FEDERAL REGISTER

Vol. 76 Wednesday,

No. 183 September 21, 2011

Part II

Environmental Protection Agency

40 CFR Part 52

Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R08–OAR–2010–0406; FRL–9461–7]

Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to partially approve and partially disapprove a revision to the North Dakota State Implementation Plan (SIP) addressing regional haze submitted by the Governor of North Dakota on March 3, 2010, along with SIP Supplement No. 1 submitted on July 27, 2010, and part of SIP Amendment No. 1 submitted on July 28, 2011. These SIP revisions were submitted to address the requirements of the Clean Air Act (CAA or Act) and our rules that require states to prevent any future and remedy any existing man-made impairment of visibility in mandatory Class I areas caused by emissions of air pollutants from numerous sources located over a wide geographic area (also referred to as the ''regional haze program''). EPA is proposing a Federal Implementation Plan (FIP) to address the deficiencies identified in our proposed partial disapproval of North Dakota's regional haze SIP. In lieu of this proposed FIP, or a portion thereof, we are proposing approval of a SIP revision if the State submits such a revision in a timely way, and the revision matches the terms of our proposed FIP.

In addition, EPA is proposing to disapprove a revision to the North Dakota SIP addressing the interstate transport of pollutants that the Governor submitted on April 6, 2009. We are proposing to disapprove it because it does not meet the Act's requirements concerning non-interference with programs to protect visibility in other states. To address this deficiency, we are proposing a FIP.

DATES: *Comments:* Comments must be received on or before November 21, 2011. *Public Hearing.* A public hearing for this proposal is scheduled to be held on Thursday, October 13, 2011, at the Bismarck Veterans Memorial Public Library, Meeting Room A, 515 North 5th Street, Bismarck, North Dakota 58501, (701) 355–1480. The public hearing will be held from 3 p.m. until 5 p.m., and again from 6 p.m. until 8 p.m.

The public hearing 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.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R08–OAR–2010–0406, by one of the following methods:

- *http://www.regulations.gov.* Follow the on-line instructions for submitting comments.
- *E-mail: r8airndhaze@epa.gov.*
- *Fax:* (303) 312–6064 (please alert the individual listed in the **FOR FURTHER INFORMATION CONTACT** section if you are faxing comments).
- *Mail:* Director, Air Program, Environmental Protection Agency (EPA), Region 8, Mailcode 8P–AR, 1595 Wynkoop Street, Denver, Colorado 80202–1129.
- *Hand Delivery:* Director, Air Program, Environmental Protection Agency (EPA), Region 8, Mailcode 8P–AR, 1595 Wynkoop Street, 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–2010–0406. 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 e-mail. 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 e-mail comment directly to EPA, without going through *http://www.regulations.gov,* your e-mail 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 information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

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, 1595 Wynkoop Street, 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: Gail Fallon, EPA Region 8, at (303) 312–6281, or *Fallon.Gail@epa.gov.*

SUPPLEMENTARY INFORMATION:

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

(iii) The initials *SIP* mean or refer to State Implementation Plan.

(iv) The initials *FIP* mean or refer to Federal Implementation Plan.

(v) The initials *NAAQS* mean or refer to National Ambient Air Quality Standards.

(vi) The words *North Dakota* and *State* mean the State of North Dakota.

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

(viii) The initials *RP* mean or refer to Reasonable Progress.

(ix) The initials NO_X mean or refer to nitrogen oxides.

(x) The initials SO_2 mean or refer to sulfur dioxide.

(xi) The initials NH_3 mean or refer to ammonia.

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

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

(xiv) The initials *OC* mean or refer to organic carbon.

(xv) The initials *EC* mean or refer to elemental carbon.

(xvi) The initials *VOC* mean or refer to volatile organic compounds.

(xvii) The initials *EGUs* mean or refer to Electric Generating Units.

(xviii) The initials *RPGs* mean or refer to Reasonable Progress Goals.

(xix) The initials *LTS* mean or refer to Long-Term Strategy.

(xx) The initials *RAVI* mean or refer to Reasonably Attributable Visibility Impairment.

(xxi) The initials *FLMs* mean or refer to Federal Land Managers.

(xxii) The initials *URP* mean or refer to Uniform Rate of Progress.

(xxiii) The initials *MRYS* mean or refer to Milton R. Young Station.

(xxiv) The initials *LOS* mean or refer to Leland Olds Station.

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

(xxvi) The initials *RPOs* mean or refer to regional planning organizations.

(xxvii) The initials *WRAP* mean or refer to the Western Regional Air Program.

(xxviii) The initials *PSD* mean or refer to Prevention of Signification Deterioration.

(xxix) The initials *Theodore Roosevelt* or *TRNP* mean or refer to Theodore Roosevelt National Park.

(xxx) The initials *Lostwood* or *LWA* mean or refer to Lostwood National Wildlife Refuge Wilderness Area.

(xxxi) The initials *TSD* mean or refer to Technical Support Document.

(xxxii) The initials *IWAQM* mean or refer to Interagency Workgroup on Air Quality Modeling.

(xxxiii) The initials *FGD* mean or refer to flue gas desulfurization.

(xxxiv) The initials *SOFA* mean or refer to separated overfire air.

(xxxv) The initials *LNB* mean or refer to low NO_X burners.

(xxxvi) The initials *PRB* mean or refer to Powder River Basin.

(xxxvii) The initials *SCR* mean or refer to selective catalytic reduction.

(xxxviii) The initials *LTO* mean or refer to low temperature oxidation.

(xxxix) The initials *NSCR* mean or refer to non-selective catalytic reduction.

(xl) The initials *ECO* mean or refer to electro-catalytic oxidation.

(xli) The initials *SNCR* mean or refer to selective non-catalytic reduction.

(xlii) The initials *RRI* mean or refer to rich reagent injection.

(xliii) The initials *FGR* mean or refer to external flue gas recirculation.

(xliv) The initials *OFA* mean or refer to overfire air.

(xlv) The initials *HE–SNCR* mean or refer to hydrocarbon enhanced SNCR.

(xlvi) The initials *CGR* mean or refer to conventional gas reburn.

(xlvii) The initials *FLGR* mean or refer to fuel-lean gas reburn.

(xlviii) The initials *ROFA* mean or refer to rotating overfire air.

(xlix) The initials *LDSCR* mean or refer to low-dust SCR.

(l) The initials *TESCR* mean or refer to tail-end SCR.

(li) The initials *ASOFA* mean or refer to advanced separated overfire air.

(lii) The initials *OEC* mean or refer to oxygen enhanced combustion.

(liii) The initials *FGD* mean or refer to flue gas desulfurization system.

(liv) The initials *CoHPAC* mean or refer to compact hybrid particulate collector.

(lv) The initials *CAM* mean or refer to compliance assurance monitoring.

(lvi) The initials *CEMS* mean or refer to continuous emission monitoring systems.

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

(lviii) The initials *SMOKE* mean or refer to Sparse Matrix Operator Kernel Emissions modeling system.

(lix) The initials *CAMx* mean or refer to Comprehensive Air Quality Model.

(lx) The initials *EIA* mean or refer to Energy Information Agency.

(lxi) The initials *GRE* mean or refer to Great River Energy.

(lxii) The initials *RMC* mean or refer to the Regional Modeling Center at the University of California Riverside.

(lxiii) The initials *WEP* mean or refer to Weighted Emissions Potential.

Table of Contents

I. Overview of Proposed Actions
A. Regional Haze
B. Interstate Transport of Pollutants that Impact Visibility
II. SIP and FIP Background
III. What is the background for our proposed actions?
A. Regional Haze
B. Roles of Agencies in Addressing Regional Haze
C. The 1997 NAAQS for Ozone and $PM_{2.5}$ and CAA 110(a)(2)(D)(i)
IV. What are the requirements for Regional Haze SIPs?
A. The CAA and the Regional Haze Rule
B. Determination of Baseline, Natural, and Current Visibility Conditions
C. Determination of Reasonable Progress Goals
D. Best Available Retrofit Technology (BART)
E. Long-Term Strategy (LTS)
F. Coordinating Regional Haze and Reasonably Attributable Visibility Impairment (RAVI)
G. Monitoring Strategy and Other SIP Requirements
H. Consultation With States and Federal Land Managers (FLMs)
V. Our Analysis of North Dakota's Regional Haze SIP
A. Affected Class I Areas
B. Determination of Baseline, Natural, and Current Visibility Conditions
1. Estimating Natural Visibility Conditions
2. Estimating Baseline Visibility Conditions
3. Natural Visibility Impairment
4. Uniform Rate of Progress (URP)
C. Evaluation of North Dakota's BART Determinations other than for NO_X for Milton R. Young Station Units 1 and 2, Leland Olds Station Unit 2, and Coal Creek Station Units 1 and 2
1. Identification of BART-Eligible Sources
2. Identification of Sources Subject to BART
a. Modeling Methodology
b. Contribution Threshold
c. Sources Identified by North Dakota as Subject to BART
3. BART Determinations and Federally Enforceable Limits
a. Great River Energy, Coal Creek Station
b. Great River Energy, Stanton Station
c. Minnkota Power Cooperative, Milton R. Young Station (MRYS)
d. Basin Electric Power Cooperative, Leland Olds Station (LOS)
e. North Dakota BART Results and Summary
D. Evaluation of North Dakota's NO_X BART Determinations for Milton R. Young Station Units 1 and 2, Leland Olds

Station Unit 2, and Coal Creek Station Units 1 and 2
1. Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2
a. Milton R. Young Station Unit 1—State Analysis
b. Milton R. Young Station Unit 2—State Analysis
c. Leland Olds Station Unit 2—State Analysis
d. EPA's Evaluation of the State's Cost Analyses for NO_X BART for Milton R. Young Station Unit 1 and 2 and Leland Olds Station Unit 2
e. EPA's Evaluation of the State's Visibility Analyses for NO_X BART for Milton R. Young Station Unit 1 and 2 and Leland Olds Station Unit 2
2. Coal Creek Station Units 1 and 2
a. Coal Creek Station Units 1 and 2—State Analysis
b. EPA's Evaluation of the State's NO_X BART Review for Coal Creek Units 1 and 2
E. Federal Implementation Plan to Address NO_X BART for Milton R. Young Station Units 1 and 2, and Leland Olds Station Unit 2
1. Introduction
2. BART analysis for Milton R. Young Station 1
3. BART analysis for Milton R. Young Station 2
4. BART analysis for Leland Olds Station 2
F. Federal Implementation Plan to Address NO_X BART for Coal Creek Station Units 1 and 2
1. Introduction
2. BART analysis for Coal Creek Units 1 and 2
G. Evaluation of North Dakota's Reasonable Progress Goal
1. North Dakota's Visibility Modeling
2. North Dakota's Reasonable Progress ''Four-Factor'' Analysis
3. North Dakota's Conclusions from the Four-Factor Analysis
4. Establishment of the Reasonable Progress Goal
5. Reasonable Progress Consultation
6. Our Conclusion on North Dakota's Reasonable Progress Goal and Need for Additional Controls
H. Our Conclusion on North Dakota's Reasonable Progress Goal and Need for Additional Controls
I. Federal Implementation Plan to Address Nitrogen Oxides (NO_X) Reasonable Progress Measures for Antelope Valley Station Units 1 and 2 and Reasonable Progress Goals
1. Introduction
2. Reasonable Progress Analysis for Antelope Valley Station Units 1 and 2
J. Long-Term Strategy
1. Emissions Inventories
2. Sources of Visibility Impairment in North Dakota Class I Areas
3. Visibility Projection Modeling
4. Consultation and Emissions Reductions for Other States' Class I Areas
5. Mandatory Long-Term Strategy Factors
a. Reductions Due to Ongoing Air Pollution Programs
b. Measures to Mitigate the Impacts of Construction Activities
c. Emission Limitation and Schedules of Compliance
d. Source Retirement and Replacement Schedules
e. Agricultural and Forestry Smoke Management Techniques
f. Enforceability of North Dakota's Measures
g. Anticipated Net Effect on Visibility Due to Projected Changes
h. Periodic SIP Revisions and 5-Year Progress Reports
K. Coordination of Reasonably Attributable Visibility Impairment and Regional Haze Requirements
L. Monitoring Strategy and Other SIP Requirements
M. Federal Land Manager Coordination
N. Periodic SIP Revisions and Five-year Progress Reports
VI. Our Analysis of North Dakota's Interstate Visibility Transport SIP Provisions
VII. FIP for Interstate Visibility Transport
VIII. Proposed Actions
A. Regional Haze
B. Interstate Transport and Visibility
IX. Statutory and Executive Order Reviews

List of Tables

Table 1. Visibility Impact Reductions Needed Based on Best and Worst Days Baselines, Natural Conditions, and Uniform Rate of Progress Goals for North Dakota Class I Areas
Table 2. Summary of Uniform Rate of Progress
Table 3. List of BART—Eligible Sources in North Dakota
Table 4. Individual BART—Eligible Source Visibility Impacts on North Dakota Class I Areas
Table 5. Summary of Coal Creek SO_2 BART Analysis for Unit 1 and Unit 2 Boilers
Table 6. Summary of Coal Creek Filterable PM BART Analysis for Unit 1 and Unit 2 Boilers
Table 7. Summary of Stanton SO_2 BART Analysis for Unit 1 Boiler with Lignite Coal
Table 8. Summary of Stanton SO_2 BART Analysis for Unit 1 Boiler with Powder River Basin Coal
Table 9. Summary of Stanton NO_X BART Analysis for Unit 1 Boiler with Lignite Coal
Table 10. Summary of Stanton NO_X BART Analysis for Unit 1 Boiler with Powder River Basin Coal
Table 11. Summary of Stanton PM BART Analysis for Unit 1 Boiler with Lignite Coal
Table 12. Summary of Milton R. Young Station SO_2 BART Analysis for Unit 1 Boiler
Table 13. Summary of Milton R. Young Station PM BART Analysis for Unit 1 Boiler
Table 14. Summary of Milton R. Young Station SO_2 BART Analysis for Unit 2 Boiler
Table 15. Summary of Milton R. Young Station PM BART Analysis for Unit 2 Boiler
Table 16. Summary of Leland Olds Station SO_2 BART Analysis for Unit 1 Boiler
Table 17. Summary of Leland Olds Station NO_X BART Analysis for Unit 1 Boiler
Table 18. Summary of Leland Olds Station PM BART Analysis for Unit 1 Boiler
Table 19. Summary of Leland Olds Station SO_2 BART Analysis for Unit 2 Boiler
Table 20. Summary of Leland Olds Station PM BART Analysis for Unit 2 Boiler
Table 21. North Dakota BART Determinations for SO_2 Emissions that EPA is Proposing to Approve
Table 22. North Dakota BART Determinations for NO_X Emissions that EPA is Proposing to Approve
Table 23. Summary of Milton R. Young Station NO_X BART Analysis for Unit 1 Boiler
Table 24. Summary of Milton R. Young Station NO_X BART Analysis for Unit 2 Boiler
Table 25. Summary of Leland Olds Station NO_X BART Analysis for Unit 2 Boiler
Table 26. North Dakota BART Determinations for NO_X Emissions for Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2
Table 27. Contrast of TESCR Cost Effectiveness
Table 28. Comparison of EPA Control Cost Manual and Burns & McDonnell Indirect Capital Costs
Table 29. Comparison of EPA Control Cost Manual & B&McD ''Other'' Capital Costs
Table 30. Comparison of Sargent & Lundy and Dr. Fox's Tail-End SCR Variable Operation and Maintenance Costs for Leland Olds Station Unit 2 (2009 Dollars)
Table 31. Summary of Coal Creek NO_X BART Analysis for Unit 1 and Unit 2 Boilers
Table 32. Summary of EPA NO_X BART Analysis Control Technologies for Milton R. Young Station Unit 1 Boiler
Table 33. Summary of EPA NO_X BART Capital Cost Analysis for SNCR on Milton R. Young Station Unit 1 Boiler
Table 34. Summary of EPA NO_X BART Annual Analysis for SNCR on Milton R. Young Station Unit 1 Boiler
Table 35. Summary of EPA NO_X BART Costs for SNCR on Milton R. Young Station Unit 1 Boiler
Table 36. Summary of EPA NO_X BART Capital Cost Analysis for TESCR on Milton R. Young Station Unit 1 Boiler
Table 37. Summary of EPA NO_X BART Annual Costs for TESCR Scenario 3 [1] on Milton R. Young Station Unit 1 Boiler
Table 38. Summary of EPA NO_X BART Costs for Various TESCR Scenarios on Milton R. Young Station Unit 1 Boiler
Table 39. Summary of EPA NO_X BART Analysis Comparison of TESCR and SNCR Options for Milton R. Young Station Unit 1 Boiler
Table 40. Summary of EPA NO_X BART Analysis Control Technologies for Milton R. Young Station Unit 2 Boiler
Table 41. Summary of EPA NO_X BART Capital Cost Analysis for SNCR on Milton R. Young Station Unit 2 Boiler
Table 42. Summary of EPA NO_X BART Annual Analysis for SNCR on Milton R. Young Station Unit 2 Boiler
Table 43. Summary of EPA NO_X BART Costs for SNCR on Milton R. Young Station Unit 2 Boiler
Table 44. Summary of EPA NO_X BART Capital Cost Analysis for TESCR

Scenario 3 [1] on Milton R. Young Station Unit 2 Boiler
Table 45. Summary of EPA NO_X BART Annual Costs for TESCR Scenario 3 [1] on Unit 2 Boiler
Table 46. Summary of EPA NO_X BART Costs for Various TESCR + ASOFA Scenarios on Milton R. Young Station Unit 2 Boiler
Table 47. Summary of EPA NO_X BART Analysis Comparison of TESCR and SNCR Options for Milton R. Young Station Unit 2 Boiler
Table 48. Summary of EPA NO_X BART Analysis Control Technologies for Leland Olds Station Unit 2 Boiler
Table 49. Summary of EPA NO_X BART Capital Cost Analysis for SNCR on Leland Olds Station Unit 2 Boiler
Table 50. Summary of EPA NO_X BART Annual Costs for SNCR on Leland Olds Station Unit 2 Boiler
Table 51. Summary of EPA NO_X BART Costs for SNCR on Leland Olds Station Unit 2 Boiler
Table 52. Summary of EPA NO_X BART Capital Cost Analysis for TESCR Scenario 3 on Leland Olds Station Unit 2 Boiler
Table 53. Summary of Some EPA NO_X BART Annual Costs for TESCR Scenario 3 [1] on Leland Olds Station Unit 2 Boiler
Table 54. Summary of EPA NO_X BART Costs for Various TESCR + ASOFA Scenarios on Leland Olds Station Unit 2 Boiler
Table 55. Summary of EPA NO_X BART Analysis Comparison of TESCR and SNCR Options for Leland Olds Station Unit 2 Boiler
Table 56. Summary of EPA Coal Creek BART Analysis Control Technologies for Units 1 and 2 Boilers
Table 57. Summary of EPA NO_X BART Capital Cost Analysis for SNCR on Coal Creek Station Units 1 and 2 Boilers
Table 58. Summary of EPA Annual Cost Analysis for SNCR + ASOFA on Coal Creek Station Units 1 and 2 Boilers
Table 59. Summary of EPA Costs for SNCR on Coal Creek Station Units 1 and 2 Boilers
Table 60. Summary of EPA Capital Cost Analysis for LDSCR on Coal Creek Station Units 1 and 2 Boilers
Table 61. Summary of EPA Annual Cost Analysis for LDSCR on Coal Creek Station Units 1 and 2 Boilers
Table 62. Summary of EPA Costs for LDSCR on Coal Creek Station Units 1 and 2 Boilers
Table 63. Summary of EPA NO_X BART Analysis for Coal Creek Station Units 1 and 2 Boilers
Table 64. North Dakota Q/D Analysis Sources with Results Greater than 10
Table 65. North Dakota Sources for Reasonable Progress Four-Factor Analyses
Table 66. Current Control for Reasonable Progress Sources
Table 67. Control Option Costs for Reasonable Progress Sources
Table 68. ND's Modeled Visibility Improvement for Reasonable Progress Sources
Table 69. Comparison of Reasonable Progress Goals to Uniform Rate of Progress on Most Impaired Days for North Dakota Class I Areas
Table 70. Comparison of Reasonable Progress Goals to Baseline Conditions on Least Impaired Days for North Dakota Class I Areas
Table 71. Summary of Antelope Valley Station NO_X Reasonable Progress Analysis Control Technologies for Units 1 and 2 Boilers
Table 72. Summary of Antelope Valley Station NO_X Reasonable Progress Cost Analysis for Units 1 and 2 Boilers
Table 73. North Dakota SO_2 Emission Inventory—2002 and 2018
Table 74. North Dakota NO_X Emission Inventory—2002 and 2018
Table 75. North Dakota Organic Carbon Emission Inventory—2002 and 2018
Table 76. North Dakota Elemental Carbon Emission Inventory—2002 and 2018
Table 77. North Dakota $PM_{2.5}$ Emission Inventory—2002 and 2018
Table 78. North Dakota Coarse Particulate Matter Emission Inventory—2002 and 2018
Table 79. ND Sources Extinction Contribution 2000–2004 for 20% Worst Days
Table 80. Source Region Apportionment for 20% Worst Days (Percentage)
Table 81. Annual Average Emissions from Fire (2000–2004) (Tons/Year)

I. Overview of Proposed Actions

A. Regional Haze

We propose to partially approve and partially disapprove North Dakota's regional haze State Implementation Plan (Regional Haze SIP) revision that was submitted on March 3, 2010, SIP Supplement No. 1 that was submitted on July 27, 2010, and part of SIP Amendment No. 1 that was submitted on July 28, 2011. Specifically, we propose to disapprove the following:

• North Dakota's NO_X BART determinations and emissions limits for Units 1 and 2 of Minnkota Power Cooperative's Milton R. Young Station, Unit 2 of Basin Electric Power Cooperative's Leland Olds Station, and Units 1 and 2 of Great River Energy's Coal Creek Station.

• North Dakota's determination under the reasonable progress requirements found at 40 CFR 51.308(d)(1) that no additional NO_X emissions controls are warranted at Units 1 and 2 of Basin Electric Power Cooperative's Antelope Valley Station.

• North Dakota's Reasonable Progress Goals (RPGs).

• Portions of North Dakota's long-term strategy that rely on or reflect other aspects of the Regional Haze SIP we are proposing to disapprove.

We are proposing to approve the remaining aspects of North Dakota's Regional Haze SIP revision that was submitted on March 3, 2010 and SIP Supplement No. 1 that was submitted on July 27, 2010. We are proposing to approve the following parts of SIP Amendment No. 1 that the State submitted on July 28, 2011: (1) Amendments to Section 10.6.1.2 pertaining to Coyote Station, and (2) amendments to Appendix A.4, the Permit to Construct of Coyote Station. We are not proposing action on the remainder of the July 28, 2011 submittal at this time.

We are proposing the promulgation of a FIP to address the deficiencies in the North Dakota Regional Haze SIP that we have identified in this proposal.

The proposed FIP includes the following elements:

• NO_X BART determinations and emission limits for Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2 of 0.07 lb/MMBtu (pounds per one million British Thermal Units) 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.

• NO_X BART determination and emission limit for Coal Creek Station Units 1 and 2 of 0.12 lb/MMBtu that applies singly to each of these units on a 30-day rolling average, but inviting comment on whether 0.14 lb/MMBtu should be the limit instead, 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.

• A reasonable progress determination and NO_X emission limit for Antelope Valley Station Units 1 and 2 of 0.17 lb/MMBtu that applies singly to each of these units on a 30-day rolling average, and a requirement that the owner/operator meet the limit as expeditiously as practicable, but no later than July 31, 2018.

• Monitoring, record-keeping, and reporting requirements for the above seven units to ensure compliance with these emission limitations.

• Reasonable progress goals consistent with the SIP limits proposed for approval and the proposed FIP limits.

• Long-term strategy elements that reflect the other aspects of the proposed FIP.

In lieu of this proposed FIP, or portion thereof, we are proposing approval of a SIP revision if the State submits such a revision in a timely way, and the revision matches the terms of our proposed FIP, or relevant portion thereof.

B. Interstate Transport of Pollutants That Impact Visibility

We are proposing to disapprove a portion of the SIP revision North Dakota submitted on April 6, 2009, for the purpose of addressing the ''good neighbor'' provisions of CAA section 110(a)(2)(D)(i) for the 1997 8-hour ozone NAAQS and the $PM_{2.5}$ NAAQS. Section 110(a)(2)(D)(i)(II) of the Act requires that states have a SIP, or submit a SIP revision, containing provisions ''prohibiting any source or other type of emission activity within the state from emitting any air pollutant in amounts which will * * * interfere with measures required to be included in the applicable implementation plan for any other State under part C [of the CAA] * * * to protect visibility.'' Because of the potential significant impacts on visibility from the interstate transport of pollutants, we interpret the ''good neighbor'' provisions of section 110(a)(2)(D)(i) as requiring states to include in their SIPs either measures to prohibit emissions that would interfere with the reasonable progress goals required to be set to protect Class I areas in other states, or a demonstration that emissions from North Dakota sources and activities will not have the prohibited impacts under the existing SIP.

The State's April 6, 2009 SIP submission suggested that North Dakota intended to address the requirements of section 110(a)(2)(D)(i)(II) by a timely submission of its Regional Haze SIP by December of 2007, but the State did not make that submission until March 3, 2010. Moreover, while North Dakota ultimately submitted a Regional Haze SIP revision that addresses visibility and reasonable progress goals directly, North Dakota did not explicitly specify that it was submitting the Regional Haze SIP revision to satisfy the visibility prong of 110(a)(2)(D)(i)(II). Most importantly, however, EPA must review the April 6, 2009 submission in light of the current facts and circumstances, and the Regional Haze SIP revision that the State ultimately submitted does not fully meet the substantive requirements of the regional haze program. The State made no other SIP submission in which it indicated that it intended to meet the visibility prong of section 110(a)(2)(D)(i)(II) in any other way. Accordingly, we are proposing to disapprove North Dakota's April 6, 2009 SIP submittal for the visibility prong of section 110(a)(2)(D)(i)(II), because that submittal neither contains adequate measures to eliminate emissions that would interfere with the required visibility programs in other states, nor a demonstration that the existing North Dakota SIP already includes measures sufficient to eliminate such prohibited impacts.

We are proposing the promulgation of a FIP to address the deficiency in North Dakota's April 6, 2009 SIP submission that we have identified in this proposal, in order to meet the interstate transport requirements of section 110(a)(2)(D)(i)(II) for visibility. Specifically, the proposed FIP consists of a finding that the combination of our proposed partial approval of North Dakota's Regional Haze SIP and our proposed partial FIP for regional haze for North Dakota will satisfy the interstate transport requirements of section 110(a)(2)(D)(i)(II) with respect to visibility. The emissions reductions resulting from the combination SIP/FIP and other provisions contained in the SIP will ensure non-interference with the required visibility programs of other states, as well as simultaneously meet the substantive requirements of the regional haze program. Simultaneous action on both the section 110(a)(2)(D)(i)(II) and regional haze program requirements will also be the most efficient approach to ensure that sources in North Dakota are controlled adequately to meet both requirements, and to avoid the possibility that sources might be required to implement two successive levels of controls in order to meet both requirements.

II. SIP and FIP Background

The CAA requires each state to develop plans to meet various air quality requirements, including protection of visibility. CAA sections 110(a), 169A, and 169B. The plans developed by a state are referred to as SIPs. A state must submit its SIPs and SIP revisions to us for approval. Once approved, a SIP is enforceable by EPA and citizens under the CAA, also known as being federally enforceable. If a state fails to make a required SIP submittal or if we find that a state's required submittal is incomplete or unapprovable, then we must promulgate a FIP to fill this regulatory gap. CAA section 110(c)(1). As discussed elsewhere in this notice, we are proposing to disapprove aspects of North Dakota's Regional Haze SIP. We are also proposing to disapprove, as not meeting the requirements of section 110(a)(2)(D)(i)(II) of the CAA regarding visibility, North Dakota's interstate transport SIP. We are proposing FIPs to address the deficiencies in North Dakota's regional haze and interstate transport SIPs.

III. What is the background for our proposed actions?

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 $PM_{2.5}$ (*e.g.,* sulfates, nitrates, organic carbon (OC), elemental carbon (EC), and soil dust) and its precursors (*e.g.,* sulfur dioxide (SO_2), NO_X, and in some cases, ammonia (NH_3) and volatile organic compounds (VOCs)). These precursors react in the atmosphere to form $PM_{2.5}$. $PM_{2.5}$ impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that one can see. $PM_{2.5}$ also can 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 and wilderness areas. The average visual range [1] in many Class I areas (*i.e.,* national parks and memorial parks, wilderness areas, and international parks meeting certain size criteria) in the western United States is 100–150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. 64 FR 35714, 35715 (July 1, 1999). 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. *Id.*

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

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

[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. *See* CAA section 162(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. *See* 44 FR 69122, November 30, 1979. The extent of a

results from manmade air pollution.'' CAA § 169A(a)(1). The terms ''impairment of visibility'' and ''visibility impairment'' are defined in the Act to include a reduction in visual range and atmospheric discoloration. *Id.* section 169A(g)(6). In 1980, we 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'' (RAVI). 45 FR 80084 (December 2, 1980). These regulations represented the first phase in addressing visibility impairment. We 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 had improved.

Congress added section 169B to the CAA in 1990 to address regional haze issues, and we promulgated regulations addressing regional haze in 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 them provisions addressing regional haze impairment and establish 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 our visibility protection regulations at 40 CFR 51.300–309. Some of the main regional haze requirements are summarized in section IV of this action. The requirement to submit a Regional Haze SIP applies to all 50 states, the District of Columbia and the Virgin Islands. States were required to submit a SIP addressing regional haze visibility impairment no later than December 17, 2007.[3] 40 CFR 51.308(b).

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 North Dakota, and the District of Columbia and the Virgin Islands, had failed to submit SIPs addressing the regional haze requirements. 74 FR 2392. 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).

B. 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. Pollution affecting the air quality in Class I areas can be transported over long distances, even hundreds of kilometers. Therefore, to address effectively the problem of visibility impairment in Class I areas, states 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, we have encouraged the states and tribes across the United States to address visibility impairment from a regional perspective. Five regional planning organizations (RPOs) were formed to address regional haze and related issues. The regional planning organizations 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 Program (WRAP) is a collaborative effort of state governments, tribal governments, and various federal agencies established to conduct data analyses, conduct pollutant transport modeling, and coordinate planning activities among the western states. 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.

C. The 1997 NAAQS for Ozone and $PM_{2.5}$ and CAA 110(a)(2)(D)(i)

On July 18, 1997, we promulgated the 1997 8-hour ozone NAAQS and the 1997 $PM_{2.5}$ NAAQS. 62 FR 38652. Section 110(a)(1) of the CAA requires states to submit SIPs to address a new or revised NAAQS within 3 years after promulgation of such standards, or within such shorter period as we may prescribe. Section 110(a)(2) of the CAA lists the elements that such new SIPs must address, as applicable, including section 110(a)(2)(D)(i), which pertains to the interstate transport of certain emissions.

On April 25, 2005, we published a ''Finding of Failure to Submit SIPs for Interstate Transport for the 8-hour Ozone and $PM_{2.5}$ NAAQS.'' 70 FR 21147. This action included a finding that North Dakota and other states had failed to submit SIPs to address interstate transport of air pollution affecting required visibility programs in other states, among other things, and started a 2-year clock for the promulgation of a FIP by us, unless a state made a submission to meet the requirements of section 110(a)(2)(D)(i), and we approved the submission, prior to that time. *Id.*

On August 15, 2006, we issued our ''Guidance for State Implementation Plan (SIP) Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8–Hour Ozone and $PM_{2.5}$ National Ambient Air Quality Standards'' (2006 Guidance). We developed the 2006 Guidance to make recommendations to states for making submissions to meet the requirements of section 110(a)(2)(D)(i) for the 1997 8-hour ozone NAAQS and the 1997 $PM_{2.5}$ NAAQS.

As identified in the 2006 Guidance, the ''good neighbor'' provisions in section 110(a)(2)(D)(i) of the CAA require each state to have a SIP that prohibits emissions that adversely affect another state in the ways contemplated in the statute. Section 110(a)(2)(D)(i) contains four distinct requirements or ''prongs'' related to the impacts of interstate transport. The SIP must prevent sources in the state from emitting pollutants in amounts which will: (1) Contribute significantly to nonattainment of the NAAQS in other states; (2) interfere with maintenance of the NAAQS in other states; (3) interfere with provisions to prevent significant deterioration of air quality in other states; or (4) interfere with efforts to protect visibility in other states.

Acknowledging that the Regional Haze SIPs were still under development and were not due until December 17, 2007, the 2006 Guidance recommended that states could make a simple SIP submission confirming that it was not possible at that point in time to assess whether there was any interference with

mandatory Class I area includes subsequent changes in boundaries, such as park expansions. CAA section 162(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'' (FLM). *See* CAA section 302(i). When we use the term ''Class I area'' in this action, we mean a ''mandatory Class I Federal area.''

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

measures in the applicable SIP for another state designed to ''protect visibility'' for the 1997 8-hour ozone NAAQS and the 1997 $PM_{2.5}$ NAAQS. See 74 FR 2392 (January 15, 2009). We note that our 2006 Guidance was based on the premise that as of the time of its issuance in August 2006, it was reasonable for EPA to recommend that states could merely indicate that the imminent Regional Haze SIP would be the appropriate means to establish that its SIP contained adequate provisions to prevent interference with the visibility programs required in other states. As discussed in more detail below, at this point in time, EPA must review the submissions in light of the actual facts and in light of the statutory requirements of section 110(a)(2)(D)(i)(II).

On June 2, 2009, WildEarth Guardians sued EPA for our failure to take action to promulgate FIPs, or to act on submitted SIPs in lieu thereof, to satisfy the requirements of section 110(a)(2)(D)(i) for the 1997 8-hour ozone NAAQS and 1997 $PM_{2.5}$ NAAQS. Seven western states were named in the lawsuit: Colorado, North Dakota, New Mexico, Oklahoma, California, Idaho, and Oregon. A consent decree was filed on November 10, 2009. The consent decree included various dates by which EPA was required to take action on each of the four prongs of section 110(a)(2)(D)(i) for each of the seven states for both of the applicable NAAQS. It required that EPA sign a notice by May 10, 2011, approving a SIP or FIP or combination SIP/FIP for North Dakota meeting the requirements of section 110(a)(2)(D) regarding interference with measures in other states related to protection of visibility. Pursuant to a subsequent modification to the consent decree and a subsequent stipulation, this date for final action was extended to February 9, 2012. The modification and subsequent stipulation also required that EPA sign a notice of proposed rulemaking by September 1, 2011.

On April 6, 2009, we received a SIP revision from North Dakota to address the interstate transport provisions of CAA 110(a)(2)(D)(i) for the 1997 8-hour ozone NAAQS and the 1997 $PM_{2.5}$ NAAQS. In prior actions we approved this North Dakota SIP submittal for the three other prongs of section 110(a)(2)(D)(i). (75 FR 31290, June 3, 2010 and 75 FR 71023, November 22, 2010). However, as noted above, we are proposing to disapprove the submittal for purposes of the visibility prong and are proposing a FIP to address this requirement. Acting on both the section 110(a)(2)(D)(i)(II) requirement and the Regional Haze SIP requirement simultaneously will ensure the most efficient use of resources by the affected sources and EPA.

IV. What are the requirements for Regional Haze SIPs?

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 SIPs must assure reasonable progress towards the national goal of achieving natural visibility conditions in Class I areas. Section 169A of the CAA and our implementing regulations require states to establish long-term strategies for making reasonable progress toward meeting this goal. Implementation plans 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 SIP requirements are discussed in further detail below.

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

The Regional Haze Rule establishes the deciview (dv) as the principal metric for measuring visibility. *See* 70 FR 39104, 39118. 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 is sometimes expressed in terms of the visual range, which is the greatest distance, in kilometers or miles, at which a dark object can just be distinguished against the sky. The deciview is a useful measure for tracking progress in improving visibility, because each deciview change is an equal incremental change in visibility perceived by the human eye. Most people can detect a change in visibility of one deciview.[4]

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 SIPs must contain measures that ensure ''reasonable progress'' toward the national goal of preventing and remedying visibility impairment in Class I areas caused by manmade air pollution by reducing anthropogenic emissions that cause regional haze. The national goal is a return to natural conditions, *i.e.,* manmade 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 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 to determine the degree of impairment (in deciviews) for the average of the 20 percent least impaired (''best'') and the average of the 20 percent most impaired (''worst'') visibility days over a specified time period at each of their Class I areas. In addition, states 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 to states regarding how to calculate baseline, natural and current visibility conditions.[5]

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. Baseline visibility conditions represent the degree of visibility impairment for the 20 percent least impaired days and 20 percent most impaired days for each calendar year from 2000 to 2004. Using monitoring data for 2000 through 2004, states 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

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

[5] *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/Regional Haze _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'').

visibility, while the future comparison of baseline conditions to the then current conditions will indicate the amount of progress made. In general, the 2000—2004 baseline period is considered the time from which improvement in visibility is measured.

C. Determination of Reasonable Progress Goals

The vehicle for ensuring continuing progress towards achieving the natural visibility goal is the submission of a series of Regional Haze SIPs from the states that establish two reasonable progress goals (*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). The Regional Haze Rule does not mandate specific milestones or rates of progress, but instead calls for states to establish goals that provide for ''reasonable progress'' toward achieving natural (*i.e.,* ''background'') visibility conditions. In setting reasonable progress goals, states must provide for an improvement in visibility for the most impaired days over the (approximately) 10-year period of the SIP, and ensure no degradation in visibility for the least impaired days over the same period. *Id.*

In establishing reasonable progress goals, states 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. States must demonstrate in their SIPs how these factors are considered when selecting the reasonable progress goals for the best and worst days for each applicable Class I area. In setting the reasonable progress goals, states must also consider the rate of progress needed to reach natural visibility conditions by 2064 (referred to hereafter as the ''Uniform Rate of Progress'') and the emission reduction measures needed to achieve that rate of progress over the 10-year period of the SIP. Uniform progress towards achievement of natural conditions by the year 2064 represents a rate of progress, which states are to use for analytical comparison to the amount of progress they expect to achieve. If a state establishes a reasonable progress goal that provides for a slower rate of improvement in visibility than the rate that would be needed to attain natural conditions by 2064, the state must demonstrate, based on the reasonable progress factors, that the rate of progress for the implementation plan to attain natural conditions by 2064 is not reasonable, and that the progress goal adopted by the state is reasonable. In setting reasonable progress goals, each state with one or more Class I areas (''Class I State'') must also consult with potentially ''contributing states,'' *i.e.,* other nearby states with emission sources that may be affecting visibility impairment at the State's Class I areas. 40 CFR 51.308(d)(1)(iv). In determining whether a state's goals for visibility improvement provide for reasonable progress toward natural visibility conditions, EPA is required to evaluate the demonstrations developed by the state pursuant to paragraphs 40 CFR 51.308(d)(1)(i) and (d)(1)(ii). 40 CFR 51.308(d)(1)(iii).

D. Best Available Retrofit Technology (BART)

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often uncontrolled, older stationary sources with the potential to emit 250 tons or more per year of any pollutant in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the Act requires states to revise their SIPs 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 [6] built between 1962 and 1977 procure, install, and operate BART, as determined by the state or by EPA in the case of a plan promulgated under section 110(c) of the CAA. Under the Regional Haze Rule, states are 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, states also have 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, we published the *Guidelines for BART Determinations Under the Regional Haze Rule* at Appendix Y to 40 CFR part 51 (''BART Guidelines'') to assist states 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. In making a BART determination for a fossil fuel-fired electric generating plant with a total generating capacity in excess of 750 megawatts (MW), a state must use the approach set forth in the BART Guidelines. A state 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, a state must meet the requirements of the CAA and our regulations for selection of BART, and the state'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, states identify those sources which meet the definition of ''BART-eligible source'' set forth in 40 CFR 51.301; [7] second, states determine 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, states then identify the best available type and level of control for reducing emissions.

States 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. We have stated that states should use their best judgment in determining whether VOC or NH_3 compounds impair visibility in Class I areas.

Under the BART Guidelines, states 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. The state must document this exemption threshold value in the SIP and must state the basis for its 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. States should consider the number of emission sources affecting the Class I areas at issue and the magnitude of the individual sources'

[6] The ''major stationary sources'' potentially subject to BART are listed in CAA section 169A(g)(7).

[7] 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.

impacts. Any exemption threshold set by the state should not be higher than 0.5 deciviews. 40 CFR part 51, appendix Y, section III.A.1.

In their SIPs, states must identify ''BART-eligible sources'' and ''subject-to-BART sources'' and document their BART control determination analyses. The term ''BART-eligible source'' used in the BART Guidelines means the collection of individual emission units at a facility that together comprises the BART-eligible source. In making BART determinations, section 169A(g)(2) of the CAA requires that states consider the following factors: (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).

A Regional Haze SIP must include source-specific BART emission limits and compliance schedules for each source subject to BART. Once a state 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 our approval of the Regional Haze SIP. 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 requirements mandate that the SIP 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 states 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.

E. Long-Term Strategy (LTS)

Consistent with the requirement in section 169A(b) of the CAA that states include in their Regional Haze SIP a 10- to 15-year strategy for making reasonable progress, section 51.308(d)(3) of the Regional Haze Rule requires that states include a long-term strategy in their Regional Haze SIPs. The long-term strategy is the compilation of all control measures a state will use during the implementation period of the specific SIP submittal to meet applicable reasonable progress goals. The long-term strategy must include ''enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals'' for all Class I areas within, or affected by emissions from, the state. 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(s) located in another state or states, the Regional Haze Rule requires the state to consult with the other state(s) in order to develop coordinated emissions management strategies. 40 CFR 51.308(d)(3)(i). Also, a state with a Class I area impacted by emissions from another state must consult with such contributing state, (id.) and must also demonstrate that it has included in its SIP all measures necessary to obtain its share of the emission reductions needed to meet the reasonable progress goals for the Class I area. *Id.* at (d)(3)(ii). The regional planning organizations have provided forums for significant interstate consultation, but additional consultations between states may be required to sufficiently address interstate visibility issues. This is especially true where two states belong to different regional planning organizations.

States should consider all types of anthropogenic sources of visibility impairment in developing their long-term strategy, including stationary, minor, mobile, and area sources. At a minimum, states must describe how each of the following seven factors listed below are taken into account in developing their long-term strategy: (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 reasonable progress goals; (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 long-term strategy. 40 CFR 51.308(d)(3)(v).

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

As part of the Regional Haze Rule, we revised 40 CFR 51.306(c) regarding the long-term strategy for reasonably attributable visibility impairment to require that the reasonably attributable visibility impairment 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 long-term strategy for addressing reasonably attributable visibility impairment and regional haze, and the state must submit the first such coordinated long-term strategy with its first Regional Haze SIP. Future coordinated long-term strategy and periodic progress reports evaluating progress towards reasonable progress goals, 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 long-term strategy must report on both regional haze and reasonably attributable visibility impairment and must be submitted to us as a SIP revision.

G. Monitoring Strategy and Other SIP 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 reasonably attributable visibility impairment. 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 reasonable progress goals 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.

H. Consultation With States and Federal Land Managers (FLMs)

The Regional Haze Rule requires that states consult with Federal Land Managers before adopting and submitting their SIPs. 40 CFR 51.308(i). States must provide Federal Land Managers an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on the SIP. This consultation must include the opportunity for the Federal Land Managers to discuss their assessment of impairment of visibility in any Class I area and to offer recommendations on the development of the reasonable progress goals and on the development and implementation of strategies to address visibility impairment. Further, a state must include in its SIP a description of how it addressed any comments provided by the Federal Land Managers. Finally, a SIP must provide procedures for continuing consultation between the state and Federal Land Managers regarding the state's visibility protection program, including development and review of SIP 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. Our Analysis of North Dakota's Regional Haze SIP

On March 3, 2010, the State of North Dakota submitted a Regional Haze SIP revision for approval into the North Dakota SIP. North Dakota provided two other submittals—SIP Supplement No. 1 on July 27, 2010 (provisions pertaining to Heskett Station) and SIP Amendment No. 1 on July 28, 2011 (provisions pertaining to Coyote Station and materials relating to the Prevention of Signification Deterioration (PSD) BACT determination for Milton R. Young Station).

