# ATTACHMENT 1

# SOUTH DAKOTA REGIONAL HAZE STATE IMPLEMENTATION PLAN, SECTION 6.0, BEST AVAILABLE RETROFIT TECHNOLOGY

# SOUTH DAKOTA'S

# REGIONAL HAZE

# STATE IMPLEMENTATION PLAN

South Dakota Department of Environment and Natural Resources

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## Executive Summary

The Department of Environment and Natural Resources (DENR) worked with the Western Regional Air Partnership (WRAP), states not members of WRAP, federal land managers, the Environmental Protection Agency (EPA), the regulated community, and others to develop this document as part of South Dakota's Regional Haze State Implementation Plan (SIP). This document along with the applicable Administrative Rules of South Dakota (ARSD) and the addition of ARSD, Chapter 74:36:21 will be South Dakota's Regional Haze State Implementation Plan and implemented by DENR to ensure South Dakota's Regional Haze Program meets the goal of achieving natural conditions in the Badlands and Wind Cave National Parks by 2064 as specified in Title 40 of the Code of Federal Regulations (CFR) §51.308.

Chapter 1 provides background information on the initial federal visibility protection program, describes the causes of visibility impairment, and describes the new federal regional haze program regulations. Chapter 2 provides information on South Dakota's two Class I areas. The two Class I areas are the Badlands National Park and Wind Cave National Park and both are located in the western third of South Dakota.

Chapter 3 describes the process DENR followed to determine natural conditions, baseline conditions, and the uniform rate of improvement for both Class I areas. Chapter 4 discusses the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring data for both Class I areas. This chapter looked at the aerosols impacting both Class I areas, what time of year they occur, and if they are increasing or decreasing over time.

Chapter 5 describes South Dakota's emission inventory for past, present, and future air emission inventories in South Dakota, what type of activities are emitting the air emissions, and if the air emissions are generated within South Dakota or from neighboring states and countries. Chapter 6 describes the BART review DENR conducted and establishes the BART requirements for the BART-eligible sources in South Dakota. The BART review covers an analysis to determine BART-eligible sources, a modeling analysis to determine if the BART-eligible source contributes to visibility impairment in a Class I area, and the establishment of BART for those BART-eligible sources that reasonably contribute to visibility impairment in any Class I area.

The BART review identified one electrical generating unit subject to the BART requirements. Otter Tail Power Company's Big Stone I facility determined that it reasonably contributes to visibility impairment in Class I areas. DENR determined the control equipment considered BART for Big Stone I is the existing baghouse, a semi-dry flue gas desulfurization system, and selective catalytic reduction. The installation of the new control equipment and establishment of BART emission limits, compliance demonstration, recordkeeping, and reporting requirements will be established in an air quality construction permit and eventually in Otter Tail Power Company's Title V air quality operating permit. The installation of the new control equipment and other requirements will be completed within five years of EPA's approval of South Dakota's Regional Haze State Implementation Plan.

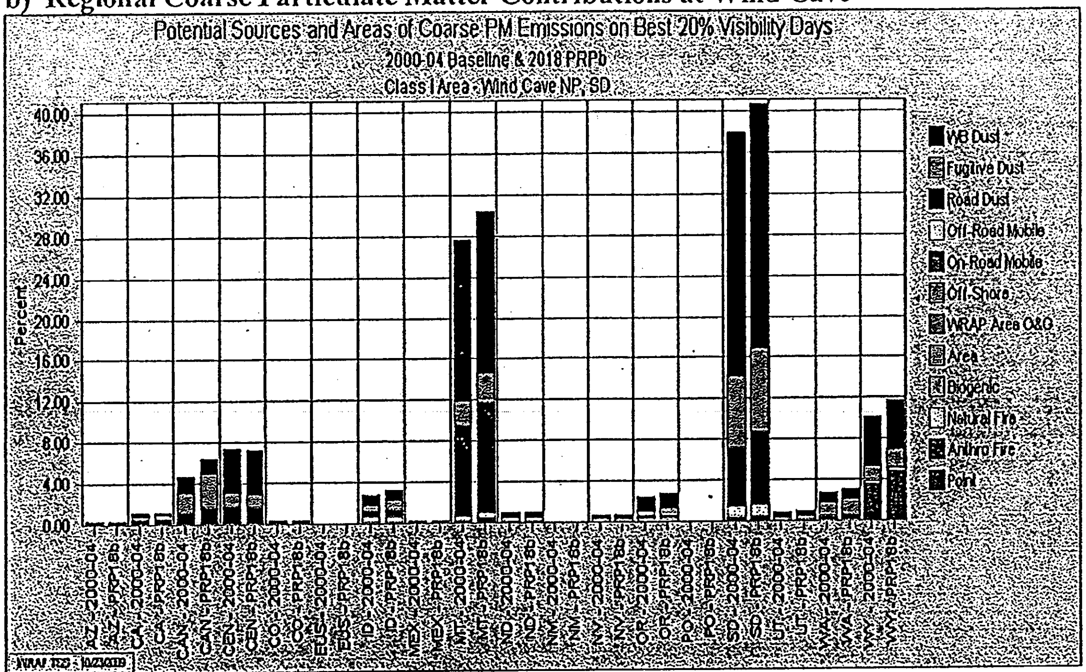
Chapter 7 discusses South Dakota's goals for demonstrating reasonable progress such as outlining existing rules that already help minimize air emissions that cause visibility impairment and the modeling WRAP conducted of the western United States to determine if states are meeting the reasonable progress goals in 2018. Sulfur dioxide emissions in South Dakota from 2002 through 2018 are expected to decline by 36%, nitrogen oxides emissions are expected to decline by 18%, organic carbon mass emissions are expected to decline by 6%, and elemental carbon emissions are expected to decline by 49%. Other states will also experience a reduction in air emissions that reasonably contribute to visibility impairment in Class I areas. Overall, sulfur dioxide emissions during the same time period are expected to decline by 26%, nitrogen oxide emissions are expected to decline by 29%, organic carbon mass are expected to decline by 6%, and elemental carbon emissions are expected to decline by 31%. These reductions are expected to demonstrate reasonable progress is being made to improve visibility at all Class I areas.

Chapter 8 describes South Dakota's long-term goals in achieving natural conditions by 2064. It also outlines DENR's proposed rules (ARSD, Chapter 74:36:21) to ensure new sources and modifications to existing sources will not reasonably contribute to visibility impairment at any Class I area. In addition, DENR will review, develop, and implement a Smoke Management Plan to address wildfires and prescribed fires.

Chapter 9 discusses DENR's monitoring plan for tracking our progress in achieving natural conditions by 2064. Chapter 10 describes the consultation DENR went through with federal land managers, states, and the public, how DENR responded to each comment, and their future involvement.

Chapter 11 describes the reviews and reporting DENR will perform to track South Dakota's progress in attaining natural conditions by 2064.

**b) Regional Coarse Particulate Matter Contributions at Wind Cave**




(WRAP TSS – http://vista.cira.colostate.edu/tss/)

# 6.0 Best Available Retrofit Technology (BART)

## 6.1 Bart-Eligible Sources

In accordance with 40 CFR § 51.308(e), South Dakota's State Implementation Plan is required to contain emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I area. A BART-eligible source is an existing stationary facility that is any of the following stationary sources of air pollutant that was not in operation prior to August 7, 1962, was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. Fugitive emissions must be included in the potential to emit, to the extent quantifiable.

1. Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input,
2. Coal cleaning plants (thermal dryers),
3. Kraft pulp mills,
4. Portland cement plants,
5. Primary zinc smelters,
6. Iron and steel mill plants,
7. Primary aluminum ore reduction plants,
8. Primary copper smelters,
9. Municipal incinerators capable of charging more than 250 tons of refuse per day,

10. Hydrofluoric, sulfuric, and nitric acid plants,
11. Petroleum refineries,
12. Lime plants,
13. Phosphate rock processing plants,
14. Coke oven batteries,
15. Sulfur recovery plants,
16. Carbon black plants (furnace process),
17. Primary lead smelters,
18. Fuel conversion plants,
19. Sintering plants,
20. Secondary metal production facilities,
21. Chemical process plants,
22. Fossil-fuel boilers of more than 250 million British thermal units per hour heat input,
23. Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
24. Taconite ore processing facilities,
25. Glass fiber processing plants, and
26. Charcoal production facilities.

In February 2004, DENR followed the procedures in 40 CFR Part 51, Appendix Y in identifying emission units at stationary facilities in South Dakota meeting the above categories, identifying the startup date of the emission units, comparing the potential emissions to the 250 tons per year cutoff, and identifying the emissions units and pollutants that constitute the BART-eligible sources. The following terms are defined below:

1. "In Operation" means engaged in activity related to the primary design function of the source. The date the unit is permitted is not important to meet this test because the focus is on actual operation of the unit;
2. "In Existence" means that the owner or operator has obtained all necessary preconstruction approvals or permits required by federal, state, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time;
3. "Date of Reconstruction" must occur during the August 7, 1962 to August 7, 1977 time period; and
4. "Potential to Emit" means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source. However, fugitive emissions, to the extent quantifiable, must be counted for the 26 categories.

In accordance with 40 CFR § 51.308(e)(1)(i), Table 6-1 provides a list of existing stationary facilities from the February 2004 analysis that may be considered a BART-eligible source and need further investigation to determine if they are subject to BART.

*Table 6-1– List of BART-Eligible Sources [1]*

| Unit | Date | Maximum Capacity | Potential to Emit TSP | $SO_2$ | NOx | VOC | BART Eligible |
|---|---|---|---|---|---|---|---|
| **Northern States Power Company – Sioux Falls** | | | | | | | |
| #1 – Babcock boiler | 1969 | 330 MMBtus/hr | 7 | 1 | 795 | 2 | Yes |
| #2 – Babcock boiler | 1969 | 330 MMBtus/hr | 7 | 1 | 795 | 2 | Yes |
| #3 – Babcock boiler | 1969 | 330 MMBtus/hr | 7 | 1 | 795 | 2 | Yes |
| **Total =** | | **990 MMBtus/hr** | **21** | **3** | **2,385** | **6** | **Yes** |
| **Pete Lien and Sons, Inc. – Rapid City** | | | | | | | |
| #6 – Vertical kiln | 1966 | - | 561 | 0 | 13 | 1 | Yes |
| #7 – Pebble lime crusher | 1970 | - | 1 | 0 | 0 | 0 | Yes |
| #8 – Large hydrator | 1965 | - | 97 | 0 | 0 | 0 | Yes |
| #12 – Lime bagging | 1963 | - | 48 | 0 | 0 | 0 | Yes |
| **Total =** | | | 707 | 0 | 13 | 1 | Yes |
| **Otter Tail Power Company – Big Stone I Power Plant** | | | | | | | |
| #1 – Babcock boiler | 1975 | 5,609 MMBtus/hr | 300 | 19,863 | 17,179 | 125 | Yes |

[1] – "TSP" means total suspended particulate, "$SO_2$" means sulfur dioxide, "NOx" means nitrogen oxide, and "VOCs" means volatile organic compounds.

In accordance with 40 CFR Part 51, Appendix Y, the next step is to identify those BART-eligible sources that may "*emit any pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility.*" For each source subject to BART, DENR is required to identify the best system of continuous emission control technology for each source after considering the following as specified in section 169A(g)(2) of the federal CAA:

1. Cost 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 visibility improvement which may reasonably be anticipated from the use of BART.

The results of the BART review are required to be submitted in the Regional Haze State Implementation Plan identifying the BART emission limitations and timeline for demonstrating compliance. The timeline for demonstrating compliance shall not exceed five years after EPA approves the Regional Haze State Implementation Plan. DENR may establish design, equipment, work practice or other operational standards when limitations on measurement technologies make emission standards infeasible.

