.

This rule will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132, because it merely addresses the State not fully meeting its obligation to prohibit emissions from interfering with other states measures to protect visibility established in the CAA. Thus, Executive Order 13132 does not apply to this action. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled *Consultation and Coordination with Indian Tribal Governments* (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' This proposed rule does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments. Thus, Executive Order 13175 does not apply to this rule. However, EPA did send letters, dated October 7, 2011, to each of the Montana Tribes explaining our regional haze FIP action and offering consultation. We did not receive any written or verbal requests from the Montana Tribes for more information or consultation. As a follow-up to our letter, we invited all of the Tribes to a January 5, 2012 conference call. The call was attended by tribal Air Program Managers and one Environmental Director from tribes from four reservations. We will be offering to meet with the Montana Tribes prior to the start of the public hearings being held in Helena and Billings, Montana. EPA specifically solicits additional comment on this proposed rule from tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045: *Protection of Children from Environmental Health Risks and Safety Risks* (62 FR 19885, April 23, 1997), applies to any rule that: (1) Is determined to be economically significant as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. EPA interprets EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it implements specific standards established by Congress in statutes. However, to the extent this proposed rule will limit emissions of NO_X, SO_2, and PM, the rule will have a beneficial effect on children's health by reducing air pollution.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12 of the National Technology Transfer and Advancement Act (NTTAA) of 1995 requires federal agencies to evaluate existing technical standards when developing a new regulation. To comply with NTTAA, EPA must consider and use ''voluntary consensus standards'' (VCS) if available and applicable when developing programs and policies unless doing so would be inconsistent with applicable law or otherwise impractical.

The EPA believes that VCS are inapplicable to this action. Today's action does not require the public to perform activities conducive to the use of VCS.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994), establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

We have determined that this proposed rule, if finalized, will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This proposed rule limits emissions of NO_X SO_2 and PM from six sources in Montana.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

Dated: March 20, 2012.

James B. Martin,

Regional Administrator, Region 8.

40 CFR part 52 is proposed to be amended as follows:

PART 52—[AMENDED]

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart BB—Montana

2. Section 52.1370 is amended by revising paragraph (c)(27)(i)(H) to read as follows:

§ 52.1370 Identification of plan.

* * * * *

(c) * * *

(27) * * *

(i) * * *

(H) Appendix G–2, Montana Smoke Management Plan, effective April 15, 1988, is superseded by § 52.1365.

* * * * *

3. Add § 52.1395 to read as follows:

§ 52.1395 Smoke management plan.

The Department considers smoke management techniques for agriculture and forestry management burning purposes as set forth in 40 CFR 51.308(d)(3)(v)(E). The Department considers the visibility impact of smoke when developing, issuing, or conditioning permits and when making dispersion forecast recommendations through the implementation of Title 17, Chapter 8, subchapter 6, ARM, Open Burning.

4. Add section 52.1396 to read as follows:

§ 52.1396 Federal implementation plan for regional haze.

(a) *Applicability.* This section applies to each owner and operator of the following coal fired electric generating units (EGUs) in the State of Montana: PPL Montana, LLC, Colstrip Power Plant, Units 1, 2; and PPL Montana, LLC, JE Corette Steam Electric Station. This section also applies to each owner and operator of cement kilns at the following cement production plants: Ash Grove Cement, Montana City Plant; and Holcim (US) Inc. Cement, Trident Plant. This section also applies to each owner or operator of Blaine County #1 Compressor Station. This section also applies to each owner and operator of CFAC and M2 Green Redevelopment LLC, Missoula site.

(b) *Definitions.* Terms not defined below shall have the meaning given them in the Clean Air Act or EPA's regulations implementing the Clean Air Act. For purposes of this section:

Boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the EGU. It is not necessary for fuel to be combusted for the entire 24-hour period.

Continuous emission monitoring system or CEMS means the equipment required by this section to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of SO_2 or NO_X emissions, other pollutant emissions, diluent, or stack gas volumetric flow rate.

Kiln operating day means a 24-hour period between 12 midnight and the following midnight during which the kiln operates.

NO_X means nitrogen oxides.

Owner/operator means any person who owns or who operates, controls, or supervises an EGU identified in paragraph (a) of this section.

PM means filterable total particulate matter.

SO_2 means sulfur dioxide.

Unit means any of the EGUs or cement kilns identified in paragraph (a) of this section.