As part of Amendment No. 1, the State submitted the entire administrative record for its BACT determination for Milton R. Young Station. The administrative record consists of at least 259 documents comprising over 850 megabytes of information. Given our September 1, 2011 deadline to sign this notice of proposed rulemaking under the consent decree discussed in section III.C, we lack sufficient time to act on or consider this aspect of Amendment No. 1. Under CAA section 110(k)(2), EPA is not required to act on a SIP submittal until 12 months after it is determined to be or deemed complete. We have considered some of the documents related to the State's BACT determination for Milton R. Young Station and have included those documents in the docket for this proposed action.

We are proposing action on the aspects of Amendment No. 1 that pertain to Coyote Station because such provisions were amenable to our evaluation in the available time.

The following is a discussion of our evaluation of the relevant submittals.

A. Affected Class I Areas

In accordance with 40 CFR 51.308(d), North Dakota identified two Class I areas within its borders: Theodore Roosevelt National Park (Theodore Roosevelt or TRNP) and Lostwood National Wildlife Refuge Wilderness Area (Lostwood or LWA). North Dakota is responsible for developing reasonable progress goals for these two Class I areas. North Dakota has also determined that North Dakota emissions have or may reasonably be expected to have impacts at Class I areas in other states including: Boundary Waters Canoe Area Wilderness Area and Voyageurs National Park in Minnesota, Isle Royale National Park and Seney National Wildlife Refuge Wilderness Area in Michigan, Medicine Lake National Wildlife Refuge Wilderness Area and U.L. Bend National Wildlife Refuge Wilderness Area in Montana, and Badlands National Park and Wind Cave National Park in South Dakota. North Dakota consulted with the appropriate state air quality agency in each of these states through their involvement with the WRAP. Assessment of North Dakota's contribution to haze in these Class I areas is based on technical analyses developed by WRAP.

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

As required by section 51.308(d)(2)(i) of the Regional Haze Rule and in accordance with our 2003 Natural Visibility Guidance, North Dakota calculated baseline/current and natural visibility conditions for its Class I areas, Theodore Roosevelt and Lostwood, on the most impaired and least impaired days, as summarized below (and further described in the Technical Support Document (TSD)). The natural visibility conditions, baseline visibility conditions, and visibility impact reductions needed to achieve the uniform rate of progress in 2018 for both North Dakota Class I areas are presented in Table 1 and further explained in this section. More detail is available in Sections 5 and 8 of the North Dakota SIP.

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

North Dakota class I area	20% Worst days				20% Best days	
	2000–2004 Baseline (dv)	2018 URP Goal (dv)	2018 Reduction needed (delta dv)	2064 Natural conditions (dv)	2000–2004 Baseline (dv)	2064 Natural conditions (dv)
Theodore Roosevelt National Park	17.80	15.47	2.33	7.8	7.76	3.04
Lostwood National Wildlife Refuge Wilderness Area	19.57	16.89	2.68	8.0	8.19	2.92

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 states to use ''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.[8] The purpose of this refinement to the ''old IMPROVE equation'' is to provide more accurate estimates of the various factors that affect the calculation of light extinction.

For Theodore Roosevelt and Lostwood, North Dakota opted to use WRAP calculations in which the default estimates for the natural conditions were combined with the ''new IMPROVE equation.'' This is an acceptable approach under our 2003 Natural Visibility Guidance. For Theodore Roosevelt, the default natural visibility value for the 20 percent worst days is 7.31 deciviews and for the 20 percent best days is 2.19 deciviews. For Lostwood, the default natural visibility value for the 20 percent worst days is 7.33 deciviews and for the 20 percent best days is 2.21 deciviews. For Theodore Roosevelt, North Dakota also referred to WRAP calculations using the new IMPROVE equation, finding the ''refined'' natural visibility value for the 20 percent worst days to be 7.8 deciviews and for the 20 percent best days to be 3.0 deciviews. For Lostwood, the ''refined'' natural visibility result for the 20 percent worst days is 8.0 deciviews and for the 20 percent best days is 2.9 deciviews. We have reviewed North Dakota's estimate of the natural visibility conditions and propose to find it acceptable using the new IMPROVE equation.

The new IMPROVE equation takes into account the most recent review of the science[9] and accounts for the effect of particle size distribution on light extinction efficiency of sulfate, nitrate, and organic carbon. It also adjusts the mass multiplier for organic carbon (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, elemental carbon (light-absorbing carbon), fine soil, and coarse mass terms, do not change between the original and new IMPROVE equations.

2. Estimating Baseline Visibility Conditions

As required by section 51.308(d)(2)(i) of the Regional Haze Rule and in accordance with our 2003 Natural Visibility Guidance, North Dakota calculated baseline visibility conditions for Theodore Roosevelt and Lostwood. The baseline condition calculation begins with the calculation of light extinction, using the IMPROVE equation. The IMPROVE equation sums the light extinction[10] resulting from individual pollutants, such as sulfates and nitrates. As with the natural visibility conditions calculation, North Dakota chose to use the new IMPROVE equation.

The period for establishing baseline visibility conditions is 2000–2004, and baseline conditions must be calculated using available monitoring data. 40 CFR 51.308(d)(2). The North Dakota Regional Haze SIP employed visibility monitoring data collected by IMPROVE monitors located in both North Dakota Class I areas for the years 2000 through 2004 and the resulting baseline conditions represent an average for 2000–2004. North Dakota calculated the baseline conditions at Theodore Roosevelt as 17.8 deciviews on the 20

[8] 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 regional planning organizations. 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 participant in visibility-related research, including the advancement of monitoring instrumentation, analysis techniques, visibility modeling, policy formulation and source attribution field studies.

[9] The science behind the revised IMPROVE equation is summarized in our Technical Support Document, in the Technical Support Document for Technical Products Prepared by the Western Regional Air Partnership (WRAP) in Support of Western Regional Haze Plans, Februrary 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 Interagency Monitoring of Protected Visual Environments (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, Marc., 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.*

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

percent worst days, and 7.8 deciviews on the 20 percent best days. North Dakota calculated the baseline conditions at Lostwood as 19.6 deciviews on the 20 percent worst days, and 8.2 deciviews on the 20 percent best days. We have reviewed North Dakota's estimations of baseline visibility conditions at Theodore Roosevelt National Park and Lostwood and propose to find them acceptable.

3. Natural Visibility Impairment

To address the requirements of 40 CFR 51.308(d)(2)(iv)(A), North Dakota also calculated the number of deciviews by which baseline conditions exceed natural visibility conditions at Theodore Roosevelt and Lostwood: for the 20 percent worst days, 10.0 deciviews (17.8 − 7.8) and 11.6 deciviews (19.6 − 8.0), respectively; for the 20 percent best days, 4.8 deciviews (7.8 − 3.0) and 5.3 deciviews (8.2 − 2.9), respectively. We have reviewed North Dakota's estimate of the natural visibility impairment and propose to find it acceptable.

4. Uniform Rate of Progress (URP)

In setting the reasonable progress goals, North Dakota analyzed and determined the uniform rate of progress needed to reach natural visibility conditions by the year 2064. In so doing, North Dakota compared the baseline visibility conditions in Theodore Roosevelt and Lostwood to the natural visibility conditions in Theodore Roosevelt and Lostwood (as described above) and determined the uniform rate of progress needed in order to attain natural visibility conditions by 2064 in both Class I areas. North Dakota constructed the uniform rate of progress 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 2000–2004 to the level of visibility conditions representing no anthropogenic impairment in 2064 for Theodore Roosevelt and Lostwood. The uniform rate of progress are summarized in Table 2 and further described below.

Using a baseline visibility value at Theodore Roosevelt of 17.8 deciviews and a "refined" natural visibility value of 7.8 deciviews for the 20 percent worst days, North Dakota calculated the uniform rate of progress to be approximately 0.17 deciviews per year (dv/year or dv/yr). This results in a total reduction of 10.0 deciviews to reach the natural visibility condition of 7.8 deciviews in 2064. The uniform rate of progress results in a visibility improvement of 2.3 deciviews needed for the period covered by this SIP revision submittal (up to and including 2018).

Using a baseline visibility value at Lostwood of 19.6 deciviews and a "refined" natural visibility value of 8.0 deciviews for the 20 percent worst days, North Dakota calculated the uniform rate of progress to be approximately 0.19 deciviews per year. This results in a total reduction of 11.6 deciviews to reach the natural visibility condition of 8.0 deciviews in 2064. The uniform rate of progress results in a visibility improvement of 2.7 deciviews needed for the period covered by this SIP revision submittal (up to and including 2018).

TABLE 2—SUMMARY OF UNIFORM RATE OF PROGRESS

Class I area	TRNP	LWA
Baseline Conditions	17.8 dv	19.6 dv.
Natural Visibility	7.8 dv	8.0 dv.
Total Improvement by 2064	10.0 dv	11.6 dv.
Improvement for this SIP by 2018	2.3 dv	2.7 dv.
URP	0.17 dv/year	0.19 dv/year.

We propose to find that North Dakota has appropriately calculated the uniform rate of progress.

C. Evaluation of North Dakota's BART Determinations Other Than for NO_X for Milton R. Young Station Units 1 and 2, Leland Olds Station Unit 2, and Coal Creek Station Units 1 and 2

BART is an element of North Dakota's long-term strategy for the first implementation period. As discussed in more detail in section IV.D 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. North Dakota addressed these steps as follows:

1. Identification of BART-Eligible Sources

The first step of a BART evaluation is to identify all the BART-eligible sources within the state's boundaries. North Dakota identified the BART-eligible sources in North Dakota by utilizing the approach set out in the BART Guidelines (70 FR 39158); 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. North Dakota initially screened its emissions inventory and permitting database to identify major facilities with emission units in one or more of the 26 BART categories. Following this, North Dakota used its databases and records to identify facilities in these source categories with potential emissions of 250 tons per year or more for any visibility-impairing pollutant from any unit that was in existence on August 7, 1977 and began operation on or after August 7, 1962. North Dakota contacted the sources, when necessary, to obtain or confirm this information.

The BART Guidelines direct states to 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 their "best judgment to determine whether VOC or NH_3 emissions from a source are likely to have an impact on visibility in an area." *See* 70 FR 39162. WRAP modeling demonstrated that VOCs from anthropogenic sources are not significant visibility-impairing pollutants at Theodore Roosevelt and Lostwood. NH_3 emissions in North Dakota are primarily due to area sources, such as livestock and fertilizer application. Because these are not point sources, they are not subject to BART. For the BART-eligible sources in North Dakota, North Dakota determined that NH_3 and VOC emissions are negligible. The emissions inventory prepared for the WRAP modeling demonstrates that NH_3 from point sources are not significant visibility-impairing pollutants in North Dakota. We have reviewed this information and propose to accept this determination.

North Dakota identified BART-eligible sources in North Dakota as shown in Table 3. This information is presented in Section 7 of North Dakota's SIP.

TABLE 3—LIST OF BART-ELIGIBLE SOURCES IN NORTH DAKOTA

BART-eligible source	Location	BART Source category (SC)	Nearest class I area
1. American Crystal Sugar Company (Main Boiler and Lime Kiln).	Drayton, northeastern North Dakota	SC 22—fossil fuel boilers >250 MMBtu/hr heat input and SC 12—lime plants.	LWA 400 km.
2. Basin Electric Power Cooperative, Leland Olds Station (Unit 1 and Unit 2).	Stanton, central North Dakota	SC 1—fossil fuel steam electric plants >250 MMBtu/hr heat input.	TRNP 150 km.
3. Great River Energy, Coal Creek Station (Unit 1 and Unit 2).	Falkirk, central North Dakota	SC 1—fossil fuel steam electric plants >250 MMBtu/hr heat input.	TRNP 160 km.
4. Great River Energy, Stanton Station (Unit 1).	Stanton, central North Dakota	SC 1—fossil fuel steam electric plants >250 MMBtu/hr heat input.	TRNP 150 km.
5. Minnkota Power Cooperative, Milton R. Young Station (Unit 1 and Unit 2).	Center, central North Dakota	SC 1—fossil fuel steam electric plants >250 MMBtu/hr heat input.	TRNP 150 km.
6. Montana Dakota Utilities Resources Group, Inc. R.M. Heskett Station (Unit 2).	Mandan, central North Dakota	SC 1—fossil fuel steam electric plants >250 MMBtu/hr heat input.	TRNP 180 km.
7. Tesoro Petroleum Corporation, Mandan Refinerry Carbon Monoxide Furnace.	Mandan, central North Dakota	SC 11—petroleum refineries	TRNP 180 km.

2. Identification of 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 states 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, North Dakota required each of its BART-eligible sources to develop and submit dispersion modeling to assess the extent of their contribution to visibility impairment at surrounding Class I areas.

a. Modeling Methodology

The BART Guidelines provide that states may use the CALPUFF [11] 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).

The BART Guidelines also recommend that states develop a modeling protocol for making individual source attributions, and suggest that states may want to consult with us and their RPO to address any issues prior to modeling. North Dakota used the CALPUFF model for North Dakota BART sources in accordance with a protocol it developed entitled ''Protocol for BART–Related Visibility Impairment Modeling Analyses in North Dakota, November 2005,'' which was approved by EPA and the Federal Land Managers and is included in Appendix A.1 of the SIP. The North Dakota protocol follows recommendations for long range transport described in appendix W to 40 CFR part 51, ''Guideline on Air Quality Models,'' and in EPA's ''Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts,'' as recommended by the BART Guidelines. 40 CFR part 51, appendix Y, section III.A.3.

To determine if each BART-eligible source has a significant impact on visibility, North Dakota used the CALPUFF model to estimate daily visibility impacts above estimated natural conditions at each Class I area within 300 km of any BART-eligible facility, based on maximum actual 24-hour emissions over a three year period (2000–2002).

North Dakota opted to conduct supplemental modeling for some sources using its own unique modeling approach. Further discussion on this is provided in section V.D and in the Technical Support Document.

b. Contribution Threshold

For states using 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 39104, 39161. 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 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 are free to

[11] 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/verio/download/download.htm.*

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.

North Dakota used a contribution threshold of 0.5 deciviews for determining which sources are subject to BART. The State's decision was based on the following factors: (1) 0.5 Deciviews equates to the 5% extinction threshold for new sources under the Prevention of Signification Deterioration New Source Review rules, (2) 0.5 deciviews represents the limit of perceptible change, (3) most of North Dakota's major point sources are over 100 miles away from Class I areas and are located downwind in the prevailing wind direction, and (4) BART screening modeling indicates the visibility impact of these point sources is either much greater than both 1.0 deciviews and 0.5 deciviews or less than 0.5 deciviews. Although we do not agree that all of the factors considered by North Dakota's Department of Health are relevant in determining whether a source can be considered to cause or contribute to visibility impairment, we propose to approve the State's threshold of 0.5 deciviews. As shown in Table 4, North Dakota exempted four of the seven BART-eligible sources in the state from further review under the BART requirements. The visibility impacts attributable to each of these four sources fell well below 0.5 deciviews. Given the relatively limited impact on visibility from these four sources, we propose to agree with North Dakota's Department of Health that 0.5 deciviews is a reasonable threshold for North Dakota in determining whether its BART-eligible sources are subject to BART.

Because our recommended modeling approach already incorporates choices that tend to lower peak daily visibility impact values,[12] our BART Guidelines state that a state should compare the 98th percentile (as opposed to the 90th or lower percentile) of CALPUFF modeling results against the ''contribution'' threshold established by the state for purposes of determining BART applicability. While North Dakota used a 98th percentile comparison, North Dakota also included a 90th percentile comparison in its SIP. The use of the 90th percentile excludes roughly the worst 36 days of data in a year compared to 7 days for the 98th percentile. We find that the 98th percentile value is appropriate. Further explanation on use of the 98th versus 90th percentile value is provided at 70 FR 39121, July 6, 2005.

c. Sources Identified by North Dakota as Subject to BART

The results of the CALPUFF modeling are summarized in Table 4. Those facilities listed with demonstrated impacts at all Class I areas less than 0.5 deciviews were determined by North Dakota to not be subject to BART; those with impacts greater than 0.5 deciviews were determined to be subject toBART.

TABLE 4—INDIVIDUAL BART-ELIGIBLE SOURCE VISIBILITY IMPACTS ON NORTH DAKOTA CLASS I AREAS

Source and unit	Class I Area	Maximum 24-hour 98th percentile visibility impact (dv)	Subject to BART or exempt
1. American Crystal Sugar Company (Main Boiler and Lime Kiln)	LWA	0.04	Exempt.
	TRNP	0.04	
2. Great River Energy, Coal Creek Station (Unit 1 and Unit 2)	LWA	4.04	Subject to BART.
	TRNP	4.48	
3. Great River Energy, Stanton Station (Unit 1)	LWA	1.35	Subject to BART.
	TRNP	1.68	
4. Minnkota Power Cooperative, Milton R. Young Station (Unit 1 and Unit 2)	LWA	4.88	Subject to BART.
	TRNP	6.69	
5. Basin Electric Power Cooperative, Leland Olds Station (Unit 1 and Unit 2)	LWA	5.42	Subject to BART.
	TRNP	6.22	
6. Montana Dakota Utilities Resources Group, Inc. R.M. Heskett Station (Unit 2)	LWA	0.23	Exempt.[13]
	TRNP	0.28	
7. Tesoro Petroleum Corporation, Mandan Refinery Carbon Monoxide Furnace	LWA	0.04	Exempt.
	TRNP	0.05	

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) 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.

All of the sources presented in Table 4 that are subject to BART are fossil-fuel-fired EGUs. North Dakota performed BART determinations for all of the sources subject to BART for NO_X, SO_2, and PM. We find that North Dakota adequately considered all five steps above in its BART determinations, with the exception of its NO_X BART determinations for Milton R. Young Station Units 1 and 2, Leland Olds Station Unit 2, and Coal Creek Station Units 1 and 2. We are proposing to disapprove the NO_X BART determinations for these five units, and we discuss them separately in Sections V.D, V.E, and V.F of this proposal. We propose to approve North Dakota's

[12] See our BART Guidelines, Section III.A.3.

[13] The State's single-source modeling for Heskett Station Unit 2 predicted the highest maximum 24-hour 98th percentile visibility impact value to be 0.82 dv at Theodore Rooseveltand 0.58 dv at Lostwood. Since these values were close to the BART exemption threshold, MDU hired a consultant to perform a refined CALPUFF modeling analysis. We and the FLMs expressed concerns about the refined modeling. MDU agreed to remodel using an EPA approved protocol. The results of the final analysis predicted the highest maximum 24-hour 98th percentile visibility impact value to be 0.28 dv at TRNP and 0.23 dv at LWA in 2001. The refined modeling used a 1 kilometer grid size instead of 3 kilometer, speciated particulate matter emissions into several components with varying light scattering potential, and used annual average background visibility instead of the annual 20% best day's background visibility. We agree with the revised modeling results and with the State's analysis that Heskett Station Unit 2 is below the BART threshold and not subject to BART. Information on the refined modeling and the State's updated analysis was submitted with SIP Supplement No. 1 on July 27, 2010.

BART determinations for all remaining cases and summarize them below.

a. Great River Energy, Coal Creek Station

Background

Coal Creek Station is a two-unit, 1,100 gross MW mine-mouth electrical generating plant located near Underwood, North Dakota. It consists primarily of two steam generators (both with a 550 MW capacity) and associated coal and ash handling systems. Both units are identical Combustion Engineering boilers that tangentially fire pulverized lignite coal. The expected remaining useful life for each is at least 20 years. In addition, the State concluded that there are 24 BART-eligible material handling transfer operations that are negligible sources of PM and five BART-eligible units—consisting of auxiliary or emergency equipment—that are negligible sources of PM, SO_2, and NO_X. The State analyzed each pollutant and its effect on the visibility in Class I areas. A summary of the State's analyses of existing controls and potential BART controls for each pollutant is set forth below, except for the discussion of NO_X BART for Units 1 and 2 which we address in section V.D.2.a. Since the Unit 1 and Unit 2 boilers are identical, the State made a single BART determination that is applicable to each unit. The State's BART determination for Coal Creek Station is provided in Appendix B.2 of the SIP. The visibility impacts noted in the following analyses are derived from the company's BART analysis provided in Appendix C.2 of the SIP (refer to Technical Support Document for more details).

Unit 1 and Unit 2 Boilers

SO_2 BART Review: Each unit is already equipped with a wet scrubber system which removes approximately 90% of the SO_2 from 60% of the flue gas. In addition, Great River Energy constructed a pilot 75 tons per hour lignite drying system in 2005 as part of a collaborative agreement under the Clean Coal Power Initiative. Lower moisture content of the coal provides the following two primary benefits: (1) Enhanced scrubber efficiency due to increased boiler efficiency and lower flue gas volume, and (2) decreased fuel combustion quantities resulting in lower emissions. Great River Energy opted to install the coal drying equipment independent of the BART controls chosen for SO_2. The State used undried coal as the worst case scenario for purposes of emissions estimating, explaining that it could not be reasonably sure of future coal moisture or British thermal unit (Btu) content. The baseline controlled SO_2 emissions that North Dakota reported in the SIP are 24,604 tons per year per unit.[14]

The State identified the following SO_2 control options as having potential application to the Coal Creek Station boilers: coal cleaning/washing, K-Fuel®, TurboSorp®, coal drying, dry sorbent injection, spray dryer, wet scrubber modification, and wet scrubber replacement. The State eliminated the following options as technically infeasible: coal cleaning/washing and K-Fuel. As noted above, Great River Energy has elected to install coal drying equipment independent of SO_2 BART controls. The average cost effectiveness of all the remaining control options, as provided by Great River Energy, was deemed reasonable with the exception of the TurboSorp® circulating dry scrubber. Since the circulating dry scrubber has a lower removal efficiency compared to a new or upgraded wet scrubber and costs more than the wet scrubber options, North Dakota eliminated a circulating dry scrubber from further consideration. The incremental cost effectiveness of a new wet scrubber was deemed excessive as it achieved no additional emission reductions as compared to the next most effective option of modifying the existing wet scrubber. The State did not identify any energy or non-air quality effects that would preclude the selection of any of the five alternatives. A summary of the State's SO_2 BART analysis, and the visibility impacts derived from modeling conducted by the source, are provided in Table 5.

TABLE 5—SUMMARY OF COAL CREEK SO_2 BART ANALYSIS FOR UNIT 1 AND UNIT 2 BOILERS

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)	Visibility impacts [1] [2]	
						Visibility improvement (delta dv)	Fewer Days > 0.5 dv (days)
Wet Scrubber Replacement	95	0.146	20,760	30.76	1,482	1.919	68
Wet Scrubber Modification [3]	95	0.146	20,760	11.52	555	1.419	49
Spray Dryer	90	0.292	16,915	29.22	1,727		
Existing Scrubber with 0% Bypass	83.1	0.493	11,610	9.84	848		
Dry Sorbent Injection	70	0.875	1,538	12.52	8,140		

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

[2] Great River Energy modeled combined SO_2 and NO_X controls. Thus, the results shown include the noted SO_2 control option and North Dakota's selected NO_X BART control, LNB Option 1.

[3] While wet scrubber modification achieves the same annual SO_2 reduction as wet scrubber replacement, Great River Energy modeled wet scrubber modification using a much higher 24-hour emission rate. This accounts for the disparity in the modeled visibility improvement between the two options.

North Dakota determined BART to be modifications to the existing wet scrubbers so as to achieve scrubbing of 100% of the flue gas stream and adding a new coal dryer serving both units (the addition of a coal dryer is clarified in Section 7.4.2 of the SIP). North Dakota specified a BART limit as a minimum control efficiency of 95% (30-day rolling average) based on the inlet SO_2 concentration to the scrubber or 0.15 lb/MMBtu (30-day rolling average)

[14] North Dakota calculated baseline emissions based on a future undried coal sulfur content of 1.10% and provided a detailed discussion of this adjustment in the SIP, Appendix B.2, pp. 8–10.

averaged over both units. The estimated cost of wet scrubber modifications was \$555 per ton (\$/ton) of SO_2 removed, and the capital and annualized costs were estimated to be \$76,220,000, and \$11,520,000 per year (\$/year or \$/yr), respectively.

We are proposing to approve the State's SO_2 BART determination for Coal Creek Units 1 and 2. The State's assessment of costs and other impacts was reasonable. The guidelines do not require EGUs with existing flue gas desulfurization (FGD) systems (another term for scrubbers) achieving greater than 50 percent control to remove these controls and replace them with new controls but do recommend that states evaluate upgrades to such existing scrubber systems (70 FR 39133 and 70 FR 39171). The upgrade to the existing wet scrubbers at Coal Creek will result in a stringent level of control comparable to a new wet scrubber and will result in a reduction in annual SO_2 emissions from the plant of approximately 20,760 tons. This substantial reduction will result in a significant improvement in visibility at Theodore Roosevelt, estimated to be 1.419 deciviews and 49 fewer days above 0.5 deciviews when combined with the State's selected NO_X BART controls, separated overfire air (SOFA) + low NO_X burners (LNB).

Filterable PM BART Review: Each unit at Coal Creek is already equipped with an electrostatic precipitator (ESP) for PM which is 99.5% efficient. The baseline controlled PM emissions that North Dakota reported in the SIP are 775 tons per year per unit with an emission rate of 0.030 lb/MMBtu. The State identified the following PM control options as having potential application to the Coal Creek Station boilers: multiclone, replacement of the dry ESP, a polishing wet ESP, and a baghouse. The State eliminated the multiclone option as technically infeasible for controlling PM emissions from the boilers. A summary of the State's PM BART analysis is provided in Table 6.

TABLE 6—SUMMARY OF COAL CREEK FILTERABLE PM BART ANALYSIS FOR UNIT 1 AND UNIT 2 BOILERS

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM\$)	Cost effectiveness (\$/ton)
Replacement Dry ESP	99.75	0.015	387	10.06	25,995
Polishing Wet ESP	99.75	0.015	387	1.92	4,961
Baghouse	99.75	0.015	387	7.67	19,819

North Dakota determined BART to be no additional controls. The State predicted the incremental visibility improvement from any of the three control options would be less than 0.027 deciviews. The alternative with the least cost for reducing filterable PM is the polishing wet ESP. This system has a cost effectiveness of \$4,961 per ton of particulate when compared to the current emission control system (ESP operating at 99.5% efficiency). Considering the negligible improvement in visibility that would be achieved by adding a polishing wet ESP, the State considers this cost, as well as the costs of the more expensive options, to be excessive. The State established a BART emission limit of 0.07 lb/MMBtu.

We are proposing to approve the State's filterable PM BART determination for Coal Creek Units 1 and 2. The State's assessment of costs and other impacts was reasonable. The existing ESP already reduces PM emissions by approximately 99.5%, and North Dakota reasonably determined that the costs of additional PM controls would be excessive given the negligible improvement in visibility that would result.

Condensable PM (PM_{10}) Review: The State provided an estimated emission rate for condensable PM of 0.02 lb/MMBtu. This emission rate is lower than the current filterable PM emission rate of 0.03 lb/MMBtu. Thus the State concluded that the visibility impacts from condensable PM would be even less than the impacts from filterable PM. Condensable PM consists of both organic and inorganic substances. Organic condensable PM includes VOCs that are in a gaseous state through the air pollution control devices but eventually change to a solid or liquid state. The primary inorganic substance from boilers is sulfuric acid mist with lesser amounts of hydrogen fluoride and ammonium sulfate. Sulfuric acid mist is the largest component of condensable PM so controlling it will control most of the condensable PM. The options for controlling sulfuric acid mist are the same as the options for controlling SO_2. BART for SO_2—modification of the existing wet scrubber—will reduce sulfuric acid mist by approximately 90%. Changes that would provide additional reductions are not warranted given the minimal improvement in visibility that would result. The State determined that ongoing good combustion controls and the BART limit for SO_2 would also constitute BART for condensable PM.

We are proposing to approve the State's condensable PM BART determination for Coal Creek Units 1 and 2. Upgrades to the wet scrubbers required as part of SO_2 BART will substantially reduce sulfuric acid mist, which is the largest component of condensable PM. North Dakota reasonably determined that the costs of additional condensable PM controls would be excessive given the negligible improvement in visibility that would result.

Auxiliary Boilers No. 91 and No. 92, Emergency Generator, Emergency Fire Pump, and Material Handling and Fugitive Sources

The State analyzed and determined BART for these small emissions sources at the plant and determined that BART is existing controls with no additional controls. The State based its conclusion on the fact that further controls would not be cost effective and would have virtually no impact on visibility. For further detail, see the State's BART analysis.

We agree with the State's conclusion and are proposing to approve its BART determination for these sources.

b. Great River Energy, Stanton Station

Background

Stanton Station is a 188 MW electrical generating plant located on the bank of the Missouri River in eastern Mercer County near Stanton, North Dakota. The plant's one main turbine generator is run by the Unit 1 and Unit 10 boilers. Unit 1, which is the only BART eligible unit at Stanton Station, began operation in 1966. An auxiliary boiler was added in 1982. Unit 1 has a dry bottom front-wall-fired configuration and is permitted to burn both lignite and sub-bituminous Powder River Basin (PRB) coal. Unit 1 has an expected remaining useful life of at least 20 years. Because Great River Energy does not intend to blend coals, North Dakota determined BART controls and emission limits separately for both each coal type that Unit 1 is permitted to burn. The use of two coals with different sulfur contents complicates the SO_2 BART analysis and determination for Unit 1. Associated limits were determined based upon each fuel, cost effectiveness, and expected visibility improvements. In addition to the boilers, there are 13 BART-eligible material handling transfer operations that are negligible sources of PM and three other BART-eligible units consisting of auxiliary or emergency equipment that are negligible sources of PM, SO_2, and NO_X. The State analyzed each pollutant and its effect on the visibility in Class I areas. A summary of the State's analyses of existing controls and potential BART controls for each pollutant is set forth below. The State's BART determination for Stanton Station is provided in Appendix B.3 of the SIP. The visibility impacts noted in the following analyses are derived from the company's BART analysis provided in Appendix C.3 of the SIP.

Unit 1 Boiler

SO_2 BART Review (Lignite Coal): Unit 1 is not equipped with any pollution controls for SO_2. The baseline uncontrolled SO_2 emissions that North Dakota reported in the SIP are 8,242 tons per year with an emission rate of 1.70 lb/MMBtu. The State identified the following SO_2 control options as having potential application to the Stanton Station boiler: wet scrubber, spray dryer/fabric filter, circulating dry scrubber, flash dryer absorber,[15] wet scrubber with 10% bypass, dry sorbent injection/fabric filter, dry sorbent injection/existing ESP, Powerspan ECO®, coal cleaning, Pahlman Process™, and K-Fuel®. The State eliminated the following options as technically infeasible: coal cleaning, K-Fuel®, Powerspan ECO®, and the Pahlman Process™. The cost of all the technically feasible control options was deemed reasonable. The flash dryer absorber with a control efficiency of 90% was not carried through the analysis as it costs more than a spray dryer with no additional emissions reduction. The State determined that there were no energy and non-air quality environmental impacts that would preclude the selection of any of the control equipment alternatives. However, the State cited the environmental impact of a wet scrubber using 20% more water and difficulties in expanding on-site pond capacity to accommodate this additional water as one reason for not selecting a wet scrubber. In addition, the State determined the incremental cost of $10,600 per ton for the circulating dry scrubber as compared to a spray dryer was excessive. Therefore, it removed the circulating dry scrubber from further consideration. The State also found that a wet scrubber would only reduce SO_2 emissions by 469 tons per year more than the spray dryer/fabric filter option and noted that the incremental visibility improvement would be 0.112 deciviews. A summary of the State's SO_2 BART analysis with lignite coal, and the visibility impacts derived from modeling conducted by the source, are provided in Table 7.

TABLE 7—SUMMARY OF STANTON SO_2 BART ANALYSIS FOR UNIT 1 BOILER WITH LIGNITE COAL

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)	Visibility impacts [1 2]	
						Visibility benefit (delta dv)	Fewer days > 0.5 (days)
Wet Scrubber	95	0.091	8,907	13.18	1,480	1.119	49
Circulating Dry Scrubber	93	0.127	8,720	14.22	1,631	....	....
SD/FF	90	0.181	8,438	11.22	1,330	1.007	43
Wet Scrubber with 10% Bypass	86	0.263	8,063	9.49	1,177	....	....
DSI/FF	55	0.817	5,157	8.43	1,635	0.382	16
DSI/ESP	35	1.18	3,282	3.2	975	0.382	16

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

[2] Visibility impacts are presented for each SO_2 control option with NO_X emissions at pre-control emission rates.

For use of lignite coal, North Dakota determined BART to be a spray dryer with a fabric filter. North Dakota specified a BART limit as a minimum control efficiency of 90% (30-day rolling average) on the inlet SO_2 concentration to the pollution control equipment or 0.24 lb/MMBtu (30-day rolling average). In establishing the 30-day rolling average limit, the State increased the calculated annual emissions rate of 0.18 lb/MMBtu to 0.24 lb/MMBtu to account for coal variability over the shorter averaging period. The estimated average cost effectiveness of the spray dryer with a fabric filter was $1,330 per ton of SO_2 removed, and the capital and annualized costs were estimated to be $77,840,000 and $11,220,000 per year, respectively. This control option will result in a significant improvement in visibility at Theodore Roosevelt, estimated to be 1.007 deciviews and 43 fewer days above 0.5 deciviews.

SO_2 BART Review (Powder River Basin Coal): North Dakota concluded that the technically feasible control options for Unit 1 are the same whether the source is burning lignite or Powder River Basin coal. North Dakota conducted its analyses based on two different baseline SO_2 emission limits which vary due to anticipated sulfur content variations in the Powder River Basin coal as the result of a new coal contract.[16] The State determined that the incremental cost of $16,000 per ton (with a 1.2 lb/MMBtu baseline emission rate) for a circulating dry scrubber compared to a spray dryer was excessive. In addition, the State considered the incremental cost of over $11,800 per ton (with a 0.64 lb/MMBtu baseline emission rate) for a wet scrubber as compared to a spray dryer

[15] North Dakota appears to have a typographical error in its BART determination. Though flash dryer absorber is not included in its list of available control options for lignite coal, flash dryer absorber is mentioned in the lignite analysis and is listed in the technically feasible options for Powder River Basin coal.

[16] Appendix B.3, pp. 17–22, of the SIP describes the basis for the 1.2 lb/MMBtu and 0.64 lb/MMBtu SO_2 baseline emission rates.

to be excessive. Therefore, the State removed the wet scrubber and circulating dry scrubber from further consideration. The State also found that a wet scrubber would only reduce SO_2 emissions by 311 tons per year more than the spray dryer/fabric filter option and that the incremental visibility improvement would be less than 0.112 deciviews, the value for lignite. A summary of the State's SO_2 BART analysis with Powder River Basin coal is provided in Table 8.

TABLE 8—SUMMARY OF STANTON SO_2 BART ANALYSIS FOR UNIT 1 BOILER WITH POWDER RIVER BASIN COAL

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)
Wet Scrubber	95	0.06	5,905	13.18	2,232
Circulating Dry Scrubber	93	0.084	5,781	14.22	2,460
SD/FF	90	0.12	5,594	11.22	2,006
Wet Scrubber with 10% Bypass	86	0.168	5,346	9.49	1,775
DSI/FF	55	0.54	3,419	8.43	2,466
DSI/ESP	35	0.78	2,176	3.20	1,471

For use of Powder River Basin coal, North Dakota determined BART to be a spray dryer with a fabric filter to achieve a minimum control efficiency of 90% (30-day rolling average) on the inlet SO_2 concentration to the pollution control equipment or an emission limit of 0.16 lb/MMBtu (30-day rolling average). In establishing the 30-day rolling average BART limit, the State increased the calculated annual emissions rate of 0.12 lb/MMBtu to 0.16 lb/MMBtu to account for coal variability over the shorter averaging period. The estimated cost of a spray dryer with a fabric filter was $2,006 per ton of SO_2 removed, and the capital and annualized costs were estimated to be $77,840,000 and $11,220,000 per year, respectively. The projected visibility improvements from this option, as well as for all other control options, when the source burns Powder River Basin coal, are anticipated to be less than when the source burns lignite coal.

We are proposing to approve the State's SO_2 BART determinations for Stanton Unit 1 for both lignite and Powder River Basin coal. The State's assessment of costs and other impacts was reasonable. The spray dryer with fabric filter represents a stringent level of control and will result in a reduction in annual SO_2 emissions from the plant of approximately 8,438 tons when lignite is burned and 5,594 tons when Powder River Basin coal is burned. This substantial reduction will result in a significant improvement in visibility at Theodore Roosevelt, estimated to be 1.007 deciviews and 43 fewer days above 0.5 deciviews. Higher performing alternatives (wet scrubber or circulating dry scrubber) would only produce a slightly greater reduction in SO_2 and improvement in visibility, at higher cost. We are proposing to find that, based on its consideration of the BART factors, the State's elimination of these control options was reasonable.

NO_X BART Review (Lignite Coal): Unit 1 is already equipped with LNB for NO_X control. North Dakota indicates in the SIP that Unit 1 has baseline controlled NO_X emissions of 1,740 tons per year with an emission rate of 0.36 lb/MMBtu. North Dakota identified the following control options as having potential application as BART: selective catalytic reduction (SCR), low temperature oxidation (LTO), non-selective catalytic reduction (NSCR), electro-catalytic oxidation (ECO), selective non-catalytic reduction (SNCR), rich reagent injection (RRI), external flue gas recirculation (FGR), overfire air (OFA), LNB, and the Pahlman Process. The State identified the following control options as technically infeasible: ECO, NSCR, the Pahlman Process, RRI, and external flue gas recirculation. The incremental cost effectiveness of both SCR and LTO were deemed excessive at $10,000 and $45,400 per ton, respectively, when compared to a combination of LNB, OFA, and SNCR (LNB + OFA + SNCR). The State determined that there were no energy and non-air quality environmental impacts that would preclude the selection of any of the control equipment alternatives. A summary of the State's NO_X BART analysis with lignite coal, and the visibility impacts derived from modeling conducted by the source, are provided in Table 9.

TABLE 9—SUMMARY OF STANTON NO_X BART ANALYSIS FOR UNIT 1 BOILER WITH LIGNITE COAL

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)	Visibility Imacts[1 2]	
						Visibility benefit (delta dv)	Fewer days > 0.5 dv (days)
SCR	90	0.044	1,929	12.49	6,475	1.405	59
LTO	90	0.044	1,929	44.78	23,217		
LNB + OFA + SNCR	45	0.239	983	3.00	3,052	1.110	52
SNCR	33	0.29	738	2.70	3,658	1.027	43
LNB + OFA						1.009	43

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

[2] Great River Energy modeled combined SO_2 and NO_X controls. Thus, the results shown include the noted NO_X control option and North Dakota's selected SO_2 BART control, a spray dryer with fabric filter.

For use of lignite coal, North Dakota determined BART to be LNB + OFA + SNCR. North Dakota specified a BART limit as a minimum control efficiency of 45% and an emission limit of 0.29 lb/MMBtu (30-day rolling average). The estimated average cost effectiveness of the selected control combination is $3,052 per ton of NO_X removed. The capital and annualized costs were estimated to be $10,660,000 and $3,000,000, respectively. This control option, when combined with the spray dryer/fabric filter determined to be BART for SO_2, will result in a significant improvement in visibility at Theodore Roosevelt, estimated to be 1.110 deciviews and 52 fewer days above 0.5 deciviews. This represents an incremental visibility improvement of 0.103 deciviews and 9 fewer days above 0.5 deciviews when compared to use of a spray dryer/fabric filter with the existing low NOx burners.

NO_X BART Review (Powder River Basin Coal): The technically feasible control options for Powder River Basin coal are the same. The costs of both SCR and LTO were deemed excessive. The State determined that there were no energy and non-air quality environmental impacts that would preclude the selection of any of the control equipment alternatives. A summary of the State's NO_X BART analysis with Powder River Basin coal is provided in Table 10.

TABLE 10—SUMMARY OF STANTON NO_X BART ANALYSIS FOR UNIT 1 BOILER WITH POWDER RIVER BASIN COAL

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)
SCR	88	0.044	1,530	12.49	8,163
LTO	88	0.044	1,530	44.78	29,268
LNB + OFA + SNCR	45	0.196	794	3.0	3,778
SNCR	36	0.230	629	2.7	4,293
LNB + OFA	21	0.286	358	0.3	838

For use of Powder River Basin coal, North Dakota determined BART to be LNB + OFA + SNCR with a minimum control efficiency of 45% and an emission limit of 0.23 lb/MMBtu (30-day rolling average). The estimated cost of the selected control combination is $3,778 per ton of NO_X removed. The capital and annualized costs were estimated to be $10,660,000 and $3,000,000, respectively. The projected visibility improvements from this option, as well as for all other control options, when the source burns Powder River Basin coal, are anticipated to be less than when the source burns lignite coal.

We are proposing to approve the State's NO_X BART determinations for Stanton Unit 1 for both lignite and Powder River Basin coal. Given the projected incremental visibility improvement of just under 0.3 deciviews from the use of SCR or LTO as compared to LNB + OFA + SNCR and the average and incremental cost effectiveness values associated with these technologies, the State reasonably concluded that the costs associated with SCR and LTO are not warranted.

Filterable PM BART Review (Lignite Coal): Unit 1 is already equipped with an ESP for PM control. The State evaluated the following control options as having potential application as BART: baghouse, new ESP, and wet ESP. All were deemed technically feasible. The State determined all options present excessive costs with the least expensive option being the wet ESP at $112,780 per ton of PM removed. North Dakota stated there would be negligible visibility improvement with additional controls. The State determined BART to be no additional controls with an emission limit of 0.07 lb/MMBtu when burning lignite. A summary of the State's PM BART analysis with lignite coal is provided in Table 11.

TABLE 11—SUMMARY OF STANTON PM BART ANALYSIS FOR UNIT 1 BOILER WITH LIGNITE COAL

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)
Baghouse	99.7+	0.015	18	4.98	276,670
New ESP	99.7	0.015	18	5.80	322,220
Wet ESP	99.7	0.015	18	2.03	112,780

Filterable PM BART Review (Powder River Basin Coal): North Dakota did not conduct a separate analysis for filterable PM when combusting Powder River Basin coal. The State noted that available pollution control equipment is expected to control emissions from both lignite and Powder River Basin coal down to similar emission rates. North Dakota determined that BART for filterable PM when burning Powder River Basin coal was the same as when burning lignite: no additional controls with an emission limit of 0.07 lb/MMBtu.

We are proposing to approve the State's filterable PM BART determination for Stanton Unit 1. The State's assessment of costs and other impacts was reasonable. Existing controls, ESP, already reduce PM emissions by approximately 99.5%, and North Dakota reasonably determined that the costs of additional PM controls would be excessive given the negligible improvement in visibility that would result.

Condensable PM (PM_{10}) *Review (Lignite Coal):* The State provided an estimated emission rate for condensable PM of 0.02 lb/MMBtu. This emission rate is about equal to the current filterable PM emission rate of 0.019 lb/MMBtu. Based on the negligible visibility impacts of filterable PM, the State anticipated that the visibility impacts of condensable PM would also be negligible. Condensable PM consists of both organic and inorganic substances. Organic condensable PM includes VOCs that are in a gaseous state through the air pollution control devices but eventually change to a solid or liquid state. The primary inorganic substance from boilers is sulfuric acid mist with lesser amounts of hydrogen fluoride and ammonium sulfate. Sulfuric acid mist is the largest component of condensable PM so controlling it will control most of the condensable PM. The options for controlling sulfuric acid mist are the same as the options for controlling SO_2. BART for SO_2—spray dryer with a fabric filter—will reduce sulfuric acid mist by approximately 90%. North Dakota determined that changes that would provide additional reductions are not warranted given the negligible improvement in visibility that would result. The State determined that ongoing good combustion controls and the BART limit for SO_2 would also constitute BART for condensable PM.

Condensable PM (*PM_{10}*) *Review* (*Powder River Basin Coal*): For the same reasons described above for condensable PM when burning lignite, North Dakota determined that ongoing good combustion controls and the BART limit for SO_2 would also constitute BART for condensable PM when burning Powder River Basin coal.