### 6.1.1 Northern States Power Company – Sioux Falls

The three units at Northern States Power Company in Sioux Falls, South Dakota is considered fossil-fuel fired steam electric plant. The units were built in 1969 and have a maximum capacity greater than 250 million Btus per hour per unit. However, Northern States Power Company decommissioned these three units and they are no longer permitted to operate in Northern States Power Company's Title V air quality permit. Therefore, these three units at Northern States Power Company's Sioux Falls site are not subject to BART.

### 6.1.2 Pete Lien and Sons, Inc. – Rapid City

Pete Lien and Sons operates a limestone quarry operation and lime plant in northwest Rapid City. There are four operations that were identified in the February 2004 analysis, not in operation prior to August 7, 1962, and in existence on August 7, 1977. The four operations are a 1966 vertical kiln, 1970 pebble lime crusher, 1965 large hydrator, and 1963 lime bagging operation. Only the 1966 vertical kiln has the potential to emit over the 250 tons per year threshold.

As identified in Pete Lien and Sons' existing Title V air quality permit issued November 12, 2008, the 1970 pebble lime crusher was replaced with a 1982 pebble lime crusher and the 1963 bagging operation was replaced with a 2004 lime bagging operation. Therefore, these two units will not be evaluated further.

Pete Lien and Sons falls under the "lime plant" category listed above. DENR researched the definition of "lime plant" to determine if the large hydrator is included in the definition of a lime plant. DENR determined that typically the definition for the 26 categories coincides with the definitions under the New Source Performance Standards. Under 40 CFR Part 60, Subpart HH, a lime manufacturing plant means, "*... any plant which used a rotary lime kiln to produce lime product from limestone by calcinations.*" Based on this definition of a lime plant, Pete Lien and Sons would not be considered a lime plant because the kiln in question is a vertical kiln and not a rotary kiln. In addition, only the kiln would be considered a "lime plant".

DENR assumed the vertical kiln was considered a lime plant and on April 21, 2006, DENR requested that WRAP model Pete Lien and Sons emissions to determine if they would cause or contribute to any impairment of visibility in a Class I area. WRAP initiated this process by running CALMET/CALPUFF modeling using WRAP's "*CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States*," August 15, 2006. The basic assumptions in the protocol are:

1. Use of three years of modeling consisting of calendar year 2001, 2002 and 2003;
2. Visibility impacts due to emissions of sulfur dioxide, nitrogen oxide and primary particulate matter emissions were calculated. Unless a state provided speciated particulate matter emissions, all PM emissions were modeled as $PM_{2.5}$. In this case all PM emissions were modeled as $PM_{2.5}$;
3. Visibility was calculated using the original IMPROVE equation and annual average natural conditions; and
4. CALPUFF version 6.112 was used in the analysis.

The CALPUFF modeling procedures are outlined in WRAP's BART Modeling Protocol, which can be reviewed at the following website:

http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf.

Table 6-2 provides a summary of the modeling outputs based on annual sulfur dioxide and nitrogen oxide emissions of 0.4 and 277 tons per year, respectively.

*Table 6-2– WRAP's Modeling Results for Pete Lien and Sons* [1]

| Class I Area | State | Minimum Distance | Max Delta (dv) | 99th (dv) | Days >0.5 | Annual 98th percentile 2001 | 2002 | 2003 |
|---|---|---|---|---|---|---|---|---|
| Badlands | SD | 73 km | 0.267 | 0.140 | 0 | 0.120 | 0.160 | 0.105 |
| Boundary Waters | MN | 946 km | 0.014 | 0.007 | 0 | 0.005 | 0.003 | 0.003 |
| Bridger | WY | 489 km | 0.021 | 0.003 | 0 | 0.001 | 0.002 | 0.001 |
| Fitzpatrick | WY | 501 km | 0.018 | 0.002 | 0 | 0.001 | 0.001 | 0.001 |
| Grand Teton | WY | 570 km | 0.005 | 0.001 | 0 | 0.000 | 0.000 | 0.000 |
| Lostwood | ND | 509 km | 0.040 | 0.009 | 0 | 0.006 | 0.005 | 0.007 |
| Medicine Lake | MT | 488 km | 0.030 | 0.011 | 0 | 0.006 | 0.005 | 0.010 |
| North Absaroka | WY | 487 km | 0.008 | 0.002 | 0 | 0.001 | 0.001 | 0.001 |
| Teton | WY | 513 km | 0.009 | 0.001 | 0 | 0.001 | 0.001 | 0.000 |
| Theodore Roosevelt | ND | 311 km | 0.049 | 0.023 | 0 | 0.014 | 0.016 | 0.015 |
| Ul Bend | MT | 516 km | 0.024 | 0.006 | 0 | 0.005 | 0.003 | 0.005 |
| Voyageurs | MN | 921 km | 0.012 | 0.006 | 0 | 0.004 | 0.002 | 0.003 |
| Washakie | WY | 461 km | 0.019 | 0.003 | 0 | 0.001 | 0.002 | 0.001 |
| Wind Cave | SD | 52 km | 0.366 | 0.203 | 0 | 0.128 | 0.137 | 0.139 |
| Yellowstone | WY | 524 km | 0.008 | 0.002 | 0 | 0.001 | 0.001 | 0.001 |

[1] - "dv" means deciview and "km" means kilometers.

The modeling conducted by WRAP demonstrated that Pete Lien and Sons did not cause or contribute to visibility impairment at a Class I area. After reviewing the modeling inputs, DENR determined the vertical kiln should be modeled again because of errors in the UTM coordinates and emission rates. However, before the modeling could be re-run, the vertical kiln was shutdown and dismantled in 2009.

Although Pete Lien and Sons' existing Title V air quality permit still identifies the vertical kiln as a unit, permit condition 1.1 specifies in the footnote of Table 1-1 that Pete Lien and Sons is required to shutdown and dismantle the vertical kiln before the initial startup of Unit #45. Pete Lien and Sons fulfilled this commitment by notifying DENR on March 13, 2009, that the vertical kiln was shutdown and dismantled. Therefore, Pete Lien and Sons' shutdown and dismantled the unit subject to BART and DENR did not re-model the vertical kiln.

### 6.1.3 Otter Tail Power Company – Big Stone I

Unit #1 at the Big Stone I Power Plant was built in 1975, has a maximum capacity greater than 250 million Btus per hour, and has the potential to emit greater than 250 tons per year of any air pollutant. The next step in this analysis is to determine if Unit #1's emissions may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area. On April 21, 2006, DENR requested that WRAP model Unit #1's emissions from Otter Tail Power Company's Big Stone I Power Plant.

WRAP initiated this process by running CALMET/CALPUFF modeling using WRAP's "CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States," August 15, 2006. The basic assumptions in the protocol are:

1. Use of three years of modeling of 2001, 2002 and 2003;
2. The sulfur dioxide, nitrogen oxide and particulate emission rates represent the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled, not including periods of startup, shutdown, or malfunctions;
3. Visibility impacts due to emissions of sulfur dioxide, nitrogen oxide and primary particulate matter emissions were calculated. Unless a state provided speciated particulate matter emissions, all PM emissions were modeled as $PM_{2.5}$;
4. Visibility was calculated using the original IMPROVE equation and annual average natural conditions; and
5. CALPUFF version 6.112 was used in the analysis.

The CALPUFF modeling procedures are outlined in WRAP's BART Modeling Protocol and can be reviewed at the following website:

http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf.

Table 6-3 provides a summary of the modeling outputs based on annual sulfur dioxide and nitrogen oxide emissions of 12,409 and 15,580 tons per year, respectively. The annual sulfur dioxide and nitrogen oxide emissions were derived from WRAP's BART protocol identified above.

*Table 6-3– WRAP's Modeling Results for Otter Tail Power Company Big Stone I*[1]

| Class I Area | State | Min Distance | Max Delta (dv) | 99th (dv) | Days >0.5 | Annual 98th percentile 2001 | 2002 | 2003 |
|---|---|---|---|---|---|---|---|---|
| Badlands | SD | 470 km | 3.047 | 1.076 | 21 | 0.364 | 0.417 | 0.683 |
| Boundary Waters | MN | 431 km | 1.653 | 1.133 | 63 | 0.951 | 0.659 | 1.034 |
| Bridger | WY | 1,041 km | 0.147 | 0.003 | 0 | 0.001 | 0.001 | 0.000 |
| Fitzpatrick | WY | 1,050 km | 0.079 | 0.005 | 0 | 0.001 | 0.001 | 0.000 |
| Grand Teton | WY | 1,112 km | 0.029 | 0.003 | 0 | 0.001 | 0.001 | 0.000 |
| Lostwood | ND | 585 km | 0.779 | 0.370 | 7 | 0.263 | 0.175 | 0.204 |
| Medicine Lake | MT | 690 km | 0.678 | 0.345 | 7 | 0.256 | 0.211 | 0.218 |
| North Absaroka | WY | 1,013 km | 0.121 | 0.026 | 0 | 0.011 | 0.008 | 0.001 |
| Teton | WY | 1,052 km | 0.049 | 0.008 | 0 | 0.004 | 0.002 | 0.001 |
| Theodore Roosevelt | ND | 555 km | 2.061 | 0.840 | 27 | 0.581 | 0.443 | 0.687 |

| Class I Area | State | Min Distance | Max Delta (dv) | 99th (dv) | Days >0.5 | Annual 98th percentile | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | 2001 | 2002 | 2003 |
| Ul Bend | MT | 902 km | 0.840 | 0.196 | 3 | 0.089 | 0.065 | 0.043 |
| Voyageurs | MN | 438 km | 1.658 | 0.915 | 52 | 0.666 | 0.703 | 0.729 |
| Washakie | WY | 1,006 km | 0.090 | 0.018 | 0 | 0.007 | 0.005 | 0.001 |
| Wind Cave | SD | 572 km | 1.545 | 0.631 | 13 | 0.224 | 0.263 | 0.261 |
| Yellowstone | WY | 1,049 km | 0.068 | 0.018 | 0 | 0.009 | 0.004 | 0.001 |

[1] - "dv" means deciview and "km" means kilometers.

WRAP had determined that Big Stone I would be reasonably anticipated to contribute to an impairment of visibility at the Badlands National Park in South Dakota, Theodore Roosevelt National Park in North Dakota, and Boundary Waters Wilderness and Voyageurs National Park in Minnesota.

## 6.2 Otter Tail Power Company's Modeling Results

Otter Tail Power Company was notified of the results and requested an opportunity to verify the results after identifying several errors in actual emission rates and stack parameters. The department allowed Otter Tail Power Company to re-run the models using the correct emission rates and stack parameters. On March 19, 2008, Otter Tail Power Company submitted an individual source analysis using CALMET/CALPUFF; but after review by the state, EPA, and federal land managers (U.S. Fish and Wildlife Service, U.S. Forest Service and National Park Service) it was determined that a BART modeling protocol should be submitted and approved by all parties, Otter Tail Power Company would run the model using the approved protocol, and submit before Otter Tail Power Company's results could be approved.