(c) *Emissions limitations.* (1) The owners/operators of EGUs subject to this section shall not emit or cause to be emitted PM, SO_2 or NO_X in excess of the following limitations, in pounds per million British thermal units (lb/MMBtu), averaged over a rolling 30-day period:

Source name	PM Emission limit (lb/MMBtu)	SO_2 Emission limit (lb/MMBtu)	NO_X Emission limit (lb/MMBtu)
Colstrip Unit 1	0.10	0.08	0.15
Colstrip Unit 2	0.10	0.08	0.15
JE Corette Unit 1	0.10	0.70	0.40

(2) The owners/operators of cement kilns subject to this section shall not emit or cause to be emitted PM, SO_2 or NO_X in excess of the following limitations, in pounds per ton of clinker produced, averaged over a rolling 30-day period:

Source name	PM Emission limit (lb/ton clinker)	SO_2 Emission limit (lb/ton clinker)	NO_X Emission limit (lb/ton clinker)
Ash Grove Cement	If the process weight rate of the kiln is less than or equal to 30 tons per hour, then the emission limit shall be calculated using $E = 4.10p^{0.67}$ where E = rate of emission in pounds per hour and p = process weight rate in tons per hour; however, if the process weight rate of the kiln is greater than 30 tons per hour, then the emission limit shall be calculated using $E = 55.0p^{0.11}-40$, where E = rate of emission in pounds per hour and P = process weight rate in tons per hour..	11.5	8.0
Holcim (US) Inc.	0.77 lb/ton	1.3	5.5

(3) The owners/operators of LP, Blaine County #1 Compressor Station shall not emit or cause to be emitted NO_X in excess of 21.8 lbs/hr (30-day rolling average).

(4) These emission limitations shall apply at all times, including startups, shutdowns, emergencies, and malfunctions.

(d) *Compliance date.* The owners and operators of Blaine County #1 Compressor Station shall comply with the emissions limitation and other requirements of this section expeditiously as practicable, but no later than July 31, 2018. The owners and operators of the BART sources subject to this section shall comply with the emissions limitations and other requirements of this section within five years of the effective date of this rule unless otherwise indicated in specific paragraphs.

(e) *Compliance determinations for SO_2 and NO_X.* (1) *CEMS for EGUs.* At all times after the compliance date specified in paragraph (d) of this section, the owner/operator of each unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR part 75, to accurately measure SO_2, NO_X, diluent, and stack gas volumetric flow rate from each unit. The CEMS shall be used to determine compliance with the emission limitations in paragraph (c) of this section for each unit.

(2) *Method for EGUs.* (i) For any hour in which fuel is combusted in a unit, the owner/operator of each unit shall

calculate the hourly average SO_2 and NO_X concentration in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR part 75. At the end of each boiler operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from the arithmetic average of all valid hourly emission rates from the CEMS for the current boiler operating day and the previous 29 successive boiler operating days.

(ii) An hourly average SO_2 or NO_X emission rate in lb/MMBtu is valid only if the minimum number of data points, as specified in 40 CFR part 75, is acquired by both the pollutant concentration monitor (SO_2 or NO_X) and the diluent monitor (O_2 or CO_2).

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

(3) *CEMS for cement kilns.* At all times after the compliance date specified in paragraph (d) of this section, the owner/operator of each unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR 60.63(f), to accurately measure concentration by volume of SO_2 and NO_X emissions into the atmosphere from each unit. The CEMS shall be used to determine compliance with the emission limitations in paragraph (c) of this section for each unit, in combination with data on actual clinker production.

(4) *Method for cement kilns.* (i) The owner/operator of each unit shall record the daily clinker production rates.

(ii) The owner/operator of each unit shall calculate and record the 30-operating day rolling emission rates of SO_2 and NO_X, in lb/ton of clinker produced, as the total of all hourly emissions data for the cement kiln in the preceding 30 days, divided by the total tons of clinker produced in that kiln during the same 30-day operating period, using the following equation:

$$E = (C_s Q_s)/(PK)$$

Where:

E = emission rate of SO_2 or NO_X, lb/ton of clinker produced

C_s = concentration of SO_2 or NO_X, in grains per standard cubic foot (gr/scf);

Q_s = volumetric flow rate of effluent gas, where C_s and Q_s are on the same basis (either wet or dry), scf/hr;

P = total kiln clinker production rate, tons/hr, and

K = conversion factor, 7000 gr/lb.

Hourly clinker production shall be determined in accordance with the requirements found at 40 CFR 60.63(b).

(iii) At the end of each kiln operating day, the owner/operator of each unit shall calculate and record a new 30-day rolling average emission rate in lb/ton clinker from the arithmetic average of all valid hourly emission rates for the current kiln operating day and the previous 29 successive kiln operating days.