We are proposing to approve the State's condensable PM BART determination for Stanton Unit 1. The spray dryer with a fabric filter required for SO_2 BART will substantially reduce sulfuric acid mist, which is the largest component of condensable PM. North Dakota reasonably determined that the costs of additional condensable PM controls would be excessive given the negligible improvement in visibility that would result.

Auxiliary Boiler, Emergency Generator, Emergency Fire Pump, Material Handling and Fugitive Sources

The State analyzed and determined BART for these small emissions sources at the plant and determined that BART is existing controls with no additional controls. The State based its conclusion on the fact that further controls would not be cost effective and would have virtually no impact on visibility. For further detail, see the State's BART analysis.

We agree with the State's conclusion and are proposing to approve its BART determination for these sources.

c. Minnkota Power Cooperative, Milton R. Young Station (MRYS)

Background

Milton R. Young Station is a two-unit 794 MW electrical generating plant located near Center, North Dakota. Both units are Babcock & Wilcox cyclone boilers burning lignite coal. Commercial operation commenced for Unit 1 (277 MW) in 1970 and for Unit 2 (517 MW) in 1977. Both units have an expected remaining useful life of at least 20 years. In addition, there are ten BART-eligible material handling transfer operations that are negligible sources of PM and four other BART-eligible units consisting of auxiliary or emergency equipment that are negligible sources of PM, SO_2, and NO_X. The State analyzed each pollutant and its effect on the visibility in Class I areas. A summary of the State's analysis of existing controls and potential BART controls is set forth below, except for the discussion of NO_X BART for Units 1 and 2, which we address in section V.D.1 below. The State's BART determination for Milton R. Young Station is provided in Appendix B.4 of the SIP. The company's BART analysis is provided in Appendix C.4 of the SIP.

Unit 1 Boiler

SO_2 BART Review: Unit 1 had no existing SO_2 control system at the time of the State's BART analysis, but as a result of a consent decree resolving alleged New Source Review violations at Milton R. Young Station, Minnkota installed a wet scrubber in April 2011. The consent decree states that if Minnkota installs a wet scrubber, it must comply with a 95% control efficiency with no alternative emission limit (lb/MMBtu) limit. The deadline to meet the new emission limit is December 31, 2011. The baseline uncontrolled SO_2 emissions that North Dakota reported in the SIP are 21,519 tons per year with an emission rate of approximately 1.87 lb/MMBtu.

The State evaluated the following SO_2 control options for having potential application as BART: wet scrubber, spray dryer, circulating dry scrubber, Powerspan ECO, fuel switching, and coal cleaning. North Dakota identified Powerspan ECO and coal cleaning as technically infeasible. The State also cited a court case as a rationale for not further analyzing fuel switching.[17] The State found all three remaining technologies to be cost effective. The State determined that there were no energy and non-air quality environmental impacts that would preclude the selection of any of the control equipment alternatives. A summary of the State's SO_2 BART analysis, and the visibility impacts derived from modeling conducted by the source, are provided in Table 12.

TABLE 12—SUMMARY OF MILTON R. YOUNG STATION SO_2 BART ANALYSIS FOR UNIT 1 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)	Visibility impacts [1,2]	
						Visibility benefit (delta dv)	Fewer days 0.5 dv (days)
Wet Scrubber	95	0.10	20,443	22.58	1,105	2.076	71
Circulating Dry Scrubber	93	0.14	20,013	24.65	1,232	....	....
Spray Dryer	90	0.20	19,367	23.68	1,222	2.002	62

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

[2] Visibility impacts are presented for each SO_2 control option with NO_X emissions at pre-control emission rates.

North Dakota determined BART to be a wet scrubber, the most efficient control alternative, operating at a minimum 95% control efficiency (30-day rolling average). Since the wet scrubber is the most efficient

[17] A decision by the Seventh Circuit Court of Appeals on a BACT determination for Prairie Generating Company, LLC indicated that fuel switching was not required for mine mouth coal generating facilities. The State's position is this would also apply to BART determinations. We agree that a State is not required to consider switching from coal to natural gas as part of a BART analysis for a coal-fired power plant. As EPA noted in the BART Guidelines, we do not consider BART as a requirement to redesign the source when considering available control alternatives. 79 FR at 39164.

technology, further evaluation of the other alternatives is not necessary. Minnkota did conduct modeling for the 90% and 95% control options; the results are included in Table 12. The estimated cost of a wet scrubber was $1,105 per ton of SO_2 removed, and the capital and annualized costs were estimated to be $111,776,000 and $22,584,000 per year, respectively.

We are proposing to approve the State's SO_2 BART determination for Milton R. Young Station Unit 1. The State selected the most efficient control technology at a 95% control level, which we consider to be consistent with the most stringent level of control currently available. Per our BART Guidelines, a state may skip the five-factor analysis if it is imposing the most stringent level of control. Nonetheless, we note that the wet scrubber will produce a reduction in annual SO_2 emissions from the unit of approximately 20,443 tons. This substantial reduction will result in a significant improvement in visibility at Theodore Roosevelt—estimated to be 2.076 deciviews and 71 fewer days above 0.5 deciviews.

Filterable PM BART Review: Unit 1 is equipped with an ESP rated at approximately 99% control efficiency. The baseline controlled PM emissions that North Dakota reported in the SIP are 268 tons per year with an emission rate of 0.019 lb/MMBtu. The State evaluated the following PM control options for having potential application as BART with all four being found technically feasible: a new baghouse; a new ESP; a compact hybrid particulate collector (CoHPAC); and upgrading the existing ESP. All were deemed to have excessive costs. The alternative with the least cost was a new baghouse at $39,433 per ton of PM removed. The State determined BART to be no additional controls. Minnkota is subject to a consent decree limiting PM emissions to 0.030 lb/MMBtu in the event Minnkota installs a wet scrubber. North Dakota stated there would be insignificant visibility improvement with additional controls. Since Minnkota has installed a wet scrubber, the State proposed that BART is an emission limit of 0.030 lb/MMBtu (average of three test runs). A summary of the State's PM BART analysis is provided in Table 13.

TABLE 13—SUMMARY OF MILTON R. YOUNG STATION PM BART ANALYSIS FOR UNIT 1 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)
Baghouse	99.7+	0.013	134	5.28	39,433
New ESP	99.7	0.015	90	4.64	51,589
CoHPAC	99.7	0.015	90	3.63	40,355

We are proposing to approve the State's filterable PM BART determination for Milton R. Young Station Unit 1. The State's assessment of costs and other impacts was reasonable. Existing controls, ESP, already reduce PM emissions by approximately 99%, and North Dakota reasonably determined that the costs of additional PM controls would be excessive given the negligible improvement in visibility that would result.

Condensable PM (PM_{10}) Review: Sulfuric acid mist is the largest component of condensable PM. North Dakota stated that the options for controlling sulfuric acid mist are the same as the options for controlling SO_2. Based on the negligible visibility impacts of filterable PM, the State anticipated that the visibility impacts of condensable PM would also be negligible. The State determined that ongoing good combustion controls and the BART limit for SO_2 would also constitute BART for condensable PM.

We are proposing to approve the State's condensable PM BART determination for Milton R. Young Station Unit 1. The wet scrubber required for SO_2 BART will substantially reduce sulfuric acid mist, which is the largest component of condensable PM. North Dakota's determination is reasonable.

Unit 2 Boiler

SO_2 BART Review: At the time of the State's BART analysis, Unit 2 was equipped with a wet scrubber system which treated approximately 78% of the flue gas with the remaining flue gas by-passed for stack gas reheat. The wet scrubber system achieved approximately 75% SO_2 removal. The baseline controlled SO_2 emissions that North Dakota reported in the SIP are 18,090 tons per year with an emission rate of approximately 0.88 lb/MMBtu. The Milton R. Young Station consent decree imposed a deadline for Unit 2 to be upgraded and achieve 90% control efficiency by December 31, 2010. The upgraded scrubber was placed into operation on December 8, 2010.

The State evaluated the following SO_2 control options for BART: A new wet scrubber; upgrade to existing scrubber (either to 90% or 95%); circulating dry scrubber; spray dryer; flash dryer absorber; Powerspan ECO; fuel switching; and coal cleaning. The Stated found coal cleaning, Powerspan ECO, and fuel switching to be technically infeasible. The average cost effectiveness of all remaining alternatives was deemed reasonable. The State determined that there were no energy and non-air quality environmental impacts that would preclude the selection of any of the control equipment alternatives. As the 95% control efficiency scrubber upgrade had equal or greater control efficiency at lower cost as compared to a new wet scrubber or a circulating dry scrubber, and the 90% control efficiency scrubber upgrade had equal control efficiency at lower cost as compared to a spray dryer or flash dryer, the State reduced the options to the 95% and 90% control efficiency scrubber upgrades. A summary of the State's SO_2 BART analysis, and visibility impacts derived from modeling conducted by the source, are provided in Table 14.

TABLE 14—SUMMARY OF MILTON R. YOUNG STATION SO_2 BART ANALYSIS FOR UNIT 2 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)	Visibility impacts[1] [2]	
						Visibility benefit (delta dv)	Fewer days > 0.5 dv (days)
Upgrade Existing Scrubber	95	0.11	16,126	8.41	522	1.627	52
Upgrade Existing Scrubber	90	0.23	14,162	7.33	518	1.423	40

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

[2] Visibility impacts are presented for each SO_2 control option with NO_X emissions at pre-control emission rates.

North Dakota determined BART to be the improvements to the wet scrubber to achieve a 95% control efficiency (from scrubber inlet to outlet, 30-day rolling average). Minnkota would have to comply with either the 95% reduction requirement or the 0.15 lb/MMBtu limit, but not both. The 90% control efficiency requirement from the consent decree resolving the alleged new source review violations is also incorporated into the BART permit, which is part of the SIP.

We are proposing to approve the State's SO_2 BART determination for Milton R. Young Station Unit 2. The State's assessment of costs and other impacts was reasonable. The upgrade to the existing wet scrubbers represents a stringent level of control and will result in a reduction in annual SO_2 emissions from the plant of approximately 16,126 tons. This substantial reduction will result in a significant improvement in visibility at Theodore Roosevelt—estimated to be 1.627 deciviews and 52 fewer days above 0.5 deciviews.

Filterable PM BART Review: Unit 2 is equipped with an ESP rated at approximately 99% control efficiency with a baseline emission rate of 0.06 lb/MMBtu. The average emission rate for this unit for 2000–2004 was 0.028 lb/MMBtu. The baseline controlled PM emissions that North Dakota reported in the SIP are 1,135 tons per year. The State evaluated the following PM control options for BART and found all four to be technically feasible: A new baghouse; a new ESP; a CoHPAC; and upgrades to the existing ESP. The cost of all options was deemed excessive, with the least expensive being CoHPAC at $6,693 per ton of PM removed. North Dakota stated that visibility impacts even at 100% control would be minimal due to the low emission reductions of 849 tons per year compared to the baseline conditions with the existing 99% efficient ESP. The State proposed BART to be no additional controls. The consent decree limits PM emissions to 0.030 lb/MMBtu. Therefore, the State proposed that BART is an emission limit of 0.030 lb/MMBtu (average of three test runs). A summary of the State's PM BART analysis is provided in Table 15.

TABLE 15—SUMMARY OF MILTON R. YOUNG STATION PM BART ANALYSIS FOR UNIT 2 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)
Baghouse	99.7+	0.013	887	8.25	9,300
New ESP	99.7	0.015	849	7.52	8,857
CoHPAC	99.7	0.015	849	5.68	6,693
Baseline	99.0	0.060		2.97	

We are proposing to approve the State's filterable PM BART determination for Milton R. Young Station Unit 2. The State's assessment of costs and other impacts was reasonable. Existing controls, ESP, already reduce PM emissions by approximately 99%, and North Dakota reasonably determined that the costs of additional PM controls would be excessive given the negligible improvement in visibility that would result.

Condensable PM (PM_{10}) Review: Sulfuric acid mist is the largest component of condensable PM. North Dakota stated that the options for controlling sulfuric acid mist are the same as the options for controlling SO_2. Based on the negligible visibility impacts of filterable PM, the State anticipated that the visibility impacts of condensable PM would also be negligible. The State determined that ongoing good combustion controls and the BART limit for SO_2 would also constitute BART for condensable PM.

We are proposing to approve the State's condensable PM BART determination for Milton R. Young Station Unit 2. The wet scrubber required for SO_2 BART will substantially reduce sulfuric acid mist, which is the largest component of condensable PM. North Dakota's determination is reasonable.

Auxiliary Boiler, Emergency Generator, Emergency Fire Pumps, and Material Handling and Fugitive Sources

The State analyzed and determined BART for these small emissions sources at the plant and determined that BART is existing controls with no additional controls. The State based its conclusion on the fact that further controls would not be cost effective and would have virtually no impact on visibility. For further detail, see the State's BART analysis.

We agree with the State's conclusion and are proposing to approve its BART determination for these sources.

d. Basin Electric Power Cooperative, Leland Olds Station (LOS)

This is a 656 MW coal-fired electrical generating plant located in Stanton, North Dakota with two boiler units. Unit 1 is a Babcock & Wilcox wall-fired, dry-bottom, pulverized coal-fired boiler serving a turbine generator with a nameplate rating of 216 MW. Unit 2 is a Babcock & Wilcox cyclone-fired unit burning crushed coal, with a turbine-generator name plate rating of 440 MW. Unit 1 began commercial operation in 1966 and Unit 2 began operation in 1976. Both boiler units burn lignite coal and have an expected remaining useful life of at least 20 years. In addition, there are seven BART-eligible material handling transfer operations that are negligible sources of PM and two other BART-eligible units consisting of auxiliary and emergency equipment that are negligible sources of PM, SO_2, and NO_X. Each pollutant and its effect on the visibility in Class I areas was analyzed by the State. A summary of the State's analysis of existing controls and potential BART controls for each pollutant is set forth below, except for the discussion of NO_X BART for Unit 2, which we address in section V.D.1.c below. The State's BART determination for Leland Olds Station is provided in Appendix B.1 of the SIP. The company's BART analysis is provided in Appendix C.1 of the SIP.

Unit 1 Boiler

SO_2 BART Review: Unit 1 has no existing SO_2 control system. The baseline uncontrolled SO_2 emissions that North Dakota reported in the SIP are 34,683 tons per year with an emission rate of approximately 3.02 lb/MMBtu. The State evaluated the following SO_2 control options for BART: Wet scrubber; spray dryer; circulating dry scrubber; flash dryer absorber; Powerspan ECO; fuel switching; and coal cleaning. Powerspan ECO and coal cleaning were identified as technically infeasible. The State conducted a cost analysis for the top three options and found all to be cost effective. The flash dryer absorber was not included in the analysis because it costs more than a spray dryer with no additional emissions reduction. The State determined that there were no energy and non-air quality environmental impacts that would preclude the selection of any of the control equipment alternatives. A summary of the State's SO_2 BART analysis for Unit 1, and visibility impacts derived from modeling conducted by the source, are provided in Table 16.

TABLE 16—SUMMARY OF LELAND OLDS STATION SO_2 BART ANALYSIS FOR UNIT 1 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)	Visibility impacts[1 2]	
						Visibility benefit (delta dv)	Fewer days > 0.5 dv (days)
Wet Scrubber	95	0.15	32,949	19.31	586	1.912	83
Circulating Dry Scrubber	93	0.21	32,255	20.72	636	1.743	78
Spray Dryer	90	0.30	31,215	18.70	599	1.707	77

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

[2] Basin Electric modeled combined SO_2 and NO_X controls. The results shown include the noted SO_2 control option and NO_X at the presumptive rate. Given that the presumptive NO_X emission rate is very close to the pre-control NO_X rate, the visibility impacts shown are largely due to the reduction in SO_2 emissions and not the reduction in NO_X emissions.

North Dakota determined BART to be the most efficient control option, a wet scrubber operating at 95% control efficiency or below an emission limit of 0.15 lb/MMBtu (30-day rolling average). Basin Electric would have to comply with either the 95% reduction requirement or the 0.15 lb/MMBtu limit, but not both. The estimated average cost effectiveness of a wet scrubber was $586 per ton of SO_2 removed, and the capital and annualized costs were estimated to be $107,220,000 and $19,310,000 per year, respectively.

We are proposing to approve the State's SO_2 BART analysis and determination for Leland Olds Station Unit 1. The State's assessment of costs and other impacts was reasonable. The wet scrubber represents a stringent level of control and will result in a reduction in annual SO_2 emissions from the plant of approximately 32,949 tons. This substantial reduction will result in a significant improvement in visibility at Theodore Roosevelt, estimated to be 1.912 deciviews and 83 fewer days above 0.5 deciviews.

NO_X BART Review: Unit 1 is equipped with LNB (installed in 1995). The baseline controlled NO_X emissions that North Dakota reported in the SIP are 2,967 tons per year with an emission rate of approximately 0.285 lb/MMBtu. The State identified the following control option combinations for BART:

- Selective catalytic reduction (SCR).
- Electro-catalytic oxidation (ECO).
- Selective non-catalytic reduction (SNCR).
- Hydrocarbon enhanced SNCR (HE–SNCR).
- Rich reagent injection (RRI).
- Rotomix (ROFA + SNCR).
- Conventional gas reburn (CGR).
- CGR + SNCR with SOFA.
- Coal reburn.
- Coal reburn + SNCR.
- Fuel-lean gas reburn (FLGR).
- FLGR + SNCR.
- Rotating overfire air (ROFA).
- Separated overfire air (SOFA).
- New low NO_X burners (LNB).
- Combustion improvements.

The State agreed with Basin Electric's determination that high dust SCR is not technically feasible but found that low-dust SCR (LDSCR) and tail-end SCR (TESCR) would be technically feasible. North Dakota also identified ECO, coal reburn plus SNCR, and RRI as technically infeasible for Unit 1. The State determined the average cost effectiveness of the four most efficient options to be excessive with estimates ranging from $4,400 to $13,600 per ton of NO_X removed. The State also determined the incremental costs of these options to be excessive with estimates ranging from $12,500 to $80,700. North Dakota discussed the benefits of pilot testing and based its acceptance of cost estimates provided by Basin Electric on the inability to mandate pilot testing in the BART process. The State noted that EPA, in the BART Guidelines, established a presumptive NO_X emission limit of 0.29 lb/MMBtu for this type of boiler. The State determined that there were no energy and non-air quality environmental impacts that would preclude the selection of any of the control equipment alternatives. A summary of the State's NO_X BART analysis for Unit 1 is provided in Table 17.

TABLE 17—SUMMARY OF LELAND OLDS STATION NO_X BART ANALYSIS FOR UNIT 1 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)
SCR Low Dust	80	0.057	2,374	18.63–26.86	7,849–11,313
SCR Tail End	80	0.057	2,374	21.51–31.01	9,061–13,628
Coal Reburn + Boosted SOFA	48.7	0.146	1,445	7.03	4,866
Coal Reburn + SOFA	46.2	0.153	1,371	5.98	4,364
SNCR + Boosted SOFA	45.1	0.156	1,338	3.82	2,854
SNCR + Basic SOFA	42.0	0.165	1,246	3.10	2,487
SNCR + Close Coupled OFA	24.5	0.215	727	3.36	4,623
Boosted SOFA	24.3	0.216	721	1.14	1,577
SOFA	19.4	0.230	576	0.14	250

North Dakota determined BART to be SNCR + basic SOFA with an emission limit of 0.19 lb/MMBtu (30-day rolling average). The estimated average cost effectiveness for SNCR + SOFA was $2,487 per ton of NO_X removed, and the capital and annualized costs were estimated to be $6,234,000 and $3,099,000 per year, respectively.

Basin Electric did not provide the modeled visibility impacts of SNCR + basic SOFA for Unit 1 individually. Instead, for this control option, Basin Electric provided the visibility impacts for Unit 1 and Unit 2 combined, with the emissions from Unit 2 held constant. The resulting visibility improvement, when compared to no controls at Unit 1, is estimated to be 0.160 deciviews at Theodore Roosevelt.

We are proposing to approve the State's NO_X BART determination for Leland Olds Station Unit 1. Based on our review of North Dakota's submission, we are proposing to find that it was reasonable for the State to eliminate higher performing control options and select SNCR + basic SOFA as BART with an emission limit of 0.19 lb/MMBtu (30-day rolling average). Three of the other controls under consideration—Coal Reburn + Boosted SOFA, Coal Reburn + SOFA, and SNCR + Boosted SOFA—would provide minimal additional reductions of NO_X, (and presumably relatively small improvements in visibility), but have higher dollar per ton values. The incremental costs of these options compared to SNCR + basic SOFA are relatively high. We note that we do not agree with the State's cost analysis for SCR, but nonetheless find the elimination of SCR for this unit to be acceptable. As we explain in greater detail in section V.D.1.d below, Basin Electric deviated significantly from EPA's control cost manual when it estimated costs for SCR for Leland Olds Station Unit 2, and substantially overestimated the costs for SCR. The State relied on Basin Electric's estimates of the costs for SCR for Unit 2 when it estimated the costs for SCR for Unit 1. Thus, we anticipate that the State's estimate for Unit 1 also overestimates the costs for SCR. Nonetheless, Unit 1 is relatively small compared to Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2 and has substantially lower baseline NO_X emissions. And, unlike those units, Unit 1 is not a cyclone boiler and so is currently fitted with low-NO_X burners. Finally, North Dakota has selected an emission limit—0.19 lb/MMBtu—based on the use of post-combustion controls (SNCR) and combustion controls, that is substantially more stringent than the presumptive BART limit for this type of boiler. This emission limit represents an adjustment of the annual rate since the 30-day rolling average is expected to be 5–15% higher. These controls will achieve a reduction in NO_X emissions of about 1,246 tons per year. Based on these factors, we are proposing to approve North Dakota's NO_X BART determination.

Filterable PM BART Review: Unit 1 is equipped with an ESP rated at approximately 99% control efficiency. The baseline controlled PM emissions that North Dakota reported in the SIP are 219 tons per year with an emission rate of approximately 0.040 lb/MMBtu. The State evaluated the following PM control options for BART and found all to be technically feasible: A new baghouse; a new ESP; and a CoHPAC. North Dakota considered the cost effectiveness for all three options to be excessive with the least expensive option being CoHPAC at an average cost effectiveness of $11,947 per ton of PM removed. North Dakota stated there would be negligible visibility improvement with additional controls. The State proposed BART to be no additional controls with an emission limit of 0.07 lb/MMBtu (average three test runs). A summary of the State's PM BART analysis for Unit 1 is provided in Table 18.

TABLE 18—SUMMARY OF LELAND OLDS STATION PM BART ANALYSIS FOR UNIT 1 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)
Baghouse	99.7+	0.013	224	3.26	15,554
New ESP	99.7	0.013	207	2.63	12,705
CoHPAC	99.7	0.013	207	2.47	11,947

Condensable PM (PM_{10}) Review: Sulfuric acid mist is the largest component of condensable PM. The options for controlling sulfuric acid mist are the same as the options for controlling SO_2; therefore, North Dakota determined that BART for condensable PM is good SO_2 control. The State determined that ongoing good combustion controls and the BART limit for SO_2 would also constitute BART for condensable PM.

We are proposing to approve the State's condensable PM BART determination for Leland Olds Station Unit 1. The wet scrubber required for SO_2 BART will substantially reduce sulfuric acid mist, which is the largest component of condensable PM. North Dakota reasonably determined that the costs of additional condensable PM controls would be excessive given the negligible improvement in visibility that would result.

Unit 2 Boiler

SO_2 BART Review: Unit 2 has no existing SO_2 control system. The baseline uncontrolled SO_2 emissions that North Dakota reported in the SIP are 67,858 tons per year with an emission rate of approximately 3.02 lb/MMBtu. The State identified the following as potential control options: new wet scrubber, spray dryer, circulating dry scrubber, flash dryer absorber, Powerspan ECO, fuel switching, and coal cleaning. Powerspan ECO and coal cleaning were determined to be technically infeasible. A summary of the State's SO_2 BART analysis for Unit 2, and visibility impacts derived from modeling conducted by the source, are provided in Table 19.

TABLE 19—SUMMARY OF LELAND OLDS STATION SO_2 BART ANALYSIS FOR UNIT 2 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)	Visibility impacts[1 2]	
						Visibility benefit (delta dv)	Fewer days > 0.5 dv (days)
Wet Scrubber	95	0.15	64,465	29.84	463	3.479	89
Circulating Dry Scrubber	93	0.21	63,108	35.58	564		
Spray Dryer	90	0.30	61,072	32.89	539		
Flash Dryer Absorber	90	0.30	61,072	32.43	531		
Fuel Switching	77	0.69	<52,251	13.49	258		

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

[2] Basin Electric modeled combined SO_2 and NO_X controls. The results shown include the noted SO_2 control option and NO_X at the SOFA emission rate. Given that the NO_X emission rate with SOFA is somewhat close to the pre-control NO_X rate, the visibility impacts shown are largely due to the reduction in SO_2 emissions and not the reduction in NO_X emissions.

North Dakota determined BART to be the most efficient control option, a wet scrubber operating at 95% control efficiency or below an emission limit of 0.15 lb/MMBtu (30-day rolling average). Basin Electric would have to comply with either the 95% reduction requirement or the 0.15 lb/MMBtu limit, but not both. The estimated average cost effectiveness of a wet scrubber was $463 per ton of SO_2 removed, and the capital and annualized costs were estimated to be $147,600,000 and $29,840,000 per year, respectively.

We are proposing to approve the State's SO_2 BART determination for Leland Olds Station Unit 2. The State's assessment of costs and other impacts was reasonable. The wet scrubber represents a stringent level of control and will result in a reduction in annual SO_2 emissions from the plant of approximately 64,465 tons. When modeled with modest NO_X reductions assumed for SOFA, the maximum improvement is estimated to be 3.479 deciviews and 89 fewer days above 0.5 deciviews at Theodore Roosevelt.

Filterable PM BART Review: Unit 2 is equipped with an ESP rated at approximately 99% control efficiency. The baseline controlled PM emissions that North Dakota reported in the SIP are 627 tons per year with an emission rate of approximately 0.034 lb/MMBtu. The State evaluated the following PM control options for BART and found all to be technically feasible: A new baghouse; a new ESP; and a CoHPAC. North Dakota considered the average cost effectiveness for all three options to be excessive, with the least expensive option being CoHPAC at $12,000 per ton. The average PM emission rate for 2000–2004 was 0.025 lb/MMBtu. The State noted that eliminating all PM emissions would result in a visibility impact of only 0.026 deciviews. The State established BART as no additional controls and the existing permitted emission limit of 0.07 lb/MMBtu (average three test runs). A summary of the State's PM BART analysis for Unit 2 is provided in Table 20.

TABLE 20—SUMMARY OF LELAND OLDS STATION PM BART ANALYSIS FOR UNIT 2 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)
Baghouse	99.7+	0.013	388	5.89	15,186
New ESP	99.7	0.015	350	4.95	14,137
CoHPAC	99.7	0.015	350	4.21	12,029
Baseline	99.3	0.034			

We are proposing to approve the State's filterable PM BART determination for Leland Olds Station Unit 2. The State's assessment of costs and other impacts was reasonable. Existing controls, ESP, already reduce PM emissions by approximately 99%, and North Dakota reasonably determined that the costs of additional PM controls would be excessive given the negligible improvement in visibility that would result.

Condensable PM (PM_{10}) Review: Sulfuric acid mist is the largest component of condensable PM. The options for controlling sulfuric acid mist are the same as the options for controlling SO_2; therefore, North Dakota determined that BART for condensable PM is good SO_2 control. The State determined that ongoing good combustion controls and the BART limit for SO_2 would also constitute BART for condensable PM.

We are proposing to approve the State's condensable PM BART determination for Leland Olds Station Unit 2. The wet scrubber required for SO_2 BART will substantially reduce sulfuric acid mist, which is the largest component of condensable PM. North Dakota reasonably determined that the costs of additional condensable PM controls would be excessive given the negligible improvement in visibility that would result.

Auxiliary Boiler, Emergency Fire Pump, and Material Handling and Fugitive Sources

The State analyzed and determined BART for these small emissions sources at the plant and determined that BART is existing controls with no additional controls. The State based its conclusion on the fact that further controls would not be cost effective and would have virtually no impact on visibility. For further detail, see the State's BART analysis.

We agree with the State's conclusion and are proposing to approve its BART determination for these sources.

e. North Dakota BART Results and Summary

We have summarized North Dakota's BART determinations that we are proposing to approve in Table 21 for SO_2 and Table 22 for NO_X, below. We have not summarized the information for PM as it has relatively low impact on visibility.

North Dakota's Regional Haze Rule requires each source subject to BART to install and operate BART no later than 5 years after we approve this Regional Haze SIP. NDAC 33–15–25–02.2. This satisfies the requirement under 40 CFR 51.308(e)(1)(iv), that ''each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.''

As noted previously, to be approvable, the Regional Haze SIP must include monitoring, recordkeeping, and reporting requirements to ensure that the BART limits are enforceable. North Dakota has included individual source permits in its Regional Haze SIP that contain such requirements. *See* SIP Appendix D. We have reviewed these requirements and find them to be adequate as they relate to the BART limits we are proposing to approve. In particular, for SO_2 and NO_X BART limits, the permits require the use of continuous emission monitoring systems (CEMS) to determine compliance, generally in accordance with 40 CFR part 75. For the filterable PM BART limits, the permits require stack testing and compliance with a compliance assurance monitoring (CAM) plan. Adequate recordkeeping and reporting requirements are also specified.

For the reasons discussed above, we propose to find that, with the exception of the NO_X BART determinations for Milton R. Young Station Units 1 and 2, Leland Olds Station Unit 2, and Coal Creek Units 1 and 2, North Dakota satisfied the BART requirements of 40 CFR 51.308(e).

TABLE 21—NORTH DAKOTA BART DETERMINATIONS FOR SO_2 EMISSIONS THAT EPA IS PROPOSING TO APPROVE

Source and unit	2000–2004 average emissions (tons/yr)	Baseline level of control (% reduction)	BART level of control (% reduction) [1]	Control device	Emissions after controls (tons/yr)	Emission reduction (tons/yr) [2]	Emission limit
Basin Electric Power Cooperative, LOS Unit 1.	16,666	0	95	New Wet Scrubber ...	1,376	15,290	95% reduction or 0.15 lb/MMBtu, 30-day rolling average.
Basin Electric Power Cooperative, Leland Olds Station Unit 2.	30,828	0	95	New Wet Scrubber ...	2,530	28,298	95% reduction or 0.15 lb/MMBtu, 30-day rolling average.
Great River Energy, Coal Creek Station Unit 1.	14,086	68	95	Modified Existing Wet Scrubber and Coal Dryer.	3,781	10,305	95% reduction or 0.15 lb/MMBtu, 30-day rolling average.
Great River Energy, Coal Creek Station Unit 2.	12,407	68	95	Modified Existing Wet Scrubber and Coal Dryer.	3,621	8,786	95% reduction or 0.15 lb/MMBtu, 30-day rolling average.
Great River Energy, Stanton Station Unit 1.	8,312	0	90	New Spray dryer and Fabric Filter.	1,179	7,133	90% reduction or 0.24 lb/MMBtu (lignite), or 0.16 lb/MMBtu (PRB) 30-day rolling average.
Minnkota Power Cooperative, MRYS Unit 1.	20,148	0	95	New Wet Scrubber ...	1,007	19,141	95% reduction, 30-day rolling average.
Minnkota Power Cooperative, MRYS Unit 2.	12,404	65	95	Modified Existing Wet Scrubber.	2,739	9,665	95% reduction, or 0.15 lb/MMBtu, 30-day rolling average. Also, 90% reduction.

[1] Based on two-year baseline emission rate for BART.
[2] Based on the average 2000–2004 operating rate.

TABLE 22—NORTH DAKOTA BART DETERMINATIONS FOR NO_X EMISSIONS THAT EPA IS PROPOSING TO APPROVE

Source and unit	2000–2004 average emissions (tons/yr)	Baseline level of control (% reduction)	BART level of control (% reduction) [1]	Control device	Emissions after controls (tons/yr)	Emission reduction (tons/yr) [2]	Emission limit
Stanton Unit 1	2,048	0	45	LNB, Overfire Air and SNCR.	1,425	623	0.29 lb/10^6 Btu, 30-day rolling average.
Leland Olds Unit 1	2,501	0	42	SOFA and SNCR	1,744	757	0.19 lb/10^6 Btu, 30-day rolling average.

[1] Based on two-year baseline emission rate for BART.
[2] Based on the average 2000–2004 operating rate.

D. Evaluation of North Dakota's NO_X BART Determinations for Milton R. Young Station Units 1 and 2, Leland Olds Station Unit 2, and Coal Creek Station Units 1 and 2

The discussion below is limited to the NO_X BART assessments for Milton R. Young Station Units 1 and 2, Leland Olds Station Unit 2, and Coal Creek Units 1 and 2. North Dakota's other BART assessments are covered in Section V.C.3, above.

1. Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2

a. Milton R. Young Station Unit 1—State Analysis

At the time Minnkota made its BART submittal upon which the State based its analysis, Milton R. Young Station Unit 1 had no existing NO_X control system. The baseline uncontrolled NO_X emissions that North Dakota reported in the SIP are 9,032 tons per year per unit with an emission rate of 0.849 lb/MMBtu. The Minnkota consent decree, discussed in section V.C.3.c, above, required Minnkota to install OFA on Unit 1 by December 31, 2009.

The State has asserted that the Milton R. Young Station units do not exceed the 750 MW threshold for mandatory application of the BART guidelines and the presumptive NO_X BART limits. That presumptive limit for a cyclone unit greater than 200 MW burning lignite is 0.10 lb/MMBtu. To reach its conclusion, North Dakota relied on the nameplate capacity of the units. We propose to disagree based on the fact that the actual operating levels for Units 1 and 2 are 277 MW and 517 MW, respectively—*i.e.,* in excess of their nameplate capacities.[18] The sum of these permitted levels results in a total generating capacity of at least 794 MW, which is above the 750 MW capacity threshold established by the CAA and the Regional Haze Rule (see 40 CFR 51.308(e)(ii)(B)). We also note that the State's regional haze regulations, at NDAC 33–15–25–03, require that facility owners or operators for whom the guidelines are not mandatory ''shall use appendix y [EPA's BART Guidelines] as guidance for preparing their best available control retrofit technology determinations.'' [19]

The State identified the following as potential control options: SCR, ECO, SNCR, HE–SNCR, RRI, Rotomix (ROFA + SNCR), CGR, CGR + SNCR + SOFA, coal reburn, coal reburn + SNCR, FLGR, FLGR + SOFA, ROFA, SOFA, advanced separated overfire air (ASOFA), combustion improvements (included with SOFA and ASOFA), and oxygen enhanced combustion (OEC). The State eliminated the following from further consideration as technically infeasible: High dust SCR, ECO, HE–SNCR, RRI, Rotomix (ROFA + SNCR), CGR + SNCR, coal reburn + SNCR, FLGR + SNCR, and OEC.

A summary of the State's analysis for NO_X BART alternatives, and modeling results provided by both the source and State are provided in Table 23 for Unit 1.

TABLE 23—SUMMARY OF MILTON R. YOUNG STATION NO_X BART ANALYSIS FOR UNIT 1 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)	Visibility impacts [1,2] Visibility benefit (delta dv)	Visibility impacts [1,2] Fewer days > 0.5 dv (days)
LDSCR + ASOFA	90	0.085	8,129	33.53–52.19	4,124–6,421	3.476	114
TESCR + ASOFA	90	0.085	8,129	39.31–56.10	4,835–6,901	3.476	114
SNCR + ASOFA	58.1	0.355	5,248	7.47	1,424	2.923	96
Gas Reburn + ASOFA	56	0.374	5,058	37.33	7,381		
Coal Reburn + ASOFA	54.6	0.385	4,931	11.39	2,309		
FLGR + ASOFA	45.9	0.460	4,146	16.99	4,098		
ASOFA	39.5	0.513	3,568	2.49	698		

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.
[2] Minnkota and the State modeled combined SO_2 and NO_X controls. The results shown include SO_2 at an emission rate reflective of SO_2 scrubbing along with the noted NO_X control option. More detail on this approach is provided in the Technical Support Document.

The State determined that the cost of all control options was reasonable with the exception of both SCR configurations. The State considered the average cost effectiveness and incremental cost effectiveness of LDSCR

[18] See letter from John T. Graves, Environmental Superintendent, Minnkota Power Cooperative, Inc., to Dana Mount, Director, Division of Environmental Engineering, North Dakota Department of Health, Re: Permit to Operate No. F76009, Permit Revisions, November 20, 1995.

[19] We are proposing to approve the State's regional haze regulations as part of this action.

and TESCR to be excessive and unreasonable. These control options, when combined with wet scrubbing for SO_2, would result in a significant improvement in visibility at Theodore Roosevelt, estimated to be 3.476 deciviews and 114 fewer days above 0.5 deciviews. This represents an incremental visibility improvement of 1.400 deciviews and 43 fewer days above 0.5 deciviews beyond that achieved by wet scrubbing alone. Moreover, when compared to SNCR + ASOFA, it would result in an incremental visibility improvement of 0.553 deciviews and 18 fewer days above 0.5 deciviews. However, the State also stated that single source visibility benefits calculated using the EPA modeling guidelines are inflated and conducted supplemental cumulative visibility modeling (*i.e.,* modeling using degraded background, reflecting emissions from all sources). The results of the State's supplemental cumulative modeling showed greatly reduced visibility benefits from use of SCR, benefits that the State considered to be negligible. The State determined that there were no energy and non-air quality environmental impacts that would preclude the selection of any of the control equipment alternatives. North Dakota determined BART to be SNCR + ASOFA (the next most efficient option after SCR), with an emission limit of 0.36 lb/MMBtu (30-day rolling average) and a separate limit during startup of 2070.2 lb/hr (24-hour rolling average). North Dakota estimated the cost effectiveness for SNCR + ASOFA to be $1,424 per ton of NO_X removed, and the capital and annualized costs to be $8,113,000 and $7,742,000 per year, respectively.

b. Milton R. Young Station Unit 2—State Analysis

At the time Minnkota made its BART submittal upon which the State based its analysis, Milton R. Young Station Unit 2 was equipped with an OFA NO_X control system. The baseline controlled NO_X emissions that North Dakota reported in the SIP were 15,507 tons per year per unit with an emission rate of approximately 0.81 lb/MMBtu. The State identified the following as potential control options: SCR, ECO, SNCR, HE–SNCR, ASOFA, RRI + SNCR + ASOFA, Rotomix (ROFA + SNCR), CGR + SNCR, coal reburn, coal reburn + SNCR, FLGR, FLGR + SOFA, ROFA, SOFA, ASOFA, combustion improvements, and OEC. The State eliminated the following from further consideration as technically infeasible: High dust SCR, ECO, HE–SNCR, RRI, Rotomix (ROFA + SNCR), CGR + SNCR, coal reburn + SNCR, FLGR + SNCR, and OEC. A summary of the State's analysis for NO_X BART alternatives, and modeling results provided by both the source and State, are provided in Table 24 for Unit 2.

TABLE 24—SUMMARY OF MILTON R. YOUNG STATION NO_X BART ANALYSIS FOR UNIT 2 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)	Visibility impacts [1 2]	
						Visibility benefit (delta dv)	Fewer days > 0.5 dv (days)
LDSCR + ASOFA	90	0.079	13,956	57.35–89.07	4,109–6,382	3.945	110
TESCR + ASOFA	90	0.079	13,956	66.51–98.81	4,765–7,081	3.945	110
SNCR + ASOFA	58.0	0.330	8,994	11.41	1,268	3.379	89
Gas Reburn + ASOFA	55.4	0.350	8,591	63.88	7,436		
Coal Reburn + ASOFA	54.2	0.360	8,405	19.48	2,317		
FLGR + ASOFA	45	0.432	6,978	29.31	4,201		
ASOFA	37.7	0.489	5,846	4.38	749		

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

[2] Minnkota and the State conducted the modeling with combined SO_2 and NO_X controls. The results shown include SO_2 at an emission rate reflective of SO_2 scrubbing along with the noted NO_X control option.

The State determined the average cost effectiveness of all control options was reasonable with the exception of both SCR configurations. The State considered the average cost effectiveness and incremental cost effectiveness of LDSCR and TESCR to be excessive and unreasonable. These control options, when combined with wet scrubbing for SO_2, would result in a significant improvement in visibility at Theodore Roosevelt National Park—estimated to be 3.945 deciviews and 110 fewer days above the 0.5 dv threshold. This represents an incremental visibility improvement of 2.318 deciviews and 58 fewer days above the 0.5 dv threshold beyond that achieved by wet scrubbing alone. Moreover, when compared to SNCR + ASOFA, SCR + ASOFA would result in an incremental visibility improvement of 0.566 deciviews and 21 fewer days above the 0.5 dv threshold. However, using the same approach it used for Milton R. Young Station Unit 1, the State determined that the visibility benefits from use of SCR would be negligible. The State determined that there were no energy and non-air quality environmental impacts that would preclude the selection of any of the control equipment alternatives. North Dakota determined BART to be SNCR + ASOFA (the next most efficient option after SCR), with an emission limit of 0.35 lb/MMBtu (30-day rolling average) and a separate limit during startup of 3,995.6 lb/hr (24-hour rolling average). The State estimated the cost effectiveness for SNCR + ASOFA to be $1,268 per ton of NO_X removed, and the capital and annualized costs to be $17,128,000 and $11,405,000 per year, respectively.

c. Leland Olds Station Unit 2—State Analysis

At the time Basin Electric made its BART submittal upon which the State based its analysis, Unit 2 had no existing NO_X control system. ASOFA was installed in November 2009. The State identified the following as potential control options: SCR, ECO, SNCR, HE–SNCR, ASOFA, RRI + SNCR + ASOFA, Rotomix (ROFA + SNCR), CGR + SNCR, coal reburn, coal reburn + SNCR, FLGR, SOFA, ASOFA, ROFA, combustion improvements, and OEC. The State eliminated the following from further consideration as technically infeasible: High dust SCR, ECO, HE–SNCR, Rotamix, CGR + SNCR, coal reburn + SNCR, FLGR + SNCR, and OEC.

A summary of the State's analysis for NO_X BART alternatives, and modeling results provided by both the source and State are provided in Table 25 for Unit 2.

TABLE 25—SUMMARY OF LELAND OLDS STATION NO_X BART ANALYSIS FOR UNIT 2 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)	Visibility impacts [1,2]	
						Visibility benefit (delta dv)	Fewer days > 0.5 dv (days)
Low Dust SCR + ASOFA	90	0.07	10,821	38.74–55.84	3,581–5,161	4.393	130
Tail End SCR + ASOFA	90	0.07	10,821	43.83–63.17	4,050–5,838	4.393	130
RRI + SNCR + ASOFA	60.3	0.266	7,250	17.4	2,400	3.963	110
SNCR + ASOFA	54.5	0.305	6,553	10.87	1,659	3.874	105
Coal Reburn + ASOFA	51.8	0.323	6,228	14.86	2,386		
ASOFA	37.7	0.482	3,366	1.24	369	3.479	89

[1] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

[2] The visibility modeling that North Dakota (for SCR) and Basin Electric (all scenarios but SCR) performed for Leland Olds Station Unit 2 included SO_2 control (FGD 95%) in addition to the noted NO_X control. Thus, these values do not reflect the distinct visibility benefit from the NO_X control options but do provide the incremental benefit between the options.