Otter Tail Power Company submitted the BART modeling protocol on January 16, 2009. After several conference calls and discussions, a revised protocol identified as June 2009, was submitted July 1, 2009. After several submittals and conference calls, Otter Tail Power Company committed to make the following changes to the protocol in an email dated August 31, 2009:

1. Although Otter Tail Power Company attached the CALMET switches it would use, it committed to using the CALMET switches recommended and approved by EPA and Federal Land Managers (FLMs) dated August 20, 2009. However, to ensure the most up-to-date CALMET switches are used, DENR is requiring Otter Tail Power Company to use the CALMET switches identified in EPA's memorandum dated August 31, 2009, from Tyler J Fox, Group Leader, Air Quality Modeling Group, to EPA Regional Modeling Contacts. The date on the listing of CALMET switches is August 28, 2009. The memorandum may be viewed in Attachment C.
2. Otter Tail Power Company committed to use the CALPUFF switches that Penny Shamblin, with Hunton and Williams, submitted to DENR by email on August 19, 2009. Although the document contains CALMET switches, only the CALPUFF switches (see Attachment D) in this email will be used by Otter Tail Power Company in the BART analysis. The CALMET switches mentioned above will be the ones used in the analysis.

3. Otter Tail Power Company proposes to revise the June 2009 modeling protocol by using a 12 kilometer MM5 grid and a 4 kilometer CALMET grid rather than the 4 kilometer MM5 grid and 4 kilometer CALMET grid identified in the June 2009 modeling protocol. DENR reviewed other acceptable modeling protocols and is acceptable to this change.
4. Although Otter Tail Power Company may run POSTUTIL option MNITRATE=2 for its own purposes, the modeling results DENR will accept for the BART analysis will be MNITRATE=1.

The CALPUFF switches Otter Tail Power Company is recommending contains five switches that are different than those recommended by EPA as defaults. The following identifies the variable, EPA's default, recommended default by Otter Tail Power Company, and DENR's response:

1. "NSPEC" – Identifies the number of species modeled. The EPA default is 5 and Otter Tail Power Company is proposing 11, which follows the FLM guidance on particle speciation and size. DENR is agreeable to this change.
2. "NSE" – Number of species emitted. The EPA default is 3 and Otter Tail Power Company is proposing 9.
3. "MSPLIT" – Allows puffing. The EPA default is 0 (No) and Otter Tail Power Company is proposing 1 (Yes). Puff splitting in necessary due to the distance from Big Stone I to a federal Class I area. DENR is agreeable to this change.
4. "MESHDN" – Grid receptor spacing. The EPA default is 1; however, Otter Tail Power Company is stating this is "Not Applicable". DENR is agreeable to this change.
5. "BCKNH3" – Ammonia background. The EPA default is 10 parts per billion and Otter Tail Power Company is recommending 1 part per billion. During the June 3, 2009, conference call, EPA stated it was okay with this change. DENR is agreeable to this change.

On September 18, 2009, the department determined that Otter Tail Power Company's BART modeling protocol as identified above. See Appendix A for the approval letter and the BART modeling protocol dated June 2009.

The modeling results identified that Otter Tail Power Company's Big Stone I Power Plant would be reasonably anticipated to contribute to an impairment of visibility at the Boundary Waters and Voyageurs federal Class I areas in northern Minnesota and the Isle Royale federal Class I area in Michigan. The reasonably anticipated to contribute to an impairment is based on visibility impacts greater than 0.5 deciview based on the 98$^{th}$ percentile at the three federal Class I areas. See Appendix B for the modeling report dated October 2009, and Table 6-4 for a summary of the modeling results.

*Table 6-4– Otter Tail Power Company's Modeling Results for Big Stone I* [1]

| Class I Area | State | Min Distance | Max Delta (dv) | 99th (dv) | 98th (dv) |
|---|---|---|---|---|---|
| Badlands | SD | 470 km | 2.202 | 0.698 | **0.481 (0.5)** |
| Boundary Waters | MN | 431 km | 3.574 | 1.351 | **1.079 (1.1)** |
| Lostwood | ND | 585 km | 1.110 | 0.722 | 0.409 (0.4) |
| Theodore Roosevelt | ND | 555 km | 2.232 | 0.772 | **0.459 (0.5)** |
| Voyageurs | MN | 438 km | 2.162 | 1.376 | **0.724 (0.7)** |
| Wind Cave | SD | 572 km | 1.671 | 0.591 | 0.325 (0.3) |
| Isle Royale | MI | 1,049 km | 1.806 | 0.789 | **0.665 (0.7)** |

[1] - "dv" means deciview and "km" means kilometers.

Otter Tail Power Company results did not match up entirely with the modeling conducted by WRAP. In particular, Otter Tail Power Company's modeling also showed that Big Stone I would reasonably contribute to impairment at the Isle Royale National Park in Michigan. DENR believes Otter Tail Power Company's modeling best represent the visibility impacts from Big Stone I since the original modeling did not have the correct emission rates and stack parameters and the CALPUFF modeling conducted by Otter Tail Power Company included puff splitting, which helps improve the accuracy of the model when used for great distances.

In accordance with the 40 CFR Part 51, Appendix Y, DENR used a contribution threshold of 0.5 deciviews for determining if Otter Tail Power Company's Big Stone I facility is subject to BART. The guideline provides the state the discretion to set a threshold below 0.5 deciviews if "the location of a large number of BART-eligible sources within the state and proximately to a Class I area justifies this approach. The discretion was based on the following factors:

1. It equates to the 5 percent extinction threshold for new sources under the PSD New Source Review rules;
2. It is consistent with the threshold selected by other states in the west, which all selected 0.5 deciviews; and
3. It represents the limit of perceptible change.

DENR chose the 0.5 deciview threshold because there is only one source that is BART-eligible and it is greater than 300 kilometers from any Class I area. Therefore, DENR will establish this threshold in its proposed ARSD Chapter 74:36:21 – Regional Haze Program. Otter Tail Power Company's Big Stone I power plant exceeded this threshold and is subject to BART. In accordance with 40 CFR § 51.308(e)(1)(i), the only source subject to BART in South Dakota is Otter Tail Power Company's Big Stone I facility.

In accordance with 40 CFR § 51.308(e)(1)(ii), DENR requested that Otter Tail Power Company complete a Case-by-Case BART analysis, which includes determining the visibility improvements expected at each of these Class I areas (see Appendix C).

### 6.3 Otter Tail Power Company's Case-by-Case BART Analysis

In accordance with 40 CFR 51.301, Best Available Retrofit Technology (BART) is defined as *"an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."*

In accordance with 40 CFR § 51.308(e)(1)(ii)(B), the determination of BART for fossil fuel fired power plants having a total generating capacity greater than 750 megawatts must be made pursuant to the guidelines in Appendix Y of this part (Guidelines for BART Determinations under the Regional Haze Rule). Appendix Y identifies a five step process in determining BART. The five steps are as follows:

1. STEP 1—Identify All Available Retrofit Control Technologies: In identifying "all" options, one should identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology. The list is complete if it includes the maximum level of control each technology is capable of achieving. Where a New Source Performance Standard (NSPS), under 40 CFR Part 60, exists for a source category, one should include a level of control equivalent to the NSPS as one of the control options;
2. STEP 2—Eliminate Technically Infeasible Options: One evaluates the technical feasibility of the control options identified in Step 1. One should document a demonstration of technical infeasibility and should explain, 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. One may then eliminate such technically infeasible control options from further consideration in the BART analysis;
3. STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies: One evaluates the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Two key issues in this process include: (1) Make sure that you express the degree of control using a metric that ensures an "apples to apples" comparison of emissions performance levels among options; and (2) Give appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels;
4. STEP 4—Evaluate Impacts and Document the Results: Once the available and technically feasible control technology options are identified, one should conduct the following analyses when you make a BART determination: (1) Impact analysis part 1 – costs of compliance; (2) Impact analysis part 2 – energy impacts, (3) Impact analysis part 3 – non-air quality environmental impacts; and (4) Impact analysis part 4 – remaining useful life; and
5. STEP 5—Evaluate Visibility Impacts: One should evaluate the net visibility improvement form the available and technically feasible control technology options.

This is accomplished by modeling the pre-control and post-control emission rates according to an accepted methodology.

In determining what is considered BART, Appendix Y identifies that the state should develop a chart (or charts) displaying each of the alternatives and include: (1) Expected emission rate (e.g., tons per year, pounds per hour); (2) Emissions performance level (e.g., percent pollutant removed, emissions per unit product, pounds per million Btus, parts per million); (3) Expected emissions reductions (e.g., tons per year); (4) Costs of compliance (e.g., total annualized costs in dollars, cost effectiveness (dollar per ton), incremental cost effectiveness (dollar per ton), any other cost-effectiveness measures (dollar per deciview)); (5) Energy impacts; (6) Non-air quality environmental impacts; and (7) Modeled visibility impacts.

Otter Tail Power Company's Big Stone I facility does not have a total generating capacity greater than 750 megawatts. Therefore, DENR is not required to follow these guidelines. As such, DENR will follow the steps identified in Appendix Y with some slight differences. For example, in identifying the available control technologies, DENR is not listing any of the permutations of the control levels for each identified control technology as suggested by EPA's guidance. DENR will use the initial step to identify control technologies without including the control levels. Step 3 is used to evaluate the control effectiveness or permutations of the control levels for those control technologies that are considered feasible to install or maintain as identified in Step 2.

### 6.3.1 Particulate BART Review

#### *6.3.1.1 Particulate Control Technologies*

Step 1 requires the identification of all available retrofit control technologies. The particulate matter emissions from fossil-fuel fired units can be categorized as either filterable or condensable particulate. The filterable particulate matter exists as a solid or liquid particle in the exhaust of a boiler as it leaves the stack. As such, the filterable particulate may be collected by placing a control device in the flue gas stream prior to the stack. Condensable particulates are emitted out the stack in a gaseous state but rapidly condense into particles when released into the atmosphere and cooled. Therefore, condensable particulates may not be readily collected by placing a control device in the stack.

Those control technologies being reviewed under Step 1 are those that would control the filterable particulate matter. Otter Tail Power Company identified the following control options for particulate matter.

1. Existing fabric filter (baghouse);
2. New fabric filter (baghouse);
3. Compact hybrid particulate collector; and
4. Electrostatic precipitator.

DENR also identified two more control technologies that may be used to control particulate emissions and are listed below:

1. Wet scrubber; and
2. Cyclone(s)/Multicyclone(s).

#### *6.3.1.2 Technically Feasible Particulate Control Technologies*

Step 2 requires the elimination of any control technologies identified in Step 1 that are technically infeasible. A compact hybrid particulate collector is a combination of an electrostatic precipitator and a baghouse in series. The compact hybrid particulate collector is generally operated with a higher air-to-cloth ratio than a typical baghouse. Since Otter Tail Power Company already has a baghouse installed at Big Stone I, Otter Tail did not further consider the compact hybrid particulate collector.

Even though Otter Tail Power Company identified a reason for not selecting the compact hybrid particulate collector, the reasoning does not identify that the technology is infeasible to install. Since both an electrostatic precipitator and a baghouse are both technically feasible options and without further evidence, DENR considers the compact hybrid particulate collector as a feasible control technology.

DENR determined that the following particulate control technologies were feasible for Otter Tail Power Company:

1. Existing fabric filter (baghouse);
2. New fabric filter (baghouse);
3. Compact hybrid particulate collector;
4. Electrostatic precipitator;
5. Wet scrubber; and
6. Cyclone(s)/Multicyclone(s).

#### *6.3.1.3 Particulate Control Effectiveness*

Step 3 requires the evaluation of control effectiveness for each control technology. DENR evaluated the control effectiveness by comparing the effectiveness in Table 6.5.