(5) The owner/operator of Blaine County #1 Compressor Station shall install a temperature-sensing device (i.e. thermocouple or resistance temperature detectors) before the catalyst in order to monitor the inlet temperatures of the catalyst for each engine. The owner/operator shall maintain the engine at a minimum of at least 750°F and no more than 1250°F in accordance with manufacturer's specifications. Also, the owner/operator shall install gauges before and after the catalyst for each engine in order to monitor pressure drop across the catalyst, and that the owner/operator maintain the pressure drop within ± 2'' water at 100% load plus or minus 10% from the pressure drop across the catalyst measured during the initial performance test. The owner/operator shall follow the manufacturer's recommended maintenance schedule and procedures for each engine and its respective catalyst. The owner/operator shall only fire each engine with natural gas that is of pipeline-quality in all respects except that the CO_2 concentration in the gas shall not be required to be within pipeline-quality.

(f) *Compliance determinations for particulate matter.* (1) *EGU particulate matter BART limits.* Compliance with the particulate matter BART emission limits for each EGU BART unit shall be determined from annual performance stack tests. Within 60 days of the compliance deadline specified in paragraph (d) of this section, and on at least an annual basis thereafter, the owner/operator of each unit shall conduct a stack test on each unit to measure particulate emissions using EPA Method 5, 5B, 5D, or 17, as appropriate, in 40 CFR part 60, Appendix A. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. Results shall be reported in lb/MMBtu. In addition to annual stack tests, owner/operator shall monitor particulate emissions for compliance with the BART emission limits in accordance with the applicable Compliance Assurance Monitoring (CAM) plan developed and approved in accordance with 40 CFR part 64.

(2) *Cement kiln particulate matter BART limits.* Compliance with the particulate matter BART emission limits for each cement kiln shall be determined from annual performance stack tests. Within 60 days of the compliance deadline specified in paragragh (d) of this section, and on at least an annual basis thereafter, the owner/operator of each unit shall conduct a stack test on each unit to measure particulate matter emissions using EPA Method 5, 5B, 5D, or 17, as appropriate, in 40 CFR part 60, Appendix A. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. The emission rate (E) of particulate matter, in lb/ton clinker, shall be computed for each run using the equation in paragraph (e)(4)(ii) of this section above. Clinker production shall be determined in accordance with the requirements found at 40 CFR 60.63(b). Results of each test shall be reported as the average of three valid test runs. In addition to annual stack tests, owner/operator shall monitor particulate emissions for compliance with the BART emission limits in accordance with the applicable Compliance Assurance Monitoring (CAM) plan developed and approved in accordance with 40 CFR part 64.

(g) *Recordkeeping for EGUs.* Owner/operator shall maintain the following records for at least five years:

(1) All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

(2) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Part 75 .

(3) Records of all major maintenance activities conducted on emission units, air pollution control equipment, and CEMS.

(4) Any other records required by 40 CFR part 75.

(h) *Recordkeeping for cement kilns.* Owner/operator shall maintain the following records for at least five years:

(1) All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

(2) All particulate matter stack test results.

(3) All records of clinker production.

(4) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by

40 CFR part 60, appendix F, Procedure 1.

(5) Records of all major maintenance activities conducted on emission units, air pollution control equipment, CEMS and clinker production measurement devices.

(6) Any other records required by 40 CFR part 75, 40 CFR part 60, Subpart F, or 40 CFR part 60, Appendix F, Procedure 1.

(i) *Reporting.* All reports under this section, with the exception of 40 CFR 53.1395(n) and (o), shall be submitted to the Director, Office of Enforcement, Compliance and Environmental Justice, U.S. Environmental Protection Agency, Region 8, Mail Code 8ENF–AT, 1595 Wynkoop Street, Denver, Colorado 80202–1129.

(1) Owner/operator of each unit shall submit quarterly excess emissions reports for SO_2 and NO_X BART limits no later than the 30th day following the end of each calendar quarter. Excess emissions means emissions that exceed the emissions limits specified in paragraph (c) of this section. The reports shall include the magnitude, date(s), and duration of each period of excess emissions, specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.

(2) Owner/operator of each unit shall submit quarterly CEMS performance reports, to include dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks), reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, and any CEMS repairs or adjustments.

(i) *For EGUs:* Owner/operator of each unit shall also submit results of any CEMS performance tests required by 40 CFR part 75 (Relative Accuracy Test Audits, Relative Accuracy Audits, and Cylinder Gas Audits).