The State determined that the average and incremental cost effectiveness of SCR + ASOFA was excessive given its finding that visibility improvement would be negligible. SCR + ASOFA, when combined with wet scrubbing for SO_2 would result in a significant improvement in visibility at Theodore Roosevelt, estimated to be 4.393 deciviews and 130 fewer days above 0.5 deciviews. As the State did not provide discrete modeling for individual pollutants, it is not possible to describe the incremental visibility benefits of SCR + ASOFA or other NO_X control options over the selected SO_2 BART control (FGD at 95%). Nonetheless, when compared to SNCR + ASOFA, SCR would result in an incremental visibility improvement of 0.512 deciviews and 25 fewer days above 0.5 deciviews. However, using the same supplemental cumulative modeling it used for Milton R. Young Station units 1 and 2, the State determined that visibility benefits from use of SCR + ASOFA would be negligible. While the State found that RRI + SNCR + ASOFA and SNCR + ASOFA both had reasonable average cost effectiveness values, it found the incremental costs for RRI + SNCR + ASOFA to be excessive given its finding that incremental visibility improvement would be negligible. By reference to its analysis for Leland Olds Station Unit 1, North Dakota noted the difficulty in accurately predicting costs for SCR based on alleged uncertainties regarding catalyst size and life. North Dakota accepted the cost estimates provided by Basin Electric. The State determined that there were no energy and non-air quality environmental impacts that would preclude the selection of any of the control equipment alternatives. North Dakota determined BART to be SNCR plus ASOFA with an emission limit of 0.35 lb/MMBtu (30-day rolling average). North Dakota estimated the cost for SNCR plus ASOFA to be $1,659 per ton of NO_X removed, and the capital and annualized costs to be $16,800,000 and $10,870,000 per year, respectively.

A summary of the pertinent information related to the State's NO_X BART determinations for Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 1 is provided in Table 26.

TABLE 26—NORTH DAKOTA BART DETERMINATIONS FOR NO_X EMISSIONS FOR MILTON R. YOUNG STATION UNITS 1 AND 2 AND LELAND OLDS STATION UNIT 2

Source and unit	2000–2004 average emissions (tons/yr)	Baseline level of control (% reduction)	BART level of control (% reduction)	Control device	Emissions after controls (tons/yr)	Emission reduction (tons/yr)	Emission limit
MRYS Unit 1	8,665	0	58.1	ASOFA and SNCR	3,857	4,808	0.36 lb/10^6 Btu, 30-day rolling average.
MRYS Unit 2	14,705	0	58	ASOFA and SNCR	6,392	8,313	0.35 lb/10^6 Btu, 30-day rolling average.
LOS Unit 2	10,422	0	54.5	ASOFA and SNCR	5,904	4,518	0.35 lb/10^6 Btu, 30-day rolling average.

d. EPA's Evaluation of the State's Cost Analyses for NO_X BART for Milton R. Young Station Unit 1 and 2 and Leland Olds Station Unit 2

As noted above, North Dakota found that the costs of SCR at Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2 were excessive and eliminated it as a control option. We propose to find that North Dakota did not properly follow the requirements of 40 CFR 51.308(e)(1)(ii)(A) in determining NO_X BART for these units. Specifically, we propose that North Dakota did not properly or reasonably ''take into consideration the costs of compliance.'' Instead, North Dakota relied on facility-provided cost estimates that greatly overestimated the costs of SCR. Given that SCR is typically considered to be a highly cost-effective control option for power plants with cyclone boilers burning lignite, and that EPA selected a presumptive NO_X limit for cyclone units of 0.10 lb/MMBtu based on the cost-effectiveness of SCR,[20] we retained two consultants (ERG and RTI, subcontractor Dr. Phyllis Fox) to independently assess the costs of installing, operating, and maintaining these controls. These consultants found that numerous aspects of the cost estimates for SCR at these units, which the State relied on, were much higher than their estimates. Our consultants revised the cost analyses using EPA's Air Pollution Control Cost Manual,[21] and where appropriate, costing assumptions used in the facility-provided analyses. Their revised analyses resulted in cost effectiveness values that are well within the range that North Dakota, other states, and we have found cost effective in the BART context. We have reviewed and evaluated our consultants' reports and agree with their findings regarding SCR at Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2. Our consultants' reports have been incorporated into the Technical Support Document.[22]

Table 27, below, contrasts North Dakota's low-end cost effectiveness values for tail end SCR (TESCR) at the three units with our estimates.[23]

TABLE 27—CONTRAST OF TESCR COST EFFECTIVENESS

Plant	North Dakota projected cost ($/ton NO_X removed)	EPA's projected cost ($/ton NO_X removed)
MRYS 1	$4,800	$2,600
MRYS 2	4,800	2,700
LOS 2	4,100	1,800

Our Technical Support Document provides a detailed comparison between the costing methodologies. However, a few general points can be made that explain why our costs differ so dramatically from North Dakota's. Both North Dakota and we used the facilities' BART evaluations as the starting points for the assessments,[24] and we largely relied on the facilities' direct capital equipment costs in our analyses.[25] However, a major issue is that the companies used numerous indirect cost and other accounting mechanisms that are not included in EPA's Air Pollution Control Cost Manual (''Control Cost Manual'') and are not adequately justified. According to the BART Guidelines, ''cost estimates should be based on the OAQPS Control Cost Manual, where possible'' ''[i]n order to maintain and improve consistency.'' 70 FR 39104, 39166. The use of the Control Cost Manual provides a reasonable standard for comparison of costs between sources and across states, and the BART Guidelines indicate that documentation should be provided for ''any * * * element of the calculation that differs from Control Cost Manual.'' 70 FR 39166. Most of North Dakota's other BART determinations did follow the Control Cost Manual and properly provide a basis for comparison to other control equipment installations nationally.[26] In preparing our cost analyses, we followed the Control Cost Manual where possible.

In addition to deviating in significant and unjustified ways from the Control Cost Manual, the companies adopted unreasonable assumptions related to catalyst size and life, catalyst cost, and outage requirements for catalyst replacement. Our analyses replaced these unreasonable assumptions with reasonable ones.

In the case of Minnkota's analyses for Milton R. Young Station Units 1 and 2, conducted by Minnkota's consultant, Burns & McDonnell, the estimated total capital costs are higher by a factor of about 1.8 than would be calculated using the Control Cost Manual,

[20] The BART Guidelines state, ''Because of the relatively high NO_X emission rates of cyclone units, SCR is more cost-effective than the use of current combustion control technology for these units. The use of SCRs at cyclone units burning bituminous coal, sub-bituminous coal, and lignite should enable the units to cost-effectively meet NO_X rates of 0.10 lb/mmbtu. As a result, we are establishing a presumptive NO_X limit of 0.10 lb/mmbtu based on the use of SCR for coal-fired cyclone units greater than 200 MW located at 750 MW power plants.'' 40 CFR part 51, appendix Y.

[21] U.S. EPA, EPA Air Pollution Control Cost Manual, EPA/452/B–02–001, 6th Ed., January 2002. The EPA Air Pollution Control Cost Manual was formerly known as the OAQPS Control Cost Manual.

[22] Dr. Phyllis Fox, Revised BART Cost-Effectiveness Analysis for Tail End Selective Catalytic Reduction at Basin Electric Power Cooperative Leland Olds Station Unit 2. Report Prepared for U.S. EPA, RTI Project Number 0209897.004.095, March 2011.

ERG Minnkota SCR Cost Summaries, May 2010 and August 2011 and EPA Region 8's Letter to Mr. Terry O'Clair dated May 10, 2010 regarding ''EPA's Comments on the NDDH's [North Dakota's] April 2010 Draft BACT Determination for NO_X for the MRYS.''

[23] The facilities, and hence, North Dakota, presented a range of cost effectiveness values for low-dust and tail-end SCR based on the alleged uncertainties with estimating costs for SCR. A comparison of North Dakota's high-end cost estimates would reflect an even greater disparity with our cost estimates.

[24] Burns & McDonnell, BART Determination Study for Milton R. Young Station Unit 1 and 2, Prepared for Minnkota Power Cooperative, Inc., October 2006, Revised August 2007.

Letter from Cris Miller, Senior Environmental Project Administrator, Basin Electric Power Cooperative, to Terry L. O'Clair, North Dakota Department of Health, Attaching Letter from William DePriest, Senior Vice President, Environmental Services, to Cris Miller, Re: BART Evaluation Update—Tail End SCR, May 27, 2009 (5/27/09 S&L Cost Analysis).

[25] For a detailed discussion, the reader should refer to our consultants' reports in the Technical Support Document.

[26] SIP Appendix C.2, Great River Energy's Coal Creek BART Analysis, is an example of a cost analysis submitted to North Dakota as part of a BART submittal that does not include many of the indirect capital costs and contingencies included in Burns & McDonnell's analysis. Although EPA is not in agreement with every aspect of the cost analysis in the example, it does illustrate a case where the Control Cost Manual format is generally followed and the estimated SCR capital costs are far less (by a factor of almost 4 for LDSCR on Unit 2, which is a smaller unit in comparison to the example and should cost less) than what was estimated for MRYS.

assuming the same base costs for direct capital costs.

For indirect capital costs, Table 28 identifies the deviations from the Control Cost Manual in the Burns & McDonnell estimates.

TABLE 28—COMPARISON OF EPA CONTROL COST MANUAL AND BURNS & MCDONNELL INDIRECT CAPITAL COSTS [27]

Indirect cost	Control cost manual (% of direct cap cost "A")	B&McD analysis (% of direct cap cost "A")
General Facilities (Construction Mgt)	0.05 × A	0.04 × A
Engineering & Home Office Fees	0.10 × A	0.15 × A
Startup Expenses	0	0.02 × A
Process Contingency (Scope Contingency)	0.05 × A	0.15 × A
Project Contingency (Pricing Contingency)	0.18 × A	0.15 × A
Totals	0.38 × A	0.51 × A

While this difference is significant, Burns & McDonnell then added two more contingencies (''cost escalation during project'' and ''owner's costs—other'') and included an allowance for funds during construction (interest) before calculating the total capital investment. The Control Cost Manual allows for ''preproduction costs'' of 2% of the sum of the direct capital costs, indirect capital costs, and ''project contingency.'' Table 29 below compares these ''other'' costs used by Burns & McDonnell to the preproduction costs provided by the Control Cost Manual. To normalize these costs with those tabulated above, percentages were related back to the direct capital costs (''A'').[28]

TABLE 29—COMPARISON OF EPA CONTROL COST MANUAL & B&MCD ''OTHER'' CAPITAL COSTS

Other costs	Control cost manual (% of direct cap cost "A")	B&McD analysis (% of direct cap cost "A")
Cost Escalation	0	0.30 × A
Allowance for Funds During Construction (Interest During Construction)	0	0.20 × A
Preproduction Costs	0.03 × A	0
Owners Cost—Other (Owner Contingency)	0	0.17 × A
Totals	0.03 × A	0.67 × A

From these tables, it is clear that Burns & McDonnell included contingencies and accounting items that deviate significantly from the Control Cost Manual and which it did not justify by reference to any need unique to Milton R. Young Station. Although North Dakota asked Burns & McDonnell to provide a detailed explanation regarding its high indirect capital cost estimates, Burns & McDonnell's February 11, 2010, response to this request (see SIP Appendix C.4) fails to justify why the Burns & McDonnell cost methodology should be allowed for the Milton R. Young Station analysis, when it is not part of the Control Cost Manual and is not the standardized methodology used by other sources.

While the Control Cost Manual does contemplate some flexibility in some contingencies (such as degree of retrofit difficulty), Burns & McDonnell has not substantiated the need to go beyond standard contingencies provided by the Control Cost Manual. As stated in the Control Cost Manual, ''[c]ontingencies is a catch-all category that covers unforeseen costs that may arise, such as possible redesign and modification of equipment, escalation increases in cost of equipment, increase in field labor costs, and delays encountered in start-up.'' [29] Thus, the contingency in the Control Cost Manual should already account for possible changes in labor costs, and inclusion of a contingency plus escalation of costs is redundant according to the Control Cost Manual methodology. Escalation of costs should not be included as a separate estimate in the estimate of Total Capital Investment since it is included as part of the contingency estimate.

Also, in Table 2.5 of the SCR chapter of the Control Cost Manual, the ''Allowance for Funds During Construction'' (inflation) is specifically listed as zero. Therefore, Burns & McDonnell should not have added what amounts to 20% of the direct capital costs to cover inflation. Including ''owner's costs'' and ''owner's contingency'' is also not consistent with the Control Cost Manual methodology and appears to be redundant.

Burns & McDonnell mentioned that it anticipated that significant retrofit work would be required that would affect the scope and price of the project. However, there have been many SCR retrofits facing much more difficult challenges with space limitations and boiler modifications than Milton R. Young Station can be expected to face installing a LDSCR or TESCR

[27] Although, Burns & McDonnell stated in its December 11, 2010 submittal to the State that its BACT cost estimates ''follow the outline of Table 2.5 in the SCR Chapter of EPA's Control Cost Manual,'' many items do not match in description, so some assumptions had to be made. Where there are differences, the Burns & McDonnell cost title is in parentheses. Also, this comparison assumes that ''project contingency'' of 15% is part of the indirect costs, so when applied exclusively to the direct capital costs only, it becomes 18%.

[28] Preproduction costs are listed as being 2% of the total direct (A), indirect (B), and ''project contingency'' (C) costs. This becomes 3% of the total direct capital costs. (B = 0.20 * A; C = 0.18 * A; A + B + C = 1.38 A; 0.02 * 1.38 A = 0.03).

[29] See Control Cost Manual, 2002, Chapter 2, Section 2.3.1.

downstream of the ESP (or flue gas desulfurization system (FGD)) in a rural location. Thus, we find that Burns & McDonnell's contingencies for extra retrofit work are not warranted. Instead, we find that the contingencies outlined in the Control Cost Manual (5% process contingency and 15% project contingency) are reasonable for purposes of the Milton R. Young Station NO_X BART analyses.

Our estimate of total installed capital costs with adjusted indirect capital costs for TESCR at Milton R. Young Station Unit 1 is $120,629,000 in 2009 dollars, compared to Burns & McDonnell's estimate of $192,830,000. For Unit 2 our estimate is $216,870,000 and Burns & McDonnell's is $329,150,000.

When it calculated annual costs for SCR at Milton R. Young Station, Burns & McDonnell also deviated from the Control Cost Manual without reasonable justification and relied on unreasonable operation and design assumptions. For example, the Control Cost Manual provides an annual maintenance factor of 1.5% of the total capital investment. Burns & McDonnell assumed 3%. The Control Cost Manual does not allow annual operation and maintenance costs to be ''levelized''—*i.e.,* adjusted based on predicted future inflation and other factors. Burns & McDonnell levelized these costs, which increased them by about 25%. The reason the Control Cost Manual does not use levelized costs is to ensure that cost comparisons are made on a current real dollar basis, relying on the most accurate information available at current prices. (See, Control Cost Manual, Section 1, chapter 1, p. 1–3, footnote 1, and Section 4.2, Chapter 2, p. 2–50, example problem.)

Regarding operation and design assumptions, Burns & McDonnell assumed that the SCR catalyst might have to be replaced as frequently as three or four times per year. Given that catalyst poisons will be removed by the ESP, or ESP and SO_2 controls, before reaching the SCR in a low-dust or tail-end configuration, Burns & McDonnell's assumption about catalyst replacement is unreasonable. While Burns & McDonnell's low-end SCR cost numbers are based on a two-year frequency for catalyst replacement, our consultants find that a three-year frequency is the most reasonable assumption.[30] Burns & McDonnell also used unreasonable assumptions related to catalyst cost and necessary outage time and related electricity costs for catalyst replacement. For example, Burns & McDonnell failed to consider that catalyst replacement could occur during outages already occurring at the plant. Our Technical Support Document contains additional details regarding the flaws in Burns & McDonnell's analysis.

Burns & McDonnell's estimate for total annual costs for TESCR at Milton R. Young Station Unit 1 was $43,290,000; using the Control Cost Manual factors and other reasonable assumptions, our estimate is $24,176,000. Burns & McDonnell's estimate for Unit 2 was $73,245,000 and ours is $40,570,000.

Sargent & Lundy, Basin Electric's consultant, also employed numerous unreasonable assumptions in estimating costs and cost effectiveness for NO_X BART at Leland Olds Station Unit 2. For example, Sargent & Lundy overestimated catalyst volume, catalyst cost, outage time for catalyst replacement, and frequency of catalyst replacement. Our consultant, Dr. Phyllis Fox, details in her report that Sargent & Lundy's estimates are often unsupported and why they are unreasonable. Also, like Burns & McDonnell, Sargent & Lundy levelized operation and maintenance costs, which increased these costs by about 20%. As noted above, levelizing these costs is inconsistent with the Control Cost Manual. Sargent & Lundy assumed that a sorbent injection system might be needed if SCR were installed. As Dr. Fox explains, no such system is needed since catalyst formulations are available to minimize sulfuric acid mist emissions. In addition, Sargent & Lundy used inflated values for the costs of utilities and supplies, including NH_3,[31] natural gas, and electricity. Further detail regarding these issues is contained in section V.D.1.d of this action and in our TSD. Table 30 contains a summary of some of the most significant differences between Sargent & Lundy's estimates and Dr. Fox's estimates.

TABLE 3—COMPARISON OF SARGENT & LUNDY AND DR. FOX'S TAIL-END SCR VARIABLE OPERATION AND MAINTENANCE COSTS FOR LELAND OLDS STATION UNIT 2

[2009 dollars]

Description	Cost factor	Dr. Fox (MM$/year)	Sargent & Lundy (MM$/year)
Ammonia		2.116	1.655
Catalyst		0.321	3.960
Power		1.879	2.930
Natural Gas for Flue Gas Reheating		2.596	7.750
Outage Penalty		0	7.392
Sorbent Injection		0	0.207
Total Variable O&M Cost, A	Sum of Various Items Listed Above	6.913	23.894
Total Fixed O&M Cost, B		0.824	0.827
Total O&M Cost	A + B	7.737	24.721
Levelized for Inflation, Discount Rate, and Equipment Life [1].	(A + B) × 1.193		29.496
Total Annual Capital Cost, C		14.361	14.423

[30] Report of Hans Hartenstein: On North Dakota Department of Health's April 10, 2010 BACT Determination for Minnkota's M.R. Young Station, On Behalf of United States Department of Justice, April 2010. Report of Phyllis Fox: Revised BART Cost Effectiveness Analysis for Tail-End Selective Catalytic Reduction at the Basin Electric Power Cooperative Leland Olds Station Unit 2 Final Report, March 2011.

[31] In the case of NH_3, Sargent & Lundy evaluated a range of costs of $450 per ton to $700 per ton even though it used a cost of $475 per ton in a September 2010 BART analysis for the Navajo Generating Station. Our consultant used $475 per ton in her cost analysis.

TABLE 3—COMPARISON OF SARGENT & LUNDY AND DR. FOX'S TAIL-END SCR VARIABLE OPERATION AND MAINTENANCE COSTS FOR LELAND OLDS STATION UNIT 2—Continued

[2009 dollars]

Description	Cost factor	Dr. Fox (MM$/year)	Sargent & Lundy (MM$/year)
Total Annual Cost	A + B + C	22.098	43.919 [2]

[1] Levelization is included only in the Sargent & Lundy analysis and is not part of the acceptable methods presented in the Control Cost Manual.

[2] **Note:** The Sargent & Lundy cost breakdown obtained during our review and included in the Technical Support Document, when summed, does not exactly match the total annual cost of $43,830,000 provided in SIP Appendices B.1 and C.1.

We also question Sargent & Lundy's estimated capital cost of $373/kW (2010 dollars) to retrofit SCR at Leland Olds Station. Sargent & Lundy provided no documentation for this figure, and it is higher than the actual installed cost for existing retrofit SCRs, including those with extreme retrofit difficulty and those requiring flue gas reheat. Despite our concern about Sargent & Lundy's capital cost estimate, we used it in our cost analysis. Thus, we consider our resulting cost effectiveness value to be conservative in Basin Electric's favor and to represent an upper bound for a reasonable cost effectiveness value for SCR (*i.e.,* it is our opinion that the actual cost effectiveness value would be lower than our estimate suggests). Our Technical Support Document contains additional details regarding our concerns regarding Sargent & Lundy's capital cost estimate for SCR.

Sargent & Lundy's estimate for total annual costs for TESCR at Leland Olds Station Unit 2 was $43,830,000; using the Control Cost Manual factors and other reasonable assumptions, our estimate is $22,098,000.

North Dakota's estimates for TESCR ($4,100—$7,100), based on company-supplied estimates, are roughly two to three times higher than estimates that are based on accepted estimating practices.[32] These differences are significant, particularly because our revised cost estimates fall within the range that North Dakota, other states, and EPA have considered as being cost effective for BART determinations. Accordingly, we do not consider North Dakota's cost estimates to be consistent with the statutory and regulatory requirement that North Dakota consider cost in determining BART. Thus, the BART analyses for these units do not meet the requirements of the regional haze regulation, and we are proposing to disapprove those analyses and the resultant BART determinations.

e. EPA's Evaluation of the State's Visibility Analyses for NO_X BART for Milton R. Young Station Unit 1 and 2 and Leland Olds Station Unit 2

Generally, to evaluate visibility improvements associated with potential BART control options, North Dakota conducted or relied on CALPUFF modeling that was consistent with the recommended approach in the BART Guidelines and the State's EPA-approved protocol included in Appendix A.1 of its Regional Haze SIP. Such modeling assumes natural background conditions—*i.e.,* without emissions from current emissions sources. However, for its NO_X BART determinations for Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2, North Dakota conducted supplemental cumulative visibility modeling—*i.e.,* modeling that included emissions from all other sources in the inventory. North Dakota did not use this alternative modeling approach for any other pollutant or any other BART units within North Dakota.

The State attached considerable weight to the results of this alternative modeling when it determined NO_X BART for the three units. SIP appendices B.1 and B.4. The State stated that it conducted this supplemental cumulative modeling because ''the single source modeling under the BART Guidelines overestimates the visibility improvement'' and ''single-source modeling results * * * tend to be five to seven times larger'' than results when the same source is combined with all other sources in a cumulative analysis. *Id.* SIP Section 7.4.2. Based on its supplemental cumulative modeling, the State determined that the visibility improvement that would result from SCR would be ''negligible'' and proceeded to eliminate SCR based on ''the excessive cost and negligible visibility improvement.'' SIP appendices B.1 and B.4.

The perceived change in visibility from controls on a single source is reduced when background contributions from other sources are included in the modeling. In other words, cumulative modeling reduces the predicted visibility benefit in deciviews from any level of control considered. For three units and one pollutant only, North Dakota relies on its supplemental cumulative modeling as a partial basis to reject SCR as BART. Not only is North Dakota's approach arbitrary, it is inconsistent with the purpose of BART and the regional haze program generally, as well as the BART modeling approach used by other states and EPA.

The CAA establishes a National goal of eliminating man-made visibility impairment from all mandatory Class I Federal areas. Use of natural background (*i.e.,* not considering other source emissions) in the BART context is consistent with the ultimate goal of the program to reach natural background conditions. Also, the modeling of visibility improvements from potential control options should be consistent with the subject-to-BART modeling, which compares single-source impacts to natural conditions. Otherwise, BART, one of the primary requirements under the regional haze regulations, could be reduced as to be meaningless. Thus, the BART Guidelines direct states to ''[c]alculate the model results for each receptor as the change in deciviews compared against natural visibility conditions.'' 40 CFR part 51, appendix Y, section IV.D, step 5. The consistent use of a clean background in BART evaluations in North Dakota and surrounding states will foster emission reductions that will speed achievement of natural background conditions, and will ensure equity among states in achieving this goal.

Because North Dakota relied on a visibility modeling method that is inconsistent with the BART Guidelines, its own EPA-approved protocol, and the purpose of the Regional Haze Rule, we do not consider North Dakota's analysis of visibility improvement for NO_X

[32] They are also much higher than the values EPA relied on in determining that SCR is cost effective on coal-fired cyclone units for purposes of determining presumptive NO_X BART limits in the BART Guidelines: ''Our analysis indicated that cost-effectiveness of applying SCR on coal-fired cyclone units is typically less than $1500 a ton, and that the average cost-effectiveness is $900 per ton.'' 70 FR 39135–39136.

BART for the three units to be reasonable.[33] We propose to find that North Dakota's analysis is inconsistent with the statutory and regulatory requirement that North Dakota consider ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.'' Thus, the BART analyses for these units do not meet the requirements of the regional haze regulation, and we are proposing to disapprove those analyses and the resultant BART determinations.[34]

We are proposing a FIP for NO_X BART for these units to fill the gap left by our proposed disapproval. We discuss our proposed FIP in section V.G, below.

2. Coal Creek Station Units 1 and 2

a. Coal Creek Station Units 1 and 2—State Analysis

Each unit is already equipped with LNB and SOFA. The State identified the following NO_X control options as having potential application to the Coal Creek Station boilers: FGR, high-dust SCR, ECO, Pahlman Process™, LDSCR, TESCR, LTO, SNCR, and modified and additional SOFA and LNB. The State eliminated the following options as technically infeasible: FGR, ECO, and the Pahlman Process™. The State deemed the incremental cost of LTO, SCR, and SNCR to be excessive. The State noted SNCR would be cost effective except for the loss of fly ash sales due to likely NH_3 contamination. The loss of fly ash sales would add to the cost of SNCR and SCR for Coal Creek Station, which has an established market for fly ash to be used in concrete. Four testimonial letters from North Dakota fly ash marketers and end-users (included in Appendix C.2 of the SIP) attest to problematic NH_3 concentrations in fly ash due to SCR and SNCR control technology. The State also noted that loss of fly ash sales would cause the undesirable non-air quality environmental impact of additional waste destined for landfill disposal. A summary of the State's NO_X BART analysis, and the modeling results provided by both the source and the State, are provided in Table 31 for each unit.

TABLE 31—SUMMARY OF COAL CREEK NO_X BART ANALYSIS FOR UNIT 1 AND UNIT 2 BOILERS

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions reduction (tons/yr)	Annualized cost (MM$)	Cost effectiveness ($/ton)	Visibility impacts [2] [3]	
						Visibility benefit (delta dv)	Fewer days > 0.5 dv (days)
LTO	90	0.022	4,821	58.07	12,045	1.853	64
LDSCR	80	0.043	4,286	56.15	13,101	1.760	62
SNCR	50	0.108	2,678	22.9	8,551	1.507	50
SOFA + LNB Option 1 [1]	30	0.15	1,607	66.0	411	1.419	49

[1] The State and company also reviewed a less desirable Option 2 which was the same control technology with a lower control efficiency of 21%.

[2] The visibility modeling that Great River Energy performed for Coal Creek Units 1 and 2 included SO_2 control in addition to the noted NO_X control. The modeling results shown above reflect the chosen SO_2 BART control, scrubber modifications, in addition to the noted NO_X control option. Thus, these values do not reflect the distinct visibility benefit from the NO_X control options but do provide the incremental benefit between the options.

[3] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

North Dakota determined BART to be modified and additional SOFA plus LNB with emission limits of 0.15 lb/MMBtu on an annual average basis and 0.17 lb/MMBtu on a 30-day rolling average basis. North Dakota provided that Unit 1 and Unit 2 emissions may be averaged provided the average does not exceed the limit. The estimated cost of modified and additional SOFA plus LNB was $411 per ton of NO_X removed, and the capital and annualized costs were estimated to be $5,260,000 and $660,000 per year, respectively.

b. EPA's Evaluation of the State's NO_X BART Review for Coal Creek Units 1 and 2

During review of North Dakota's NO_X BART analyses for Coal Creek Station, we identified a possible discrepancy with Great River Energy's and the State's costs associated with lost fly ash sales. Upon our request, subsequent to submittal of the SIP, North Dakota obtained additional supporting information from Great River Energy for lost fly ash revenue and for the potential cost of fly ash NH_3 mitigation. The supporting information included an updated cost analysis from Great River Energy noting that the correct sales price for fly ash was $5 per ton instead of $36 per ton. Great River Energy indicated the $36 per ton price was a typographical error. The updated analysis included corrected fly ash revenue data and NH_3 mitigation costs.

That analysis, dated June 16, 2011, indicated that the average cost effectiveness for SNCR at Coal Creek Station Units 1 and 2 would be $2,318 per ton of NO_X emissions reductions rather than the original estimate of $8,551 per ton. While Great River Energy subsequently revised this value to $3,198 per ton based on concerns regarding the technical feasibility of mitigating the NH_3 in North Dakota lignite fly ash,[35] either of these values is substantially less than the values North Dakota relied on to make its NO_X BART determination for Coal Creek Station Units 1 and 2. They are also within the cost effectiveness range that North Dakota found reasonable for BART controls at other BART sources and that we and other states have found reasonable. Great River Energy's error

[33] In fact, by adopting a different set of rules for modeling the visibility benefits of SCR at MRYS and LOS, it appears that North Dakota singled these units out for preferential treatment without a valid justification.

[34] In addition to the cost and visibility issues, we disagree with North Dakota that separate NO_X limits during startup at Milton R. Young Station Units 1 and 2 are necessary or represent BART. The SIP does not demonstrate that such special treatment is appropriate or needed. We find that a 30-day rolling average limit is adequate to address emissions variations that may result from startup at a facility that is properly managing its operations. We also note that no other source sought or was granted a separate limit during startup. This forms another basis for our proposed disapproval of the NO_X BART limits for Milton R. Young Station Units 1 and 2.

[35] See July 15, 2011 letter from Great River Energy to Terry O'Clair.

also affected the cost effectiveness values for SCR.

Because of the significant error underlying the State's cost analysis, we are proposing to disapprove the State's NO_X BART determination for Coal Creek Station Units 1 and 2 and are proposing a FIP to establish NO_X BART limits for these units.

E. Federal Implementation Plan To Address NO_X BART for Milton R. Young Station Units 1 and 2, and Leland Olds Station Unit 2

1. Introduction

As noted above, North Dakota selected SNCR + ASOFA as NO_X BART for Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2, but in doing so, inappropriately eliminated SCR + ASOFA as potential BART. Thus, in our proposed FIP, we are re-evaluating these two technologies and associated emission limits as potential BART. Our analysis follows our BART Guidelines for both facilities. For Milton R. Young Station 1 and 2, the BART Guidelines are mandatory. Milton R. Young Station has a capacity of 794 megawatts.[36] For Leland Olds Station 2, the guidelines are not mandatory, but we are following them because they provide a reasonable and consistent approach for determining BART.

2. BART Analysis for Milton R. Young Station 1

Step 1: Identify All Available Technologies.

Our analysis only considers SNCR + ASOFA and SCR + ASOFA. Because the State selected SNCR +ASOFA as BART, and our concern is that the State did not properly evaluate SCR as BART, there is no need to consider lower-performing technologies.

Step 2: Eliminate Technically Infeasible Options.

We are not eliminating either SNCR or SCR as being technically infeasible. Both technologies have been widely employed to control NO_X emissions from coal-fired power plants.[37 38 39] The State determined SNCR was technically feasible for North Dakota EGUs. We agree with the State that SNCR is technically feasible. The State also determined in Section 7 of the SIP that two forms of SCR are technically feasible for use on North Dakota EGUs burning lignite coal, stating the following:

> The seven BART sources determined SCR is not technically feasible for installation on boilers in North Dakota burning lignite coal. The Department agrees that high dust SCR is not technically feasible; however, LDSCR and TESCR are considered technically feasible.

The State based its conclusion on an analysis contained in Appendix B.5 that the State submitted with its Regional Haze SIP.

According to our BART Guidelines, a demonstration of technical infeasibility must be documented and must show, ''based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option on the emissions unit under review.'' 40 CFR part 51, appendix Y, section IV.D, Step 2. Only then may a control technology be eliminated from further consideration in the BART analysis. *Id.* The BART Guidelines go on to state that a control technology is technically feasible if it is ''available'' and ''applicable.''

A technology is considered available if the source owner may obtain it through commercial channels, or it is otherwise available in the common sense meaning of the word. *Id.* SCR technology has been available through commercial channels for many years, and it could be purchased for use at Milton R. Young Station Units 1 and 2. SCR technology is not in the ''pilot scale testing stages of development'' for use at coal-fired power plants, and there is no need for Minnkota ''to conduct extended trials to learn how to apply [the] technology on a totally new and dissimilar source type.'' *Id.*

A technology is considered applicable if it can reasonably be installed and operated on the source type under consideration. EPA must exercise its technical judgment in making this determination. *Id.* The Guidelines state that a commercially available control option will be presumed applicable if it has been used on the same or a similar source type. Given that SCR has been deployed at hundreds [40] of EGUs, burning a wide variety of coals, it is presumed that it is applicable to the coal-fired EGUs at Milton R. Young Station.

While Minnkota, the owner of Milton R. Young Station, and more recently the State of North Dakota,[41] have asserted that SCR technology is not technically feasible, we cannot reasonably conclude that SCR is not available or applicable to Milton R. Young Station. In EPA's view, the concerns raised by Minnkota and the State relate only to the specific length of catalyst life at Milton R. Young Station, not to the commercial availability of SCR, or the ability of SCR to reduce NO_X emissions from the flue gas stream, at Milton R. Young Station Units 1 and 2. Their primary argument is that the fuel used at Milton R. Young Station, and in turn the flue gas stream, contain relatively high concentrations of certain constituents (primarily sodium and potassium) that will deactivate the catalyst relatively rapidly and require that the catalyst be replaced too often. We consider this to be a cost issue, not a matter of technical feasibility. The BART Guidelines state, ''Where the resolution of technical difficulties is merely a matter of increased cost, you should consider the technology to be technically feasible.'' 40 CFR part 51, appendix Y, section IV.D, step 2. As noted above, SCR has a long and proven history of successfully reducing NO_X emissions from coal-fired electric steam generating units.

We also note that in the BACT context, the State gives great weight to the fact that two catalyst vendors queried by Minnkota indicated an unwillingness to provide typical catalyst life guarantees without first performing catalyst deactivation field

[36] Letter from John T. Graves, Environmental Superintendent, Minnkota Power Cooperative, Inc. to Dana Mount, Director, Division of Environmental Engineering, North Dakota Department of Health, Re: Permit to Operate No. F76009, Permit Revisions, November 20, 1995.

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

[38] 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.

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

[40] ICAC White Paper, May 2009.

[41] In the context of a recent BACT determination for MRYS, the State reversed its prior position and decided in that context that SCR is technically infeasible on cyclone boilers burning North Dakota lignite coal. On July 28, 2011, the State submitted to EPA as part of Amendment No. 1 to the regional haze SIP the entire administrative record for its BACT determination for MRYS. The administrative record consists of at least 259 documents comprising over 850 megabytes of information. EPA was unable to consider this administrative record/SIP revision in this proposed action; the time available under a relevant consent decree deadline did not allow EPA to. Note that under the CAA, EPA is not required to act on a SIP submittal until 12 months after it is determined to be or deemed complete. EPA has individually considered some of the documents included in the State's BACT administrative record and has included those documents in the docket for this proposed action. We note that under the dispute resolution provisions of a separate consent decree between EPA, the State of North Dakota, Minnkota Power Cooperative, Inc., and Square Butte Electric Cooperative, (Civil Action No. 1:06–CV–034), EPA has filed a petition with the United States District Court for the District of North Dakota disputing the State's PSD BACT determination and its finding in that context that SCR is technically infeasible at MRYS. Our proposed action here pertains to BART, not BACT, is governed by CAA provisions and regulations specific to regional haze and BART, and is not governed by such consent decree.

tests on the coal Minnkota burns at Milton R. Young Station. However, as noted in our BART Guidelines, ''lack of a vendor guarantee by itself does not present sufficient justification that a control option or an emissions limit is technically infeasible.'' 40 CFR part 51, appendix Y, section IV.D, step 2. Here, the vendor guarantee for a specific catalyst life, or lack thereof, is not relevant to the availability of SCR, or its ability to remove NO_X from the gas stream at Milton R. Young Station, but only to the willingness of two catalyst companies to provide a specific catalyst life guarantee without more information. Neither vendor contacted by Minnkota indicated it would not provide SCR catalyst absent any prior field testing. One of the two catalyst vendors contacted by Minnkota is willing to provide full performance guarantees on critical operating parameters such as NO_X reduction, NH_3 slip, SO_2 to sulfur trioxide (SO_3) conversion, and pressure drop. This is strong evidence that at least one of the two catalyst vendors contacted by Minnkota believes NO_X can be successfully controlled with SCR at Milton R. Young Station and that SCR is commercially available. In addition, both catalyst vendors contacted by Minnkota have stated they believe a catalyst life guarantee can be offered once the field testing data is collected. The fact that some catalyst vendors have not yet offered a catalyst life guarantee without field testing of deactivation rates is not evidence that SCR is not available or is technically infeasible at Milton R. Young Station. Given the record before us, the lack of a vendor guarantee for a specific catalyst life is not sufficient to overcome the presumption that this commercially available technology is applicable to coal-fired power plants, including Milton R. Young Station.

Additional support for our finding that SCR is not technically infeasible is contained in Appendix B.5 of the State's SIP. There, the State concluded that low-dust and tail-end SCR were technically feasible. A LDSCR would be located after the electrostatic precipitator (ESP), which removes particulates. Alternatively, a TESCR would be located after both the ESP and SO_2 scrubber. Testing has shown that these control devices would remove a high percentage of the ash and catalyst poisons before they would reach the SCR, thereby negating the higher concentrations of catalyst poisons in North Dakota lignite coal compared to other applications of high-dust SCR at coal-fired utility boilers.

North Dakota reviewed PM stack tests at Milton R. Young Station Unit 2 (August 2007 and May 2008) that indicated an average sodium and potassium removal efficiency of greater than 99% by the ESP and wet scrubber, with resulting emission rates at 0.78 milligrams sodium sulfate and 0.20 milligrams potassium sulfate per normal cubic meter. See Appendix B.5 to the SIP submittal. The State found that these loadings of sodium and potassium aerosols, which would enter a LDSCR or TESCR at Milton R. Young Station, were significantly lower than the concentrations present in the gas streams of boilers burning peat and wood that were the subject of experimental and pilot scale testing of SCR catalyst life. The State carefully evaluated the results of such testing and concluded that a reasonable catalyst life could be achieved at Milton R. Young Station.[42] *Id.* Appendix B.5 also indicates that North Dakota independently consulted three vendors who opined to the State that SCR would be technically feasible at Milton R. Young Station.[43] Finally, the State found that existing biomass boilers, with flue gas characteristics that approximate those from North Dakota lignite, have used TESCR successfully. *Id.*

Also, Microbeam Technologies, Inc. (Microbeam) performed PM emissions testing for Milton R. Young Station Unit 2 in March of 2009. The Microbeam results demonstrate the high removal efficiency of PM and the primary catalyst poisons of interest (sodium and potassium) by the ESP and scrubber at Milton R. Young Station. The results reflected a PM removal efficiency of 99.76%, and that the amount of sodium oxide plus potassium oxide was approximately 50–90 times greater entering the ESP than exiting the ESP. The results were similar for sodium oxide plus potassium oxide entering the ESP versus exiting the wet scrubber. This means the loading of sodium oxide plus potassium oxide on a high-dust SCR at Milton R. Young Station would be approximately 50–90 times higher than on a LDSCR or TESCR. Put another way, the Microbeam results showed that the ESP removes at least 98% of the catalyst poisons, which would be before the flue gas reaches a LDSCR or TESCR. Thus, any differences in fuel quality (especially concentrations of catalyst poisons in the ash) of North Dakota lignite compared to other types of coal in the United States would be offset at the control percentages described because Milton R. Young Station would employ a LDSCR or TESCR, whereas the vast majority of SCR installations in the United States are configured as high-dust SCRs.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology.

For the purposes of our SNCR + ASOFA cost analysis, we used a control efficiency of 58% and an emission rate of 0.355 lb/MMBtu, the same control efficiency that North Dakota used. For our TESCR + ASOFA cost analysis we used the control efficiency of 93.8% that Minnkota used in its BART analysis and an emission rate of 0.05 lb/MMBtu, instead of North Dakota's 90% control efficiency and 0.085 lb/MMBtu emission rate. We find that SCR technology, by itself, can achieve 90% control efficiency and that the overall NO_X reduction would be even greater (93.8%) with the use of combustion controls in combination with SCR. A summary of emissions projections for the two control options is provided in Table 32.

[42] The State concluded that an SCR system would require a catalyst life of at least 10,000 hours to be considered an applicable technology and technically feasible. We do not agree with this arbitrarily-selected bright-line threshold. Catalyst life relates to how often the catalyst needs to be replaced to maintain the ability of the SCR to successfully reduce NO_X emissions. Thus, catalyst life is a component of the cost analysis for SCR.

[43] ''The Department [North Dakota] contacted three of the vendors, Ceram Environmental, Haldor Topsoe and Babcock Power. The companies generally confirmed the information in the emails to Mr. Hartenstein. Babcock Power indicated that they had no worries about getting 10,000 hours of catalyst life at the M.R. Young Station. However, they recommended 'coupon' testing prior to design of the SCR. Ceram was convinced it was technically feasible; however, their representative did acknowledge that if the sodium and potassium aerosols are making it through the ESP and wet scrubber, catalyst deactivation could be a problem. Haldor Topsoe indicated that the catalyst deactivation at M.R. Young would be manageable if the catalyst is kept dry during outages.'' SIP Appendix B.5.

TABLE 32—SUMMARY OF EPA NO_X BART ANALYSIS CONTROL TECHNOLOGIES FOR MILTON R. YOUNG STATION UNIT 1 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions (tons/yr)	Emissions reduction (tons/yr)
TESCR + ASOFA	93.8	0.053	627	9,410
SNCR + ASOFA	58	0.355	3,784	5,248
No Controls (Baseline)	0	0.849	[1] 10,037	

[1] North Dakota used a baseline of 9,032 tons/yr. We changed this to reflect maximum heat input and the utilization rate reported by Minnkota.

Step 4: Evaluate Impacts and Document Results.

Factor 1: Costs of compliance.

SNCR + ASOFA.

We are not relying on North Dakota's costs for SNCR. Though the North Dakota costs derived by Burns & McDonnell are generally consistent with the Control Cost Manual, at least one cost, related to lost revenue due to outage, is not. The North Dakota costs are also based on lower reagent costs which we acknowledge do fluctuate. To ensure a fair comparison between the two competing technologies, we have re-worked the costs for SNCR. We relied on Minnkota's Burns & McDonnell estimate for total capital equipment costs for SNCR. However, we have then generally used factors and assumptions provided by the Control Cost Manual for the remainder of the SNCR analysis. In the absence of a Control Cost Manual method for combustion controls, we have used all the costs provided by North Dakota for ASOFA. This approach is similar to the one we used to analyze the costs for SCR at Milton R. Young Station Unit 1, which enables us to compare the costs of the two technologies on a consistent basis. This was not an exhaustive effort, but it did result in a downward adjustment in the cost estimate for SNCR. We deem the analysis adequate for comparing the cost effectiveness values of the two top control options—SCR and SNCR.

Regarding specific elements in our cost analysis, we used $475 per ton to estimate urea costs and did not allow for lost revenue due to outage (consistent with Control Cost Manual). 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 our costs from our SNCR cost analysis in Tables 33, 34, and 35.

TABLE 33—SUMMARY OF EPA NO_X BART CAPITAL COST ANALYSIS FOR SNCR ON MILTON R. YOUNG STATION UNIT 1 BOILER

Description	Cost factor	Cost ($)
Capital Investment ASOFA, A		4,277,000
Capital Investment SNCR, B		4,007,000
Total Capital Investment, TCI (2009$)	A + B	8,284,000

TABLE 34—SUMMARY OF EPA NO_X BART ANNUAL ANALYSIS FOR SNCR ON MILTON R. YOUNG STATION UNIT 1 BOILER

Description	Cost factor	Cost ($)
Annual Maintenance	.015 × TCI	60,108
Reagent		949,747
Electricity		21,529
Water		958
Increased Coal		36,845
Increased Ash		2,639
Total Direct Annual Cost (TDAC)	Sum of Various Items Listed Above	1,071,827
Indirect Annual Cost [1] (IDAC)	CRF × TCI	378,253
Total Annual Cost SNCR (TACS)	TDAC + IDAC	1,450,081
Total Annual Cost ASOFA (TACA)	North Dakota Appendix B.4	2,520,719
Total Annual Cost SNCR+ASOFA	TACS + TACA	3,970,799

[1] Capital Recovery Factor (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 35—SUMMARY OF EPA NO_X BART COSTS FOR SNCR ON MILTON R. YOUNG STATION UNIT 1 BOILER

Control option	Total installed capital cost (MM$)	Total annual cost (MM$)	Emissions reductions (tons/yr)	Average cost effectiveness ($/ton)
SNCR + ASOFA	8.284	3.971	5,777	687

SCR + ASOFA.