*Table 6-5 – Comparison of Control Effectiveness for Particulate Controls*

| | | Emission Rate | | Control Efficiency | |
|---|---|---|---|---|---|
| | | Otter Tail [1] | RBLC [3] | PFDR [4] | IEA [5] |
| Rank | Control | (lbs/MMBtus) [2] | (lbs/MMBtus) [2] | (%) | (%) |
| #1 | Baghouse | 0.015 | 0.010 to 0.03 | 95 to 99.9 | >99 to >99.9999 |
| #2 | Electrostatic Precipitator | 0.015 | 0.015 to 0.03 | 80 to 99.5 | >99 to >99.99 |
| #3 | COHPAC [6] | Not Provided | 0.015 | Not Identified | Not Identified |
| #4 | Wet Scrubber(s) | Not Provided | Not Identified | 75 to 99 | 90 to 99.9 |
| #5 | Cyclone(s)/ Multicyclone(s) | Not Provided | Not Identified | 50 to 95 | 75 – 99 |

[1] – The identified emission rates were identified in Otter Tail Power Company's BART analysis;
[2] – "lbs/MMBtus" means pounds per million British thermal units;
[3] – The identified emission rates were obtained from EPA's Reasonable Achievable Control Technology, Best Available Control Technology, and Lowest Achievable Emission Rate Clearinghouse (RBLC) considering data for permits issued after calendar year 2000;
[4] – The control efficiencies, in percent removal, are derived from page 473 of "Particulates and Fine Dust Removal Process and Equipment by Marshal Sittig";
[5] – The control efficiencies, in percent removal, are derived from the IEA Clean Coal Centre's Webpage at http://www.iea-coal.org.uk/site/ieacoal/home; and
[6] – "COHPAC" means Compact Hybrid Particulate Collector.

#### *6.3.1.4 Particulate Control Technology Impacts*

In Step 4, DENR looked at impacts associated with the control alternatives such as cost of compliance, energy impacts, non-air quality environmental impacts, and the remaining useful life of the project. These impacts are intended to provide rational in choosing between the alternative control options when determining what is considered BART. Otter Tail Power Company already has installed and is operating a baghouse, which is the top particulate control technology. Therefore, there is no additional compliance cost, energy impacts, etc. that Otter Tail Power Company would have to endure. As such, no additional impacts analysis will be conducted to determine the appropriate controls for particulate matter.

### 6.3.2 Sulfur Dioxide BART Review

#### *6.3.2.1 Sulfur Dioxide Control Technologies*

Step 1 requires the identification of all available retrofit control technologies. Otter Tail Power Company identified the following control options for sulfur dioxide:

1. Fuel switching;
2. Semi-dry flue gas desulfurization; and
3. Wet flue gas desulfurization.

DENR also identified the following control technologies that may be used to control sulfur dioxide emissions:

1. Coal cleaning;
2. Coal upgrading;
3. Hydrated lime injection; and
4. Emerging control technologies such as Enviroscrub, Electro catalytic oxidation, and Airborne process.

#### *6.3.2.2 Technically Feasible Sulfur Dioxide Control Technologies*

Fuel switching is a viable method to reduce sulfur dioxide emissions by switching to a fuel with lower sulfur content. Otter Tail Power Company's Big Stone facility's primary fuel source is subbituminous coal obtained from the Powder River Basin in Wyoming. Powder River Basin subbituminous coal has one of the lowest sulfur contents available in the United States. As such, Otter Tail Power Company has already implemented fuel switching.

Coal cleaning is typically performed by physical gravimetric separation which is capable of reducing sulfur, ash and impurities from the coal. The effectiveness of gravimetric separation is dependent on the ash content and the distribution of fuel bound sulfur between organic and inorganic. If the sulfur compounds are predominantly inorganic materials, then coal cleaning is fairly effective, but if the sulfur compounds are predominantly organic materials, then coal cleaning is not effective. Physical cleaning or gravimetric separation may be effective with bituminous coals that contain high levels of inorganic sulfur and ash. However, gravimetric coal cleaning is not technically feasible for low sulfur, low ash, and low inorganic-sulfur content coal such as the coal from the Powder River Basin in Wyoming. Otter Tail Power Company's Big Stone facility's primary fuel source is subbituminous coal obtained from the Powder River Basin in Wyoming. As such, coal cleaning is not a technical feasible option for Otter Tail Power Company.

Coal upgrading such as a process developed by Evergreen Energy (formerly KFx) called the K-Fuel process enriches the coal by utilizing high pressure and temperature conditions to reduce moisture and inorganic materials. Typically, the K-Fuel process is utilized to reduce the moisture content and increase the coal heating value, however, the process may remove some sulfur compounds. Evergreen Energy constructed a K-Fuel production facility in Gillette, Wyoming which may produce approximately 750,000 tons per year of K-Fuel. Otter Tail Power Company burned approximately 2,268,000 tons of coal in 2008. As such, coal upgrading is not a technically feasible option for Otter Tail Power Company because there is not enough being produced to supply Otter Tail Power Company's needs. In addition, based on Evergreen Energy's webpage, this facility has been idle since calendar year 2008.

Hydrated lime injection is a system that injects hydrated lime prior to the particulate collection system. The hydrated lime absorbs the sulfur dioxide and is collected in the particulate control device. Hydrated lime is also referred to as calcium hydroxide. The sulfur dioxide reacts with the calcium hydroxide to form calcium sulfate or calcium sulfite. Fly ash from the Powder River Basin has a calcium content of up to 30 percent. Since the Powder River Basin coal is already providing additional calcium to adsorb sulfur dioxide, the hydrated lime will not likely provide additional sulfur dioxide removal. Otter Tail Power Company's primary fuel source is subbituminous coal obtained from the Powder River Basin in Wyoming. As such, hydrated lime injection is not considered a technically feasible option for Otter Tail Power Company since the concept is already taking place by using Power River Basin coal.

Emerging control technologies such as Enviroscrub, Electro catalytic oxidation, and the Airborne process have not been commercially available and have not been demonstrated for long-term levels of performance. As noted in 40 CFR Part 51, Appendix Y, a control technology needs to be commercially available to be considered technically feasible. As such these emerging technologies are not considered technically feasible options for Otter Tail Power Company.

DENR determined that the following sulfur dioxide control technologies were feasible for Otter Tail Power Company:

1. Semi-dry flue gas desulfurization; and
2. Wet flue gas desulfurization.

#### *6.3.2.3 Sulfur Dioxide Control Effectiveness*

Step 3 requires the evaluation of control effectiveness for each control technology. DENR evaluated the control effectiveness by comparing the effectiveness in Table 6.6.

*Table 6-6 – Comparison of Control Effectiveness for Sulfur Dioxide Controls*

| | | Emission Rate | | | Control Efficiency |
|---|---|---|---|---|---|
| | | Otter Tail [1] | RBLC [3] | Basin [4] | EPA [5] |
| **Rank** | **Control** | (lbs/MMBtus) [2] | (lbs/MMBtus) [2] | (lbs/MMBtus) [2] | (%) |
| #1 | **Wet Flue Gas Desulfurization** | 0.043 to 0.15 | 0.1 to 0.167 | 0.05 | 90 to 98 |
| #2 | **Semi-Dry Flue Gas Desulfurization** | 0.09 to 0.15 | 0.038 to 0.16 | 0.07 | 80 to 90 |

[1] – The identified emission rates were identified in Otter Tail Power Company's BART analysis;
[2] – "lbs/MMBtus" means pounds per million British thermal units;
[3] – The identified emission rates were obtained from EPA's Reasonable Achievable Control Technology, Best Available Control Technology, and Lowest Achievable Emission Rate Clearinghouse (RBLC) considering data for permits issued after calendar year 2000;
[4] – The emission rates are based on the BACT analysis provided by Basin Electric Power Cooperative's proposed NextGen project in South Dakota; and
[5] – The control efficiencies, in percent removal, are from EPA's "Air Pollution Control Technology Fact Sheet on Flue Gas Desulfurization Systems".

#### *6.3.2.4 Sulfur Dioxide Control Technology Impacts*

Step 4 requires DENR to look at impacts associated with the control alternatives such as cost of compliance, energy impacts, non-air quality environmental impacts, and the remaining useful life of the project. These impacts are intended to provide rational in choosing between the alternative control options when determining what is considered BART.

Otter Tail Power Company identified cost estimates for each of the control options. In addition, Otter Tail Power Company identified cost estimated for two different operating scenarios for each of the two control alternatives. Table 6-7 summarizes Otter Tail Power Company's estimated costs.

In 40 CFR Part 51, Appendix Y – Guidelines for BART Determination Under the Regional Haze Rule, in the section titled "How should I determine visibility impacts in the BART determination" it notes that the model should use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). The 18,000 tons per year of sulfur dioxide is based on the highest average 24-hour average emission rate (4,832 pounds per hour) for calendar years 2001 through 2003 and operating 85% of the time or 7,746 hours per year. Based on the BART guidelines, the baseline emissions are 18,000 tons per year.

*Table 6-7 – Comparison of Control Effectiveness for Sulfur Dioxide Controls*

| Control Option | Capital Cost | O&M [1] | Annual Cost [2] | Reduction [3] | Cost Effectiveness [4] |
|---|---|---|---|---|---|
| WFGD #1 [5] | $171,800,000 | $9,600,000 | $29,050,000 | 17,100 | $1,699 |
| WFGD #2 [6] | $171,800,000 | $9,490,000 | $28,900,000 | 14,870 | $1,944 |
| SDFGD #1 [7] | $141,300,000 | $7,660,000 | $23,570,000 | 16,120 | $1,462 |
| SDFGD #2 [8] | $141,300,000 | $7,480,000 | $23,330,000 | 14,870 | $1,569 |

[1] – O&M represents the operational and maintenance cost estimate for the control alternative;
[2] – Annual cost is the annualized cost for each control alternative taking into account both the capital and operational and maintenance costs;
[3] – Reduction represents the amount of sulfur dioxide reduced in tons per year annual from the baseline level of 18,000 tons of sulfur dioxide per year;
[4] – Cost Effectiveness represents the annualized cost divided by the identified emission reductions (dollar per ton);
[5] – WFGD #1 represents a wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[6] – WFGD #2 represents a wet flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[7] – SDFGD #1 represents a semi-dry flue gas desulfurization system meeting an emission rate of 0.9 pounds per million British thermal units; and
[8] – SDFGD #2 represents a semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units.

Otter Tail Power Company did not identify the cost effectiveness on a dollar per visibility reduction. DENR considered this cost effectiveness in Step 5 of the analysis.

Otter Tail Power Company identified the energy impacts cost associated for each of the control options. Table 6-8 summarizes Otter Tail Power Company's estimated energy impacts.

*Table 6-8 – Estimated Energy Impacts for Sulfur Dioxide Controls*

| Control | Energy Demand | Percent of Generation |
|---|---|---|
| Wet Flue Gas Desulfurization | 9,500 kilowatts | 2.0 percent |
| Semi-Dry Flue Gas Desulfurization | 3,325 kilowatts | 0.7 percent |

The non-air quality environmental impacts of the two control alternatives include the solid and aqueous waste streams. The semi-dry flue gas desulfurization system would be installed upstream of the existing baghouse. The baghouse would be used to collect the injected lime and reacted sulfur dioxide emissions along with other existing particulate matter emissions. Otter Tail Power Company did not identify how much additional particulate matter would be collected by the baghouse due to the use of the semi-dry flue gas desulfurization system. At this time, it is assume the additional material collected in the baghouse is negligible compared to the existing collection. Otter Tail Power Company estimates that the wet flue gas desulfurization system would generate an additional 44,700 tons of gypsum solids which would need to be properly disposed.

In conducting its cost analysis, Otter Tail Power Company used 30 years as the life expectancy averaging period for the control alternatives. Since the useful life of Otter Tail Power Company's Big Stone I facility is expected to be longer than 30 years, there is no difference between the control options based on useful life.