(ii) *For cement kilns:* Owner/operator of each unit shall also submit results of any CEMS performance tests required by 40 CFR part 60, appendix F, Procedure 1 (Relative Accuracy Test Audits, Relative Accuracy Audits, and Cylinder Gas Audits).

(3) When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted during the reporting period, such information shall be stated in the quarterly reports required by sections (h)(1) and (2) of this section.

(4) Owner/operator of each unit shall submit results of any particulate matter stack tests conducted for demonstrating compliance with the particulate matter BART limits in paragragh (c) of this section.

(j) Monitoring, recordkeeping, and reporting requirements for Blaine County #1 Compressor Station:

(1) The owner/operator shall measure NO_X emissions from each engine at least semi-annually or once every six month period to demonstrate compliance with the emission limits. To meet this requirement, the owner/operator shall measure NO_X emissions from the engines using a portable analyzer and a monitoring protocol approved by EPA.

(2) The owner/operator shall submit the analyzer specifications and monitoring protocol to EPA for approval within 45 calendar days prior to installation of the NSCR unit.

(3) Monitoring for NO_X emissions shall commence during the first complete calendar quarter following the owner/operator's submittal of the initial performance test results for NO_X to EPA.

(4) The owner/operator shall measure the engine exhaust temperature at the inlet to the oxidation catalyst at least once per week and shall measure the pressure drop across the oxidation catalyst monthly.

(5) Each temperature-sensing device shall be accurate to within plus or minus 0.75% of span and that the pressure sensing devices be accurate to within plus or minus 0.1 inches of water.

(6) The owner/operator shall keep records of all temperature and pressure measurements; vendor specifications for the thermocouples and pressure gauges; vendor specifications for the NSCR catalyst and the air-to-fuel ratio controller on each engine.

(7) The owner/operator shall keep records sufficient to demonstrate that the fuel for the engines is pipeline-quality natural gas in all respects, with the exception of the CO_2 concentration in the natural gas.

(8) The owner/operator shall keep records of all required testing and monitoring that include: The date, place, and time of sampling or measurements; the date(s) analyses were performed; the company or entity that performed the analyses; the analytical techniques or methods used; the results of such analyses or measurements; and the operating conditions as existing at the time of sampling or measurement.

(9) The owner/operator shall maintain records of all required monitoring data and support information (*e.g.* all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required) for a period of at least five years from the date of the monitoring sample, measurement, or report and that these records be made available upon request by EPA.

(10) The owner/operator shall submit a written report of the results of the required performance tests to EPA within 90 calendar days of the date of testing completion.

(k) *Notifications.* (1) Owner/operator shall submit notification of commencement of construction of any equipment which is being constructed to comply with the SO_2 or NO_X emission limits in paragraph (c) of this section.

(2) Owner/operator shall submit semi-annual progress reports on construction of any such equipment.

(3) Owner/operator shall submit notification of initial startup of any such equipment.

(l) *Equipment operation.* At all times, owner/operator shall maintain each unit, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

(m) *Credible evidence.* Nothing in this section shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with requirements of this section if the appropriate performance or compliance test procedures or method had been performed.

(n) CFAC notification. CFAC must notify EPA 60 days in advance of resuming operation. CFAC shall submit such notice to the Director, Air Program, U.S. Environmental Protection Agency, Region 8, Mail Code 8P–AR, 1595 Wynkoop Street, Denver, Colorado 80202–1129. Once CFAC notifies EPA that it intends to resume operation, EPA will initiate and complete a BART determination after notification and revise the FIP as necessary in accordance with regional haze requirements, including the BART provisions in 40 CFR 51.308(e). CFAC will be required to install any controls that are required as soon as practicable, but in no case later than five years following the effective date of this rule.

(o) *M2Green Redevelopment LLC notification.* M2Green Redevelopment LLC must notify EPA 60 days in advance of resuming operation. M2Green Redevelopment LLC shall submit such notice to the Director, Air Program, U.S. Environmental Protection Agency, Region 8, Mail Code 8P–AR, 1595 Wynkoop Street, Denver, Colorado 80202–1129. Once M2 Green Redevelopment LLC notifies EPA that it intends to resume operation, EPA will initiate and complete a four factor analysis after notification and revise the FIP as necessary in accordance with regional haze requirements including the ''reasonable progress'' provisions in 40 CFR 51.308(d)(1). M2 Green Redevelopment LLC will be required to install any controls that are required as soon as practicable, but in no case later than July 31, 2018.

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