Our contractor, ERG, prepared a cost analysis for SCR for Milton R. Young Station Units 1 and 2. As explained below, ERG started with some of the cost information in the Burns & McDonnell (Minnkota's contractor) BACT cost analyses provided in the NO_X BACT Analysis Study, Supplemental Reports, for Units 1 and 2 dated February 2010 and November 2009, respectively. *See* SIP Appendix C.4.

ERG used Burns & McDonnell's original SCR equipment costs and other costs that were not independently verified by EPA (auxiliaries/balance of plant, construction costs, natural gas pipeline, reagent costs, natural gas costs), but then calculated total capital costs and annual costs for SCR using the applicable Control Cost Manual methodology and factors and certain information supplied by EPA. While EPA could not independently verify many of the Burns & McDonnell-estimated costs, and believes they may overestimate actual costs, the result is a cost estimate that should represent the upper end of likely costs for these items. EPA provided ERG with information regarding catalyst volume, catalyst cost, catalyst replacement frequency, and estimated additional outage time for replacing spent catalyst. EPA provided a reasonable value for catalyst cost of $6,000 per cubic meter based on vendor data. This cost could be significantly reduced if regenerated catalyst were used. Contingencies were calculated using the Control Cost Manual assumptions. The maintenance costs were adjusted using the cost factor in the Control Cost Manual, and annual costs were not ''levelized.'' [44]

To be conservative, ERG calculated four different catalyst replacement scenarios. Scenarios 1 through 3 assume catalyst replacement of one layer per year, one layer every two years, and one layer every three years. ERG's Scenarios 1 through 3 do not include additional outage time that Minnkota claimed would be necessary for boiler maintenance for solidified slag removal specifically attributable to the installation of ASOFA. For Scenario 3, which we find most reasonable for reasons further described below, there would be no additional unit outage time (and associated electricity costs) for catalyst replacement, because all of this work could be completed during a regularly scheduled major unit outage event. Despite our disagreement about the extent of additional outage time due to ASOFA, we had ERG run Scenario 4 as a ''worst-case'' scenario that assumes the accuracy of Burns & McDonnell's estimate of additional outage time needed for solidified slag removal due to the installation of ASOFA.[45] For all scenarios, ERG modified the amount of time required for each catalyst layer replacement from Burns & McDonnell's assumptions, recalculated the unit availability using the revised downtime, and recalculated electricity costs and corresponding NO_X emissions using the new availability.

We find that Scenario 3 is the most reasonable based on the following considerations regarding catalyst life:

- An SCR catalyst must be changed out periodically. The catalyst lifetime is a function of catalyst activity and NH_3 slip. As catalyst activity decreases over time, NH_3 slip increases until it reaches the design limit, at which point new catalyst is added. One of the two catalyst vendors queried by Minnkota prepared a budgetary proposal that estimated a catalyst exchange cycle for Milton R. Young Station based on the catalyst design presented in the proposal. This catalyst design was developed by the catalyst vendor based on the detailed boiler and fuel specifications supplied by Minnkota. The catalyst design was also intended to reflect the three year planned outage schedule at Milton R. Young Station specified by Minnkota. In the budgetary proposal, the catalyst design includes an initial fill of two catalyst layers with one empty spare layer. The catalyst vendor estimated the two initial catalyst layers would operate for 24,000 hours, at which time a third layer of catalyst (in the spare layer) would be added. The vendor estimated that the first layer of catalyst would need replacement at about 88,000 hours, or over 10 years of SCR operation. The second catalyst layer replacement would not be needed until approximately 125,000 hours or approximately 15 years of SCR operation. Thus, EPA's assumption of replacing a layer of catalyst every three years is conservative and a reasonable assumption. Based on the catalyst vendor's expected catalyst exchange cycles, the three year replacement assumption would overestimate annual costs once the third layer of catalyst is added after the third year of operation. At that point, the catalyst vendor estimates less frequent need for catalyst replacement. While the other catalyst vendor queried by Minnkota estimates an approximately two year catalyst replacement cycle, there is no reason to give more deference to that proposal.
- SCR catalyst is typically specified to last 16,000 to 24,000 hours for hot-side (or high dust) SCRs (after the boiler), the worst-case location for catalyst life. In the tail-end position, after ash and catalyst poisons have been significantly reduced by pollution control devices, SCR catalyst typically lasts 50,000 to over 100,000 hours.[46]
- We have assumed the SCR at Milton R. Young Station 1 would be located at the tail end, after the ESP and new wet scrubber. As noted, these control devices remove the majority of the ash and catalyst poisons. Flue gas composition data collected at Milton R. Young Station 2, which has an inefficient, older wet scrubber, proves that the amount of submicron alkali aerosols is so small that catalyst deactivation would not occur rapidly.[47] Further, any remaining soluble alkaline substances would not poison the catalyst at TESCR operating temperatures. Significant deactivation only occurs if condensed moisture is present at the catalyst surface, *i.e.,* when the catalyst is being cooled down to below the water dew point. Unit startups and shutdowns do not occur frequently at Milton R. Young Station 1. Furthermore, condensation on the catalyst can be prevented by bypassing or buttoning up the SCR reactor during forced outages of a few days.[48]

[44] As discussed in section V.D., above, the Control Cost Manual does not provide for ''levelization'' of annual costs.

[45] Minnkota asserts there is a potential reduction in reliability and availability of a lignite-fired cyclone boiler as a result of installing and operating a separated overfire air system due to challenges in maintaining adequate slag layer development and flow within the cyclone barrels or furnace bottom compared with non air-staged combustion. Minnkota claims the need for forced or extended scheduled outages to remove the solidified slag. EPA does not agree that these additional outage times for ASOFA are legitimate. For further detail regarding this issue, please refer to our Technical Support Document.

[46] See, for example, vendor e-mails in Appendix D of the North Dakota Report: Selective Catalytic Reduction (SCR) Technical Feasibility for M.R. Young Station; McIlvaine, Next Generation SCR Choices—High-Dust, Low-Dust and Tail-End, FGD & DeNOx Newsletter, no. 369, January 2009; Hans Hartenstein, Steag's Long-Term SCR Catalyst Operating Experience and Cost, EPRI SCR Workshop, 2005.

[47] 1/8/10 EPA Comments, enclosure 2, pp. 24–25 (''As discussed extensively in the Minnkota BACT comments, the actual flue gas composition analysis data measured downstream of the wet FGD at MRYS [Milton R. Young Station] proves that the amount of submicron alkalie aerosols is so small that catalyst deactivation does not occur rapidly and a relatively long catalyst life can reasonably expected (sic) compared to most HDSCR [high dust SCR] installations.'')

[48] 5/6/08 Cochran (CERAM) E-mail, p. 2 (As to high dust SCR:, a worst case: ''Due to the high sodium and iron concentrations it is recommended that a full SCR bypass system be installed. During lay-up periods the catalyst would need to remain warm and dry (above condensing conditions), for instance with an air drying or dehumidification

Continued

Regardless, catalyst vendors have ample experience preventing moisture condensation in SCR catalysts.[49] In other words, available evidence suggests that catalyst life would be relatively long, consistent with that experienced at plants burning other types of coal and fuel.

ERG derived the annual cost of $2,161,000 (2009 dollars) for installation, operation, and maintenance of ASOFA for Unit 1 from tables 4–6–SF of Minnkota's February 2010 Supplemental BACT Analysis for Milton R. Young Station. As we noted above relative to the ASOFA slag issue and associated costs due to additional unit outage time assumed by Minnkota in calculating annual operating costs, EPA does not concur that this cost is entirely representative, but the ERG analysis relied on this cost due to time constraints. As with the annual costs for SCR, ERG did not ''levelize'' these annual costs for SNCR. ERG added the annual costs for ASOFA to the annual costs for SCR to arrive at a total cost for the combined controls.

To estimate the average cost effectiveness (dollars per ton of emissions reductions), ERG divided the total annual cost by the estimated NO_X emissions reductions.

We summarize our costs from the ERG cost analysis in Tables 36, 37 and 38. See our Technical Support Document for the full analyses, in particular, our letter to Mr. Terry O'Clair, North Dakota Department of Health, dated May 10, 2010, and attached spreadsheet.

TABLE 36—SUMMARY OF EPA NO_X BART CAPITAL COST ANALYSIS FOR TESCR ON MILTON R. YOUNG STATION UNIT 1 BOILER

Description	Control cost manual factor or calculation	Cost (MM$)
Total Direct Capital Costs, A		86.32
Indirect Installation Costs		
General Facilities	0.05 × A	4.32
Engineering and Home Office Fees	0.10 × A	8.63
Process Contingencies	0.05 × A	4.32
Total Indirect Installation Costs, B	0.20 × A	17.26
Project Contingency, C	0.15 × (A + B)	15.54
Total Plant Cost, D	A + B + C	119.12
Preproduction Cost, G	0.02 × D	2.41
Inventory Capital (Reagent), H		0.087
Natural Gas Pipeline		1.50
Total Capital Investment, TCI = D + G + H		123.13

TABLE 37—SUMMARY OF EPA NO_X BART ANNUAL COSTS FOR TESCR SCENARIO 3[1] ON MILTON R. YOUNG STATION UNIT 1 BOILER

Description	Cost factor	Cost (MM$)[2]
Annual Maintenance	.015 × TCI	1.809
Reagent		2.716
Catalyst		0.250
Electricity		2.711
Natural Gas for Flue Gas Reheating and Urea to Ammonia Conversion		3.756
Total Direct Annual Cost (TDAC)	Sum of Various Items Listed Above	11.281
Indirect Annual Cost[3] (IDAC)	CRF × TCI	10.735
Annual ASOFA Cost (AAC)		2.161
Total Annual Cost (TAC)	TDAC + IDAC + AAC	24.176

[1] See Table 38 for an explanation of Scenarios.
[2] Costs are in 2009 dollars.
[3] Capital Recovery Factor (CRF) is 0.0872 and is based on a 6% interest rate and 20 year equipment life. From Minnkota NO_X BACT Analysis Study, Milton R. Young Station Unit 1, Table C.1–1, p. C1–4, October 2006 (provided in BART Determination Study for Milton R. Young Station Unit 1 and 2, October 2006, SIP Appendix C.4).

system. This may necessitate the use of a dehumidifier and air lock system to access the reactor.''), in 5/8/08 Milton R. Young Additional Information.

[49] Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Additional Information and Discussion of Vendor Responses on SCR Technical Feasibility, North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2, Appendix A, Vendor Emails, Email from John Cochran, CERAM Environmental, Inc., to Robert Blakley, Re: Request for Lignite SCR Feasibility Commercial and Technical Information, May 6, 2008 (''Sodium is a catalyst poison. Concerns reported by Dr. Benson regarding high sodium content and fine fume are duly noted, but inadequate evidence is presented that this could be a fatal flaw to application of SCR considering the flawed pitch and resultant pluggage of the catalyst used during the Coyote Station testing [North Dakota lignite]. Sodium is not a poison to catalyst at SCR operating temperatures. Significant deactivation can occur if condensed moisture transports sodium residing at the surface into the catalyst pore structure during outage or layup. CERAM has experience with high sodium applications to substantiate this effect. Important to avoid deactivation from sodium is the need to protect the catalyst from going through a condensation event.'')

TABLE 38—SUMMARY OF EPA NO_X BART COSTS FOR VARIOUS TESCR SCENARIOS ON MILTON R. YOUNG STATION UNIT 1 BOILER

Scenario	Description	Emissions reductions [1] (tons/year)	Total annual cost ($MM)	Average cost effectiveness ($/ton)
1	1 layer replaced every year	9,418	25.53	2,711
2	1 layer replaced every 2 years	9,414	24.73	2,627
3	1 layer replaced every 3 years	9,410	24.18	2,569
4	ASOFA downtime allowed	9,424	26.23	2,783

[1] Reductions vary based on impacts to boiler availability in each scenario (*i.e.,* lower boiler operating hours equate to lower emission reductions).

Factor 2: Energy impacts.

The additional energy requirements involved in installation and operation of the evaluated controls are not significant enough to warrant eliminating either SNCR or SCR.

Factor 3: Non-air quality environmental impacts.

The non-air quality environmental impacts are not significant enough to warrant eliminating either SNCR or SCR.

Factor 4: Remaining useful life.

The remaining useful life of Milton R. Young Station Unit 1 is at least 20 years. Thus, this factor does not impact our BART determination.

Factor 5: Evaluate visibility impacts.

Minnkota modeled the visibility benefits for SNCR + ASOFA using natural background per the BART Guidelines. North Dakota then performed additional modeling for the SCR + ASOFA control option. Minnkota and North Dakota both provided single-source modeling results using natural background conditions, complying with the BART Guidelines. The SCR + ASOFA option, when combined with wet scrubbing for SO_2, would result in a significant improvement in visibility at Theodore Roosevelt, estimated to be 3.476 deciviews and 114 fewer days above 0.5 deciviews. This represents an incremental visibility improvement of 1.400 deciviews and 43 fewer days above 0.5 deciviews beyond that achieved by wet scrubbing alone. Moreover, when compared to SNCR + ASOFA, it would result in an incremental visibility improvement of 0.553 deciviews and 18 fewer days above 0.5 deciviews. North Dakota conducted supplemental cumulative modeling for SCR at Milton R. Young Station 1 that is discussed in more detail in section V.D.1.e. For the reasons described there, we are disregarding North Dakota's alternative modeling in our analysis.

More information on our interpretation of the State's and source's modeling information is included in the Technical Support Document.

Step 5: Select BART.

We propose to find that BART is SCR + ASOFA at Milton R. Young Station 1 with an emission limit of 0.07 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. We agree with the State that the other three factors are not relevant to this BART determination.

In our BART analysis for NO_X at Milton R. Young Station 1, we considered SNCR + ASOFA and SCR + ASOFA. The comparison between our SNCR analysis and our TESCR Scenario 3 analysis is provided in Table 39.

TABLE 39—SUMMARY OF EPA NO_X BART ANALYSIS COMPARISON OF TESCR AND SNCR OPTIONS FOR MILTON R. YOUNG STATION UNIT 1 BOILER

Control option	Total installed capital cost (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1 2 4]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 dv
TESCR + ASOFA (Scenario 3)	[3] 123.13	24.18	2,569	4,855	3.476	114
SNCR + ASOFA	8.28	3.97	687		2.923	96

[1] Minnkota's and the State's modeling for both SNCR and SCR was based on lower emissions reductions (fewer tons removed) than we anticipate; thus, we anticipate slightly greater visibility benefits (delta deciview) than reflected in these values. The visibility benefit shown is for the most impacted Class I area, Theodore Roosevelt.

[2] Minnkota and the State modeled combined SO_2 and NO_X controls. The results shown include SO_2 at an emission rate reflective of wet scrubbing along with the noted NO_X control option.

[3] This installed capital cost estimate does not include the capital cost of ASOFA. The total annualized cost does include the capital cost of ASOFA.

[4] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

We have concluded that SNCR + ASOFA and SCR + ASOFA are both cost effective control technologies and that both would provide substantial visibility benefits. SNCR + ASOFA has a cost effectiveness value of $687 per ton. While SCR + ASOFA is more expensive than SNCR + ASOFA, it has a cost effectiveness value of $2,569 per ton of NO_X emissions reduced. This is well within the range of values we have considered reasonable for BART and that states other than North Dakota have considered reasonable for BART. Even with more frequent catalyst replacement, SCR would still be cost effective even at the high end of the range ($2,783 per ton) allowing for the most frequent catalyst replacement of one layer per year and allowing for the questionable costs of lost power generation revenue in TESCR Scenario 4. We also analyzed the SCR costs assuming the same baseline emissions of 9,032 tons per year used by North Dakota and determined that the high-end cost effectiveness value, assuming the most frequent catalyst replacement frequency, would be about $3,115 per ton of NO_X reduced. All of these cost effectiveness values are well within the range of values that North Dakota considered reasonable in several of its NO_X BART determinations, where predicted visibility improvement was considerably lower.

We have weighed costs against the anticipated visibility impacts at Milton R. Young Station 1, as modeled by Minnkota and the State. Both sets of controls would have a positive impact on visibility. As compared to SNCR + ASOFA, SCR + ASOFA would provide an additional visibility benefit 0.553 deciviews and 18 fewer days above 0.5 deciviews at Theodore Roosevelt. We consider these impacts to be substantial, especially in light of the fact that neither of these Class I areas is projected to meet the uniform rate of progress. We also note that the 0.553 deciview improvement at Theodore Roosevelt is greater than the improvement in visibility that North Dakota found reasonable to support other NO_X BART determinations in the SIP despite higher cost effectiveness values for the sources involved in these other BART determinations. Given the incremental visibility improvement associated with SCR + ASOFA, the relatively low incremental cost effectiveness between the two control options ($4,855 per ton), and the reasonable average cost effectiveness values for SCR + ASOFA, we propose that the NO_X BART emission limit for Milton R. Young Station 1 should be based on SCR + ASOFA.

In proposing a BART emission limit of 0.07 lb/MMBtu, we adjusted the annual design rate of 0.05 lb/MMBtu upwards to allow for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[50] 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 implementation plan revision.'' Based on the retrofit of other SCR installations we have reviewed, we propose a compliance deadline of five (5) years from the date our final FIP becomes effective.

3. BART analysis for Milton R. Young Station 2

Step 1: Identify All Available Technologies.

Our analysis only considers SNCR + ASOFA and SCR + ASOFA. Because the State selected SNCR + ASOFA as BART, and our concern is that the State did not properly evaluate SCR as BART, there is no need to consider lower-performing technologies.

Step 2: Eliminate Technically Infeasible Options.

For the reasons described in our BART analysis and determination for Milton R. Young Station Unit 1, we are not eliminating either SNCR or SCR as being technically infeasible.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology.

For the purposes of our SNCR + ASOFA cost analysis, we used a control efficiency of 58% and an emission rate of 0.355 lb/MMBtu, the same control efficiency that North Dakota used. For our TESCR + ASOFA cost analysis we used the control efficiency of 93.8% that Minnkota used in its BART analysis and an emission rate of 0.05 lb/MMBtu, instead of North Dakota's 90% control efficiency and 0.085 lb/MMBtu emission rate. We find that SCR technology, by itself, can achieve 90% control efficiency and that the overall NO_X reduction would be even greater (93.8%) with the use of combustion controls in combination with SCR. A summary of emissions projections for the two control options is provided in Table 40.

TABLE 40—SUMMARY OF EPA NO_X BART ANALYSIS CONTROL TECHNOLOGIES FOR MILTON R. YOUNG STATION UNIT 2 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions (tons/yr)	Emissions reduction (tons/yr)
TESCR + ASOFA	93.8	0.049	984	14,807
SNCR + ASOFA	58	0.330	6,630	9,162
No Controls (Baseline)	0	0.786	[1] 15,792	

[1] North Dakota used a baseline of 15,507 tons/yr. We adjusted this to reflect maximum heat input and the utilization rate reported by Minnkota.

Step 4: Evaluate Impacts and Document Results.

Factor 1: Costs of compliance.

SNCR + ASOFA.

For the reasons described in our BART analysis and determination for Milton R. Young Station Unit 1, we are not relying on North Dakota's costs for SNCR. We have adjusted North Dakota's costs using the same methodology we describe in our BART analysis and determination for Milton R. Young Station Unit 1.

We summarize our costs from our SNCR cost analysis in Tables 41, 42, and 43.

TABLE 41—SUMMARY OF EPA NO_X BART CAPITAL COST ANALYSIS FOR SNCR ON MILTON R. YOUNG STATION UNIT 2 BOILER

Description	Cost factor	Cost ($)
Capital Investment ASOFA, A		10,008,000
Capital Investment SNCR, B		7,437,806
Total Capital Investment, TCI (2009$)	A + B	17,445,806

[50] 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.

TABLE 42—SUMMARY OF EPA NO_X BART ANNUAL ANALYSIS FOR SNCR ON MILTON R. YOUNG STATION UNIT 2 BOILER

Description	Cost factor	Cost ($)
Annual Maintenance	.015 × TCI	111,567
Reagent		1,768,029
Electricity		37,963
Water		1,784
Increased Coal		68,590
Increased Ash		4,913
Total Direct Annual Cost (TDAC)	Sum of Various Items Listed Above	1,992,847
Indirect Annual Cost [1] (IDAC)	CRF × TCI	702,076
Total Annual Cost SNCR (TACS)	TDAC + IDAC	2,694,923
Total Annual Cost ASOFA (TACA)	North Dakota Appendix B.4	3,749,684
Total Annual Cost SNCR + ASOFA	TACS + TACA	6,444,608

[1] Capital Recovery Factor (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 43—SUMMARY OF EPA NO_X BART COSTS FOR SNCR ON MILTON R. YOUNG STATION UNIT 2 BOILER

Control option	Total installed capital cost (MM$)	Total annual cost (MM$)	Emissions reductions (tons/yr)	Average cost effectiveness ($/ton)
SNCR + ASOFA	17.46	6.444	9,162	703

SCR + ASOFA.

Our contractor, ERG, prepared a cost analysis for SCR for Milton R. Young Station Units 1 and 2. For a description of the approach/assumptions ERG used in preparing its cost analysis, please see our BART analysis and determination for Milton R. Young Station Unit 1. For further detail, please refer to our Technical Support Document.

For the reasons discussed with respect to Milton R. Young Station Unit 1 in section V.E.2., we find that Scenario 3 with a 3-year catalyst life is the most reasonable assumption for Milton R. Young Station Unit 2.

ERG derived the annual cost of $3,843,000 (2009 dollars) for installation, operation, and maintenance of ASOFA from tables 4–6SF of Minnkota's February 2010 Supplement BACT Analysis for Milton R. Young Station. As we noted above relative to the ASOFA slag issue, EPA does not concur that this cost is representative, but the ERG analysis relied on this cost due to time constraints. ERG added the annual costs for ASOFA to the annual costs for SCR to arrive at a total cost for the combined controls.

We summarize our costs from the ERG cost analysis in Tables 44 and 45. See our Technical Support Document for the full analyses, in particular, our letter to Mr. Terry O'Clair, North Dakota Department of Health, dated May 10, 2010, and attached spreadsheet.

TABLE 44—SUMMARY OF EPA NO_X BART CAPITAL COST ANALYSIS FOR TESCR SCENARIO 3 [1] ON MILTON R. YOUNG STATION UNIT 2 BOILER

Description	Control cost manual factor or calculation	Cost (MM$)
Total Direct Capital Costs, A		151.97
Indirect Installation Costs		
General Facilities	0.05 × A	7.60
Engineering and Home Office Fees	0.10 × A	15.20
Process Contingencies	0.05 × A	7.60
Total Indirect Installation Costs, B	0.20 × A	30.39
Project Contingency, C	0.15 × (A + B)	27.36
Total Plant Cost, D	A + B + C	212.53
Preproduction Cost, G	0.02 x D	4.25
Inventory Capital (Reagent), H		0.087
Natural Gas Pipeline		2.81
Total Capital Investment, TCI = D + G + H		216.87

[1] See Table 46 for an explanation of Scenarios.

TABLE 45—SUMMARY OF EPA NO_X BART ANNUAL COSTS FOR TESCR SCENARIO 3 [1] ON UNIT 2 BOILER

Description	Cost factor	Cost ($) [2]
Annual Maintenance	.015 × TCI	3.25
Reagent		0.396
Catalyst		0.425
Electricity		3.96
Natural Gas for Flue Gas Reheating and Urea to Ammonia Conversion		6.00
Total Direct Annual Cost (TDAC)	Sum of Various Items Listed Above	17.82
Indirect Annual Cost [3] (IDAC)	CRF × TCI	18.91
Annual ASOFA Cost (AAC)		3.84
Total Annual Cost (TAC)	TDAC + IDAC + AAC	40.57

[1] See Table 46 for an explanation of Scenarios.
[2] Costs are in 2009 dollars.
[3] Capital Recovery Factor (CRF) is 0.0872 and is based on a 6% interest rate and 20 year equipment life. From Minnkota NO_X BACT Analysis Study, Milton R. Young Station Unit 1, Table C.1–1, p. C1–4, October 2006 (provided in BART Determination Study for Milton R. Young Station Units 1 and 2, October 2006, SIP Appendix C.4).

TABLE 46—SUMMARY OF EPA NO_X BART COSTS FOR VARIOUS TESCR + ASOFA SCENARIOS ON MILTON R. YOUNG STATION UNIT 2 BOILER

Scenario	Description	Emissions reductions [1] (tons/year)	Total annual cost ($MM)	Average cost effectiveness ($/ton)
1	1 layer replaced every year	14,825	43.63	2,943
2	1 layer replaced every 2 years	14,816	41.89	2,827
3	1 layer replaced every 3 years	14,807	40.57	2,740
4	ASOFA downtime allowed	14,829	42.89	2,892

[1] Reductions vary based on impacts to boiler availability in each scenario (*i.e.,* lower boiler operating hours equate to lower emissions).

Factor 2: Energy impacts.

The additional energy requirements involved in installation and operation of the evaluated controls are not significant enough to warrant eliminating either SNCR or SCR.

Factor 3: Non-air quality environmental impacts.

The non-air quality environmental impacts are not significant enough to warrant eliminating either SNCR or SCR.

Factor 4: Remaining useful life.

The remaining useful life of Milton R. Young Station Unit 2 is at least 20 years. Thus, this factor does not impact our BART determination.

Factor 5: Evaluate visibility impacts.

Minnkota modeled the visibility benefits for SNCR + ASOFA using natural background per the BART Guidelines, North Dakota then performed additional modeling for the SCR + ASOFA control option. Minnkota and North Dakota both provided single-source modeling results using natural background conditions, complying with the BART Guidelines. The SCR + ASOFA option, when combined with wet scrubbing for SO_2, would result in a significant improvement in visibility at Theodore Roosevelt—estimated to be 3.945 deciviews and 110 fewer days above 0.5 deciviews. This represents an incremental visibility improvement of 2.318 deciviews and 58 fewer days above 0.5 deciviews beyond that achieved by wet scrubbing alone. Moreover, when compared to SNCR + ASOFA, it would result in an incremental visibility improvement of 0.566 deciviews and 21 fewer days above 0.5 deciviews. North Dakota conducted supplemental cumulative modeling for SCR at Milton R. Young Station 2 that is discussed in more detail in section V.D.1.e. For the reasons described there, we are disregarding North Dakota's alternative modeling in our analysis. More information on our interpretation of the State's and source's modeling information is included in the Technical Support Document.

Step 5: Select BART.

We propose to find that BART is SCR + ASOFA at Milton R. Young Station 2 with an emission limit of 0.07 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. We agree with the State that the other three factors are not relevant to this BART determination.

In our BART analysis for NO_X at Milton R. Young Station 2, we considered SNCR + ASOFA and SCR + ASOFA. The comparison between our SNCR analysis and our TESCR Scenario 3 analysis is provided in Table 47.

TABLE 47—SUMMARY OF EPA NO_X BART ANALYSIS COMPARISON OF TESCR AND SNCR OPTIONS FOR MILTON R. YOUNG STATION UNIT 2 BOILER

Control option	Total installed capital cost (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1 2 4]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 dv
TESCR + ASOFA (Scenario 3)	[3] 216.9	40.57	2,740	5,695	3.945	110

TABLE 47—SUMMARY OF EPA NO_X BART ANALYSIS COMPARISON OF TESCR AND SNCR OPTIONS FOR MILTON R. YOUNG STATION UNIT 2 BOILER—Continued

Control option	Total installed capital cost (MM$)	Total annual cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1 2 4]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 dv
SNCR + ASOFA	17.45	6.44	703		3.379	89

[1] Minnkota's and the State's modeling for both SNCR and SCR was based on lower emissions reductions (fewer tons removed) than we anticipate; thus, we anticipate slightly greater visibility benefits (delta deciview) than reflected in these values. The visibility benefit shown is for the most impacted Class I area, Theodore Roosevelt.

[2] Minnkota and the State conducted the modeling with combined SO_2 and NO_X controls. The results shown include SO_2 at an emission rate reflective of wet scrubbing along with the noted NO_X control option.

[3] This installed capital cost estimate does not include the capital cost of ASOFA. The total annualized cost does include the capital cost of ASOFA.

[4] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

As discussed in more detail in the Technical Support Document, we have concluded that SNCR + ASOFA and SCR + ASOFA are both cost effective control technologies and that both would provide substantial visibility benefits. SNCR + ASOFA has a cost effectiveness value of $703 per ton. While SCR + ASOFA is more expensive than SNCR + ASOFA, it has a cost effectiveness value of $2,740 per ton of NO_X emissions reduced. This is well within the range of values we have considered reasonable for BART and that states other than North Dakota have considered reasonable for BART. Even with more frequent catalyst replacement, SCR would still be cost effective even at the high end of the range ($2,892 per ton) allowing for the most frequent catalyst replacement of one layer per year and allowing for the questionable costs of lost power generation revenue in TESCR Scenario 4. We also analyzed the SCR costs assuming the same baseline emissions of 15,507 tons per year used by North Dakota and determined that the high-end cost effectiveness value, assuming the most frequent catalyst replacement frequency, would be about $2,949 per ton of NO_X reduced. All of these cost effectiveness values are well within the range of values that North Dakota considered reasonable in several of its NO_X BART determinations, where predicted visibility improvement was considerably lower.

We have weighed costs against the anticipated visibility impacts at Milton R. Young Station Unit 2, as modeled by Minnkota and the State. Both sets of controls would have a positive impact on visibility. As compared to SNCR + ASOFA, SCR + ASOFA would provide an additional visibility benefit of 0.566 deciview at Theodore Roosevelt and 21 fewer days above 0.5 deciviews. We consider these impacts to be substantial, especially in light of the fact that neither of these Class I areas is projected to meet the uniform rate of progress. We also note that the 0.566 deciview improvement at Theodore Roosevelt is greater than the improvement in visibility that North Dakota found reasonable to support other NO_X BART determinations in the SIP, at higher cost effectiveness values. Given the visibility improvement associated with SCR + ASOFA, the relatively low incremental cost effectiveness between the two control options ($6,045 per ton), and the reasonable average cost effectiveness values for SCR + ASOFA, we propose that the NO_X BART emission limit for Milton R. Young Station 2 should be based on SCR + ASOFA.

In proposing a BART emission limit of 0.07 lb/MMBtu, we adjusted the annual design rate of 0.05 lb/MMBtu upwards to allow for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including during startup, shutdown, and malfunction.[51] 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 implementation plan revision.'' Based on the retrofit of other SCR installations we have reviewed, we propose a compliance deadline of five (5) years from the date our final FIP becomes effective.

[51] 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.

4. BART Analysis for Leland Olds Station 2

Step 1: Identify All Available Technologies.

As with the Milton R. Young Station Units, our analysis for Leland Olds Unit 2 only considers SNCR + ASOFA and SCR + ASOFA. Because the State selected SNCR + ASOFA as BART, and our concern is that the State did not properly evaluate SCR as BART, there is no need to consider lower-performing technologies.

Step 2: Eliminate Technically Infeasible Options.

We are not eliminating either SNCR or SCR as being technically infeasible. Both technologies have been widely employed to control NO_X emissions from coal-fired power plants. The State determined SNCR was technically feasible for North Dakota EGUs. We agree with the State that SNCR is technically feasible. The State also determined, in Section 7 of the SIP, that two forms of SCR are technically feasible for use on North Dakota EGUs burning lignite coal. The State based its conclusion on an analysis it provided in Appendix B.5 to its Regional Haze SIP.

For further discussion concerning the technical feasibility of SCR, please see our NO_X BART analysis and determination for Milton R. Young Station Unit 1 and our Technical Support Document.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies.

For the purposes of our SNCR + ASOFA cost analysis, we used a control efficiency of 54% and an emission rate of 0.305 lb/MMBtu, the same control efficiency that North Dakota used. For our TESCR + ASOFA cost analysis we used a control efficiency of 93% and an emission rate of 0.05 lb/MMBtu, instead of North Dakota's 90% control efficiency and 0.07 lb/MMBtu emission rate. We find that SCR technology, by itself, can achieve 90% control efficiency and that the overall NO_X reduction would be even greater (93%) with the use of combustion controls in combination with SCR. A summary of emissions and the two control options is provided in Table 48.

TABLE 48—SUMMARY OF EPA NO_X BART ANALYSIS CONTROL TECHNOLOGIES FOR LELAND OLDS STATION UNIT 2 BOILER

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions (tons/yr)	Emissions reduction (tons/yr)
TESCR + ASOFA	93	0.05	900	12,100
SNCR + ASOFA	54	0.305	5,900	7,100
No Controls (Baseline)	0	0.67	[1] 13,000	

[1] We calculated our baseline using the same method used by Sargent & Lundy in its May 2009 report, but we adjusted the capacity factor downward to 86.5%.

Step 4: Evaluate Impacts and Document Results.

Factor 1: Cost of compliance.

SNCR + ASOFA.

We are not relying on North Dakota's costs for SNCR. Though the North Dakota costs, developed by Sargent & Lundy on behalf of Basin Electric, are generally consistent with the Control Cost Manual, at least one cost, related to lost revenue due to outage, is not. To ensure a fair comparison between the two competing technologies, we have re-worked the costs for SNCR.

We relied on Sargent & Lundy's estimate for total capital investment costs but adjusted them for 2009 dollars.[52] Then, we generally used factors and assumptions for annual costs provided by the Control Cost Manual. In the absence of a Control Cost Manual method for combustion controls, we used all the costs that North Dakota provided for ASOFA.

This is the same approach we used to analyze the costs for TESCR at Leland Olds Station 2, which enables us to compare the costs of SNCR and TESCR on a consistent basis. Our effort to re-estimate the costs for SNCR was not exhaustive, but it did result in a downward adjustment in the cost estimate for SNCR. We deem the analysis adequate for comparing the cost effectiveness values of the two top control options—SCR and SNCR.

Regarding specific elements in our cost analysis, we used $475 per ton to estimate urea costs and did not allow for lost revenue due to outage because the Control Cost Manual does not allow for lost revenue due to outage. To estimate the average cost effectiveness (dollars per ton of emissions reductions), we divided the total annualized cost by the estimated NO_X emissions reductions. We summarize our costs from our SNCR cost analysis in Tables 49, 50, and 51. See the Technical Support Document for our full analyses.

TABLE 49—SUMMARY OF EPA NO_X BART CAPITAL COST ANALYSIS FOR SNCR ON LELAND OLDS STATION UNIT 2 BOILER

Description	Cost factor	Cost ($)
Capital Investment ASOFA, A		11,440,000
Capital Investment SNCR, B		7,800,000
Total Capital Investment, TCI (2009$)	A + B	19,240,000

TABLE 50—SUMMARY OF EPA NO_X BART ANNUAL COSTS FOR SNCR ON LELAND OLDS STATION UNIT 2 BOILER

Description	Cost factor	Cost ($)
Annual Maintenance	.015 × TCI	117,000
Reagent		2,704,208
Electricity		44,656
Water		2,183
Increased Coal		83,927
Increased Ash		6,117
Total Direct Annual Cost (TDAC)	Sum of Various Items Listed Above	2,958,090
Indirect Annual Cost [1] (IDAC)	CRF × TCI	736,265
Total Annual Cost SNCR (TACS)	TDAC + IDAC	3,694,355
Total Annual Cost ASOFA [2] (TACA)		1,256,855
Total Annual Cost SNCR + ASOFA	TACS + TACA	4,951,210

[1] Capital Recovery Factor (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/.*

[52] We obtained capital costs from the company's BART analysis in Appendix C of the SIP. Adjustment to 2009 dollars was accomplished using the Chemical Engineering Plant Cost Index (CEPCI) for 2009 and 2006 (521.9/499.6=1.044). Available from Chemical Engineering Magazine (*http://www.che.com*).

[2] Calculated from Table 2.5–2, Basin Electric letter, May 29, 2009, Appendix C.1.

TABLE 51—SUMMARY OF EPA NO_X BART COSTS FOR SNCR ON LELAND OLDS STATION UNIT 2 BOILER

Control option	Total installed capital cost (MM$)	Total annualized cost (MM$)	Emissions reductions (tons/yr)	Average cost effectiveness ($/ton)
SNCR + ASOFA	19.24	4.95	7,100	700

TESCR + ASOFA.

Dr. Phyllis Fox, PhD, PE, as subcontractor to our contractor, RTI, prepared a cost analysis for TESCR for Leland Olds Station Unit 2. Dr. Fox started with the cost information in the Sargent & Lundy letter report dated May 27, 2009 with Basin Electric cover letter dated May 29, 2009. See SIP Appendix C.1. As described in greater detail below, while Dr. Fox relied on Sargent & Lundy's estimate for total capital investment for TESCR equipment and for the unit cost for catalyst, she adjusted Sargent & Lundy's assumptions for various other costs to make them consistent with the Control Cost Manual and reasonable costing assumptions.

TESCR + ASOFA Capital Costs.

The May 27, 2009 Sargent & Lundy Cost Analysis reports a capital cost range of $165,800,000 to $170,800,000 for installed capital costs for TESCR + ASOFA in 2009 dollars.[53] Sargent & Lundy calculated these costs from a lump sum unit capital cost estimate expressed in dollars per kilowatt of electricity generated. These costs are significantly higher than costs reported for similar installations.[54] We were not able to determine the basis for the deviation because Sargent & Lundy did not provide support for its unit capital cost estimate. Contrary to common practice, Sargent & Lundy did not separately identify equipment (*e.g.,* reactor housing, ducts, bypass, NH_3 injection system, sonic horns, *etc.*) and installation costs. Nonetheless, we used Sargent & Lundy's total capital investment estimate as the basis for our analysis, with the exception of the total capital costs for sorbent injection.[55] The result is a cost estimate that should represent the upper bound of likely costs.

For our analysis, we used a total installed capital cost estimate of $164,676,000 in 2009 dollars. This includes the cost of ASOFA but not the cost of a dry sorbent injection control system. This estimate is based primarily on the Sargent & Lundy lump sum unit capital cost estimate expressed in dollars per kilowatt of electricity generated, $350/kW, in 2009 dollars.

TESCR + ASOFA Annual Costs.

As previously discussed, the total capital cost is annualized using a capital recovery factor. This value is then summed with estimated annual operating and maintenance costs to arrive at a value for total annual costs.

Using an appropriate capital recovery factor of 0.08718, Dr. Fox calculated an annualized capital cost of $14,356,000 in 2009 dollars. Dr. Fox estimated that total annual operating and maintenance costs would be $22,090,000. Sargent & Lundy's estimate of variable operating and maintenance costs (NH_3, catalyst, power, natural gas, outage cost, and sorbent injection) was three to five times higher than Dr. Fox's estimate.

Below, we provide further detail regarding some of the major assumptions and reasoning underlying our estimate of annual operating and maintenance costs.[56]

Costs Related to Catalyst

Catalyst Lifetime

As noted already, an SCR catalyst must be changed out periodically. Information regarding catalyst life that we relied on for our cost analysis for Milton R. Young Station Units 1 and 2 is also relevant here. Leland Olds Station Unit 2 burns similar North Dakota lignite in a similar cyclone boiler. We note that Dr. Fox examined information related to catalyst life at Milton R. Young Station and independently considered relevant data and information to conclude that 24,000 hours is a reasonable assumption for catalyst life at Leland Olds Station. This is what Dr. Fox used for her cost analysis for Leland Olds Station Unit 2. Dr. Fox rejected Sargent & Lundy's estimate that catalyst life would only be six to 12 months; she found that Sargent & Lundy's estimate was based on a number of faulty assumptions. For further detail regarding catalyst life, please see our BART analysis and determination for Milton R. Young Station Unit 1 and our Technical Support Document.

Although we are confident that 24,000 hours represents a conservative assumption for catalyst life at Leland Olds Station Unit 2, we have also prepared cost estimates using 8,000 and 16,000 hours as assumptions for catalyst life in order to determine the sensitivity of costs to this variable. Further information is provided below.

Number of Catalyst Layers

The catalyst volume required to achieve a given NO_X level is typically divided into layers that can be separately replaced. Most SCR designs include an empty layer that can be filled with catalyst as the need arises. The most common configuration is two active layers with one spare. Initially, two layers are filled with catalyst. The third layer is added at the end of the initial catalyst lifetime.

We assumed an initial configuration of two filled and one empty layer of catalyst in our cost analysis, which is consistent with the design of modern SCRs. The empty layer would be filled after 24,000 hours, the assumed catalyst life.

Time Value of Money

The Control Cost Manual explains that the future worth factor should be used to amortize catalyst cost over the years preceding the actual catalyst purchase. As money is allocated in advance of purchase, the sum of the

[53] 5/27/09 S&L Cost Analysis, Table 2.5–2.

[54] Data indicates that Sargent & Lundy's estimate of capital costs to retrofit SCR at Leland Olds ($373/kW in 2010 dollars) is higher than actual installed costs for existing retrofit SCRs, including those with extreme retrofit difficulty and those requiring flue gas reheat. For further detail, please see our Technical Support Document. Thus, we consider our resulting cost effectiveness value to be conservative in favor of Basin Electric and to represent an upper bound for installation and operation of an SCR on LOS Unit 2. Put another way, we believe the cost effectiveness of SCR on LOS Unit 2 is more favorable than our estimate suggests.

[55] Dr. Fox concluded that a sorbent injection system would not be needed to reduce sulfuric acid mist because low conversion catalysts are available and because tail-end SCR would operate at a much lower temperature than high-dust SCR, which would significantly reduce the conversion of SO_2 to SO_3. Dr. Fox concluded that the conversion could be kept below the significance level. Our rationale for excluding sorbent injection is further discussed in our Technical Support Document.

[56] Contrary to Sargent & Lundy's approach, Dr. Fox did not "levelize" annual costs. As explained more fully in our evaluation of the State's NOx BART determinations for MRYS Units 1 and 2 and LOS Unit 2, the Control Cost Manual does not provide for levelization of annual costs.

annual catalyst replacement cost is less than the purchase price of the catalyst. Thus, we have multiplied the catalyst purchase price by a future worth factor. Assuming an interest rate of 7%, a catalyst life of 24,000 hours, and a capacity factor of 86.5%, the future worth factor is 0.31.[57]

Unit Catalyst Cost

We have assumed a cost of $7,500 per cubic meter of catalyst ($/m³), which is the same cost assumed in Sargent & Lundy's analysis. This is very high compared to values typically quoted by vendors, $4,500/m³ − $6,500/m³, depending upon volume per order.[58] While we find that $7,500/m³ is high, we did not have access to specific vendor quotes for this element due to confidentiality claims. This is another element that makes our cost estimate conservatively high.

Catalyst Volume

Sargent & Lundy assumed a catalyst volume of 530 m³ in its cost calculations.[59] The Sargent & Lundy spreadsheets produced in response to our CAA section 114 request indicate that this figure was derived by arbitrarily increasing a catalyst volume of 440 m³ by 20%.[60] The source of the starting point (440 m³) and the 20% adjustment are not disclosed.

As we commented on the draft Regional Haze SIP, the value of 530 m³ is high for a TESCR. Typically, cyclone fired units require about 1.5 m³ of catalyst per MW for a high-dust SCR, while TESCRs require less than half the catalyst volume of a high-dust SCR.[61] Thus, one would expect a catalyst volume of about 330 m³ for Leland Olds Station Unit 2. However, we used the unadjusted catalyst volume of 440 m³ from Sargent & Lundy's spreadsheets as a highly conservative upper bound.

Catalyst Changeout Time

First, a special outage to change out the catalyst would not be required. The catalyst can be changed out during scheduled major outages, which occur every 3 years. The first catalyst change would occur 3 years after installation. Thus, careful planning would align the first and subsequent changes with major outages, requiring no lost generation charges.

Second, the estimated catalyst exchange rate for a TESCR on the similar Milton R. Young Station units was 2.2 days for Unit 1 (257 MW) and 3.8 days for Unit 2 (477 MW).[62] Based on these values, the proportional exchange time for Leland Olds Station Unit 2 is 3.6 days. This is generally consistent with industry experience. Alternatively, as the boiler is typically down for cleaning 3 to 4 times per year for a period of about 4 days each time, this downtime would be sufficient to exchange a layer should one be required before a major outage. SCR systems are designed to minimize unit downtime to minimize operating costs.

Thus, we assumed there would be no lost generation during catalyst replacement because it would be prudent design and operating practice to schedule these events during routinely scheduled maintenance outages.