### 6.3.3 Nitrogen Oxide BART Review

#### *6.3.3.1 Nitrogen Oxide Control Technologies*

Step 1 requires the identification of all available retrofit control technologies. Otter Tail Power Company identified the following control options for nitrogen oxide:

1. Low-nitrogen oxide burners (LNBs);
2. Over-fire air (OFA);
3. Separated over-fire air (SOFA);
4. Selective non-catalytic reduction (SNCR);
5. Rich reagent injection (RRI); and
6. Selective catalytic reduction (SCR).

DENR also identifies the following control technologies that may be used to control nitrogen oxide emissions:

1. Flue-gas recirculation;
2. Oxygen enhanced combustion;
3. Catalytic absorption/oxidation;
4. Gas reburn; and
5. Emerging control technologies such as Enviroscrub, Electro-catalytic oxidation, NOxStar, and Cascade processes.

#### *6.3.3.2 Technically Feasible Nitrogen Oxide Control Technologies*

Low-nitrogen oxide burners limit nitrogen oxide formation by controlling the stoichiometric and temperature profiles of the combustion process. Low-nitrogen oxide burners attempt to delay the complete mixing of fuel and air as long as possible within the constraints of the furnace design. This is the reason flames from low-nitrogen oxide burners are longer than conventional burners. Cyclone furnace's length and diameter are not designed with sufficient size to allow for low-nitrogen oxide burners to be installed allowing stable combustion. As such, low-nitrogen oxide burners are not considered a technically feasible option for Otter Tail Power Company.

Flue-gas recirculation reduces the formation of thermal nitrogen oxide emissions in a boiler by limiting the amount of oxygen available for oxidation in the fuel rich zone of the boiler. Flue-gas recirculation is not known to reduce nitrogen oxide emissions any further when added with an over-fire air system. Therefore, Otter Tail Power Company did not conduct any further review of flue-gas recirculation. However, this reasoning does not justify that flue-gas recirculation is not a feasible technology to consider. Therefore, DENR will consider the flue-gas recirculation as a feasible control technology.

Catalytic absorption/oxidation such as SCONOx or EMx systems is a nitrogen oxide control technology that utilizes a proprietary catalytic oxidation and absorption technology which oxidizes nitrogen oxide (NO) and carbon monoxide (CO) to nitrogen dioxide (NO2) and carbon dioxide (CO2), respectively. The nitrogen dioxide is then absorbed onto an absorption media while carbon dioxide is released to the atmosphere. Once the absorption media becomes saturated, the nitrogen dioxide is desorbed and treated by a proprietary catalyst. The SCONOx system is being considered as a cross over technology to coal-fired boilers, but to date has only been applied to "clean flue gas" systems such as natural-gas fired combustions turbines. The catalytic absorption/oxidation system requires a high operating temperature and low particulate loading. Therefore, the system would have to be installed after the particulate control device and require a flue gas reheater. DENR was unable to find a coal-fired system that was using a catalytic absorption/oxidation system or find that this system was being marketed commercially for coal fired boilers. As noted in 40 CFR Part 51, Appendix Y, a control technology needs to be commercially available to be considered technically feasible. As such the catalytic absorption/oxidation system is not considered a technically feasible option for Otter Tail Power Company.

Gas reburning is a nitrogen oxide control technology that uses a second combustion zone following the primary combustion zone in the boiler. In a cyclone boiler, such as the one being operated at Otter Tail Power Company's Big Stone I facility, burning the coal produces molten slag along the cyclone barrels. The molten slag catches subsequent coal until the combustion is complete. Generally, cyclone burners operate near the slag-tapping limits. Therefore, using natural gas or another fuel source as the reburn fuel may inhibit the molten slag formation. In addition, by trying to lower the air to fuel ratio more than achieved by the existing over-fire air systems may cause slag "freezing" at low load levels. As such gas reburn is not considered a technically feasible option for Otter Tail Power Company.

Oxygen enhanced combustion is a nitrogen oxide combustion control technology that reduces the formation of thermal nitrogen oxides in the boiler. Developed by Praxair Technology Inc., this method uses oxygen in the burner instead of air to achieve additional nitrogen oxide reductions. To date, the largest demonstration of this technology is a 30 megawatt pilot demonstration at Babcock and Wilcock's Clean Environmental Development facility in Alliance, Ohio. As noted on Babcock and Wilcock's website - http://www.babcock.com/, the project was a pilot test of the technology and the next step is to demonstrate the technology at a commercial scale. As noted in 40 CFR Part 51, Appendix Y, a control technology needs to be commercially available to be considered technically feasible. As such the oxygen enhanced combustion is not considered a technically feasible option for Otter Tail Power Company.

Emerging control technologies such as Enviroscrub, Electro catalytic oxidation, and the Airborne process have not been commercially available and have not been demonstrated for long-term levels of performance. As noted in 40 CFR Part 51, Appendix Y, a control technology needs to be commercially available to be considered technically feasible. As such these emerging technologies are not considered technically feasible options for Otter Tail Power Company.

DENR determined that the following nitrogen oxide control technologies were feasible for Otter Tail Power Company:

1. Over-fire air (OFA);
2. Separated over-fire air (SOFA);
3. Selective non-catalytic reduction (SNCR);
4. Rich reagent injection (RRI);
5. Selective catalytic reduction (SCR) ; and
6. Flue-gas recirculation.

### *6.3.3.3 Nitrogen Oxide Control Effectiveness*

Step 3 requires the evaluation of control effectiveness for each control technology. DENR evaluated the control effectiveness by comparing the effectiveness in Table 6.9.

*Table 6-9 – Comparison of Control Effectiveness for Nitrogen Oxide Controls*

| Rank | Control | Emission Rate | | | Control Efficiency | |
|---|---|---|---|---|---|---|
| | | Otter Tail [1] (lbs/MMBtus) [2] | RBLC [3] (lbs/MMBtus) [2] | Basin [4] (lbs/MMBtus) [2] | EPA [5] (%) | IEA [6] (%) |
| #1 | SCR and SOFA [7] | 0.10 | 0.05 to 0.1 | 0.05 | 35 to 90 | 80 to 90 |
| #2 | RRI, SNCR and SOFA [8] | 0.20 | 0.07 to 0.15 | 0.10 | 35 to 90 | 30 to 50 |
| #3 | SNCR and SOFA [9] | 0.35 | 0.07 to 0.15 | 0.10 | 35 to 90 | 30 to 50 |
| #4 | Separated over-fire air | 0.50 | Not Identified | Not Identified | 30 to 70 | Not Identified |
| #5 | Over-fire air | 0.65 | Not Identified | Not Identified | 30 to 70 | Not Identified |
| #6 | Flue Gas Recirculation | Not Identified | Not Identified | Not Identified | 30 to 70 | Not Identified |

[1] – The identified emission rates were identified in Otter Tail Power Company's BART analysis;
[2] – "lbs/MMBtus" means pounds per million British thermal units;
[3] – The identified emission rates were obtained from EPA's Reasonable Achievable Control Technology, Best Available Control Technology, and Lowest Achievable Emission Rate Clearinghouse (RBLC) considering data for permits issued after calendar year 2000;
[4] – The emission rates are based on the BACT analysis provided by Basin Electric Power Cooperative's proposed NextGen project in South Dakota which is for a new pulverized-fired boiler equipped with a low-NOx burner combustion technology. The emission rates were primarily based on if the system used selective catalytic reduction or selective non-catalytic reduction;
[5] – The emission rates are from page 27 of the EPA's Technical Bulletin – *"Nitrogen Oxides; Why and How they are Controlled"*.
[6] – The emission rates were obtained from the IEA Clean Coal Centre's Webpage - http://www.iea-coal.org.uk/site/ieacoal/home. The emission rates were primarily based on if the system used selective catalytic reduction or selective non-catalytic reduction.

[7] – SCR and SOFA refers to selective catalytic reduction and separated over-fire air;
[8] – RRI, SNCR, and SOFA refers to rich reagent injection, selective non-catalytic reduction and separated over-fire air, respectively; and
[9] – SNCR and SOFA refers to selective non-catalytic reduction and separated over-fire air.

#### *6.3.3.4 Nitrogen Oxide Control Technology Impacts*

Step 4 requires DENR to look at impacts associated with the control alternatives such as cost of compliance, energy impacts, non-air quality environmental impacts, and the remaining useful life of the project. These impacts are intended to provide rational in choosing between the alternative control options when determining what is considered BART.

Otter Tail Power Company identified cost estimates for five control options. Table 6-10 summarizes Otter Tail Power Company's estimated costs.

In 40 CFR Part 51, Appendix Y – Guidelines for BART Determination Under the Regional Haze Rule, in the section titled "How should I determine visibility impacts in the BART determination" it notes that the model should use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). The 18,000 tons per year of nitrogen oxide is based on the highest average 24-hour average emission rate (4,855 pounds per hour) for calendar years 2001 through 2003 and operating 85% of the time or 7,746 hours per year. Based on the BART guidelines, the baseline emissions are 18,000 tons per year.

*Table 6-10 – Comparison of Control Effectiveness for Nitrogen Oxide Controls*

| Control Option | Capital Cost | O&M [1] | Annual Cost [2] | Reduction [3] | Cost Effectiveness [4] |
|---|---|---|---|---|---|
| SCR and SOFA [5] | $81,800,000 | $4,110,000 | $13,210,000 | 16,000 | $825 |
| RRI, SNCR and SOFA [6] | $16,200,000 | $7,260,000 | $11,390,000 | 13,910 | $818 |
| SNCR and SOFA [7] | $11,900,000 | $2,120,000 | $3,990,000 | 10,780 | $197 |
| SOFA [8] | $4,800,000 | $152,000 | $650,000 | 7,640 | $85 |
| Over-fired air | $0 | $106,000 | $140,000 | 4,510 | $31 |

[1] – O&M represents the operational and maintenance cost estimate for the control alternative;
[2] – Annual cost is the annualized costs for each control alternative taking into account both the capital and operational and maintenance costs;
[3] – Reduction represents the amount of nitrogen oxide reduced in tons per year annual from the baseline level of 18,000 tons of nitrogen oxide per year;
[4] – Cost Effectiveness represents the annualized cost divided by the identified emission reductions (dollar per ton);
[5] – SCR and SOFA refers to selective catalytic reduction and separated over-fire air;
[6] – RRI, SNCR, and SOFA refer to rich reagent injection, selective non-catalytic reduction and separated over-fire air;
[7] – SNCR and SOFA refers to selective non-catalytic reduction and separated over-fire air; and
[8] – SOFA refers to separated over-fire air.

Otter Tail Power Company did not identify a cost effectiveness on a dollar per visibility reduction. DENR considered this cost effectiveness in Step 5 of the analysis.

Otter Tail Power Company identified the energy impacts cost associated for each of the control options. Table 6-11 summarizes Otter Tail Power Company's estimated energy impacts.

*Table 6-11 – Estimated Energy Impacts for Nitrogen Oxide Controls*

| Control | Energy Demand | Percent of Generation |
|---|---|---|
| Selective catalytic reduction and Separated over-fire air | 400 to 1,000 kilowatts | Less than 0.2 percent |
| Rich reagent injection, Selective non-catalytic reduction and Separated over-fire air | 150 to 400 kilowatts | Less than 0.1 percent |
| Selective non-catalytic reduction and Separated over-fire air | 150 to 400 kilowatts | Less than 0.1 percent |
| Separated over-fire air | 1 kilowatt | Negligible |
| Over-fire air | 1 kilowatt | Negligible |

The over-fire air and the separated over-fire air will increase the amount of unburned carbon in the flyash, which will increase the amount of flyash that needs to be properly disposed. Otter Tail Power Company considers this increase negligible compared to the existing amount flyash being properly disposed.

The selective non-catalytic reduction and the selective catalytic reduction will generate a small amount of unreacted ammonia or urea to be emitted. Even though ammonia and urea are not considered regulated air pollutants, these emissions are involved in the formation of ammonium sulfates and ammonium nitrates, which contribute to the amount of visibility impairment.

In conducting its cost analysis, Otter Tail Power Company used 30 years as the life expectancy averaging period for the control alternatives. Since the useful life of Otter Tail Power Company's Big Stone I facility is expected to be longer than 30 years, there is no difference between the control options based on useful life.

### 6.3.4 Visibility Impact Evaluations

In accordance with 40 CFR Part 51, Appendix Y, a source that has an impact equal to or greater than 1.0 deciviews is considered to "cause" a visibility impairment and that establishing a threshold for what is considered to "contribute" to a visibility impairment should not be any higher than 0.5 deciviews. DENR is proposing to define "contribute" to visibility impairment as a change in visibility impairment in a mandatory Class I federal area of 0.5 deciviews or more, based on a 24-hour average, above the average natural visibility baseline. A source exceeds the threshold when the 98$^{th}$ percentile (eighth highest value) of the modeling results, based on one year of the three years of meteorological data modeled, exceeds the 0.5 deciviews.

Otter Tail Power Company modeled its existing operations impact on seven Class I areas that are located in Michigan, Minnesota, North Dakota, and South Dakota. Table 6-12 identifies the potential impact based on the 98$^{th}$ percentile for the existing Big Stone I facility has while emitting approximately 18,000 tons of sulfur dioxide, 18,000 tons of nitrogen oxides, and 300 tons of particulate matter per year.

*Table 6-12 – Potential Impact of Existing Big Stone I (98$^{th}$ Percentile)*

| Class I Area | 2002 [1,2] | 2006 [1,2] | 2007 [1,2] |
|---|---|---|---|
| Boundary Waters | 0.574 (0.6) | 0.790 (0.8) | 1.079 (1.1) |
| Voyageurs | 0.623 (0.6) | 0.574 (0.6) | 0.724 (0.7) |
| Wind Cave | 0.305 (0.3) | 0.120 (0.1) | 0.325 (0.3) |
| Theodore Roosevelt | 0.215 (0.2) | 0.459 (0.5) | 0.322 (0.3) |
| Lostwood | 0.232 (0.2) | 0.385 (0.4) | 0.409 (0.4) |
| Badlands | 0.452 (0.5) | 0.481 (0.5) | 0.471 (0.5) |
| Isle Royale | 0.629 (0.6) | 0.506 (0.5) | 0.665 (0.7) |

1 – The modeling was conducted using the meteorological data for calendar years 2002, 2006, and 2007; and

2 – The results are represented in deciviews. Otter Tail Power Company identified the deciview valued identified in the model to three decimal places which is consistent with how WRAP reported the visibility impacts in Table 6-3. The value in parentheses represents the value that is used to compare to the proposed contribution threshold of 0.5.

Based on the modeling results, Otter Tail Power Company's Big Stone I facility contributes to visibility impairment at Boundary Waters, Voyageurs, Theodore Roosevelt, Badlands, and Isle Royale because they have a deciview impact of 0.5 or greater.

Otter Tail Power Company conducted visibility modeling for 10 different control option scenarios and each scenario for three calendar years worth of meteorological data. The 10 different control option scenarios simultaneously considered the emissions of nitrogen oxide, sulfur dioxide, and particulate matter. Table 6-13 identifies the emission rates used in the modeling for each different control option.

*Table 6-13 – Emission Rates for Each Control Option*

| Option | Control Equipment | SO2 [11] | NOx [12] | PM10 [13] |
|---|---|---|---|---|
| #1 | OFA and Dry FGD #1 [1] | 841.4 | 3645.9 | 84.1 |
| #2 | OFA and Wet FGD #1 [2] | 841.4 | 3645.9 | 84.1 |
| #3 | OFA and Dry FGD #2 [3] | 504.8 | 3645.9 | 84.1 |
| #4 | OFA and Wet FGD #2 [4] | 241.2 | 3645.9 | 84.1 |
| #5 | SOFA and Dry FGD #1 [5] | 841.4 | 2804.5 | 84.1 |
| #5a | SOFA and Dry FGD #2 [6] | 504.8 | 2804.5 | 84.1 |
| #5b | SOFA and Wet FGD #2 [7] | 241.2 | 2804.5 | 84.1 |
| #6 | SNCR, SOFA, and Dry FGD #1 [8] | 841.4 | 1963.2 | 84.1 |
| #7 | RRI, SNCR, SOFA, and Dry FGD #1 [9] | 841.4 | 1121.8 | 84.1 |
| #8 | SCR, SOFA, and Dry FGD #1 [10] | 841.4 | 560.9 | 84.1 |

[1] – OFA and Dry FGD #1 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[2] – OFA and Wet FGD #1 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[3] – OFA and Dry FGD #2 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[4] – OFA and Wet FGD #2 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[5] – SOFA and Dry FGD #1 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[6] – SOFA and Dry FGD #2 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[7] – SOFA and Wet FGD #2 refers to separated over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[8] – SNCR, SOFA, and Dry FGD #1 refers to selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[9] – RRI, SNCR, SOFA, and Dry FGD #1 refers to rich reagent injection, selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[10] – SCR, SOFA, and Dry FGD #1 refers to selective catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[11] – SO2 represents the sulfur dioxide emission rate in pounds per hour;
[12] – NOx represents the nitrogen oxide emission rate in pounds per hour; and
[13] – PM10 represents the particulate matter less than 10 microns emission rate in pounds per hour.

Table 6-14 provides the results of the modeling (98$^{th}$ percentile) using the different control options and emissions rates in Table 6-13. Again, Otter Tail Power Company identified the deciview valued identified in the model to three decimal places which is consistent with how WRAP reported the visibility impacts in Table 6-3. The value in parentheses represents the value that DENR used to compare to the proposed contribution threshold of 0.5.

*Table 6-14 – Modeling Results for Each Control Option (98th Percentile – Deciviews)*

| Option | Control Equipment | Class I Area | 2002 | 2006 | 2007 |
|---|---|---|---|---|---|
| #1 | OFA and Dry FGD #1 [1] | Boundary Waters | 0.330 (0.3) | 0.548 (0.5) | **0.657 (0.7)** |
| | | Voyageurs | 0.329 (0.3) | 0.399 (0.4) | 0.460 (0.5) |
| | | Isle Royale | 0.377 (0.4) | 0.296 (0.3) | 0.339 (0.3) |
| | | Badlands | 0.223 (0.2) | 0.176 (0.2) | 0.241 (0.2) |
| | | Theodore Roosevelt | 0.092 (0.1) | 0.247 (0.2) | 0.190 (0.2) |
| #2 | OFA and Wet FGD #1 [2] | Boundary Waters | 0.360 (0.4) | 0.546 (0.5) | **0.667 (0.7)** |
| | | Voyageurs | 0.349 (0.3) | 0.494 (0.5) | 0.521 (0.5) |
| | | Isle Royale | 0.367 (0.4) | 0.273 (0.3) | 0.323 (0.3) |
| | | Badlands | 0.234 (0.2) | 0.199 (0.2) | 0.254 (0.3) |
| | | Theodore Roosevelt | 0.099 (0.1) | 0.244 (0.2) | 0.161 (0.2) |
| #3 | OFA and Dry FGD #2 [3] | Boundary Waters | 0.319 (0.3) | 0.534 (0.5) | **0.620 (0.6)** |
| | | Voyageurs | 0.307 (0.3) | 0.391 (0.4) | 0.450 (0.5) |
| | | Isle Royale | 0.363 (0.4) | 0.287 (0.3) | 0.323 (0.3) |
| | | Badlands | 0.219 (0.2) | 0.172 (0.2) | 0.230 (0.2) |
| | | Theodore Roosevelt | 0.087 (0.1) | 0.234 (0.2) | 0.173 (0.2) |
| #4 | OFA and Wet FGD #2 [4] | Boundary Waters | 0.350 (0.4) | 0.521 (0.5) | **0.611 (0.6)** |
| | | Voyageurs | 0.312 (0.3) | 0.464 (0.5) | 0.502 (0.5) |
| | | Isle Royale | 0.351 (0.4) | 0.250 (0.3) | 0.290 (0.3) |
| | | Badlands | 0.225 (0.2) | 0.191 (0.2) | 0.234 (0.2) |
| | | Theodore Roosevelt | 0.084 (0.1) | 0.230 (0.2) | 0.138 (0.1) |
| #5 | SOFA and Dry FGD #1 [5] | Boundary Waters | 0.264 (0.3) | 0.433 (0.4) | 0.524 (0.5) |
| | | Voyageurs | 0.263 (0.3) | 0.314 (0.3) | 0.364 (0.4) |
| | | Isle Royale | 0.298 (0.3) | 0.235 (0.2) | 0.272 (0.3) |
| | | Badlands | 0.169 (0.2) | 0.137 (0.1) | 0.191 (0.2) |
| | | Theodore Roosevelt | 0.076 (0.1) | 0.199 (0.2) | 0.156 (0.2) |
| #5a | SOFA and Dry FGD #2 [6] | Boundary Waters | 0.250 (0.3) | 0.419 (0.4) | 0.493 (0.5) |
| | | Voyageurs | 0.249 (0.2) | 0.306 (0.3) | 0.354 (0.4) |
| | | Isle Royale | 0.285 (0.3) | 0.226 (0.2) | 0.256 (0.3) |
| | | Badlands | 0.165 (0.2) | 0.133 (0.1) | 0.180 (0.2) |
| | | Theodore Roosevelt | 0.069 (0.1) | 0.186 (0.2) | 0.141 (0.1) |
| #5b | SOFA and Wet FGD #2 [7] | Boundary Waters | 0.274 (0.3 | 0.407 (0.4) | 0.478 (0.5) |
| | | Voyageurs | 0.244 (0.2) | 0.365 (0.4) | 0.393 (0.4) |
| | | Isle Royale | 0.274 (0.3) | 0.195 (0.2) | 0.227 (0.2) |
| | | Badlands | 0.174 (0.2) | 0.147 (0.1) | 0.182 (0.2) |
| | | Theodore Roosevelt | 0.066 (0.1) | 0.180 (0.2) | 0.108 (0.1) |
| **#6** | **SNCR, SOFA, and Dry FGD #1** [8] | **Boundary Waters** | **0.200 (0.2)** | **0.318 (0.3)** | **0.388 (0.4)** |
| | | **Voyageurs** | **0.196 (0.2)** | **0.228 (0.2)** | **0.267 (0.3)** |
| | | **Isle Royale** | **0.221 (0.2)** | **0.174 (0.2)** | **0.199 (0.2)** |
| | | **Badlands** | **0.120 (0.1)** | **0.098 (0.1)** | **0.143 (0.1)** |

| Option | Control Equipment | Class I Area | 2002 | 2006 | 2007 |
|---|---|---|---|---|---|
| | | Theodore Roosevelt | 0.063 (0.1) | 0.150 (0.2) | 0.121 (0.1) |
| #7 | RRI, SNCR, SOFA, and Dry FGD #1 [9] | Boundary Waters | 0.137 (0.1) | 0.202 (0.2) | 0.256 (0.3) |
| | | Voyageurs | 0.130 (0.1) | 0.157 (0.2) | 0.176 (0.2) |
| | | Isle Royale | 0.142 (0.1) | 0.115 (0.1) | 0.134 (0.1) |
| | | Badlands | 0.090 (0.1) | 0.066 (0.1) | 0.099 (0.1) |
| | | Theodore Roosevelt | 0.050 (0.1) | 0.101 (0.1) | 0.080 (0.1) |
| #8 | SCR, SOFA, and Dry FGD #1 [10] | Boundary Waters | 0.097 (0.1) | 0.136 (0.1) | 0.170 (0.2) |
| | | Voyageurs | 0.086 (0.1) | 0.107 (0.1) | 0.123 (0.1) |
| | | Isle Royale | 0.092 (0.1) | 0.077 (0.1) | 0.098 (0.1) |
| | | Badlands | 0.079 (0.1) | 0.060 (0.1) | 0.070 (0.1) |
| | | Theodore Roosevelt | 0.036 (0.0) | 0.070 (0.1) | 0.064 (0.1) |

[1] – OFA and Dry FGD #1 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[2]- OFA and Wet FGD #1 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[3] - OFA and Dry FGD #2 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[4] - OFA and Wet FGD #2 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[5] – SOFA and Dry FGD #1 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[6] – SOFA and Dry FGD #2 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[7] – SOFA and Wet FGD #2 refers to separated over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[8] – SNCR, SOFA, and Dry FGD #1 refers to selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[9] - RRI, SNCR, SOFA, and Dry FGD #1 refers to rich reagent injection, selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units; and
[10] - SCR, SOFA, and Dry FGD #1 refers to selective catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units.