Cost of Utilities and Supplies

We have included costs for NH_3, the reagent used in the SCR, and natural gas, used to reheat the flue gas. Our costs for these items do not reflect potential changes in future commodity prices. This is because cost effectiveness methodology is based on the current annualized cost without escalation. The Control Cost Manual approach, recommended by the BART Guidelines, explicitly excludes future escalation because cost comparisons are made on a current real dollar basis. Inflation is not included in cost effectiveness analyses as these analyses rely on the most accurate information available at current prices and do not try to extrapolate those prices into the future.[63]

Ammonia (NH_3)

Recent BART analyses have used values in the range of $450 per ton. Black & Veatch, an engineering firm that designs SCRs, used an anhydrous ammonia cost of $450 per ton in a September 2010 BART analysis for Boardman.[64] Sargent & Lundy used an anhydrous ammonia cost of $475 per ton in a September 2010 BART analysis for the Navajo Generating Station.[65] We used $475 per ton for the cost of NH_3.

Natural Gas

The temperature of the flue gas exiting the wet scrubber must be raised to SCR operating temperature. There is more than one method for doing this. One method uses natural gas. The other uses steam. The cost of reheating the flue gas is typically one of the most significant operating costs for a TESCR.

Steam has important advantages over natural gas for use in flue gas reheating: lower cost, no increase in flue gas flow rate from gas combustion byproducts, no moisture condensation on the catalyst, and no risk of re-vaporization of catalyst poisons in the flame of a duct burner. Most TESCRs in Europe use steam for reheating.[66] Vendors in the Milton R. Young Station case uniformly recommended the use of a steam coil in place of natural gas-fired duct burners.[67] However, Sargent & Lundy did not evaluate the use of steam, and we lack the information needed to accurately calculate the cost of steam. Thus, we assumed the use of natural gas in our cost estimates. This is another indication that our estimate is conservative.

Operating experience with numerous TESCRs in Europe over the past 20 years indicates that an increase of 20 to 25 degrees F is adequate for reheat.[68] Further, an SCR operating temperature of 525–550 degrees F is sufficient for a TESCR as the flue gas SO_2 concentrations after the wet scrubber are low, eliminating the concern with deposition of ammonia salts on the catalyst.[69] Burns & McDonnell estimated a natural gas firing rate of 66.4

[57] Cost Manual, pdf 489–490, Eqn. 2.52: $FWF = 0.07[1/(1.07^3 - 1)] = 0.31$. $Y = 24{,}000\ hr/(8760)(0.865) = 3.2$, rounds to 3.

[58] Letter from Callie A. Videtich, Director, Air Program, EPA Region 8, to Terry O'Clair, Director, Division of Air Quality, North Dakota Department of Health, Re: EPA Region 8 Comments on December 2009 Draft Regional Haze SIP (Public Comment Version), January 8, 2010, Enclosure 2, p. 28; e-mail from Anthony C. Favale, Director—SCR Products, Hitachi Power Systems America, Ltd., to Anita Lee, U.S. EPA, Region 9, Re: CX Catalyst Question, April 1, 2010 ($5,500/m³ to $6,000/m³); e-mail from Flemming Hansen, Manager SCR DeNOx Catalyst, Haldor Tøpsoe, to Phyllis Fox, P.E., Re: Catalyst Cost, January 23, 2008 ($6,000/m³).

[59] 5/27/09 S&L Cost Analysis, p. 7.

[60] See, *e.g.,* Sargent & Lundy spreadsheet: low-high dust scr-leland old2—Sens2-cat life_05109.xls, cell E25 (440x1.20).

[61] 1/8/10 EPA Comments, Enclosure 1, p. 27.

[62] Hartenstein Report, April 2010, p. 36.

[63] See, *e.g.,* Cost Manual, p. 2–36, pdf 50.

[64] Black & Veatch, Portland General Electric Boardman Plant, Best Available Retrofit Technology (BART)/Reasonable Progress Analysis Revision 3: Boardman 2020 Alternative, August 27, 2010, Table 2–2.

[65] Sargent & Lundy, Salt River Project Navajo Generating Station—Units 1, 2, 3, SCR and Baghouse Capital Cost Estimate Report, Revision D, August 17, 2010, pdf 58, Table 9–2.

[66] 1/8/10 EPA Comments, Enclosure 1, p. 25.

[67] See, *e.g.,* Hartenstein Report, April 2010, pp. 34–35, 40–43.

[68] Hartenstein Report, April 2010, p. 40.

[69] McIlvaine, Next Generation SCR Choices—High-Dust, Low-Dust and Tail-End, FGD & DeNOx Newsletter, No. 369, January 2009; 5/6/08 Cochran (CERAM) e-mail, p. 2 (''Ammonia should not be injected below the minimum operating temperatures (MOT). Based on the SO2 to SO3 reported the MOT would be approximately 600 F. For lower sulfur fuels [such as ND lignite] and/or reduced NO_X removal performance a lower MOT would be possible. Additionally, brief periods of operation below the MOT would be possible without permanent degradation. In no event would any ammonia be allowed to be injected below 530 F for any likely combination of reasonable sulfur and NO_X removal parameters.''), in 5/8/08 Milton R. Young Additional Information.

MMBtu/hr for TESCR on Milton R. Young Station Unit 2.[70] The Burns & McDonnell estimate is consistent with European experience. Thus, we used 66.4 MMBtu/hr in our cost analysis.

Next, we determined an appropriate price assumption for natural gas. As noted, BART cost effectiveness analyses are based on the best estimate of current costs at the time of the analysis and do not consider future escalation. As cost effectiveness is determined relative to other similar sources, future escalation in gas prices would affect all natural gas users, not just Leland Olds Station.

The most recent data reported to the Energy Information Agency (EIA) indicates that the cost of natural gas to electric power consumers in North Dakota has ranged from $4.48/MMBtu (October 2010) to $5.37/MMBtu (June 2010).[71] As very little natural gas is currently used in North Dakota, a more reasonable estimate for a dedicated supply is the Henry Hub spot price plus transportation cost. The 2010 Henry Hub price of natural gas is $4.37/MMBtu.[72] The expected Henry Hub natural gas spot price for 2011 is $4.16/MMBtu, or $0.21/MMBtu lower than 2010. The Energy Information Agency expects the natural gas market to begin to tighten in 2012, with the Henry Hub spot price increasing to an average of $4.58/MMBtu.[73] Transportation cost is typically less than $1/MMBtu. Thus, a reasonable estimate for purposes of our analysis is about $5.50/MMBtu.

Power

An SCR increases power demand for auxiliary equipment, including the induced draft fans used to overcome the increase in backpressure from the SCR plus electricity to run the NH_3 system, dilution air blower, dilution air heaters, and seal air fans. Thus, auxiliary power is the electricity required to run the plant, or electricity not sold.

This cost is estimated by multiplying the electricity demand in kilowatts by the cost of electricity in dollars per megawatt hour (MWh). Cost effectiveness analyses are based on the cost to the owner to generate electricity, or the busbar cost, not market retail rates. The unit cost of electricity used by Sargent & Lundy, $50/MWh, is high for a lignite-fired boiler built near its fuel source. Burns & McDonnell assumed $38/MWh in the 2005 Feasibility Analysis for Leland Olds [74] and $35/MWh for Milton R. Young Unit 1.[75] We used $38/MWh, the value Burns & McDonnell reported for Leland Olds.

Capacity Factor

The capacity factor is the fraction of the available capacity that is actually used. It is calculated as the ratio of the actual electrical output to its full capacity, typically over a year. The emission reductions and variable operating and maintenance costs are both directly proportional to the capacity factor. The higher the capacity factor, the larger the emission reductions and the higher the variable operating and maintenance costs.

The BART Guidelines indicate that: ''in the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.'' [76] The Sargent & Lundy analysis calculated the capacity factor assuming the unit would operate at full capacity at all times except during catalyst change-outs. This resulted in capacity factors of 92% to 96%, which are higher than operating experience.

Dr. Fox calculated a capacity factor of 86.5%. This was based on a comparison of Leland Olds Station Unit 2's actual electrical output for a baseline period, obtained from monthly Clean Air Markets data, to its rated capacity (440 MW).[77] This 86.5% value was used to calculate NO_X emission reductions and variable operating and maintenance costs.

NO_X Emission Reduction

In our calculations, we assumed TESCR + ASOFA reduced baseline NO_X emissions of 0.67 lb/MMBtu [78] to 0.05 lb/MMBtu. An SCR outlet NO_X emission rate of 0.05 lb/MMBtu can be readily achieved by TESCR + ASOFA. The May 27, 2009 Sargent & Lundy analysis and supporting spreadsheets assumed the combination achieved 0.05 lb/MMBtu. In the Sargent & Lundy analysis, the SCR was specifically assumed to reduce NO_X from an inlet of 0.48 lb/MMBtu, a level consistent with performance of Leland Olds Unit 2 since installation of ASOFA, to 0.05 lb/MMBtu or 90% NO_X control.

We added the annual costs for ASOFA to the annual costs for TESCR to arrive at a total annual cost for the combined controls. To estimate the average cost effectiveness (dollars per ton of emissions reductions), we then divided the total annual cost by the estimated NO_X emission reductions. We summarize our cost estimates in Tables 52, 53 and 54. See our Technical Support Document for the full analyses.

TABLE 52—SUMMARY OF EPA NO_X BART CAPITAL COST ANALYSIS FOR TESCR SCENARIO 3 ON LELAND OLDS STATION UNIT 2 BOILER

Description	Cost factor	Cost ($)
Capital Investment (2010$) ASOFA, A		11,440,000
Capital Investment (2010$) SCR, B		164,121,000
Total Capital Investment, TCI (2010$)	A + B	175,561,000
Total Capital Investment, TCI (2009$)	TCI(2010) × CEPCI(521.9/556.2)	164,734,423

[70] Burns & McDonnell, Technology Feasibility Analysis and Cost Estimates for Leland Olds Station Unit 1 and 2, Basin Electric Power Cooperative, Final Draft, December 2005, p. 86.

[71] EIA, Natural Gas Monthly:*http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_monthly/ngm.html.*

[72] *http://tonto.eia.gov/dnav/ng/hist/rngwhhda.htm.*

[73] *http://www.eia.doe.gov/analysis/* and *http://www.eia.gov/emeu/steo/pub/contents.html.*

[74] Burns & McDonnell, Technology Feasibility Analysis and Cost Estimate for Leland Olds Station Unit 1 and 2, Basin Electric Power Cooperative, Final Draft, December 2005, p. 86.

[75] Burns & McDonnell, NO_X Best Available Control Technology Analysis Study—Supplemental Report for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., November 2009, p. 4–42.

[76] 70 FR 39167 (July 6, 2005).

[77] Capacity factor = 3,334,426 MWh/[(440)(8760)] = 0.865.

[78] North Dakota's BART Determination for Leland Olds Station Units 1 and 2, SIP Appendix B.1, p. 24.

TABLE 53—SUMMARY OF SOME EPA NO_X BART ANNUAL COSTS FOR TESCR SCENARIO 3[1] ON LELAND OLDS STATION UNIT 2 BOILER

Description	Cost factor	Cost ($)[2]
Annual Maintenance	.015×TCI	823,564
Reagent		2,115,190
Catalyst		320,796
Electricity		1,878,814
Natural Gas for Flue Gas Reheating and Urea to Ammonia Conversion		2,595,446
Total Direct Annual Cost (TDAC).		7,733,810
Indirect Annual Cost[3] (IDAC)	CRF × TCI	14,356,473
Total Annual Cost (TAC)	TDAC + IDAC	22,090,283

[1] See Table 54 for an explanation of Scenarios.
[2] Costs are in 2009 dollars.
[3] Capital Recovery Factor (CRF) is 0.08718 and is based on a 6% interest rate and 20 year equipment life. From Table 1.2–3, BART Determination Study, Leland Olds Units 1 and 2, August 2006, SIP Appendix C.1.

TABLE 54—SUMMARY OF EPA NO_X BART COSTS FOR VARIOUS TESCR + ASOFA SCENARIOS ON LELAND OLDS STATION UNIT 2 BOILER

Scenario	Description	Emissions reductions (tons/year)	Total annualized cost ($MM)	Average cost effectiveness ($/ton)
1	1 layer replaced every year	12,050	24.31	1,892
2	1 layer replaced every 2 years	12,050	23.74	1,848
3	1 layer replaced every 3 years	12,050	23.55	1,833

Factor 2: Energy impacts.

The additional energy requirements involved in installation and operation of the evaluated controls are not significant enough to warrant eliminating either SNCR or SCR.

Factor 3: Non-air quality environmental impacts.

The non-air quality environmental impacts are not significant enough to warrant eliminating either SNCR or SCR.

Factor 4: Remaining useful life.

The remaining useful life of Leland Olds Station Unit 2 is at least 20 years. Thus, this factor does not impact our BART determination.

Average cost effectiveness for each option.

To estimate the average annual cost effectiveness (dollars per ton of emissions reductions), we divided the total annual cost by the estimated NO_X emissions reductions. These estimates are noted in our summary in Table 55. Our average annual cost effectiveness estimate for SNCR + ASOFA at Leland Olds Station Unit 2 is $700 per ton of NO_X reductions. Our average annual cost effectiveness estimate for SCR + ASOFA at Leland Olds Station Unit 2 is $1,833 per ton of NO_X reductions.

Step 5: Evaluate Visibility Impacts.

Basin Electric modeled the visibility benefits for SNCR + ASOFA using natural background per the BART Guidelines. North Dakota then performed additional modeling for the SCR + ASOFA control option. Basin Electric and North Dakota both provided single-source modeling results using natural background conditions, complying with the BART Guidelines. The SCR + ASOFA option, when combined with FGD at 95% for SO_2, would result in a significant improvement in visibility at Theodore Roosevelt, estimated to be 4.393 deciviews and 130 fewer days above 0.5 deciviews. As the State did not provide discrete modeling for individual pollutants, it is not possible to describe the incremental visibility benefits of SCR + ASOFA or other NO_X control options over the selected SO_2 BART control (FGD at 95%). Nonetheless, when compared to SNCR + ASOFA, SCR would result in an incremental visibility improvement of 0.512 deciviews and 25 fewer days above 0.5 deciviews. North Dakota conducted supplemental cumulative modeling for SCR at Milton R. Young Station 1 that is discussed in more detail in section V.D.1.e. For the reasons described there, we are disregarding North Dakota's alternative modeling in our analysis.

More information on our interpretation of the State's and source's modeling information is included in the Technical Support Document.

Step 6: EPA BART Determination for Leland Olds Station 2.

We propose to find that BART is SCR + ASOFA at Leland Olds Station 2 with an emission limit of 0.07 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. We agree with the State that the other three factors are not relevant to this BART determination.

The comparison between our SNCR + ASOFA analysis and our TESCR + ASOFA Scenario 3 analysis is provided in Table 55.

TABLE 55—SUMMARY OF EPA NO_X BART ANALYSIS COMPARISON OF TESCR AND SNCR OPTIONS FOR LELAND OLDS STATION UNIT 2 BOILER

Control option	Total installed capital cost (MM$)	Total annualized cost (MM$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts [1, 2]	
					Visibility improvement (delta deciviews)	Fewer days > 0.5 dv
TESCR + ASOFA (Scenario 3)	164.68	22.09	1,833	3,489	4.393	130
SNCR + ASOFA	19.24	4.95	700	....	3.874	105

[1] The visibility modeling that North Dakota (for SCR) and Basin Electric (all scenarios but SCR) performed for Leland Olds Station Unit 2 included SO_2 control (FGD 95%) in addition to the noted NO_X control. Thus, these values do not reflect the distinct visibility benefit from the NO_X control options but do provide the incremental benefit between the options.

[2] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

We have concluded that SNCR + ASOFA and SCR + ASOFA are both cost effective control technologies and that both would provide substantial visibility benefits. SNCR + ASOFA has a cost effectiveness value of $700 per ton. While SCR + ASOFA is more expensive than SNCR + ASOFA, it has a cost effectiveness value of $1,833 per ton of NO_X emissions reduced. This is well within the range of values we have considered reasonable for BART and that states other than North Dakota have considered reasonable for BART. Even if we assume a catalyst replacement frequency of one layer per year, which we find is highly unlikely, SCR would still be cost effective ($1,892 per ton). We also analyzed the SCR costs assuming the same baseline emissions of 12,023 tons per year used by North Dakota and determined that the high-end cost effectiveness value, assuming the most frequent catalyst replacement frequency, would be about $2,035 per ton of NO_X reduced. All of these cost effectiveness values are well within the range of values that North Dakota considered reasonable in several of its NO_X BART determinations, where predicted visibility improvement was considerably lower.

We have weighed costs against the anticipated visibility impacts at Leland Olds Station 2. Both sets of controls would have a positive impact on visibility. As compared to SNCR + ASOFA, SCR + ASOFA would provide an additional visibility benefit 0.512 deciviews and 25 fewer days above 0.5 deciviews at Theodore Roosevelt. We consider these impacts to be substantial, especially in light of the fact that neither of these Class I areas are projected to meet the uniform rate of progress. We also note that the 0.512 deciview improvement at Theodore Roosevelt is greater than the improvement in visibility that North Dakota found reasonable to support other NO_X BART determinations in the SIP, at higher cost effectiveness values. Given the appreciable incremental visibility improvement associated with SCR + ASOFA, the relatively low incremental cost effectiveness between the two control options ($3,489 per ton), and the reasonable average cost effectiveness values for SCR + ASOFA, we propose that the NO_X BART emission limit for Leland Olds Station 2 should be based on SCR + ASOFA.

In proposing a BART emission limit of 0.07 lb/MMBtu, we adjusted the annual design rate of 0.05 lb/MMBtu upwards to allow for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including during startup, shutdown, and malfunction.[79] 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 implementation plan revision.'' Based on the retrofit of other SCR installations we have reviewed, we propose a compliance deadline of five (5) years from the date our final FIP becomes effective.

Note regarding SCR at Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2: Our proposal that SCR is BART at Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2 has been thoroughly analyzed and considered. As we indicate above, the sources and the State believe that SCR is technically infeasible, based on their views regarding catalyst deactivation and the lack of firm vendor guarantees of catalyst life. We disagree with the sources and the State and have adopted assumptions we and our consultants consider reasonable regarding SCR catalyst life at these units. We note that, should we finalize our FIP as proposed, Minnkota, Basin Electric, and/or the State may request reconsideration of our final action based on the potential outcomes of any field testing regarding catalyst life they may choose to undertake prior to the date the emission limits in our FIP become effective.

[79] 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.

F. Federal Implementation Plan to Address NO_X BART for Coal Creek Station Units 1 and 2

1. Introduction

As noted above, North Dakota selected SOFA + LNB as NO_X BART for Coal Creek Station Units 1 and 2 but in doing so, inappropriately eliminated SNCR + SOFA + LNB and SCR + SOFA + LNB as potential BART based on erroneous cost information for Coal Creek Station's fly ash sales. Thus, in our proposed FIP, we are re-evaluating LTO, SCR, SNCR, and low-NO_X burners and SOFA as potential BART. Our analysis follows our BART Guidelines. For Coal Creek Station Units 1 and 2, the BART Guidelines are mandatory. Coal Creek Station has a capacity of 1,100 MWs. North Dakota selected low-NO_X burners and SOFA with an associated limit of 0.17 pounds per million Btu as NO_X BART for Coal Creek.

2. BART analysis for Coal Creek Units 1 and 2

Since Coal Creek Units 1 and 2 are identical, we are considering average historical data for each unit and then proposing a single BART determination that applies to each unit.

Step 1: Identify All Available Technologies.

Our analysis for Coal Creek Units 1 and 2 considers SOFA + LNB (combustion controls), and combustion controls in combination with SNCR, SCR, and LTO.

Step 2: Eliminate Technically Infeasible Options.

For the reasons described in our BART analysis and determination for Milton R. Young Station Units 1 and 2 and Leland Olds Station 2, we are not eliminating either SNCR or SCR as being technically infeasible. We are not eliminating any of the other control options as being technically infeasible. For ease of comparison, we are evaluating LDSCR (downstream of the particulate control device). This is the option that North Dakota and Great River Energy (GRE) evaluated, and this location for the SCR equipment is preferable to a high-dust location (upstream of the particulate control device) for minimizing the amount of ash and catalyst poisons that would otherwise be present in the flue gases, thus increasing catalyst life and decreasing operating costs. A tail-end location (downstream of the particulate control and the SO_2 wet scrubber control devices) is another feasible option. (See our BART determinations for Milton R. Young Station and Leland Olds Station units in sections V.E.2 and V.E.3 for further discussion of LDSCR and TESCR.) The State determined all options to be technically feasible, including LDSCR and TESCR, for North Dakota EGUs.

Step 3: Evaluate Control Effectiveness of Remaining Control Technology.

For the purposes of our SOFA + LNB cost analysis, we used a control efficiency of 29% and an emission rate of 0.15 lb/MMBtu. In our SNCR + ASOFA cost analysis, we used a control efficiency of 49% and an emission rate of 0.108 lb/MMBtu. For our LDSCR + ASOFA cost analysis we used a control efficiency of 80% and an emission rate of 0.043 lb/MMBtu. We used the same emission rates as North Dakota and calculated slightly different efficiency ratings based on an emissions baseline for years 2000 through 2004. Due to limited time, we did not perform a separate cost analysis for LTO and are accepting the Great River Energy cost estimates that North Dakota used. These were based on a control efficiency of 90% and an emission rate of 0.022 lb/MMBtu. A summary of emissions and control options is provided in Table 56.

TABLE 56—SUMMARY OF EPA COAL CREEK BART ANALYSIS CONTROL TECHNOLOGIES FOR UNITS 1 AND 2 BOILERS

Control option	Control efficiency (%)	Emission rate (lb/MMBtu)	Emissions (tons/yr)	Emissions reduction (tons/yr)
LTO + SOFA + LNB	90	0.022	536	4,821
LDSCR + SOFA + LNB	80	0.043	1,084	4,210
SNCR + SOFA + LNB	49	0.108	2,722	2,572
SOFA + LNB	29	0.150	3,780	1,514
SOFA + LNB (Baseline)	0	0.22	5,294[1]	

[1] Calculated average for historic baseline (2000–2004) for Unit 1. Units 1 and 2 comparable in size and emissions.

Step 4: Evaluate Impacts and Document Results.

Factor 1: Costs of compliance.

SOFA + LNB.

We relied on North Dakota's and Great River Energy's cost analysis for SOFA + LNB. (See SIP, Appendices B.2 and C.2.) Great River Energy evaluated two slightly different emissions rates. We find that the lower emission rate (higher control efficiency) and associated costs are reasonable, and we rely on this information to supplement our other control option cost analyses. We used an emission rate of 0.151 lb/MMBtu, with a resulting capital cost of $5.37 million, a total annual cost of $673,100, and an average cost effectiveness of $412 per ton of NO_X emissions reductions.

SNCR+ SOFA + LNB.

We are not relying on North Dakota's costs for SNCR due to the erroneous fly ash cost information used by Great River Energy, which the State relied on in its analyses. We prepared a cost analysis for SNCR for Coal Creek Station Units 1 and 2. As explained below, we have used some of the cost information provided in a Great River Energy letter from Ms. Mary Jo Roth to Mr. Terry O'Clair dated July 15, 2011. The original price for fly ash in Great River Energy's analysis was $36.00 per ton. (See SIP, Appendix C.2). In its July 15, 2011 letter, Great River Energy corrected this value to $5.00 per ton. We have used this value in our analyses.

Regarding this value for fly ash sales, North Dakota concluded that SCR and SNCR use at Coal Creek would likely result in NH_3 in the fly ash due to NH_3 slip which would negatively affect fly ash salability. According to Great River Energy and North Dakota, fly ash that is currently beneficially used in the production of concrete would, instead, be landfilled. While we have opted to agree that fly ash will not be saleable for the SNCR and SCR options for purposes of our cost analyses, we are seeking comment on this issue, particularly related to the levels of NH_3 that fly ash marketers deem problematic, and the availability, applicability, and cost of applying NH_3 mitigation techniques to fly ash derived from lignite coal.

We also relied on Great River Energy's estimate for direct capital equipment costs for SNCR. We then generally used factors and assumptions provided by the Control Cost Manual for the remainder of our SNCR analysis, as well as cost estimates we consider to be reasonable for certain recurring costs. This is the same approach we used to analyze the costs for SCR and SNCR at Leland Olds Station Unit 2 and Milton R. Young Station Units 1 and 2. This enables us to compare the costs of the various technologies on a consistent basis. We summarize our costs from our SNCR cost analysis in Tables 57, 58, and 59.

TABLE 57—SUMMARY OF EPA NO_X BART CAPITAL COST ANALYSIS FOR SNCR ON COAL CREEK STATION UNITS 1 AND 2 BOILERS

Description	Cost factor	Cost ($)
Capital Investment ASOFA, A		4,913,000
Capital Investment SNCR, B		5,374,000
Total Capital Investment, TCI (2009$)	A + B	10,287,000

TABLE 58—SUMMARY OF EPA ANNUAL COST ANALYSIS FOR SNCR + ASOFA ON COAL CREEK STATION UNITS 1 AND 2 BOILERS

Description	Cost factor	Cost ($)
Annual Maintenance	.015xTCI	80,600
Reagent		1,000,000
Electricity		35,600
Water		1,000
Increased Coal		38,000
Increased Ash		2,900
Additional Ash Disposal		2,023,700
Lost Ash Sales		2,023,700
Total Direct Annual Cost (TDAC)	Sum of Various Items Listed Above	5,250,000
Indirect Annual Cost [1] (IDAC)	CRF x TCI	507,000
Total Annual Cost SNCR (TACS)	TDAC + IDAC	5,760,000
Total Annual Cost ASOFA (TACA)	North Dakota Appendix B.4	673,000
Total Annual Cost SNCR + ASOFA	TACS + TACA	6,430,000

[1] Capital Recovery Factor (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 59—SUMMARY OF EPA COSTS FOR SNCR ON COAL CREEK STATION UNITS 1 AND 2 BOILERS

Control option	Total installed capital cost (MM$)	Total annual cost (MM$)	Emissions reductions (tons/yr)	Average cost effectiveness ($/ton)
SNCR + SOFA + LNB	10.29	6.40	2,572	$2,500

SCR+ SOFA + LNB.

We are not relying on North Dakota's costs for SCR + SOFA + LNB due to the erroneous fly ash cost information used by Great River Energy, which the State relied on in its analyses. Here again, we used the source's corrected sales price for fly ash of $5.00 per ton. As with SNCR, we relied on Great River Energy's estimate for direct capital equipment costs for SCR. We then generally used factors and assumptions provided by the Control Cost Manual for the remainder of our SCR analysis, as well as cost estimates we consider to be reasonable for certain recurring costs. This is the same approach we used to analyze the costs for SCR and SNCR at Leland Olds Station Unit 2 and Milton R. Young Station Units 1 and 2. This enables us to compare the costs of the various technologies on a consistent basis. We summarize our costs from our SCR cost analysis in Tables 60, 61, and 62.

TABLE 60—SUMMARY OF EPA CAPITAL COST ANALYSIS FOR LDSCR ON COAL CREEK STATION UNITS 1 AND 2 BOILERS

Description	Cost factor	Cost ($)
Capital Investment ASOFA, A		4,913,000
Capital Investment LDSCR, B		60,241,000
Total Capital Investment, TCI (2009$)	A + B	65,154,000

TABLE 61—SUMMARY OF EPA ANNUAL COST ANALYSIS FOR LDSCR ON COAL CREEK STATION UNITS 1 AND 2 BOILERS

Description	Cost factor	Cost ($)
Annual Maintenance	.015 × TCI	903,600
Reagent		498,000
Electricity		974,000
Catalyst		708,000
Natural Gas		3,890,000
Additional Ash Disposal		2,023,700
Lost Ash Sales		2,023,700
Total Direct Annual Cost (TDAC)	Sum of Various Items Listed Above	11,021,000
Indirect Annual Cost [1] (IDAC)	CRF x TCI	5,686,000
Total Annual Cost LDSCR (TACS)	TDAC + IDAC	16,707,000
Total Annual Cost ASOFA (TACA)	North Dakota Appendix B.4	620,400

TABLE 61—SUMMARY OF EPA ANNUAL COST ANALYSIS FOR LDSCR ON COAL CREEK STATION UNITS 1 AND 2 BOILERS—Continued

Description	Cost factor	Cost ($)
Total Annual Cost LDSCR + ASOFA	TACS + TACA	17,328,000

[1] Capital Recovery Factor (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 62—SUMMARY OF EPA COSTS FOR LDSCR ON COAL CREEK STATION UNITS 1 AND 2 BOILERS

Control option	Total installed capital cost (MM$)	Total annual cost (MM$)	Emissions reductions (tons/yr)	Average cost effectiveness ($/ton)
LDSCR + SOFA + LNB	65,154,000	17,328,000	4,210	4,116

Factor 2: Energy impacts.

The additional energy requirements involved in installation and operation of the evaluated controls are not significant enough to warrant eliminating any of the control options.

Factor 3: Non-air quality environmental impacts.

The non-air quality environmental impacts are not significant enough to warrant eliminating any of the options. It is possible that fly ash will need to be landfilled if it cannot be sold due to NH_3 contamination. We have considered this possibility in our cost analysis. However, while North Dakota considered this to be of some importance in its evaluation of non-air quality environmental impacts and its elimination of SNCR as a potential BART option at Coal Creek Station, we note that North Dakota has selected SNCR as BART at several other units. In those determinations, North Dakota did not indicate that landfilling of fly ash would cause any particular non-air quality environmental impacts. And given that this is the typical practice at many facilities using SCR and SNCR to control NO_X, we do not find this to be a consideration that warrants elimination of SCR or SNCR as potential BART control options.

Factor 4: Remaining useful life.

The remaining useful life of Coal Creek Station Units 1 and 2 is at least 20 years. Thus, this factor does not impact our BART determination.

Factor 5: Evaluate visibility impacts.

Great River Energy modeled the visibility benefits for all the control options using natural background per the BART Guidelines. The SO_2 scrubber controls were included with every modeling run for the NO_X control options. This modeling predicted that the visibility improvement would range from 1.853 deciviews with LTO + scrubber modifications down to 1.378 deciviews for the least efficient technology, SOFA + LNB + scrubber modifications, at Theodore Roosevelt (98th percentile). More information on our interpretation of Great River Energy's modeling information is included in the Technical Support Document.

Based on Great River Energy's modeling, we anticipate that SNCR + SOFA + LNB would provide additional visibility improvement compared to SOFA + LNB (higher control option) of about 0.105 deciviews at Theodore Roosevelt, Northern Unit, and 0.088 deciviews at Theodore Roosevelt, Southern Unit. Also, when compared to SOFA + LNB, SNCR + SOFA + LNB would provide six fewer days above 0.5 deciviews at Lostwood, three fewer days at Theodore Roosevelt, Northern Unit, and one less day at Theodor Roosevelt, Southern Unit.[80]

Step 5: Select BART.

We propose to find that BART is SNCR + SOFA + LNB at Coal Creek Station Units 1 and 2 with an emission limit of 0.12 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. As indicated above, we find that the other three factors are not significant for this BART determination.

Our evaluation of the four control options is summarized in Table 63.

TABLE 63—SUMMARY OF EPA NO_X BART ANALYSIS FOR COAL CREEK STATION UNITS 1 AND 2 BOILERS

Control option	Total installed capital cost (MM$)	Total annual cost (MM$)	Emissions reductions (tons/year)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts[1 2]	
						Visibility improvement (delta dv)	Fewer days > 0.5 dv
LTO + SOFA + LNB	44.32	58.21	4,821	11,608		1.853	64
LDSCR + SOFA + LNB [1]	65.15	17.33	4,210	4,116	6,653	1.760	62
SNCR + SOFA + LNB	10.29	6.43	2,572	2,500	5,441	1.507	50
SOFA + LNB	4.91	0.67	1,517	445		1.419	49

[1] The visibility modeling that Great River Energy performed for Coal Creek Units 1 and 2 included SO_2 control in addition to the noted NO_X control. The modeling results shown above reflect the chosen SO_2 BART control, scrubber modifications, in addition to the noted NO_X control option. Thus, these values do not reflect the distinct visibility benefit from the NO_X control options but do provide the incremental benefit between the options. Also, this table only presents the modeling results for Theodore Roosevelt, Southern Unit, for 2002, because this is where and when Great River Energy modeled the largest 98th percentile absolute impact under any scenario. However, as noted in the text and in North Dakota's SIP, Great River Energy modeled greater incremental benefit between SOFA + LNB and SNCR + SOFA + LNB at Theodore Roosevelt, Northern Unit for 2002.

[80] In its BART determination, the State presented the deciview improvement at Theodore Roosevelt, Northern Unit.

[2] The visibility improvement described in this table represents the change in the maximum 98th percentile impact over the modeled 3-year meteorological period (2001–2003) at the highest impacted Class I area, Theodore Roosevelt. Similarly, the number of days above 0.5 deciviews is the total for the modeled 3-year meteorological period at Theodore Roosevelt.

We have concluded that SOFA + LNB and SNCR + SOFA + LNB are both cost effective control technologies and that both would provide incremental visibility benefits. SOFA + LNB has a cost effectiveness value of $445 per ton of NO_X emissions reduced. While SNCR + ASOFA is more expensive than SOFA + LNB, it has a cost effectiveness value of $2,500 per ton of NO_X emissions reduced. We note that this figure would be substantially lower—approximately $1,700 per ton—if NH_3 contamination in the fly ash can be mitigated. Either of these values is well within the range of values we have considered reasonable for BART and that states other than North Dakota have considered reasonable for BART. It is also within the range of values that North Dakota considered reasonable in its NO_X BART determinations, with comparable predicted visibility improvement. We note that Great River Energy's July 15, 2011 cost effectiveness estimate of $3,198 per ton for SNCR is also within the range that North Dakota has considered reasonable in selecting SNCR as BART at other EGUs.

We find the cost effectiveness values for LTO + SOFA + LNB and LDSCR + SOFA + LNB to be excessive and are proposing to eliminate these options as BART. While the incremental visibility improvement of 0.35 to 0.25 deciviews compared to the SNCR option is not insignificant, both the average and incremental cost effectiveness values associated with these options are high. The average cost effectiveness value for LTO + SOFA + LNB is $11,608 per ton. We find it is not reasonable to impose this cost given the predicted visibility improvement.

Using the value Great River Energy supplied for installed capital cost, we calculated an average cost effectiveness value for SCR + SOFA + LNB of $4,116 per ton. Given the anticipated visibility improvement, and the incremental cost effectiveness value of $6,653, we are not prepared to impose this option as BART. We also conducted some further analysis of costs. We determined that Great River Energy's value for installed capital cost equates to approximately $110/kW. This value appears to be low based on actual industry experience. For comparison, we performed an additional analysis for LDSCR + SOFA + LNB using an installed capital cost of $280/kW. We derived this value from EPA's Integrated Planning Model.[81] The analysis resulted in an average cost effectiveness value of $6,600 per ton. This analysis provides further support for our conclusion that the SCR option is not reasonable.

SNCR, when combined with scrubber modifications achieving 95% control, would result in a significant improvement in visibility at Theodore Roosevelt, estimated to be 1.507 deciviews and 50 fewer days above 0.5 deciviews. As the State did not provide discrete modeling for individual pollutants, it is not possible to describe the incremental visibility benefits of SNCR, or other NO_X control options, over the selected SO_2 BART control (scrubber modifications at 95% control). Nonetheless, when compared to SOFA plus LNB, SNCR would result in an incremental visibility improvement of 0.088 deciviews at Theodore Roosevelt South Unit. North Dakota reports an even higher visibility benefit, 0.105 deciviews, at Theodore Roosevelt North Unit in Appendix B of the SIP, though this was not the most impacted unit in the baseline modeling. We note that the State imposed SNCR as BART at Stanton Station, where emission reductions were estimated to be 390 tons per year or less compared to the next lower control option, incremental visibility improvement was estimated to be 0.135 deciviews or less compared to the next lower control option, and where cost effectiveness values ranged from $3,052 to $3,778 per ton. Given the reasonable cost effectiveness value of $2,500 per ton and the incremental visibility benefit, we find it reasonable to select SNCR as BART, especially in light of the fact that neither of North Dakota's Class I areas are projected to meet the uniform rate of progress.

In proposing a BART emission limit of 0.12 lb/MMBtu, we adjusted the annual design rate of 0.108 lb/MMBtu upwards to allow for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including during startup, shutdown, and malfunction.[82] While we are proposing a BART limit of 0.12 lb/MMBtu, we invite comment on whether we should impose a different emission limit of 0.14 lb/MMBtu on a 30-day rolling average. Great River Energy has suggested in its July 15, 2011 letter that the Coal Creek Station units may be able to achieve a limit below 0.14 lb/MMBtu with a coal-drying process in combination with combustion controls, presumably at a lower cost effectiveness value than SNCR plus combustion controls.

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." Based on the retrofit of other SNCR installations we have reviewed, we propose a compliance deadline of five (5) years from the date our final FIP becomes effective.

We are also proposing monitoring, recordkeeping, and reporting requirements in regulatory text at the end of this proposal.

G. Evaluation of North Dakota's Reasonable Progress Goal

In order to establish reasonable progress goals for Theodore Roosevelt and Lostwood and to determine the controls needed for the long-term strategy, North Dakota followed the process established in the Regional Haze Rule. First, North Dakota identified the anticipated visibility improvement in 2018 in both North Dakota Class I areas using the WRAP Community Multi-Scale Air Quality (CMAQ) modeling results. This modeling identified the extent of visibility improvement from the baseline by pollutant for each Class I area. The modeling relied on projected source emission inventories, which included enforceable Federal and state regulations already in place and anticipated BART controls.

North Dakota then identified sources and source categories (other than BART sources) in North Dakota that are major contributors to visibility impairment and considered whether these sources should be controlled based on a consideration of the factors identified in the CAA and EPA's regulations. *See* CAA 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A). Next, based on controls selected through this analysis, North Dakota set the reasonable progress goals for each Class I area and compared the reasonable progress goals for each area to the 2018 uniform rate of progress. The SIP includes North Dakota's analysis and conclusion that reasonable progress will be made by

[81] *http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html.*

[82] 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.

2018, including an analysis of pollutant trends, emission reductions, and improvements expected. The reasonable progress discussion and analyses are included in Section 9 of the SIP. We are proposing to disapprove North Dakota's submitted reasonable progress goals as described more fully below.

1. North Dakota's Visibility Modeling

The primary tool WRAP relied upon for modeling regional haze improvements by 2018, and for estimating North Dakota's Reasonable Progress Goals, was the CMAQ model. The CMAQ model was used to estimate 2018 visibility conditions in North Dakota 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 Regional Modeling Center (RMC) at the University of California Riverside conducted the CMAQ modeling under the oversight of the WRAP Modeling Forum. The Regional Modeling Center 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 2005. 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. A more detailed description of the CMAQ modeling performed by WRAP can be found in Appendix A.5 of the SIP and in the EPA Technical Support Document.

To supplement the WRAP modeling effort, North Dakota conducted further analyses using a hybrid modeling approach to address its concerns regarding weight of evidence and spatial resolution issues. The North Dakota hybrid modeling approach involved nesting a local North Dakota CALPUFF domain within the WRAP National CMAQ domain, and is explained in detail in Section 8 of the SIP.

North Dakota indicates its modeling methodology more realistically defines plume geometry for local large point sources and discounts the impacts of international sources in Canada over which North Dakota has no control. North Dakota is the only WRAP State which opted to develop its own reasonable progress modeling methodology. Appendix W outlines specific criteria for the use of alternate models and it does not appear that those criteria have been satisfied for the use of North Dakota's hybrid modeling.

2. North Dakota's Reasonable Progress "Four-Factor" Analysis

In determining the measures necessary to make reasonable progress, States must take into account the following four factors and demonstrate how they were taken into consideration in selecting reasonable progress goals for a Class I area:

- 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 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, the four-factor analysis conducted by North Dakota addresses only anthropogenic sources, on the assumption that the focus should be on sources that can be "controlled." In its evaluation of potential sources or source categories for reasonable progress, North Dakota primarily considered point sources. North Dakota also only considered controls for emissions of SO_2 and NO_X (*i.e.,* sulfate and nitrate) which are typically associated with anthropogenic sources. Previous BART modeling that the State conducted showed that PM emissions from point sources contribute only a minimal amount to the visibility impairment in the North Dakota Class I areas. More discussion on sources of sulfate and nitrate emissions and the State's rationale for focusing on point sources is included in Section 9.4 of the SIP.

To identify the point sources in North Dakota that potentially affect visibility in Class I areas, North Dakota started with the list of sources subject to Title V permitting requirements. Based on 2007 data, the State determined that Title V source emissions represent a very high percentage of the point source SO_2 and NO_X emissions in North Dakota—approximately 98 to 99%. North Dakota then divided the actual emissions (Q) in tons per year from the Title V sources by their distance (D) in kilometers to the nearest Class I Federal area. Actual annual emissions were determined based on total average emissions for the period 2000–2004 for SO_2 and NO_X combined. North Dakota decided to use a Q/D value of 10 as its threshold for further evaluation for reasonable progress controls. North Dakota chose this value based on the Federal Land Managers' proposed FLAG guidance amendments for initial screening criteria, as well as the State's interpretation of statements in EPA's BART guidelines.[83] A comprehensive list of the Title V Sources the State reviewed is included in Table 9.4 of the North Dakota SIP. The sources with Q/D results greater than 10 are listed below in Table 64.

TABLE 64—NORTH DAKOTA Q/D ANALYSIS SOURCES WITH RESULTS GREATER THAN 10

Source	Owner	SO_2 + NO_X 2000–2004 Average (tons)	Nearest class I area	Distance to nearest class I area (km)	Nearest Q/D (tons/km)
Antelope Valley Station Unit 1	Basin Electric	13,864	TRNP	107	129.6
Antelope Valley Station Unit 2	Basin Electric	12,796	TRNP	107	119.6
Grasslands Gas Plant	Bear Paw Energy	748	TRNP	38	19.7
Lignite Gas Plant	Bear Paw Energy	463	Lostwood	15	30.9
Great Plains Synfuels	Dakota Gasification Co	10,802	TRNP	107	101.0

[83] 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 tons per year 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 tons per year 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 51, appendix Y, section III, How to Identify Sources "Subject to BART.") The values described equate to a Q/D of 10.

TABLE 64—NORTH DAKOTA Q/D ANALYSIS SOURCES WITH RESULTS GREATER THAN 10—Continued

Source	Owner	$SO_2 + NO_X$ 2000–2004 Average (tons)	Nearest class I area	Distance to nearest class I area (km)	Nearest Q/D (tons/km)
Tioga Gas Plant	Hess Corporation	3,655	Lostwood	35	104.4
Heskett Plant Unit 2	MDU Company	3,411	TRNP	182	18.7
Comp. Station No. 4	Northern Border Pipeline	188	TRNP	18	10.4
Coyote Station	Otter Tail Power Company	27,804	TRNP	112	248.3
Little Knife Gas Plant	Petro-Hunt	422	TRNP	39	10.8
Mandan Refinery	Tesoro	5,757	TRNP	182	31.6

For the reasons described below, the State eliminated from further consideration several sources that met the Q/D criteria. After the 2000–2004 baseline period, Bear Paw Energy began injecting acid gas at its Grasslands and Lignite Gas Plants. This has eliminated SO_2 emissions, except during malfunctions of the injection equipment. The gas injection process is included in Bear Paw Energy's Title V permits and reduces its Q/D for the two facilities to 9.8 and 8.1 including malfunction emissions. The Northern Border Pipeline Company Compressor Station No. 4 is powered by a natural gas turbine that was replaced with a lower emitting turbine in 2005; this reduced its Q/D to 6.6. Petro Hunt's Little Knife Gas Plant's SO_2 and NO_X emissions are on the decline due to a decrease in gas volume and new production coming from the Bakken formation, which contains sweet gas. Based on its emissions in 2008, the Little Knife Gas Plant had a Q/D of 7.6, and emissions are expected to continue to decline in the future. The Tesoro Refining and Marketing Company's Mandan Refinery is subject to a consent decree that requires substantial emissions reductions. Since the baseline period, Tesoro has installed a wet scrubber and ESP to control SO_2 emissions from the catalytic cracking unit, LNB in the boilers, and other improvements that have reduced its Q/D to 7.9.

North Dakota undertook a more detailed analysis of the remaining sources that exceeded a Q/D of 10. These sources are shown below in Table 65.

TABLE 65—NORTH DAKOTA SOURCES FOR REASONABLE PROGRESS FOUR-FACTOR ANALYSES

Source	Owner	Unit	Type	Capacity	$SO_2 + NO_X$ 2000–2004 Average (tons/yr)
Antelope Valley Station	Basin Electric Power Coop.	1	EGU	435 MWe	13,864
Antelope Valley Station	Basin Electric Power Coop.	2	EGU	435 MWe	12,796
Coyote Station	Otter Tail Power Co.	Main Boiler	EGU	450 MWe	27,804
Great Plains Synfuels Plant	Dakota Gasification Co.	Boilers A, B and S	Industrial Boilers	763 x 10^6 BTU/hr each	10,802
Tioga Gas Plant	Hess Corp.	3	Sulfur Recovery Unit (SRU)	225 long tons per day (LTPD)	1,097
Tioga Gas Plant	Hess Corp.	C1–A to F	Compressor engines	1920–2350 BHp each	1,353
Heskett Station [84]	Montana Dakota Utilities	2	EGU	78 MWe	3,411

The control options and costs that North Dakota considered were derived, in part, from WRAP's report, *Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota,* May 18, 2009. A copy of this report and other related information is included in Appendix I.1 of the SIP. A summary of the control options considered along with their corresponding costs is provided in Table 67. The State made certain adjustments to WRAP's values; these are identified in the SIP.

Four Factor Analysis

Current Controls

Table 66 shows the current controls in place at each reasonable progress source.

TABLE 66—CURRENT CONTROL FOR REASONABLE PROGRESS SOURCES

Source	Pollutant	Control
Antelope Valley Station 1	SO_2	Spray Dryer.
	NO_X	OFA.
Antelope Valley Station 2	SO_2	Spray Dryer.
	NO_X	OFA.

[84] Because of a BART applicability issue, North Dakota did not complete the reasonable progress analysis for Heskett Unit 2 in time for inclusion as part of its March 3, 2010 submittal. The State submitted the four factor analysis for Heskett as Supplement No. 1.

TABLE 66—CURRENT CONTROL FOR REASONABLE PROGRESS SOURCES—Continued

Source	Pollutant	Control
Coyote	SO_2	Spray Dryer.
	NO_X	None.
Tioga Gas Plant SRU Engines	SO_2	3 Stage Claus + 4 bed Cold Bed Absorber.
	NO_X	None.
Great Plains Synfuels Plant—Boilers	SO_2	Wet Scrubber.
	NO_X	None.
Heskett	SO_2	None.
	NO_X	None.

Because upgrades of the spray dryers at Antelope Valley Units 1 and 2 are already in progress, the State did not consider this option for these units during this planning period. The State expects the spray dryers to achieve 90% removal efficiency but doesn't expect a reduction in emissions because of an anticipated increase in coal sulfur content. At the Coyote Station, the State evaluated replacing the existing spray dryer. The boilers at Great Plains Synfuels Plant are equipped with an NH_3 reagent wet scrubbing system followed by a wet ESP. This system is achieving 96–97% removal of SO_2 from the flue gas. The State determined that this removal efficiency is comparable to BACT and BART for industrial boilers of this size; thus the State did not evaluate additional SO2 controls for this source.

Cost of Compliance

Table 67 shows the cost of compliance for the control technologies evaluated for each of the reasonable progress sources.

TABLE 67—CONTROL OPTION COSTS FOR REASONABLE PROGRESS SOURCES

Source	Unit	Pollutant	Control technology	Control efficiency (%)	Emissions reductions (tons/yr)	Total annualized cost ($ millions)	Cost effectiveness ($/ton)
Antelope Valley Station.	1	SO_2	New Wet Scrubber.	95	6,780	32.17	4,745
		NO_X	LNB	51	3,889	2.28	586
			SNCR	40	3,050	8.96	2,938
			LNB + SNCR	65	4,956	11.24	2,268
			SCR w/reheat	80	6,100	44.00	7,213
			LNB + SCR w/reheat.	90	6,863	46.30	6,746
Antelope Valley Station.	2	SO_2	New Wet Scrubber.	95	5,899	32.17	5,453
		NO_X	LNB	51	3,450	2.28	661
			SNCR	40	2,706	8.96	3,311
			LNB + SNCR	65	4,397	11.24	2,556
			SCR w/reheat	80	5,411	44.00	8,132
			LNB + SCR w/reheat.	90	6,087	46.30	7,606
		SO_2	New Wet Scrubber.	95	12,835	33.28	2,593
Coyote Station	1	NO_X	ASOFA	40	5,223	1.28	246
			SNCR	40	5,223	8.52	1,631
			ASOFA + SNCR	55	7,182	11.25	1,566
			SCR w/reheat	80	10,446	45.30	4,337
			ASOFA + SCR w/reheat.	90	11,752	46.60	3,965
Heskett Station	2	SO_2	WS + LI	96	2,582	13.35	5,171
			WS	95	2,556	12.30	4,813
			CDS/Bag + LI	95	2,556	11.95	4,673
			SD/Bag + LI	94	2,539	10.86	4,296
			CDS/Bag	92	2,475	10.99	4,402
			SD/Bag	90	2,421	9.81	4,054
			LI	60	1,614	1.05	651
		NO_X	LDSCR	80	858	5.21	6,079
			TESCR	80	858	6.05	7,050
			SNCR	33	354	1.42	4,023
			Staged Combustion.	20	215	0.37	1,702
Tioga Gas Plant	SRU	SO_2	Tail Gas Clean Up.	99.8	1,018	5.80	5,697
	1920 Hp Engines	NO_X	Air Fuel Ratio Controller.	25	305	0.26	852
			Ignition Timing Retard.	22	268	0.14	522

TABLE 67—CONTROL OPTION COSTS FOR REASONABLE PROGRESS SOURCES—Continued

Source	Unit	Pollutant	Control technology	Control efficiency (%)	Emissions reductions (tons/yr)	Total annualized cost ($ millions)	Cost effectiveness ($/ton)
			LEC Retrofit	85	1,035	0.56	541
			SCR	80	974	1.60	1,643
	2350 Hp Engines	NO_X	SCR	50	34	0.50	1,471
Great Plains Synfuels Plant.	Boilers (information is per each boiler).	NO_X	SNCR	30	259	1.69	6,525
			SCR	80	670	5.50	8,216

The State found that the following control options have excessive cost effectiveness values:

- Antelope Valley 1 & 2—Wet scrubber; SCR w/reheat; and LNB + SCR w/reheat.
- Coyote—SCR w/reheat and ASOFA + SCR w/reheat.
- Heskett—Wet scrubber; circulating dry scrubber, with or without limestone injection; spray dryer, with or without limestone injection; SCR; and SNCR .
- Tioga Gas Plant—Tail Gas Cleanup.
- Great Plains Synfuels Plant—SNCR and SCR.

Also, at Heskett, the State found that SNCR plus staged combustion is not technically feasible. The State expressed concerns that SCR and SNCR may not be technically feasible at Great Plains Synfuels Plant. The State did not further evaluate the controls that it found had excessive cost effectiveness values or that it found were not technically feasible.

Time Necessary for Compliance

Relying on the EC/R report, the State found that up to 6.5 years after SIP approval would be necessary to achieve compliance with some of the control options and that additional time might be necessary if normal maintenance outages did not coincide with projected schedules.

Energy and Non-Air Impacts

The State found that all of the control technologies for the various sources would consume energy and that enhancement of the lb/MMBtu scrubbing system at Coyote Station would increase the amount of solid waste generated. However, the State concluded that the energy and non-air impacts would not preclude the selection of any of the technologies identified at any of the facilities.

Remaining Useful Life of the Source

With the exception of the engines at Tioga Gas Plant, the State found that the remaining useful life of the sources would be at least 20 years and would not preclude the selection of any of the control options. The State anticipated that the engines at Tioga may need to be refurbished before 20 years but that this would extend their remaining useful life indefinitely.

Visibility Improvement

In addition to evaluating the four statutory factors, North Dakota also considered the visibility impacts associated with the control options for each RP source. However, in modeling visibility impacts, North Dakota used a hybrid cumulative modeling approach that is inappropriate for determining the visibility impact for individual sources. As with the modeling North Dakota conducted for its NO_X BART analysis for MRYS Units 1 and 2 and LOS Unit 2, the approach fails to compare single-source impacts to natural background. While there is no requirement that States, when performing RP analyses, follow the modeling procedures set out in the BART guidelines, or that they consider visibility impacts at all, we find that North Dakota's visibility modeling significantly understates the visibility improvement that would be realized for the control options under consideration. Accordingly, we are disregarding the modeling analysis that North Dakota has used to support its RP determinations for individual sources. Table 68 shows the State's cost effectiveness and visibility modeling results.

TABLE 68—NORTH DAKOTA'S MODELED VISIBILITY IMPROVEMENT FOR REASONABLE PROGRESS SOURCES [1]

Source	Pollutant	Control technology	Visibility improvement (dv)		Cost effectiveness ($/dv)
			TRNP	LWA	
Antelope Valley Station 1	NO_X	LNB + SNCR	0.005	0.01	1,124,000,000
Antelope Valley Station 2	NO_X	LNB + SNCR	0.005	0.01	1,124,000,000
Coyote	SO_2 NO_X	Wet Scrubber ASOFA + SNCR	0.02	0.04	1,113,000,000
Tioga G.P. 1920 BHp Engines 2350 BHp Engines.	NO_X	SCR	0	[2] 0.05	21,200,000
Heskett	SO_2	Limestone Injection	....	....	116,667,000
	NO_X	SNCR Staged Combustion	0.009	0.003	158,222,000
					40,667,000
	.				

[1] For Tioga, the visibility improvement is for all engines. The visibility improvement numbers for Coyote and Heskett represent the combined benefit from SO_2 and NO_X. For Heskett, the State modeled one scenario that assumed 95% SO_2 control and 40% NO_X control.

[2] For Tioga, the SIP indicates the visibility improvement is 0.5 deciviews. The State informed us in a letter dated August 3, 2010 that this was an error and that the actual modeled value is 0.05 deciviews.

3. North Dakota's Conclusions From Its Four-Factor Analysis

The State determined that requiring additional controls on the reasonable progress sources will not substantially improve visibility in the Class I Federal Areas. Based on its cumulative modeling for the average of the 20% worst days, the State determined that the maximum combined improvement from use of the most efficient control options carried forward in the analysis for each source would be 0.11 deciviews at Lostwood and 0.03 deciviews at Theodore Roosevelt. According to the State, this amounts to a 0.17% improvement at Theodore Roosevelt over the baseline condition for the most impaired days and 0.56% improvement at Lostwood National Wildlife Refuge Wilderness Area. The State determined that the cost effectiveness value was over 618 million dollars per deciview of improvement at Lostwood and 2.3 billion dollars per deciview at Theodore Roosevelt. For all reasonable progress sources, the State determined that the cost ($/deciviews) was excessive, both on an individual and a cumulative basis. Therefore, the State concluded that no additional controls are warranted under reasonable progress during this planning period.

Controls at Coyote Station and Heskett Station

While the State concluded that additional controls are not warranted for purposes of meeting reasonable progress, the State nonetheless included controls for Coyote Station and Heskett Station in the SIP. For Coyote Station, the State reached an agreement with the owner/operator to reduce NO_X emissions by approximately 4,213 tons per year from the facility's 2000 to 2004 baseline. This represents a decrease of approximately 32%. To effectuate this reduction, North Dakota issued a permit to construct to Coyote Station and included it in the SIP. See SIP Amendment No. 1, submitted July 28, 2011. The permit requires that Coyote Station comply with an emissions limit of 0.50 lb/MMBtu (30-day rolling average) by July 1, 2018.

For Heskett Station, the State reached an agreement with the owner/operator to use limestone injection into the boiler to reduce SO_2 emissions by approximately 573 tons per year from the facility's 2000 to 2004 baseline emissions. This represents a decrease of approximately 34% from the facility's 2007 to 2008 baseline emissions. To effectuate this reduction, North Dakota issued a permit to construct to Heskett Station and included it in the SIP. See SIP Supplement No. 1, submitted July 27, 2011. The permit requires that Heskett Station achieve a minimum 70% reduction of SO_2 (coal to stack) or comply with an SO_2 emissions limit of 0.60 lb/MMBtu (12-month rolling average) within five years of EPA's approval of the permit to construct as part of the SIP.

4. Establishment of the Reasonable Progress Goal

40 CFR 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 reasonable progress goals 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 reasonable progress goals for the first planning period are goals for the year 2018.

Based on (1) The results of the WRAP CMAQ modeling, (2) the results of the four-factor analysis of major North Dakota sources, and (3) the emission controls on North Dakota BART sources, North Dakota established reasonable progress goals for the most impaired days for both of North Dakota's Class I areas, as identified in Table 69 below. Also shown in Table 69 is a comparison of the reasonable progress goals to the uniform rate of progress for both Class I areas. The reasonable progress goals for the 20% worst days fall short of the uniform rate of progress by 1.77 and 2.25 deciviews for Theodore Roosevelt and Lostwood, respectively. In Sections 8 and 9 of the SIP, the State presented additional scenarios that compared the State's hybrid modeling results to the WRAP modeling results. The State's hybrid modeling approach results in more optimistic estimations of visibility improvements. However, even when the State set all North Dakota SO_2 and NO_X emissions to zero in the hybrid model, it could not meet the uniform rate of progress.

TABLE 69—COMPARISON OF REASONABLE PROGRESS GOALS TO UNIFORM RATE OF PROGRESS ON MOST IMPAIRED DAYS FOR NORTH DAKOTA CLASS I AREAS

North Dakota class I area	Visibility conditions on 20% worst days (dv)			Percentage of URP achieved
	Average for 20% worst days (baseline 2000–2004)	2018 URP goal	RPG (WRAP projection)	
Theodore Roosevelt National Park	17.80	15.47	17.24	24.0
Lostwood Wilderness Area	19.57	16.87	19.12	16.7

North Dakota's reasonable progress goals for Theodore Roosevelt for 2018 for the 20% worst days represents a 0.6 deciviews improvement over baseline and its reasonable progress goals for Lostwood for 2018 represents a 0.5 deciviews improvement over baseline. North Dakota's reasonable progress goals establish a slower rate of progress than the uniform rate of progress. North Dakota has calculated that under the rate of progress represented by its reasonable progress goals, North Dakota would attain natural visibility conditions in 156 years at Theodore Roosevelt and 232 years at Lostwood.

Table 70 provides a comparison of North Dakota's reasonable progress goals to baseline conditions on the least impaired days. This comparison demonstrates that North Dakota's reasonable progress goals will result in no degradation in visibility conditions in the first planning period; instead, for the 20% best days, there would be a slight improvement in visibility from the baseline for both Class I areas.

TABLE 70—COMPARISON OF REASONABLE PROGRESS GOALS TO BASELINE CONDITIONS ON LEAST IMPAIRED DAYS FOR NORTH DAKOTA CLASS I AREAS

North Dakota class I area	Visibility conditions on 20% best days (dv)		Achieved "no degradation" (Y/N)
	Average for 20% best days (baseline 2000–2004)	RPG (WRAP projection)	
Theodore Roosevelt National Park	7.76	7.67	Y
Lostwood Wilderness Area	8.19	8.06	Y

North Dakota believes the reasonable progress goals it established for the North Dakota 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 the four-factor analysis along with the State's visibility analyses resulted in excessive dollar per deciview costs for additional controls.

2. Sources outside of the modeling domain and in Canada contribute 50–67% of the sulfate or nitrate to North Dakota's Class I areas. These are the pollutants that cause the greatest visibility impairment in such areas. Canadian sources are not under the control of North Dakota or the surrounding States and will not be significantly controlled by 2018. North Dakota conducted modeling to emulate 100% control of all in-state sources and demonstrated that the uniform rate of progress would still not be met.

3. After sulfate and nitrate, the next largest contributor to visibility impairment in North Dakota's Class I areas is organic carbon. Much of the organic carbon emissions, which account for approximately 15% and 18% of the extinction at Lostwood and Theodore Roosevelt, respectively, on the 20% worst days, are from natural fires that cannot be controlled.

5. Reasonable Progress Consultation

North Dakota consulted directly with neighboring states and through the WRAP, 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. In addition, North Dakota consulted directly with the State of Minnesota through the Minnesota Pollution Control Agency. 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.

40 CFR 51.308(d)(3)(ii) of the Regional Haze Rule 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 reasonable progress goals. Based on the consultation described above, North Dakota identified no major contributions that supported developing new interstate strategies, mitigation measures, or emission reduction obligations. Both North Dakota 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 reasonable progress goals for their Class I areas, and that future consultation would address any new strategies or measures needed.

H. Our Conclusion on North Dakota's Reasonable Progress Goal and Need for Additional Controls

We agree with North Dakota's conclusion that it is not reasonable to meet the uniform rate of progress for Theodore Roosevelt and Lostwood by 2018. In particular, North Dakota's modeling showed that even if all in-State emissions were reduced to zero, North Dakota could still not achieve the uniform rate of progress at its Class I areas. We also agree with North Dakota's conclusion that it appropriately consulted with other states and determined that it needed no further controls beyond those already contained in the SIP to address impacts on Class I areas in other states. However, we disagree with North Dakota's conclusion that no additional controls on non-BART sources are reasonable and disagree with North Dakota's selected reasonable progress goals.

Because the reasonable progress goals fall short of the uniform rate of progress, North Dakota must demonstrate that its reasonable progress goals and rejection of reasonable progress controls is reasonable, based on the four factors. 40 CFR 51.308(d)(1)(ii).

As an initial matter, we disagree with the State's assessment of visibility improvement at individual reasonable progress sources. While it is reasonable for a state to consider visibility improvement as an additional factor in its reasonable progress analysis when evaluating visibility benefits from potential control options at individual sources, it is not appropriate to assume degraded background conditions, as the State did. As we note above, using degraded rather than natural background in the modeling produces estimates that greatly underestimate the benefits of potential control options. The ultimate goal of the regional haze program is to achieve natural visibility conditions, not to preserve degraded conditions.

As a result of North Dakota's inappropriate visibility modeling approach, North Dakota greatly understated visibility improvements in deciviews.[85] Thus, cost effectiveness values, when expressed in dollars per deciview, were overestimated. Also, it is important to recognize that dollars per deciview values will always be significantly higher, often by several orders of magnitude, than the more

[85] The SIP includes 98th percentile modeling using natural background for the BART sources. Many of the reasonable progress sources are also large EGUs that are located in the same general area of the State. While we do not have specific BART Guidelines-compliant modeling for all of the reasonable progress sources, we would expect similar emissions reductions at the reasonable progress sources would produce visibility benefits of the same order of magnitude as at the BART sources. We do not find it reasonable to model BART sources one way and then model similar reasonable progress sources a different way when the ultimate goal is the same—attain natural visibility conditions by 2064.

commonly used and understood dollars per ton values.

Below we discuss each reasonable progress source and EPA's conclusions regarding the State's reasonable progress determination.

Antelope Valley Station Units 1 and 2

EPA is proposing to approve the State's conclusion that no additional SO_2 controls are warranted for these two units for this planning period. The cost effectiveness values for a new wet scrubber at each unit are $4,735 and $5,453 per ton. Also, the State noted that the existing spray dryers are already being upgraded. Based on the cost effectiveness values, we find that North Dakota reasonably rejected additional SO_2 controls during this planning period.

EPA does not agree with the State's conclusion that no additional controls are reasonable for NO_X for this planning period. In particular, the cost effectiveness values for low-NO_X burners at each unit are $586 and $661 per ton. These values are very reasonable and far less than many of the cost effectiveness values the State found reasonable in making its BART determinations. Given predicted NO_X reductions of approximately 3,500 tons per unit per year, and the fact that North Dakota's reasonable progress goals will not meet the uniform rate of progress, we find that it was unreasonable for the State to reject these highly inexpensive controls. EPA is proposing NO_X controls for these two units in section V.I below.

Coyote Station

EPA is proposing to approve the State's conclusion that no additional SO_2 control is warranted for this planning period. The cost effectiveness value for a new wet scrubber is $2,593 per ton. While this is within the range of cost effectiveness values that North Dakota, other states, and we have considered reasonable in the BART context, it is not so low that we are prepared to disapprove the State's conclusion in the reasonable progress context. We emphasize that Coyote currently employs a spray dryer to control SO_2 emissions at a control efficiency of approximately 66%. The existence of these controls has also influenced our decision.

EPA does not agree with the State's conclusion that no additional NO_X controls are reasonable for this planning period. In particular, the cost effectiveness value for ASOFA is $246 per ton. This value is very reasonable and far less than many of the cost effectiveness values the State found reasonable in making its BART determinations. Given the predicted NO_X reduction of approximately 5,223 tons per year, and the fact that North Dakota's reasonable progress goals will not meet the uniform rate of progress, we find that it was unreasonable for the State to reject this highly inexpensive control for reasonable progress. However, as noted above, the State reached an agreement whereby the owner/operator of Coyote Station will meet a NO_X emission limit of 0.50 lb/MMBtu by July 1, 2018. It is anticipated the source will meet this limit by installing OFA. North Dakota has made this limit enforceable through a permit to construct that it submitted as part of SIP Amendment No. 1. While we disagree with the State's reasoning regarding reasonable progress, we find the proposed limit to be reasonable to meet reasonable progress requirements at Coyote Station for this initial planning period. We are proposing to approve the permit to construct that contains this limit.

Tioga Gas Plant

Based on the relatively small predicted emissions reductions and the cost effectiveness values, we are proposing to approve the State's determination that no additional SO_2 or NO_X controls are reasonable for this source in this initial planning period.

Great Plains Synfuels Plant

EPA agrees with the State that the current SO_2 controls are achieving the most stringent level of control; thus, analysis of other SO_2 controls is not necessary. We also agree with the State's determination that additional NO_X controls are not reasonable during this initial planning period based on the high cost effectiveness values for those controls ($6,525 to $8,216 per ton) and the relatively modest emissions reductions that would be achieved.

Heskett Station Unit 2

We find reasonable the State's conclusion that some of the higher performing SO_2 controls are not reasonable for SO_2 for this initial planning period. The cost effectiveness values for all SO_2 control options above limestone injection are relatively high, ranging from about $4,000 to $5,000 per ton. We do not agree with the State's conclusion that limestone injection, at $651 per ton, is not reasonable during this planning period. However, as noted above, the State reached an agreement whereby the owner/operator of Heskett Station will install limestone injection and will reduce SO_2 by at least 70% (coal to stack, 12-month rolling average) or meet an SO_2 emissions limit of 0.60 lb/MMBtu (12-month rolling average). North Dakota has made this limit enforceable through a permit to construct that it submitted as part of SIP Supplement No. 1. The permit requires compliance with the emissions limits within five years of EPA's approval of the permit. While we disagree with the State's reasoning regarding reasonable progress, we find the proposed SO_2 limits to be reasonable to meet reasonable progress requirements at Heskett Station for this initial planning period. We are proposing to approve the permit to construct that contains these limits.

EPA is proposing to approve the State's determination that no additional NO_X controls at Heskett Station Unit 2 are reasonable in this planning period. The cost effectiveness values for potential NO_X controls are too high and/or the emissions reductions are too modest.

Because we are proposing to disapprove North Dakota's reasonable progress determination for NO_X for Antelope Valley Station Units 1 and 2 and setting NO_X limits through a FIP, and because we are proposing to disapprove North Dakota's NO_X BART determinations for Milton R. Young Station Units 1 and 2, Leland Olds Station Unit 2, and Coal Creek Station Units 1 and 2, we are proposing to disapprove North Dakota's reasonable progress goals. North Dakota's reasonable progress goals do not represent appropriate NO_X BART controls at Milton R. Young Station Units 1 and 2, Leland Olds Station Unit 2, and Coal Creek Station Units 1 and 2 or appropriate NO_X reasonable progress controls at Antelope Valley Station Units 1 and 2. Accordingly, we are proposing to replace North Dakota's reasonable progress goals in our FIP.

I. Federal Implementation Plan To Address Nitrogen Oxides (NO_X) Reasonable Progress Measures for Antelope Valley Station Units 1 and 2 and Reasonable Progress Goals

1. Introduction

As discussed above, we propose to disapprove North Dakota's reasonable progress conclusion that no additional controls at Antelope Valley Station Units 1 and 2 are warranted during this planning period. To correct the deficiencies identified in our proposed disapproval, we are proposing a FIP. Because we are proposing to disapprove North Dakota's reasonable progress goals, we are also proposing a FIP to replace them.

In proposing a FIP to address reasonable progress emission reductions and reasonable progress goals, we must consider the same factors that states are required to consider.

2. Reasonable Progress Analysis for Antelope Valley Station Units 1 and 2

As noted above in section V.G.2., North Dakota conducted an analysis of potential NO_X controls at Antelope Valley Station. In doing so, it considered the factors identified in the CAA and EPA's regulations. *See* CAA 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A). It also considered visibility impacts. Our analysis is based on the information provided by North Dakota, except that, as we explain below, we are disregarding North Dakota's visibility analysis.

The BART Guidelines recommend that states utilize a five-step process for determining BART for EGU sources above 750 MW in size. Although this five-step process is not required for making reasonable progress determinations, we have elected to largely follow it in our reasonable progress analysis because there is some overlap in the statutory BART and reasonable progress factors and because it provides a reasonable structure for evaluating potential control options.

Units 1 and 2 are tangentially-fired boilers, each having a generating capacity of 435 MW. These boilers are not BART-eligible because they commenced operation in the 1980s, after the 15-year period specified in the Regional Haze Rule. The boilers burn North Dakota lignite.

Step 1: Identify All Available Technologies.

Our analysis considers LNB, SNCR, SNCR + LNB, SCR, and SCR + LNB. Both boilers are already equipped with OFA systems.

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.

A summary of emissions projections for the various control options is provided in Table 71.

TABLE 71—SUMMARY OF ANTELOPE VALLEY STATION NO_X REASONABLE PROGRESS ANALYSIS CONTROL TECHNOLOGIES FOR UNITS 1 AND 2 BOILERS

Control option	Control efficiency (%)	Emissions [1] (tons/yr)	Emissions reduction (tons/yr)	Emissions [1] (tons/yr)	Emissions reduction (tons/yr)
		Unit 1		Unit 2	
SCR + LNB	90	762	6,863	678	6,087
SCR	80	1,525	6,100	1,354	5,411
SNCR + LNB	65	2,669	4,956	2,368	4,397
SNCR	40	4,575	3,050	4,059	2,706
LNB	51	3,736	3,889	3,315	3,450
No Controls (Baseline)	0	7,625		6,765	

[1] Calculated from North Dakota's emissions reductions and control efficiencies.

Step 4: Evaluate Impacts and Document Results.

Factor 1: Costs of compliance.

Table 72 provides a summary of estimated annual costs for the various control options. These values are based on North Dakota's estimates in Section 9 of the SIP.

TABLE 72—SUMMARY OF ANTELOPE VALLEY STATION NO_X REASONABLE PROGRESS COST ANALYSIS FOR UNITS 1 AND 2 BOILERS

Control option	Total Annual [1] Cost (MM$) (same for both units)	Cost Effectiveness ($/ton)	Cost Effectiveness ($/ton)
		Unit 1	Unit 2
SCR + LNB	46.3	6,746	7,606
SCR	44	7,213	8,132
SNCR + LNB	11.24	2,268	2,556
SNCR	8.96	2,938	3,311
LNB	2.28	586	661

[1] North Dakota presented a range of costs for SCR; we are reporting the low end of the range based on our position on catalyst life and other considerations discussed in our BART FIP for Milton R. Young Station and Leland Olds Station.

Factor 2: Energy impacts.

The additional energy requirements involved in installation and operation of the evaluated controls are not significant enough to warrant eliminating any of the control options.

Factor 3: Non-air quality environmental impacts.

The non-air quality environmental impacts are not significant enough to warrant eliminating any of the control options.

Factor 4: Remaining useful life.

The remaining useful life of Antelope Valley Units 1 and 2 is at least 20 years. Thus, this factor does not impact our reasonable progress determination.

Optional Factor 5: Evaluate visibility impacts.

Although visibility impact is not one of the four statutory factors, North Dakota opted to include the visibility impacts in its reasonable progress analysis in Section 9 of the SIP. As explained in section V.D.1.e, above, we are disregarding these modeling results because the State did not conduct its modeling in a manner that properly represents impacts from individual sources. (See our Technical Support Document for further explanation of our reasoning.) In a document separate from the SIP, North Dakota provided results of visibility modeling for Antelope Valley Station that was conducted per the BART Guidelines—*i.e.,* assuming natural background. This modeling predicts a visibility benefit of 0.754 deciviews at Theodore Roosevelt from the installation of LNB for both units combined.

Step 6: Select Reasonable Progress Controls.

Based on our examination of North Dakota's cost estimates and the predicted visibility benefit of 0.754 deciviews, we propose to find that LNB + SOFA are reasonable controls to address reasonable progress for the initial planning period, with an emission limit of 0.17 lb/MMBtu (30-day rolling average). Of the four reasonable progress factors and the optional factor of visibility improvement, cost and visibility improvement were the critical ones in our analysis of controls for this source. We agree with the State that the other three factors are not relevant to this reasonable progress determination. The average cost effectiveness values for LNB at each unit are $586 and $661 per ton. These values are very reasonable and far less than many of the cost effectiveness values the State found reasonable in making its BART determinations. Also, the Antelope Valley Station units are comparable in size to other large EGUs in North Dakota for which the State selected SNCR or combustion controls in the BART context. And, North Dakota predicted that installation of LNB would achieve NO_X reductions of approximately 3,500 tons per unit per year, which is substantial. Given the significant predicted visibility benefit, the low cost, and the fact that North Dakota's reasonable progress goals will not meet the uniform rate of progress, we find that it is reasonable to require a reasonable progress limit at Antelope Valley Station Units 1 and 2 based on the installation of LNB.

We have eliminated higher performing options—SNCR + LNB, SCR, and SCR + LNB—because their cost effectiveness values are significantly higher and/or the emission reductions are not that much higher than LNB. Considering the statutory factors, we find that it is not reasonable to insist on these higher control levels in this first planning period. However, we expect the State to consider such controls in the next planning period.

We are proposing an emission limit of 0.17 lb/MMBtu (30-day rolling average) based on a baseline emission rate of 0.35 lb/MMBtu and a predicted control efficiency of 51%. We also note that this is the presumptive limit in the BART Guidelines for this type of large boiler using combustion controls. We find the BART Guidelines' analysis of cost effective control technologies/emission limits for similar sources useful in assessing achievable emission limits. The emission limit would apply on a continuous basis, including during startup, shutdown, and malfunction.

We propose to require that Basin Electric start meeting our proposed emission limit at Antelope Valley Station Units 1 and 2 as expeditiously as practicable, but no later than July 31, 2018. This is consistent with the requirement that the SIP cover an initial planning period that ends July 31, 2018. We invite comment on whether a different deadline would be appropriate.

We are proposing monitoring, recordkeeping, and reporting requirements for Antelope Valley that are the same as those we are proposing for BART for Milton R. Young Station, Leland Olds Station, and Coal Creek Station.

3. Reasonable Progress Goals for North Dakota

We are proposing to impose reasonable progress controls on Antelope Valley Station Units 1 and 2 as described above, as well as more stringent BART controls on Milton R. Young Station Units 1 and 2, Leland Olds Station Unit 2, and Coal Creek Station Units 1 and 2 than North Dakota and WRAP assumed in modeling North Dakota's reasonable progress goals. Also, we assume that controls included in the SIP for Heskett Station and Coyote Station were not modeled when the reasonable progress goals were determined.

We could not re-run the WRAP modeling due to time and resource constraints, but anticipate that the additional controls would result in an increase in visibility improvement during the 20% worst 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 uniform rate of progress at Theodore Roosevelt and Lostwood in 2018. We expect the State to quantify the visibility improvement in its next Regional Haze SIP revision.

For purposes of this action, we are proposing reasonable progress goals that are consistent with the additional controls we are proposing and the Heskett and Coyote controls included in the SIP. While we would prefer to quantify the reasonable progress goals, we note that the reasonable progress goals themselves are not enforceable values. The more critical elements for our FIP are the emissions limits we are proposing to impose, which will be enforceable.

J. Long-Term Strategy

As described in section IV.E of this action, the long-term strategy is a compilation of state-specific control measures relied on by the state for achieving its reasonable progress goals. The long-term strategy must include ''enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals'' for all Class I areas within, or affected by emissions from, the state. 40 CFR 51.308(d)(3). North Dakota's long-term strategy for the first implementation period addresses the emissions reductions from federal, state, and local controls that take effect in the state from the end of the baseline period starting in 2004 until 2018. The North Dakota long-term strategy was developed by North Dakota, in coordination with the WRAP, through an evaluation of the following components: (1) WRAP emission inventories for a 2002 baseline and a 2018 projection (including reductions from WRAP member state controls required or expected under federal and state regulations (including BART)); (2) modeling to determine visibility improvement and apportion individual state contributions; (3) state consultation; and (4) application of the long-term strategy factors. The State's detailed long-term strategy is included in Section 10 of the Regional Haze SIP.

1. Emissions Inventories

40 CFR 51.308(d)(3)(iii) requires that North Dakota 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 it affects. North Dakota must identify the baseline emissions inventory on which its strategies are based. 40 CFR 51.308(d)(3)(iv) requires that North Dakota identify all anthropogenic (human-caused) sources of visibility impairment it considered in developing its long-term strategy. This includes major and minor stationary

sources, mobile sources, and area sources. In its efforts to meet these requirements, North Dakota relied on technical analyses developed by WRAP and approved by all state participants, as described below.

Emissions within North Dakota are both naturally occurring and man-made. Two primary sources of naturally occurring emissions include wildfires and windblown dust. In North Dakota, 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 North Dakota inventory includes emissions of SO_2, NO_X, $PM_{2.5}$, PM_{10}, organic carbon, elemental carbon, VOCs, and NH_3.

An emissions inventory for each pollutant was developed by WRAP for North Dakota for the baseline year 2002 and for 2018, which is the first reasonable progress 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. North Dakota made some adjustments to area oil and gas to include SO_2 emissions from flaring and lease use of sour gas at well sites. Emissions included in the 2018 WRAP inventory for the proposed Gascoyne 500 coal-fired power plant were removed since the Permit-to-Construct application for this facility was withdrawn. North Dakota disagreed with the WRAP-estimated NO_X emissions for area oil and gas production predicted for 2018, and based on discussions with the Oil and Gas Division of the North Dakota Industrial Commission and representatives of WRAP, adjusted these emissions to 2.5 times the 2002 emission rate.

There are ten different emission inventory source categories identified in the North Dakota regional haze Plan: Point, area, area oil and gas, on-road, off-road, all fire, biogenic, road dust, fugitive dust, and windblown dust. Tables 73 through 78 show the 2002 baseline emissions, the 2018 projected emissions, and net changes of emissions for SO_2, NO_X, organic carbon, elemental carbon, $PM_{2.5}$, and PM_{10} by source category in North Dakota. The methods that WRAP used to develop these emission inventories are described in more detail in Appendix A.5 of the SIP and in the EPA Technical Support Document.

SO_2 emissions in North Dakota, shown in Table 73, come mostly from coal combustion at electrical generation facilities, with smaller amounts coming from the oil and gas industry, natural gas combustion, and mobile sources. A 60% statewide reduction in SO_2 emissions is expected by 2018 due to planned controls on existing sources. This includes emission reductions of approximately 98,000 tons from the installation of SO_2 BART controls on the EGUs at Milton R. Young Station, Leland Olds Station, Coal Creek Station, and Stanton Station.

TABLE 73—NORTH DAKOTA SO_2 EMISSION INVENTORY—2002 AND 2018

[North Dakota statewide SO_2 emissions (tons/year)]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	157,069	59,560	−97,509	−62
All Fire	540	337	−203	−38
Biogenic	0	0	0	0
Area	5,557	5,995	438	8
Area Oil and Gas	4,958	4,200	−758	−15
On-Road Mobile	812	81	−731	−90
Off-Road Mobile	7,246	276	−6,970	−96
Road Dust	3	3	0	0
Fugitive Dust	26	30	4	15%
Wind Blown Dust	0	0	0	0
Total	176,211	70,482	−105,729	−60

NO_X emissions in North Dakota, shown in Table 74, are expected to decline 25% by 2018, primarily due to significant improvements in mobile sources. Off-road and on-road vehicle NO_X emissions are estimated to decline by more than 40,000 tons per year from the base case emissions total of 80,000 tons per year. Also, the State projected emission reductions of over 21,000 tons from the installation of NO_X BART controls on the EGUs at Milton R. Young Station, Leland Olds Station, Coal Creek Station, and Stanton Station. Increases in area oil and gas sources are related to increased drilling and production activity, which is expected to taper off from current levels to 2.5 times the 2002 levels by 2018.

TABLE 74—NORTH DAKOTA NO_X EMISSION INVENTORY—2002 AND 2018

[North Dakota statewide NO_X emissions (tons/year)]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	87,438	62,383	−25,055	−29
All Fire	1,774	1,073	−701	−40
Biogenic	44,569	44,569	0	0
Area	10,833	12,456	1,623	15
Area Oil and Gas	4,631	11,577	6,946	150
On-Road Mobile	24,746	4,906	−19,840	−80
Off-Road Mobile	55,502	34,557	−20,945	−38
Road Dust	3	3	0	0
Fugitive Dust	40	41	1	3

TABLE 74—NORTH DAKOTA NO_X EMISSION INVENTORY—2002 AND 2018—Continued

[North Dakota statewide NO_X emissions (tons/year)]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Wind Blown Dust	0	0	0	0
Total	229,536	171,566	−57,970	−25

Most of the organic carbon emissions in North Dakota are from fires as shown in Table 75. Natural (non-anthropogenic) wildfire can fluctuate greatly from year to year. 2002 was an average year for wildfires in North Dakota. Another sizable source is anthropogenic fire (human-caused), such as forestry prescribed burning, agricultural field burning, and outdoor residential burning. Overall, organic carbon emissions are estimated to decline by 19% by 2018.

TABLE 75—NORTH DAKOTA ORGANIC CARBON EMISSION INVENTORY—2002 AND 2018

[North Dakota statewide organic carbon emissions (tons/year)]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	262	248	−14	−5
All Fire	3,657	2,647	−1,010	−28
Biogenic	0	0	0	0
Area	1,466	1,387	−79	−5
Area Oil and Gas	0	0	0	0
On-Road Mobile	231	151	−80	−35
Off-Road Mobile	1,034	457	−577	−56
Road Dust	201	193	−8	−4
Fugitive Dust	1,989	2,041	52	3
Wind Blown Dust	0	0	0	0
Total	8,840	7,124	−1,716	−19

The primary source of elemental carbon is off-road mobile sources as shown in Table 76. Another contributor is fire. Other emissions of note are area and on-road mobile sources. Elemental carbon emissions are estimated to decrease by 52% by 2018 due mostly to new Federal mobile source regulations.

TABLE 76—NORTH DAKOTA ELEMENTAL CARBON EMISSION INVENTORY—2002 AND 2018

[North Dakota Statewide Elemental Carbon Emissions (tons/year)]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	29	32	3	10
All Fire	510	449	−61	−12
Biogenic	0	0	0	0
Area	262	267	5	2
Area Oil and Gas	0	0	0	0
On-Road Mobile	272	48	−224	−82
Off-Road Mobile	3,625	1,363	−2,262	−62
Road Dust	15	14	−1	−7
Fugitive Dust	135	139	4	3
Wind Blown Dust	0	0	0	0
Total	4,848	2,312	−2,536	−52

As detailed in Tables 77 and 78, 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 2–3% by 2018. North Dakota has approximately 38 million acres of farm and ranch land—approximately 86% of the State's area. Working the land produces significant amounts of fugitive and windblown dust. The WRAP estimated that emission sources in North Dakota put more than 420,000 tons of PM into the atmosphere in 2002. Fugitive dust from agricultural activities and windblown dust from farm fields were major contributors to these emissions. Although PM emissions were large, the effect on visibility in the North Dakota Class I areas was relatively small, but not insignificant. At Theodore Roosevelt, coarse mass and soil combined to contribute approximately 11% of the total extinction during the 20% worst days of the baseline period. At Lostwood, approximately 7% of the total extinction was due to coarse mass and soil. North Dakota sources contributed approximately 45% of the $PM_{2.5}$ and PM_{10} at Theodore Roosevelt and approximately 30% at Lostwood during the 20% worst days in 2000–2004. North Dakota stated that it anticipated an increase in agricultural conservation tillage practices by 2018, with a resultant reduction in $PM_{2.5}$ and PM_{10} emissions; however, North Dakota did not adjust the WRAP figures. WRAP figures for potential emission sources on the 20% worst visibility days are provided in Section 6 of the SIP.

TABLE 77—NORTH DAKOTA $PM_{2.5}$ EMISSION INVENTORY—2002 AND 2018

[North Dakota Statewide $PM_{2.5}$ Emissions (tons/year)]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	2,002	2,086	84	4
All Fire	821	404	−417	−51
Biogenic	0	0	0	0
Area	1,617	1,647	30	2
Area Oil and Gas	0	0	0	0
On-Road Mobile	0	0	0	0
Off-Road Mobile	0	0	0	0
Road Dust	3,086	2956	−130	−4
Fugitive Dust	36,354	37999	1,645	5
Wind Blown Dust	17,639	17639	0	0
Total	61,519	62,731	1,212	2

TABLE 78—NORTH DAKOTA COARSE PARTICULATE MATTER EMISSION INVENTORY—2002 AND 2018

[North Dakota Statewide Coarse Particulate Matter Emissions (tons/year)]

Source category	Baseline 2002	Future 2018	Net change	Percent change
Point	565	2,349	1,784	316
All Fire	503	460	−43	−9
Biogenic	0	0	0	0
Area	199	216	17	9
Area Oil and Gas	0	0	0	0
On-Road Mobile	141	111	−30	−21
Off-Road Mobile	0	0	0	0
Road Dust	28,711	27,478	−1,233	−4
Fugitive Dust	172,606	184,063	11,457	7
Wind Blown Dust	158,752	158,752	0	0
Total	361,477	373,429	11,952	3

2. Sources of Visibility Impairment in North Dakota Class I Areas

In order to determine the significant sources contributing to haze in North Dakota's Class I areas, North Dakota relied upon two source apportionment analysis techniques developed by the WRAP. The first technique was regional modeling using the Comprehensive Air Quality Model (CAMx) and the PM Source Apportionment Technology (PSAT) tool, used for the attribution of sulfate and nitrate sources only. The second technique was the Weighted Emissions Potential (WEP) tool, used for attribution of sources of organic carbon, elemental carbon, $PM_{2.5}$, 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 (2000–2004) to 2018 values, to show the improvement expected by 2018, for sulfate, nitrate, organic carbon, elemental carbon, $PM_{2.5}$, and PM_{10}. More information on the WRAP modeling methodologies is available in the EPA Technical Support Document.

The PSAT and WEP results presented in Tables 79 and 80 were derived from Section 6 of the SIP. Table 79 shows the contribution of different pollutant species from North Dakota sources. Sulfates and nitrates are the primary pollutants contributing to extinction.

TABLE 79—ND SOURCES EXTINCTION CONTRIBUTION 2000–2004 FOR 20% WORST DAYS

Class I area	Pollutant species	Extinction (Mm^{-1})	Species contribution to total extinction (%)	ND sources contribution to species extinction (%) [1]
TRNP	Sulfate	17.53	35	21
	Nitrate	13.74	27	19

TABLE 79—ND SOURCES EXTINCTION CONTRIBUTION 2000–2004 FOR 20% WORST DAYS—Continued

Class I area	Pollutant species	Extinction (Mm^{-1})	Species contribution to total extinction (%)	ND sources contribution to species extinction (%) [1]
	OC	10.82	21	12
	EC	2.75	5	29
	$PM_{2.5}$	0.9	2	44
	PM_{10}	4.82	10	45
	Sea Salt	0.07	0	0
LWA	Sulfate	21.4	34	18
	Nitrate	22.94	36	13
	OC	11.05	18	23
	EC	2.84	5	35
	$PM_{2.5}$	0.62	1	28
	PM_{10}	3.93	6	32
	Sea Salt	0.26	0	0

[1] Contribution of sulfate and nitrate based on PSAT; OC, EC, $PM_{2.5}$, PM_{10}, and Sea Salt contribution based on WEP.

Table 80 shows influences from sources both inside and outside of North Dakota. The results for sulfates and nitrates indicate that the 20% worst days at Lostwood and at Theodore Roosevelt are mostly impacted by a combination of sources in North Dakota and Canada, as well as sources outside the modeling domain.

TABLE 80—SOURCE REGION APPORTIONMENT FOR 20% WORST DAYS

[Percentage]

Contributing area	Class I area			
	TRNP		LWA	
	SO_4	NO_3	SO_4	NO_3
North Dakota	21.1	19.1	17.9	13.0
Canada	28.3	31.8	45.9	44.6
Outside Domain	32.6	17.9	20.2	14.0
Montana	3.1	15.0	2.4	9.3
CENRAP	4.9	2.5	5.3	5.1
Other	10.5	13.7	8.3	14.0

See the Technical Support Document for details on how the 2018 emissions inventory was constructed. WRAP and North Dakota used this inventory and other states' 2018 emission inventories to construct visibility projection modeling for 2018.

3. Visibility Projection Modeling

The Regional Modeling Center at the University of California Riverside, under the oversight of the WRAP Modeling Forum, performed modeling for the regional haze long-term strategy for the WRAP member states, including North Dakota. The modeling analysis is a complex technical evaluation that began with selection of the modeling system. Regional Modeling Center primarily used the CMAQ photochemical grid model to estimate 2018 visibility conditions in North Dakota and all western Class I areas, based on application of the regional haze strategies in the various state plans, including assumed controls on BART sources.

The Regional Modeling Center 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 2005. 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. The WRAP states' modeling was developed in accordance with our guidance.[86] A more detailed description of the CMAQ modeling performed for the WRAP can be found in Appendix A.5 of the SIP and in the Technical Support Document.

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 Regional Modeling Center 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 long-term strategy and for use in the modeling assessment. The 2002

[86] 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.

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 Regional Modeling Center determined that model performance was acceptable, it used the model to determine the 2018 reasonable progress goals using the current and future year air quality modeling predictions, and compared the reasonable progress goals to the uniform rate of progress.

To supplement the WRAP modeling effort, North Dakota conducted further analyses using a hybrid modeling approach to address concerns pertaining to weight of evidence and spatial resolution issues. The North Dakota hybrid modeling approach involved nesting a local North Dakota CALPUFF domain within the WRAP National CMAQ domain. This approach is explained in detail in Section 8 of the SIP.

North Dakota believes its modeling methodology more realistically defines plume geometry for local large point sources and discounts the impacts of international sources in Canada over which North Dakota has no control. North Dakota is the only WRAP State which opted to develop its own reasonable progress modeling methodology. Appendix W outlines specific criteria for the use of alternate models and it does not appear that those criteria have been satisfied for the use of North Dakota's hybrid modeling. In addition, as modeling science has improved, there have been a number of technical changes in the CALPUFF modeling system and EPA/Federal Land Managers recommended default settings, changes that have been implemented since North Dakota proposed the CMAQ/CALPUFF hybrid modeling approach in 2007. In the Reasonable Progress modeling, the hybrid CALPUFF/CMAQ modeling results were adjusted based on IMPROVE monitoring data, and it is not clear whether the use of these obsolete settings affected the weight of evidence factors or the Reasonable Progress demonstration. The settings North Dakota used in the CALPUFF model within the hybrid modeling system would not be considered technically sound if contained in a regulatory modeling protocol in future projects. However, in this instance it did not make a difference since North Dakota is not able to meet the uniform rate of progress with either the WRAP analysis or North Dakota's hybrid modeling system.

4. Consultation and Emissions Reductions for Other States' Class I Areas

40 CFR 51.308(d)(3)(i) requires that North Dakota consult with another state if its emissions are reasonably anticipated to contribute to visibility impairment at that state's Class I area(s), and that North Dakota consult with other states if those other states' emissions are reasonably anticipated to contribute to visibility impairment at Theodore Roosevelt or Lostwood. North Dakota's consultations with other states are described in section V.G.5 above. After evaluating whether emissions from North Dakota sources contribute to visibility impairment in other states' Class I areas, North Dakota concluded there was no contribution sufficient to require consultation. North Dakota's evaluation relied upon NO_X BART and reasonable progress reductions as described in the SIP. Nontheless, North Dakota did consult with other states and tribes, largely through the WRAP process, in order to meet the regulatory requirements.

40 CFR 51.308(d)(3)(ii) requires that if North Dakota emissions cause or contribute to impairment in another state's Class I area, North Dakota must demonstrate that it has included in its Regional Haze SIP all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for that Class I area. Section 51.308(d)(3)(ii) also requires that, since North Dakota participated in a regional planning process, it must ensure it has included all measures needed to achieve its apportionment of emission reduction obligations agreed upon through that process. As we state in the Regional Haze Rule, North Dakota's commitments to participate in WRAP bind it to secure emission reductions agreed to as a result of that process, unless it proposes a separate process and performs its consultations on the basis of that process. See 64 FR 35735,

North Dakota accepted and incorporated the WRAP-developed visibility modeling into its Regional Haze SIP, and the Regional Haze SIP includes the controls assumed in the modeling. North Dakota satisfied the Regional Haze Rule's requirements for consultation and included controls in the SIP sufficient to address the relevant requirements of the Regional Haze Rule related to impacts on Class I areas in other states. However, we are proposing to disapprove the long-term strategy for other reasons, as described below.

5. Mandatory Long-Term Strategy Factors

40 CFR 51.308(d)(3)(v) requires that North Dakota, at a minimum, consider certain factors in developing its long-term strategy (the long-term strategy factors). These are: (a) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment; (b) measures to mitigate the impacts of construction activities; (c) emissions limitations and schedules for compliance to achieve the reasonable progress goal; (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 long-term strategy.

a. Reductions Due to Ongoing Air Pollution Programs

In addition to its BART determinations, North Dakota's long-term strategy incorporates emission reductions due to a number of ongoing air pollution control programs.

i. Prevention of Significant Deterioration/New Source Review Rules

The two primary regulatory tools for addressing visibility impairment from industrial sources are BART and the Prevention of Signification Deterioration New Source Review rules. The Prevention of Signification Deterioration rules protect visibility in Class I areas from new industrial sources and major changes to existing sources. North Dakota's Air Pollution Control Rules (NDAC Chapter 33–15–19) contain requirements for visibility impact assessment and mitigation associated with emissions from new and modified major stationary sources. A primary responsibility of North Dakota under these rules is visibility protection. Chapter 33–15–19 describes mechanisms for visibility impact assessment and review by North Dakota, as well as impact modeling methods and requirements. Typically, this modeling is conducted for sources within 300 kilometers of a Class I area. North Dakota will not issue an air quality permit to any new major source or major modification within this distance that is found through modeling to cause significant visibility impairment, unless the impact is mitigated.

ii. North Dakota's Phase I Visibility Protection Program

In 1987 North Dakota adopted NDAC Chapter 33–15–19 for visibility protection to address EPA's Phase I visibility rules. Also in 1987, North Dakota adopted NDAC Chapter 33–15–04 for open burning restrictions; it provides that, except in an emergency, the visibility of any class I area cannot be adversely impacted.

iii. On-Going Implementation of State and Federal Mobile Source Regulations

Mobile source annual emissions show a major decrease in NO_X in North Dakota from 2002 to 2018. This reduction will result from numerous ''on the books'' Federal mobile source regulations. 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 parts per million (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.

b. Measures To Mitigate the Impacts of Construction Activities

In developing its long-term strategy, North Dakota has considered the impact of construction activities. Based on 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 North Dakota Class I areas, North Dakota found that current State regulations adequately address construction activities.

Current rules addressing impacts from construction activities in North Dakota include NDAC 33–15–17, which regulates fugitive dust emissions. The rule addresses ''fugitive emissions'' from a variety of sources applicable to construction activities. This regulation requires ''reasonable precautions'' be taken to prevent PM from becoming airborne from activities such as construction projects. Types of actions to be taken include the use of water or chemicals for control of dust from demolition, construction operations, unpaved roads at construction sites, and material stockpiles. North Dakota requires permits for asphalt and concrete plants and rock, sand, and gravel plants. The State has committed to re-evaluating emissions from construction activities related to the oil and gas industry, including construction of oil well pads, compressor stations, and gas plants, in future Regional Haze SIP planning periods since this has the potential to be a growing source category.

c. Emission Limitation and Schedules of Compliance

The SIP contains emission limits and schedules of compliance for those sources subject to BART: Milton R. Young Station, Leland Olds Station, Coal Creek Station, and Stanton Station. The schedules for implementation of BART for these sources are identified in Section 7.5 of the SIP and in permits included in Appendix D of the SIP.

While the State did not impose any emission limits to meet reasonable progress requirements, the State did include emission limits for Coyote Station and Heskett Station in the SIP. These ''other'' emission reductions are discussed in the long-term strategy under Section 10.6.1 of the SIP and the limits and compliance schedules are included in permits contained in Appendix A of the SIP. See section V.G.3 of this action for further discussion of these limits and schedules.

d. Source Retirement and Replacement Schedules

The State does not anticipate major source retirements or replacements. Replacement of existing facilities will be managed according to the existing Prevention of Signification Deterioration program. The 2018 modeling that WRAP conducted included three new power plants in North Dakota. Two are now unlikely to be built. Construction of new power plants or replacement of existing plants prior to 2018 is unlikely.

e. Agricultural and Forestry Smoke Management Techniques

North Dakota has an area of approximately 44.16 million acres. Of this total, 26.5 million acres is cropland, 11 million acres is pasture/rangeland, and 236,000 acres is woodland/forest, with five State forests comprising 13,300 acres. Prescribed burning is governed by State rules in NDAC 33–15–04–02 and must be approved in advance. Although agricultural crop burning does not require advance approval, most agricultural cropland burning takes place in the eastern two-thirds of the State away from the State's Class I areas. In general, prevailing winds carry smoke from cropland burning away from North Dakota Class I areas. Table 81, below, shows WRAP's estimate of emissions from fire in North Dakota for the 2000–2004 baseline period.

TABLE 81—ANNUAL AVERAGE EMISSIONS FROM FIRE (2000–2004)

[Tons/Year]

Source	$PM_{2.5}$	PM_{10}	NO_X	SO_2	OC	EC
Natural	225	441	773	250	2,214	424
Anthropogenic	596	62	1001	290	1,443	86
Total	821	503	1774	540	3,657	510

40 CFR 308(d)(3)(v)(E) of the Regional Haze Rule requires the long-term strategy to address smoke management techniques for agricultural and forestry burning. These two sources generally have a very small contribution to visibility impairment in North Dakota Class I areas except during the worst days in late July and August when organic carbon, an indicator of fire emissions, replaces sulfate and nitrate as the dominant contributor to

extinction. Much of these fire emissions are from wildfires, which fluctuate significantly from year to year. According to the source apportionment analyses conducted by the WRAP, anthropogenic fire emissions in North Dakota contribute less than 1% of the total sulfate and nitrate concentrations at Theodore Roosevelt and Lostwood. North Dakota found that the current smoke management rules are sufficient to achieve reasonable progress toward the national visibility goal but will reevaluate these rules in future planning periods.

f. Enforceability of North Dakota's Measures

40 CFR 51.308(d)(3)(v)(F) of the Regional Haze Rule requires States to ensure that emission limitations and control measures used to meet reasonable progress goals are enforceable. In addition to what is required by the Regional Haze Rule, general SIP requirements mandate that the SIP must also include adequate monitoring, recordkeeping, and reporting requirements for the regional haze emission limits and requirements. See CAA section 110(a). As noted, the SIP specifies BART and other emission limits and compliance schedules, and North Dakota has included such limits and compliance schedules in State-enforceable air quality permits that North Dakota has included in the SIP.[87] (*See* Appendix A and Appendix D of the SIP.) In addition to specifying the limits and compliance schedules, these permits specify monitoring, recordkeeping, and reporting requirements. North Dakota worked closely with EPA in developing these requirements. For SO_2 and NO_X limits, North Dakota has required 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, the SIP requires testing in accordance with EPA-approved test methods and compliance with a CAM plan approved as part of a Title V permit. The SIP requires that relevant records be kept for five years, and that sources report excess emissions on a quarterly basis.

In addition to these permits, various requirements that are relevant to regional haze are codified in North Dakota's regulations, including North Dakota's Regional Haze Rule (NDAC 33–15–25, contained in Appendix H of the SIP) and its Prevention of Signification Deterioration and other provisions mentioned above.

g. 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 sections V.J.3 above.

h. Periodic SIP Revisions and 5-Year Progress Reports

Consistent with 40 CFR 51.308(g), North Dakota committed to submit to EPA a progress report, in the form of a SIP revision, every five years following the initial submittal of the SIP. The report will evaluate progress towards the reasonable progress goal for each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State. These requirements and commitment are discussed in detail in section 11.2 of the North Dakota SIP.

6. Our Conclusion on North Dakota's Long Term Strategy

We propose to partially approve and partially disapprove North Dakota's long-term strategy. Because we are proposing to disapprove the NO_X BART determinations for Milton R. Young Station Units 1 and 2, Leland Olds Station Unit 2, and Coal Creek Station Units 1 and 2, we are also proposing to disapprove the corresponding permit limits and monitoring, recordkeeping, and reporting provisions that North Dakota relied on as part of its long-term strategy. Because we are proposing to disapprove the reasonable progress determination for Antelope Valley Station Units 1 and 2, we are also proposing to disapprove the long-term strategy because it does not include appropriate NO_X reasonable progress emission limits, compliance schedule, and corresponding monitoring, recordkeeping, and reporting requirements for Antelope Valley Station Units 1 and 2. Except for these elements, the long-term strategy satisfies the requirements of 40 CFR 51.308(d)(3), and we are proposing to approve it.

7. Partial FIP for Long Term Strategy

We are proposing regulatory language as part of our FIP that specifies emission limits, compliance schedules, and monitoring, recordkeeping, and reporting requirements for the following sources, requirements, and pollutants:

a. Milton R. Young Station Units 1 and 2, BART, NO_X.
b. Leland Olds Station Unit 2, BART, NO_X.
c. Coal Creek Units 1 and 2, BART, NO_X.
d. Antelope Valley Station Units 1 and 2, reasonable progress, NO_X.

We are proposing this regulatory language to fill the gap in the long-term strategy that would be left by our proposed partial disapproval of the long-term strategy. Our monitoring, recordkeeping, and reporting requirements generally mirror those imposed by North Dakota, except that all cross-references are to federal regulations only, we have modified some of the requirements from 40 CFR part 75, and we are not providing a separate limit for startup for Milton R. Young Station Units 1 and 2. We note that no other source or unit has requested or received a separate limit for startup, and we conclude that such a limit is not warranted. The 30-day averaging period for the limit already accounts for potential fluctuations due to properly-conducted startups, and nothing in North Dakota's record convinces us that Milton R. Young Station will be unable to comply with the BART limits we have selected.

K. Coordination of Reasonably Attributable Visibility Impairment and Regional Haze Requirements

Our visibility regulations direct states to coordinate their reasonably attributable visibility impairment long-term strategy and monitoring provisions with those for regional haze, as explained in section IV.F, above. Under our reasonably attributable visibility impairment regulations, the reasonably attributable visibility impairment portion of a state SIP must address any integral vistas identified by the Federal Land Managers 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 area. The Federal Land Managers did not identify any integral vistas in North Dakota. In addition, neither Class I area in North Dakota is experiencing reasonably attributable visibility impairment, nor are any North Dakota sources affected by the reasonably attributable visibility impairment provisions. The North Dakota Regional Haze SIP, in Sections 10.6.1 and 4.1, does address the two requirements regarding coordination of the regional haze long-term strategy and monitoring

[87] Because they are included in the SIP, these permits will remain unchanged for federal purposes unless and until North Dakota submits a change to permit terms as a SIP revision, and EPA approves such SIP revision.

provisions with the reasonably attributable visibility impairment long-term strategy and monitoring provisions. As noted in the Regional Haze SIP, North Dakota has previously made a commitment to address reasonably attributable visibility impairment should a Federal Land Manager certify visibility impairment from an individual source. See North Dakota visibility SIP revisions to address reasonably attributable visibility impairment, (NDAC 13–15–19, EPA approved September 28, 1988, 53 FR 37757), and Prevention of Signification Deterioration visibility provisions (NDAC 13–15–15, EPA approved July 19, 2007, 72 FR 39564). We propose to find that the Regional Haze SIP appropriately supplements and augments North Dakota's reasonably attributable visibility impairment visibility provisions by updating the monitoring and long-term strategy provisions to address regional haze. We discuss the relevant monitoring provisions further below.

L. Monitoring Strategy and Other SIP Requirements

40 CFR 51.308(d)(4) requires that the SIP 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 reasonably attributable visibility impairment. 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 reasonable progress goals to address regional haze for all mandatory Class I Federal areas within the state are being achieved. Consistent with EPA's monitoring regulations for reasonably attributable visibility impairment and regional haze, North Dakota indicates in Section 4.2 of the Regional Haze SIP that it will rely on the IMPROVE network for compliance purposes, in addition to any reasonably attributable visibility impairment monitoring that may be needed in the future. The IMPROVE monitors at the North Dakota Class I Areas also described in Section 4.2 of the SIP. We propose to find that North Dakota has satisfied the requirements in 40 CFR 51.308(d)(4) enumerated in this paragraph.

40 CFR 51.308(d)(4)(ii) requires that North Dakota establish procedures by which monitoring data and other information are used in determining the contribution of emissions from within North Dakota 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. We therefore propose that North Dakota has satisfied this requirement.

40 CFR 51.308(d)(4)(iv) requires that the SIP 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, North Dakota should report visibility monitoring data electronically. 40 CFR 51.308(d)(4)(vi) also requires that the SIP provide for other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility. We propose that North Dakota'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 North Dakota 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. The state must also include a commitment to update the inventory periodically. Please refer to section V.J.1, above, where we discuss North Dakota's emission inventory. North Dakota states in Section 4 of the SIP that it intends to update the North Dakota statewide emissions inventories periodically and review periodic emissions information from other states and future emissions projections. We propose that this satisfies the requirement.

M. Federal Land Manager Coordination

Lostwood is managed by the Fish and Wildlife Service, and Theodore Roosevelt is managed by the National Park Service; these are the respective Federal Land Managers for these North Dakota Class I areas. Although the Federal Land Managers are very active in participating in the regional planning organizations, the Regional Haze Rule grants the Federal Land Managers a special role in the review of the regional haze SIPs, summarized in section IV.H, above. The Federal Land Managers and the state environmental agencies are our partners in the regional haze process.

Under 40 CFR 51.308(i)(2), North Dakota was obligated to provide 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 SIP. North Dakota sent a draft of its Regional Haze SIP to the Fish and Wildlife Service and the National Park Service on August 9, 2009 and at the same time notified the Federal Land Managers of the State's January 7, 2010 public hearing.

40 CFR 51.308(i)(3) requires that North Dakota provide in its Regional Haze SIP a description of how it addressed any comments provided by the Federal Land Managers. The Federal Land Managers communicated to the State (and EPA) their dissatisfaction with the BART determinations for Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2 among other issues. They expressed their view that SCR, instead of SNCR, is NO_X BART for these sources. The Federal Land Managers also disagreed with North Dakota's rejection of reasonable progress controls. North Dakota responded to the Federal Land Managers' comments and concerns in Appendix J of the Regional Haze SIP.

Lastly, 40 CFR 51.308(i)(4) specifies the regional haze SIP must provide procedures for continuing consultation between the State and Federal Land Managers 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. North Dakota commits in Section 11 of its Regional Haze SIP to continue to coordinate and consult with the Federal Land Managers as required by 40 CFR 51.308(i)(4). North Dakota states that it intends to consult the Federal Land Managers 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 North Dakota and other Class I areas.

While we disagree with the substance of North Dakota's decisions regarding NO_X BART for Milton R. Young Station

Units 1 and 2, Leland Olds Station Unit 2, and Coal Creek Station Units 1 and 2, and reasonable progress controls for NO_X for AVS Units 1 and 2, we are proposing that the State complied with the requirements of 40 CFR 51.308(i).

N. Periodic SIP Revisions and Five-year Progress Reports

North Dakota commits in Section 11 of the SIP to complete items required in the future by the Regional Haze Rule. North Dakota acknowledged its obligation under 40 CFR 51.308(f) to submit periodic progress reports and Regional Haze SIP revisions, with the first report due by July 31, 2018 and every ten years thereafter.

North Dakota acknowledged its obligation under 40 CFR 51.308(g) to submit a progress report in the form of a SIP revision to us every five years following the initial submittal of the Regional Haze SIP. The report will evaluate the progress made towards the reasonable progress goals for each mandatory Class I area located within North Dakota and in each mandatory Class I area located outside North Dakota that may be affected by emissions from within North Dakota.

VI. Our Analysis of North Dakota's Interstate Visibility Transport SIP Provisions

In July 1997, EPA promulgated the 1997 8-hour ozone NAAQS and the 1997 $PM_{2.5}$ NAAQS. Sections 110(a)(1) and (2) of the CAA require states to submit SIPs that provide for the implementation, maintenance, and enforcement of a new or revised NAAQS within three years following the promulgation of the new or revised standard. Thus, states were required to submit SIPs that satisfy the applicable requirements under sections 110(a)(1) and (2), including the requirements of section 110(a)(2)(D)(i), by July 2000. Among other things, section 110(a)(2)(D)(i) requires states to make a submission that establishes that the state's SIP contains adequate provisions to prevent interference with measures required to be included in the SIPs of other states to protect visibility. A state could establish the adequacy of its SIP for this purpose by demonstrating that existing provisions prevent such interference, by adding new provisions to prevent such interference, or by a combination of existing and new provisions.

States, including North Dakota, did not meet the statutory July 2000 deadline for submission of these SIPs. Accordingly, on April 25, 2005, EPA made findings of failure to submit, notifying all states, including North Dakota, of their failure to make the required SIP submission to address interstate transport under section 110(a)(2)(D)(i). 70 FR 21147. This finding started a 24-month FIP clock under section 110(c). Pursuant to section 110(c), EPA is required to promulgate a FIP to address the applicable interstate transport requirements, unless a state makes the required submission and EPA fully approves such submission, within the 24-month period. As noted earlier, EPA was sued by WildEarth Guardians for failing to meet its statutory FIP obligation for North Dakota by the applicable deadline in April of 2007, and is thus under a consent decree deadline to take the necessary SIP approval or FIP action.

EPA issued the 2006 Guidance to make recommendations to states about how to make SIP submissions for purposes of section 110(a)(2)(D)(i), including the visibility prong. Acknowledging that the regional haze SIPs were still under development and were not due until December 17, 2007, we recommended that states could make a SIP submission confirming that it was not possible at that point in time to assess whether there was any interference with measures in the applicable SIP for another state designed to ''protect visibility'' for the 1997 8-hour ozone NAAQS and the 1997 $PM_{2.5}$ NAAQS. We note that our 2006 Guidance was based on the premise that as of the time of its issuance in August 2006, it was reasonable for EPA to recommend that states could merely indicate that the imminent regional haze SIP would be the appropriate means to establish that its SIP contained adequate provisions to prevent interference with the visibility programs required in other states. Subsequent events have demonstrated that we were mistaken in our assumptions that all states would submit regional haze SIPs by December of 2007, and mistaken in our assumption that all such submissions would meet applicable regional haze program requirements and therefore be approved shortly thereafter. Our 2006 Guidance was intended to make recommendations that were relevant at that point in time, and subsequent events have rendered it inappropriate in this specific action. EPA's 2006 Guidance was not intended to delay indefinitely the consideration of impacts on other states' Class I areas, or to allow the states' failure to submit regional haze SIPs on time, or to submit approvable regional haze SIPs, to provide an excuse for failing to analyze those impacts in a reasonable way. At this point in time, EPA must review the submission from the State in light of the actual facts and in light of the statutory requirements of section 110(a)(2)(D)(i)(II).

North Dakota submitted a SIP on April 6, 2009, intended to address all four prongs of the interstate transport requirements of CAA 110(a)(2)(D)(i) for the 1997 8-hour ozone NAAQS and the 1997 $PM_{2.5}$ NAAQS. With respect to the visibility prong section in 110(a)(2)(D)(i)(II), North Dakota merely stated that it was at that time working with the WRAP, including associated states and stakeholders, to prepare a regional haze SIP. However, North Dakota did not explicitly state in its April 6, 2009, submittal that it intended that its Regional Haze SIP be used to satisfy the visibility prong, nor did it include such a statement in its Regional Haze SIP ultimately submitted or in the Governor's letter that accompanied it. The state also did not make any other SIP submission indicating that intended to meet the requirements of section 110(a)(2)(D)(i)(II) by any other means. However, the state did not make the Regional Haze SIP by the deadline for such submissions, and the Regional Haze SIP itself does not fully meet the requirements of the regional haze program. Hence, we are not able to consider the Regional Haze SIP in determining the adequacy of North Dakota's SIP vis-à-vis the visibility prong of 110(a)(2)(D)(i). Instead, we are considering only the adequacy of North Dakota's April 6, 2009 submittal to address the visibility prong.

The visibility prong, contained in CAA section 110(a)(2)(D)(i)(II), requires that states submit a SIP revision containing provisions ''prohibiting any source or other type of emission activity within the state from emitting any air pollutant in amounts which will * * * interfere with measures required to be included in the applicable implementation plan for any other State under part C [of the CAA] to protect visibility.'' Because of the impacts on visibility from the interstate transport of pollutants, we interpret the ''good neighbor'' provisions of section 110 of the Act described above as requiring states to include in their SIPs either measures to prohibit emissions that would interfere with the reasonable progress goals required to be set to protect Class I areas in other states, or a demonstration that emissions from North Dakota sources and activities will not have the prohibited impacts.

The State's April 6, 2009 SIP submission did contain some statements concerning the requirements of the visibility prong of section 110(a)(2)(D)(i). Section 7.8 of North Dakota's submission generally describes the requirements of CAA section 110(a)(2)(D)(i). With respect to the visibility prong, Section 7.8 states the following:

"In the review process for new or modified stationary sources, or other types of emissions activities, the Department will assess the impact on neighboring states. * * * With respect to visibility, an assessment on Prevention of Signification Deterioration Class I area's visibility will be made when a significant impact is suspected."

It is evident that the State intended this provision to address interstate visibility impacts of emissions from new or modified sources. This provision was not intended, and is not sufficient, to satisfy the requirements of the visibility prong regarding the interstate impacts on visibility of emissions from existing North Dakota sources.

Section 7.8.1.D of the SIP specifically addresses interstate visibility impacts from existing sources. First, it cites language from EPA's 2006 Guidance regarding CAA section 110(a)(2)(D)(i) [88] that reads as follows:

"At this point in time, EPA has made no determination that emissions from any State interfere with measures required to be included in a plan to address reasonably attributable visibility impairment. Further, EPA is not aware of any certification of existing reasonably attributable impairments of visibility by a Federal Land Manager that has not already been resolved. The EPA accordingly believes that States should be able to make a relatively simple SIP submission verifying that no source within the State emits pollutants that interfere with measures included in the visibility SIPs under the 1980 regulations."

The State responded to EPA's 2006 Guidance by concluding in Section 7.8.1.D, that "there are no North Dakota sources of emissions that interfere with implementation of visibility SIP [sic] under the 1980 regulations." We find North Dakota's conclusion to be reasonable in so far as it addressed the issue of potential adverse visibility impacts as contemplated in the 1980 regulations. However, EPA's 2006 Guidance also recommended that states address regional haze SIPs under EPA's regional haze regulations, and the statute requires a determination with respect to measures required in the SIPs of other states.

Noting that the regional haze SIPs were not due until December 17, 2007 (over a year after the 2006 Guidance was issued), EPA stated that "[t]he States and Regional Planning Organizations are currently engaged in the task of identifying those Class I areas impacted by each State's emissions and developing strategies for addressing regional haze to be included in the States' regional haze SIPs." Thus, EPA indicated that "it is currently premature" to determine whether a state's SIP contains adequate provisions to prohibit emissions that interfere with measures in other states' regional haze SIPs. EPA concluded by saying, "Accordingly, EPA believes that States may make a simple SIP submission confirming that it is not possible at this time to assess whether there is any interference with measures in the applicable SIP for another State designed to 'protect visibility' for the 8-hour ozone and $PM_{2.5}$ NAAQS until regional haze SIPs are submitted and approved." Thus, EPA's recommendation to states as of that particular point in time was that they refer to the imminent regional haze SIP submission as the means by which they could address the visibility prong of section 110(a)(2)(D)(i).

Apparently keying off this recommendation, North Dakota included the following statement regarding visibility transport and regional haze in Section 7.8.1.D:

"The State of North Dakota is working with the Western Regional Air Partnership, including associated States and stakeholders, to prepare a SIP to address the EPA Regional Haze regulation (40 CFR 51.308). Until regional haze SIPs are submitted and approved, North Dakota believes it is not possible at this time to assess whether there is any interference with measures in the applicable SIP for another state for regional haze."

The State's April 6, 2009 SIP submission contains no other statements or analysis regarding the impact of emissions from North Dakota sources on visibility programs in other states, and in particular no other statements concerning impacts on the regional haze program in other states.

North Dakota's April 6, 2009 SIP submission thus suggested that the State intended to address the requirements of section 110(a)(2)(D)(i)(II) by a timely submission of its regional haze SIP by December of 2007, but due to intervening circumstances the State did not in fact make that submission until March 3, 2010. Moreover, while North Dakota ultimately did submit the Regional Haze SIP to address the requirements of the regional haze program directly, North Dakota did not explicitly specify that it was submitting the Regional Haze SIP revision to satisfy the visibility prong of 110(a)(2)(D)(i)(II). Most importantly, however, EPA must review the April 6, 2009 submission in light of the current facts and circumstances, and the Regional Haze SIP revision that the State ultimately submitted does not fully meet the substantive requirements of the regional haze program. The State made no other SIP submission in which it indicated that it intended to meet the visibility prong of section 110(a)(2)(D)(i)(II) in any other way.

Accordingly, we are proposing to disapprove North Dakota's April 6, 2009 SIP submittal for the visibility prong of section 110(a)(2)(D)(i)(II), because that submittal neither contains adequate measures to eliminate emissions that would interfere with the required visibility programs in other states, nor a demonstration that the existing North Dakota SIP already includes measures sufficient to eliminate such prohibited impacts. To the extent that the State intended to meet the requirement of section 110(a)(2)(D)(i)(II) with the Regional Haze SIP, the Regional Haze SIP submission itself is not fully approvable.

VII. FIP for Interstate Visibility Transport

Because we are proposing to disapprove North Dakota's April 6, 2009 SIP submission with respect to the visibility prong of section 110(a)(2)(D)(i)(II), we are proposing a FIP to fill the gap that would be left by our proposed disapproval. As an initial matter, we note that section 110(a)(2)(D)(i)(II) does not explicitly specify how we should ascertain whether a state's SIP contains adequate provisions to prevent emissions from sources in that state from interfering with measures required in another state to protect visibility. Thus, the statute is ambiguous on its face, and we must interpret that provision.

Our 2006 Guidance recommended that a state could meet the visibility prong of the transport requirements of section 110(a)(2)(D)(i)(II) of the CAA by submission of the regional haze SIP, due in December 2007. Our reasoning was that the development of the regional haze SIPs was intended to occur in a collaborative environment among the states. In fact, in developing their respective reasonable progress goals, WRAP states consulted with each other through WRAP's work groups. As a result of this process, the common understanding was that each state would take action to achieve the emissions reductions relied upon by other states in their reasonable progress

[88] "Guidance for State Implementation Plan Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8–Hour Ozone and $PM_{2.5}$ National Ambient Air Quality Standards."

demonstrations under the Regional Haze Rule. WRAP states consulted in the development of reasonable progress goals, using the products of this technical consultation process to co-develop their reasonable progress goals. In developing their visibility projections using photochemical grid modeling, WRAP states assumed a certain level of emissions from sources within North Dakota that coincided with North Dakota's BART determinations and North Dakota's existing controls for other sources. Although we have not yet received all regional haze SIPs, we understand that the WRAP states used the visibility projection modeling to establish their own respective reasonable progress goals. Thus, we believe that an implementation plan that provides for emissions reductions consistent with the assumptions used in those states' modeling is one means to ensure that emissions from North Dakota sources do not interfere with the measures designed to protect visibility in other states.

North Dakota's Regional Haze SIP submission includes BART determinations and reasonable progress conclusions that are consistent with the information and assumptions North Dakota provided to the WRAP and that other states will have relied upon in the development of their own regional haze SIPs. Therefore, North Dakota's Regional Haze SIP, as submitted to us, would have been sufficient to obtain North Dakota's needed share of emission reductions for interstate transport purposes for visibility, if it had been submitted to us for that purpose and if it were fully approvable. However, as already noted, North Dakota did not specify that it intended to submit its Regional Haze SIP to meet the visibility prong of CAA section 110(a)(2)(D)(i)(II). In addition, we are proposing to disapprove North Dakota's NO_X BART determinations for Milton R. Young Station 1 and 2, Leland Olds Station 2, and Coal Creek Station Units 1 and 2 and North Dakota's NO_X reasonable progress determination for Antelope Valley Station Units 1 and 2, and instead proposing a FIP for purposes of the regional haze program. Thus, we are proposing a FIP to meet the visibility prong of CAA section 110(a)(2)(D)(i)(II) that relies on the combination of the North Dakota Regional Haze SIP provisions that we are proposing to approve and the additions to the regional haze program for North Dakota that we are proposing in our FIP for NO_X BART for Milton R. Young Station Units 1 and 2, Leland Olds Station Unit 2, and Coal Creek Station Units 1 and 2 and NO_X reasonable progress for Antelope Valley Station Units 1 and 2. Because this combination exceeds the stringency of BART and reasonable progress limits that were already factored into the WRAP modeling for reasonable progress goals, we propose that this combination meets the visibility prong of CAA section 110(a)(2)(D)(i)(II). We propose to find that this combination of regional haze controls will ensure that emissions from sources in North Dakota do not interfere with other states' visibility programs as required by section 110(a)(2)(D)(i)(II) of the CAA.

VIII. Proposed Actions

A. Regional Haze

We are proposing to partially approve and partially disapprove North Dakota's Regional Haze SIP revision that was submitted on March 3, 2010, SIP Supplement No. 1 that was submitted on July 27, 2010, and part of SIP Amendment No. 1 that was submitted on July 28, 2011. Specifically, we are proposing to disapprove the following:

○ North Dakota's NO_X BART determinations and emissions limits for Milton R. Young Station Units 1 and 2, Leland Olds Station Unit 2, and Coal Creek Station Units 1 and 2.

○ North Dakota's determination under the reasonable progress requirements found at section 40 CFR 51.308(d)(1) that no additional NO_X emissions controls are warranted at Units 1 and 2 of Basin Electric Power Cooperative's Antelope Valley Station.

○ North Dakota's reasonable progress goals.

○ Portions of North Dakota's long-term strategy that rely on or reflect other aspects of the Regional Haze SIP we are proposing to disapprove.

We are proposing to approve the remaining aspects of North Dakota's Regional Haze SIP revision that was submitted on March 3, 2010 and SIP Supplement No. 1 that was submitted on July 27, 2010. We are proposing to approve the following parts of SIP Amendment No. 1 that the State submitted on July 28, 2011: (1) Amendments to Section 10.6.1.2 pertaining to Coyote Station, and (2) amendments to Appendix A.4, the Permit to Construct of Coyote Station. We are not proposing action on the remainder of the July 28, 2011 submittal at this time.

We are proposing the promulgation of a FIP to address the deficiencies in the North Dakota Regional Haze SIP that we have identified in this proposal.

The proposed FIP includes the following elements:

- NO_X BART determinations and emission limits for Milton R. Young Station Units 1 and 2 and Leland Olds Station Unit 2 of 0.07 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.
- NO_x BART determination and emission limit for Coal Creek Station Units 1 and 2 of 0.12 lb/MMBtu that applies singly to each of these units on a 30-day rolling average, but inviting comment on whether 0.14 lb/MMBtu should be the limit instead, 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.
- A reasonable progress determination and NO_X emission limit for Antelope Valley Station Units 1 and 2 of 0.17 lb/MMBtu that applies singly to each of these units on a 30-day rolling average, and a requirement that the owner/operator meet the limit by July 31, 2018.
- Monitoring, recordkeeping, and reporting requirements for the above seven units to ensure compliance with these emission limitations.
- Reasonable progress goals consistent with the SIP limits proposed for approval and proposed FIP limits.
- Long-term strategy elements that reflect the other aspects of the proposed FIP.

In lieu of this proposed FIP, or portion thereof, we are proposing approval of a SIP revision if the State submits such a revision in a timely way, and the revision matches the terms of our proposed FIP, or relevant portion thereof.

B. Interstate Transport of Visibility

We are also proposing to disapprove a portion of a SIP revision submitted by the State of North Dakota for the purpose of addressing the ''good neighbor'' provisions of the CAA section 110(a)(2)(D)(i) for the 1997 8-hour ozone NAAQS and the 1997 $PM_{2.5}$ NAAQS. Specifically, we propose to disapprove the portion of the April 6, 2009, SIP in which North Dakota intended to address the requirement of section 110(a)(2)(D)(i)(II) that emissions from North Dakota sources do not interfere with measures required in the SIP of any other state under part C of the CAA to protect visibility. Because of this proposed disapproval, we also need to propose a FIP to meet this requirement of section 110(a)(2)(D)(i)(II). To meet this FIP duty, we are proposing to find that North Dakota sources will be sufficiently controlled to eliminate interference with the visibility programs of other states by a combination of the measures that we are simultaneously proposing to approve as meeting the regional haze SIP requirements combined with the additional measures that we are proposing to impose in a FIP to meet the remaining regional haze SIP requirements.

IX. 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 four facilities. 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 four 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. The FIP that EPA is proposing for purposes of the visibility prong of section 110(a)(2)(D)(i)(II) consists of the combination of the proposed approval of the state'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 NO_X emissions on specific units at three sources in North Dakota, and imposing controls to meet the reasonable progress requirement for NO_X emissions at one additional source in North Dakota. The net result of these two simultaneous FIP actions is that EPA is proposing direct emission controls on selected units at only four sources. The sources in question are each large electric generating plants that 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 1 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 1 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. 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, 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 from four facilities in North Dakota. The 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.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Nitrogen dioxides, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide, Volatile organic compounds.

Dated: September 1, 2011.

James B. Martin,

Regional Administrator, EPA, 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 JJ—North Dakota

2. Section 52.1820 is amended as follows:

a. In paragraph (c) by adding entries to the end of the table.

b. In paragraph (d) by adding entries to the end of the table.

c. Adding paragraphs (e)(23) through (e)(25).

§ 52.1820 Identification of plan.

* * * * *

(c) * * *

STATE OF NORTH DAKOTA REGULATIONS

State citation	Title/subject	State effective date	EPA approval date and citation	Explanations
*	*	*	*	* * *

33–15–25 REGIONAL HAZE REQUIREMENTS

State citation	Title/subject	State effective date	EPA approval date and citation [1]	Explanations
33–15–25–01	Definitions	1/1/07		
33–15–25–02	Best Available Retrofit Technology	1/1/07		
33–15–25–03	Guidelines for Best Available Retrofit Technology Determinations Under the Regional Haze Rule.	1/1/07		
33–15–25–04	Monitoring, Recordkeeping, and Reporting	1/1/07		

[1] In order to determine the EPA effective date for a specific provision listed in this table, consult the **Federal Register** notice cited in this column for the particular provision.

(d) * * *

Name of source	Nature of requirement	State effective date	EPA approval date and citation [3]	Explanations
*	*	*	*	* * *
Leland Olds Station Units 1 and 2.	Air Pollution Control Permit to Construct for Best Available Retrofit Technology (BART).	2/23/10		Excluding the NO_X BART limits for Unit 2 and corresponding monitoring, recordkeeping, and reporting requirements, which EPA is proposing to disapprove.
Milton R. Young Station Units 1 and 2.	Air Pollution Control Permit to Construct for Best Available Retrofit Technology (BART).	2/23/10		Excluding the NO_X BART limits for Units 1 and 2 and corresponding monitoring, recordkeeping, and reporting requirements, which EPA is proposing to disapprove.
Coal Creek Station Units 1 and 2.	Air Pollution Control Permit to Construct for Best Available Retrofit Technology (BART).	2/23/10		Excluding the NO_X BART limits for Units 1 and 2 and corresponding monitoring, recordkeeping, and reporting requirements, which EPA is proposing to disapprove.
Stanton Station Unit 1	Air Pollution Control Permit to Construct for Best Available Retrofit Technology (BART).	2/23/10		
Heskett Station Unit 2	Air Pollution Control Permit to Construct, PTC10028.	7/22/10		
Coyote Station Unit 1	Air Pollution Control Permit to Construct, PTC10008.	3/14/11		

[3] In order to determine the EPA effective date for a specific provision listed in this table, consult the **Federal Register** notice cited in this column for the particular provision.

(e) * * *

Name of nonregulatory SIP provision	Applicable geographic or non-attainment area	State submittal date/adopted date	EPA approval date and citation [3]	Explanations
*	*	*	*	*
(23) North Dakota State Implementation Plan for Regional Haze.	Statewide	Submitted: 3/3/10		Excluding [provisions we are disapproving and anything superseded].
(24) North Dakota State Implementation Plan for Regional Haze Supplement No. 1.	Statewide	Submitted: 7/27/10		Excluding [provisions we are disapproving and anything superseded].
(25) North Dakota State Implementation Plan for Regional Haze Amendment No. 1.	Statewide	Submitted: 7/28/11		Excluding [provisions we are not acting on].

[3] In order to determine the EPA effective date for a specific provision listed in this table, consult the **Federal Register** notice cited in this column for the particular provision.

3. New § 52.1825 is added to read as follows:

§ 52.1825 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 North Dakota: Milton R. Young Station, Units 1 and 2; Leland Olds Station, Unit 2; Coal Creek Station, Units 1 and 2; Antelope Valley Station, Units 1 and 2.

(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 NO_X emissions, other pollutant emissions, diluent, or stack gas volumetric flow rate.

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.

Unit means any of the EGUs identified in paragraph (a) of this section.

(c) *Emissions limitations*—(1) The owners/operators subject to this section shall not emit or cause to be emitted 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	NO_X Emission limit (lb/MMBtu)
Milton R. Young Station, Unit 1	0.07
Milton R. Young Station, Unit 2	0.07
Leland Olds Station Unit 2	0.07
Coal Creek Station, Unit 1	0.12
Coal Creek Station, Unit 2	0.12
Antelope Valley Station, Unit 1	0.17
Antelope Valley Station, Unit 2	0.17

(2) These emission limitations shall apply at all times, including startups, shutdowns, emergencies, and malfunctions.

(d) *Compliance date.* The owners and operators subject to this section shall comply with the emissions limitations and other requirements of this section by March 11, 2017 unless otherwise indicated in specific paragraphs.

(e) *Compliance determination*—(1) CEMS. 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 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.* (i) For any hour in which fuel is combusted in a unit, the owner/operator of each unit shall calculate the hourly average 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 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 NO_X pollutant concentration monitor 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.

(f) *Recordkeeping.* 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.

(g) *Reporting.* All reports under this section 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 shall submit quarterly excess emissions reports no later than the 30th day following the end of each calendar quarter. Excess emissions means emissions that exceed the emissions limits specified in

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 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, any CEMS repairs or adjustments, and results of any CEMS performance tests required by 40 CFR part 75 (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 report.

(h) *Notifications.* (1) Owner/operator shall submit notification of commencement of construction of any equipment which is being constructed to comply with the 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.

(i) *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.

(j) *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.

[FR Doc. 2011–23372 Filed 9–20–11; 8:45 am]

BILLING CODE 6560–50–P