Based on the modeling results in Table 6-14, Otter Tail Power Company would have to use Option #6, #7, or #8 to not reasonably contribute to visibility impairment in the Boundary Waters, Voyageurs, Isle Royale, Badlands, and Theodore Roosevelt National Parks.

Otter Tail Power Company did not provide a cost per deciview reduction for each of the proposed control options. DENR calculated a cost per deciview reduction by summing the annualized cost of each of the control alternatives associated with the control options and dividing by the visibility reduction identified by the modeling from the baseline condition. Table 6-15 provides a cost per deciview comparison.

*Table 6-15 – Cost per Deciview Comparison ($/deciview)*

| Option | Control Equipment | Class I Area | 2002 | 2006 | 2007 |
|---|---|---|---|---|---|
| #1 | OFA and Dry FGD #1 [1] | Boundary Waters | $ 96,188,525 | $ 96,983,471 | $ 55,616,114 |
| | | Voyageurs | $ 79,829,932 | $ 134,114,286 | $ 88,901,515 |
| | | Isle Royale | $ 93,134,921 | $ 111,761,905 | $ 71,993,865 |
| | | Badlands | $ 102,489,083 | $ 79,950,820 | $ 102,043,478 |
| | | Theodore Roosevelt | $ 190,813,008 | $ 110,707,547 | $ 177,803,030 |
| | | **Cumulative** | **$ 15,998,637** | **$ 16,108,442** | **$ 13,542,989** |
| #2 | OFA and Wet FGD #1 [2] | Boundary Waters | $ 135,700,935 | $ 119,016,393 | $ 70,485,437 |
| | | Voyageurs | $ 105,985,401 | $ 363,000,000 | $ 143,054,187 |
| | | Isle Royale | $ 110,839,695 | $ 124,635,193 | $ 84,912,281 |
| | | Badlands | $ 133,211,009 | $ 102,978,723 | $ 133,824,885 |
| | | Theodore Roosevelt | $ 250,344,828 | $ 135,069,767 | $ 180,372,671 |
| | | **Cumulative** | **$ 20,625,000** | **$ 21,337,252** | **$ 17,224,199** |
| #3 | OFA and Dry FGD #2 [3] | Boundary Waters | $ 92,980,392 | $ 92,617,188 | $ 51,655,773 |
| | | Voyageurs | $ 75,031,646 | $ 129,562,842 | $ 86,532,847 |
| | | Isle Royale | $ 89,135,338 | $ 108,264,840 | $ 69,327,485 |
| | | Badlands | $ 101,759,657 | $ 76,731,392 | $ 159,127,517 |
| | | Theodore Roosevelt | $ 185,234,375 | $ 105,377,778 | $ 98,381,743 |
| | | **Cumulative** | **$ 15,466,406** | **$ 15,588,429** | **$ 12,795,467** |
| #4 | OFA and Wet FGD #2 [4] | Boundary Waters | $ 130,312,500 | $ 108,513,011 | $ 62,371,795 |
| | | Voyageurs | $ 93,858,521 | $ 265,363,636 | $ 131,486,486 |
| | | Isle Royale | $ 105,000,000 | $ 114,023,438 | $ 77,840,000 |
| | | Badlands | $ 128,590,308 | $ 100,655,172 | $ 123,164,557 |
| | | Theodore Roosevelt | $ 222,824,427 | $ 127,467,249 | $ 158,641,304 |
| | | **Cumulative** | **$ 19,140,984** | **$ 19,590,604** | **$ 15,617,978** |
| #5 | SOFA and Dry FGD #1 [5] | Boundary Waters | $ 77,354,839 | $ 67,170,868 | $ 43,207,207 |
| | | Voyageurs | $ 66,611,111 | $ 92,230,769 | $ 66,611,111 |
| | | Isle Royale | $ 72,447,130 | $ 88,487,085 | $ 61,017,812 |
| | | Badlands | $ 84,734,392 | $ 69,709,302 | $ 85,642,857 |
| | | Theodore Roosevelt | $ 172,517,986 | $ 92,230,769 | $ 144,457,831 |
| | | **Cumulative** | **$ 13,411,633** | **$ 13,018,458** | **$ 11,045,601** |
| #5a | SOFA and Dry FGD #2 [6] | Boundary Waters | $ 74,753,086 | $ 65,283,019 | $ 41,331,058 |
| | | Voyageurs | $ 64,759,358 | $ 90,373,134 | $ 65,459,459 |
| | | Isle Royale | $ 70,406,977 | $ 86,500,000 | $ 59,217,604 |
| | | Badlands | $ 84,390,244 | $ 69,597,701 | $ 83,230,241 |
| | | Theodore Roosevelt | $ 165,890,411 | $ 88,717,949 | $ 133,812,155 |
| | | **Cumulative** | **$ 13,070,696** | **$ 12,727,273** | **$ 10,544,188** |
| #5b | SOFA and Wet FGD #2 [7] | Boundary Waters | $ 99,000,000 | $ 77,545,692 | $ 49,417,637 |
| | | Voyageurs | $ 78,364,116 | $ 142,105,263 | $ 89,728,097 |
| | | Isle Royale | $ 83,661,972 | $ 95,498,392 | $ 67,808,219 |
| | | Badlands | $ 106,834,532 | $ 88,922,156 | $ 102,768,166 |
| | | Theodore Roosevelt | $ 199,328,589 | $ 106,451,613 | $ 138,785,047 |

| Option | Control Equipment | Class I Area | 2002 | 2006 | 2007 |
|---|---|---|---|---|---|
| | | **Cumulative** | **$ 16,019,417** | **$ 15,730,932** | **$ 12,724,936** |
| #6 | SNCR, SOFA, and Dry FGD #1 [8] | Boundary Waters | $ 73,048,128 | $ 57,881,356 | $ 39,536,903 |
| | | Voyageurs | $ 63,981,265 | $ 78,959,538 | $ 59,781,182 |
| | | Isle Royale | $ 66,960,784 | $ 82,289,157 | $ 58,626,609 |
| | | Badlands | $ 82,289,157 | $ 71,331,593 | $ 83,292,683 |
| | | Theodore Roosevelt | $ 179,736,842 | $ 88,414,239 | $ 135,920,398 |
| | | **Cumulative** | **$ 13,115,699** | **$ 12,262,118** | **$ 10,368,121** |
| #7 | RRI, SNCR, SOFA, and Dry FGD #1 [9] | Boundary Waters | $ 79,450,801 | $ 59,047,619 | $ 42,187,120 |
| | | Voyageurs | $ 70,425,963 | $ 83,261,391 | $ 63,357,664 |
| | | Isle Royale | $ 71,293,634 | $ 88,797,954 | $ 65,386,064 |
| | | Badlands | $ 95,911,602 | $ 83,662,651 | $ 93,333,333 |
| | | Theodore Roosevelt | $ 210,424,242 | $ 96,983,240 | $ 143,471,074 |
| | | **Cumulative** | **$ 14,711,864** | **$ 13,467,804** | **$ 11,280,052** |
| #8 | SCR, SOFA, and Dry FGD #1 [10] | Boundary Waters | $ 76,603,774 | $ 55,871,560 | $ 40,198,020 |
| | | Voyageurs | $ 68,044,693 | $ 78,244,111 | $ 60,798,669 |
| | | Isle Royale | $ 68,044,693 | $ 85,174,825 | $ 64,444,444 |
| | | Badlands | $ 97,962,466 | $ 86,793,349 | $ 91,122,195 |
| | | Theodore Roosevelt | $ 204,134,078 | $ 93,933,162 | $ 141,627,907 |
| | | **Cumulative** | **$ 14,329,412** | **$ 13,101,470** | **$ 10,900,955** |

[1] – OFA and Dry FGD #1 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[2] - OFA and Wet FGD #1 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[3] - OFA and Dry FGD #2 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[4] - OFA and Wet FGD #2 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[5] – SOFA and Dry FGD #1 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[6] – SOFA and Dry FGD #2 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[7] – SOFA and Wet FGD #2 refers to separated over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[8] – SNCR, SOFA, and Dry FGD #1 refers to selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units;
[9] - RRI, SNCR, SOFA, and Dry FGD #1 refers to rich reagent injection, selective non-catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units; and
[10] - SCR, SOFA, and Dry FGD #1 refers to selective catalytic reduction, separated over-fire air, and semi-dry flue gas desulfurization system meeting an emission rate of 0.15 pounds per million British thermal units.

Based on the cost per deciview reduction numbers in Table 6-15, the most cost effective controls options are #5A, #6 and #8. The cost effective control costs are generally within 10 percent of each other.

### 6.3.5 BART Emissions Limits for Big Stone I

EPA identifies in 40 CFR Part 51, Appendix Y that in determining the "best" available retrofit technology, the state has discretion to determine the order in which the state should evaluate control options for BART. The state should provide a justification for adopting the technology that is selected as the ''best'' level of control, including an explanation of the Clean Air Act factors that led the state to choose that option over other control levels.

To complete the BART process, the state should establish enforceable emission limits that reflect the BART requirements and require compliance within a given period of time. In particular, the state should establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source. In addition, the state should require compliance with the BART emission limitations no later than five years after EPA approves South Dakota's State Implementation Plan for regional haze. If technological or economic limitations in the application of a measurement methodology to a particular emission unit make a conventional emissions limit infeasible, the state may instead prescribe a design, equipment, work practice, operation standard, or combination of these types of standards.

#### *6.3.5.1 Particulate Matter BART Recommendation*

Otter Tail Power Company already installed and is operating a baghouse, which is the top particulate control technology. Therefore, there is no additional compliance cost, energy impacts, etc. that Otter Tail Power Company would have to endure. As such, DENR considers the continual use of the baghouse as BART for particulate matter.

Otter Tail Power Company proposes an emission limit of 84.1 pounds per hour which they based on an emission rate of 0.015 pounds per million Btu and a maximum fuel heat input of 5,609 million Btus per hour. Otter Tail Power Company proposes to comply with the pounds per hour limit using a 30-day rolling average. Each day, Otter Tail Power Company will multiply the emission rate, in pounds per million Btus as determined by the most recent annual performance test, by the heat input to the boiler, as determined by a continuous emission monitoring system, and dividing by the number of hours the boiler operated that day.

In the December 11, 2006, application, Otter Tail Power Company proposed to replace the advanced hybrid particulate collector control system with the current day baghouse. In that application, Otter Tail Power Company noted that the baghouse would have a maximum filterable particulate matter emission rate of 0.012 pounds per million Btu of fuel heat input. The emission rate equates to 67.3 pounds per hour at 5,609 million Btus per hour heat input In May 2009, Otter Tail Power Company conducted a performance test on the baghouse. The test results noted an average filterable particulate matter emission rate of 0.011 pounds per million Btus and 57.6 pounds per hour.

DENR considers the emission limit representing BART as 67.3 pounds per hour. The hourly emission limit includes periods of startup and shutdown. DENR is also establishing a BART emission limit of 0.012 pounds per million Btus, which includes periods of startup and shutdown. Compliance with both emission limits shall be based on an annual stack performance test using the average of three 1-hour test runs.

### *6.3.5.2 Sulfur Dioxide BART Recommendation*

Otter Tail Power Company is proposing the second ranked control option (semi-dry flue gas desulfurization system) to control sulfur dioxide emissions. Since control options #6, #7, and #8, which were the only three options that reduced the visibility less than the contribution level of 0.5 deciviews, did not include the top ranked sulfur dioxide control alternative an analysis of the visibility impacts of the other control alternatives was considered. Even though the top ranked control option (wet flue gas desulfurization system) reduces the sulfur dioxide emissions more than the second ranked control option, neither of the two control options is considered a better control option when considering the visibility impacts. For example, Table 6-16 displays the comparison of the visibility impacts for control option #3 to control option #4 and control option #5a to control option #5b. These options were chosen because the emission rates for nitrogen oxide and particulate matter were constant, while the sulfur dioxide emissions varied as noted by the two different control alternatives.

***Table 6-16 – Visibility Comparison between Wet and Dry Scrubbers***

| | Control Option | Class I Area | 2002 | 2006 | 2007 |
|---|---|---|---|---|---|
| #3 | OFA and Dry FGD #2 [1] | Boundary Waters | 0.319 | 0.534 | 0.620 |
| | | Voyageurs | 0.307 | 0.391 | 0.450 |
| | | Isle Royale | 0.363 | 0.287 | 0.323 |
| | | Badlands | 0.219 | 0.172 | 0.230 |
| | | Theodore Roosevelt | 0.087 | 0.234 | 0.173 |
| #4 | OFA and Wet FGD #2 [2] | Boundary Waters | 0.350 | 0.521 | 0.611 |
| | | Voyageurs | 0.312 | 0.464 | 0.502 |
| | | Isle Royale | 0.351 | 0.250 | 0.290 |
| | | Badlands | 0.225 | 0.191 | 0.234 |
| | | Theodore Roosevelt | 0.084 | 0.230 | 0.138 |
| | Comparison Review | Boundary Waters | ↑ | ↓ | ↓ |
| | | Voyageurs | ↑ | ↑ | ↑ |
| | | Isle Royale | ↓ | ↓ | ↓ |
| | | Badlands | ↑ | ↑ | ↑ |
| | | Theodore Roosevelt | ↓ | ↓ | ↓ |
| #5a | SOFA and Dry FGD #2 [3] | Boundary Waters | 0.250 | 0.419 | 0.493 |
| | | Voyageurs | 0.249 | 0.306 | 0.354 |
| | | Isle Royale | 0.285 | 0.226 | 0.256 |
| | | Badlands | 0.165 | 0.133 | 0.180 |
| | | Theodore Roosevelt | 0.069 | 0.186 | 0.141 |
| #5b | SOFA and Wet FGD #2 [4] | Boundary Waters | 0.274 | 0.407 | 0.478 |
| | | Voyageurs | 0.244 | 0.365 | 0.393 |

| | Control Option | Class I Area | 2002 | 2006 | 2007 |
|---|---|---|---|---|---|
| | | Isle Royale | 0.274 | 0.195 | 0.227 |
| | | Badlands | 0.174 | 0.147 | 0.182 |
| | | Theodore Roosevelt | 0.066 | 0.180 | 0.108 |
| | Comparison Review | Boundary Waters | ↑ | ↓ | ↓ |
| | | Voyageurs | ↓ | ↑ | ↑ |
| | | Isle Royale | ↓ | ↓ | ↓ |
| | | Badlands | ↑ | ↑ | ↑ |
| | | Theodore Roosevelt | ↓ | ↓ | ↓ |

[1] - OFA and Dry FGD #2 refers to over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units;
[2] - OFA and Wet FGD #2 refers to over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units;
[3] – SOFA and Dry FGD #2 refers to separated over-fire air and semi-dry flue gas desulfurization system meeting an emission rate of 0.09 pounds per million British thermal units; and
[4] – SOFA and Wet FGD #2 refers to separated over-fire air and wet flue gas desulfurization system meeting an emission rate of 0.043 pounds per million British thermal units.

As noted in the table, approximately 40 percent of the modeling, the top ranked control option generated a higher visibility impact than the second ranked control option. Whereas, approximately 60 percent of the modeling, the second ranked control option generated a higher visibility impact than the top ranked control option. Therefore, based on the visibility modeling there is no discernable difference between these two control options. As such, DENR considers that the semi-dry flue gas desulfurization system is considered BART.

Otter Tail Power Company proposes an emission limit of 505 pounds per hour based upon a 30-day rolling average, which is based on the emission rate of 0.09 pounds per million Btu of fuel heat input at 5,609 million Btus per hour heat input.

The presumptive emission limit established by EPA for scrubber systems is 0.15 pounds per million Btus of fuel heat input. The limit proposed by Otter Tail Power Company is more stringent than the presumptive limit identified by EPA. DENR considers the emission limit representing BART should be 505 pounds per hour and 0.09 pounds per million Btus, which would include periods of startup, shutdown and malfunction. Compliance with these emission limits shall be based on the continuous emission monitoring system and on a 30-day rolling average.

### *6.3.5.3 Nitrogen Oxide BART Recommendation*

Otter Tail Power Company is proposing the fourth ranked control option (separated over-fire air) to control nitrogen oxide emissions. In reviewing the higher ranked control options, each option reduces the amount of nitrogen oxide emissions and the visibility impacts more than the fourth ranked control option (separated over-fire air). However, each of these higher ranking control options comes with a higher financial cost.

In establishing the nitrogen oxide presumptive BART requirements, EPA identified that $1,500 per ton of nitrogen oxide removed was considered cost effective. (Federal Register Volume 70 Number 128 on pages 39134 and 39135). EPA considers this threshold cost effective for a coal fired unit greater than 200 megawatts existing at a facility with a combined capacity greater than 750 megawatts.

Otter Tail Power Company's Big Stone I facility does not have a capacity greater than 750 megawatts and is not applicable to the established nitrogen oxide presumptive BART requirements. However, Otter Tail Power Company's Big Stone I's coal fired unit is greater than the 200 megawatt. As noted in Table 6-10, the cost of the control options on a $ per ton basis are all less than $900 per ton. As such DENR considers all the identified control options as cost effective on a $ per ton basis.

As noted in Table 6-15, the cost on a $ per deciview basis indicates that control options #5a, #6 and #8 are the most cost effective. Options #5a, #6 and #8 consider the operation of separated over-fire air, selective non catalytic reduction and selective catalytic reduction. It should be noted that the $ per deciview includes the cost for both sulfur dioxide and nitrogen oxide.

As noted in Table 6-14, control options #6, #7, #8, were the only options that resulted in modeling less than 0.5 deciviews of visibility impairment. Again, it should be noted the modeling results includes the emissions of particulate matter, sulfur dioxide, and nitrogen oxide.

None of the nitrogen oxide control alternatives have identified energy, non-air environmental, or have issues with the current life expectancy of the Big Stone I coal fire unit to preclude the use of any of the control options. As such DENR considers all the identified control options as being acceptable options based on impacts to energy, non-air environmental and life expectancy.

Based on the visibility modeling, the first ranked control option (selective catalytic reduction) reduces the visibility more than any other control option. The selective catalytic reduction system also reduces the visibility an additional 34 percent over the second ranked control option and an additional 65 percent over the fourth ranked control option. The selective catalytic reduction is also considered cost effective on a $ per ton basis, is represented as part of the control option #8 that is one of the most cost effective options on a $ per deciview reduction basis and one of the options that modeling demonstrates less than 0.5 deciviews of visibility impairment. DENR considers selective catalytic reduction and separate over-fire air system as BART.

The presumptive emission limit established by EPA for a selective catalytic reduction system installed on a cyclone coal fired unit is 0.10 pounds per million Btus of fuel heat input (Federal Register Volume 70 Number 128 on page 39172). DENR considers the emission limit representing BART should be 561 pounds per hour and 0.10 pounds per million Btus, which would include periods of startup, shutdown and malfunction. Compliance with the emission limits shall be based on the continuous emission monitoring system and on a 30-day rolling average.

### 6.4 BART Requirements

Otter Tail Power Company's Big Stone I reasonably contributes to visibility impairment at Class I areas and is considered a BART-eligible source subject to BART. Therefore, DENR is adopting BART requirements in its Administrative Rules of South Dakota under Chapter 74:36:21 – Regional Haze Program.

These requirements will be part of South Dakota's Regional Haze State Implementation Plan and will be enforceable because they will establish emission limits representing BART; in accordance with 40 CFR § 51.308(e)(1)(v), the BART control equipment will be required to be properly operated and maintained; and testing, monitoring, recordkeeping, and reporting requirements will be established to ensure compliance with BART. One method of determining if control equipment is being properly operated and maintained is through monitoring the emissions from the unit. In Otter Tail Power Company's case, continuous emission monitoring sulfur dioxide and nitrogen oxide is already required in their existing permit. The minimum requirements for the operation, maintenance, and monitoring requirements will be established in ARSD 74:36:21:07. In accordance with 40 CFR § 51.308(e)(1)(iv), DENR will require BART to be installed and operating as expeditiously as practicable, but no later than 5 years from EPA's approval of South Dakota's Regional Haze Program. The deadline for installing BART will be established in ARSD 74:36:21:06.

In accordance with 40 CFR § 51.308(e)(5), once the requirements of BART are achieved, Otter Tail Power Company will be subject to the requirements of South Dakota's State Implementation Plan in the same manner as other sources.

## 7.0 Reasonable Progress

In accordance with 40 CFR § 51.308(d)(1), for each mandatory Class I area located within the state, the state must establish goals, expressed in deciviews, that provide reasonable progress towards achieving natural visibility conditions by 2064. The reasonable progress goals must provide improvement in visibility for the 20% most impaired days over the period of the implementation plan and ensure no degradation in visibility for the 20% least impaired days over the same period. In accordance with 40 CFR § 51.308(d)(1)(v), the reasonable progress goals established by the state are not directly enforceable but will be considered in the evaluation of the adequacy of the measures a state would implement to achieve natural conditions by 2064. In accordance with 40 CFR § 51.308(d)(1)(vi), the state may not adopt a reasonable progress goal that represents less visibility improvement than is expected to result from implementation of other requirements of the federal Clean Air Act during the applicable planning period.

The EPA published the *Guidance for Setting Reasonable Progress Goals under the Regional Haze Rule, 2007*, for setting reasonable progress goals. The basic steps include:

1. Establish baseline and natural visibility conditions;
2. Determine the glide path or uniform rate of progress;
3. Identify and analyze the measures aimed at achieving the uniform rate of progress using the following approaches: