SOUTH DAKOTA'S

REGIONAL HAZE

STATE IMPLEMENTATION PLAN

South Dakota Department of Environment and Natural Resources

Draft

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Executive Summary

The Department of Environment and Natural Resources (DENR) worked with the Western Regional Air Partnership (WRAP), states that were 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 that impact 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.

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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.

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1.0 Introduction

1.1 Initial Visibility Protection Program

In August 1977, the federal Clean Air Act was amended by adding section 169A. In section 169A(a)(1), Congress established the following national goal for visibility protection:

> "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from man-made air pollution."

To address this goal for each of the 156 mandatory federal Class I areas across the nation, the federal Environmental Protection Agency (EPA) developed regulations to reduce the impact of large industrial sources on nearby Class I areas. It was recognized at the time that regional haze, which comes from a wide variety of sources that may be located far from a Class I area, was also a part of the visibility problem. However, monitoring networks and visibility models at that time were not developed to the degree necessary to understand the causes of regional haze.

The 1977 Clean Air Act Amendments also established the Prevention of Significant Deterioration (PSD) permit program, which included requirements for protecting visibility in national parks, national wilderness areas, national monuments and national seashores. The PSD permit program included area specific (e.g., Class I, II and III) increments or limits on the maximum allowable increase in air pollutants (e.g., particulate matter and sulfur dioxide) and a preconstruction permit review process for new or modifying major sources that allows for careful consideration of control technology, consultation with federal land managers on visibility impacts and public participation in permitting decisions. The PSD permit program was delegated to South Dakota on July 6, 1994, and later approved in South Dakota's State Implementation Plan on January 22, 2008.

Under Section 169A(b) of the Clean Air Act, Congress established new requirements on major stationary sources in operation within a 15-year period prior to enactment of the 1977 amendments. Major stationary sources within that timeframe that may reasonably be anticipated to cause or contribute to visibility impairment in a Class I area must install best available retrofit technology (BART) as determined by the state. In determining BART, the state must take into consideration the costs of compliance, the energy and non-air quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

In 1980, EPA adopted regulations to address "reasonably attributable visibility impairment", or visibility impairment caused by one or a small group of man-made sources generally located in close proximity to a specific Class I area. At that time, EPA deferred writing rules to address regional haze, because they lacked the monitoring, modeling and scientific information needed to understand the nature of long range transport and formation of regional haze. South Dakota did not adopt the visibility rules of 1980 in its State Implementation Plan. Therefore, EPA is currently implementing the program in a Federal Implementation Plan.

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1.2 Visibility Impairment

Most visibility impairment occurs when pollution in the form of small particles scatters or absorbs light. Air pollutants are emitted from a variety of natural and anthropogenic (man-made) sources. Natural sources can include windblown dust and smoke from wildfires. Anthropogenic sources can include motor vehicles, electric utility and industrial fuel burning, prescribed burning, and manufacturing operations. More pollutants mean more absorption and scattering of light, which reduce the clarity and color of scenery. Some types of particles such as sulfates and nitrates scatter more light, particularly during humid conditions. Other particles like elemental carbon from combustion processes are highly efficient at absorbing light.

Commonly, visibility is observed by the human eye and the object may be a single viewing target or scenery. In the 156 Class I areas across the nation, a person's visual range has been substantially reduced by air pollution. In eastern parks, the average visual range decreased from 90 miles to 15-25 miles. In the West, the visual range decreased from an average of 140 miles to 35-90 miles.

Some particles that cause haze are directly emitted into the air while others are formed when gases emitted into the air form particles as they are carried from the source of the pollutants. Some haze forming pollutants are also linked to human health problems and others to environmental damage. Exposure to very small particles in the air has been linked with increased respiratory illness, decreased lung function, and premature death. In addition, particles such as nitrates and sulfates contribute to acid deposition potentially making lakes, rivers, and streams unsuitable for some forms of aquatic life and impacting flora in the ecosystem. These same acid particles can also erode materials such as paint, buildings or other natural and manmade structures.

1.3 1990 Amendments to Regional Haze Program

In the 1990 Clean Air Act Amendments, Congress added section 169B to strengthen and reaffirm the national goal and address visibility impairment from a collection of sources whose emissions are mixed and transported over long distances to the Class I areas. Section 169B(e) calls for EPA to "carry out the Administrator's regulatory responsibilities under section 169A, including criteria for measuring 'reasonable progress' toward the national goal."

In response to these mandates, EPA promulgated the regional haze rule on July 1, 1999. Under 40 CFR, § 51.308(d)(1), states must "establish goals (expressed in deciviews) that provide for reasonable progress towards achieving natural visibility conditions" for each Class I area within a state by 2064. The reasonable progress goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period.

The purpose of this submittal is to address the State Implementation Plan requirements for the State of South Dakota found in 40 CFR § 51.308 – Regional Haze Program Requirements of 40 CFR Part 51 Subpart P – Protection of Visibility. The South Dakota Department of Environment

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and Natural Resources (DENR), the agency designated to administer and coordinate a statewide program of air pollution control, has general legal authority under South Dakota Codified Laws Title 34A-1 – Air Pollution Control to adopt and enforce rules for visibility protection including regional haze visibility impairment.

This document along with the adopted rules is South Dakota's State Implementation Plan for adopting a Regional Haze Program meets these goals. Pursuant to the requirements in 40 CFR § 51.308(a) and (b), the State Implementation Plan is intended to meet the requirements in EPA's regional haze regulations that were adopted to comply with the requirements established in Section 169B of the Clean Air Act. This document addresses the following elements of South Dakota's State Implementation Plan:

1. In accordance with 40 CFR § 51.308(d), the core regional haze program requirements (e.g., identification of Class I areas; determination of baseline conditions, natural conditions, and uniform rate of progress; and baseline, current and future emissions inventories);
2. In accordance with 40 CFR § 51.308(e), who is subject to BART and BART controls, emissions limits, compliance determinations, recordkeeping, and reporting requirements;
3. In accordance with 40 CFR § 51.308(f), a commitment to conduct comprehensive periodic revisions of South Dakota's Regional Haze State Implementation Plan;
4. In accordance with 40 CFR § 51.308(g), a commitment to periodically report the progress towards achieving reasonable progress goals;
5. In accordance with 40 CFR § 51.308(h), a commitment to determine the adequacy of the existing implementation plan; and
6. In accordance with 40 CFR § 51.308(i), the requirements for continued coordination with states and federal land managers.

South Dakota is a member of WRAP which is a collaborative effort of tribal governments, state governments and various federal agencies to help states and tribes develop and implement a regional haze program that complies with the EPA's regional haze regulations.

2.0 Class I Areas in South Dakota

In accordance with 40 CFR § 51.308(d), states must address regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from within the state. There are 156 national parks and wilderness areas in the nation that are considered Class I areas in the Clean Air Act (see Figure 2-1). South Dakota is home to two of the 156 national parks and wilderness areas. They are the Badlands National Park and the Wind Cave National Park.

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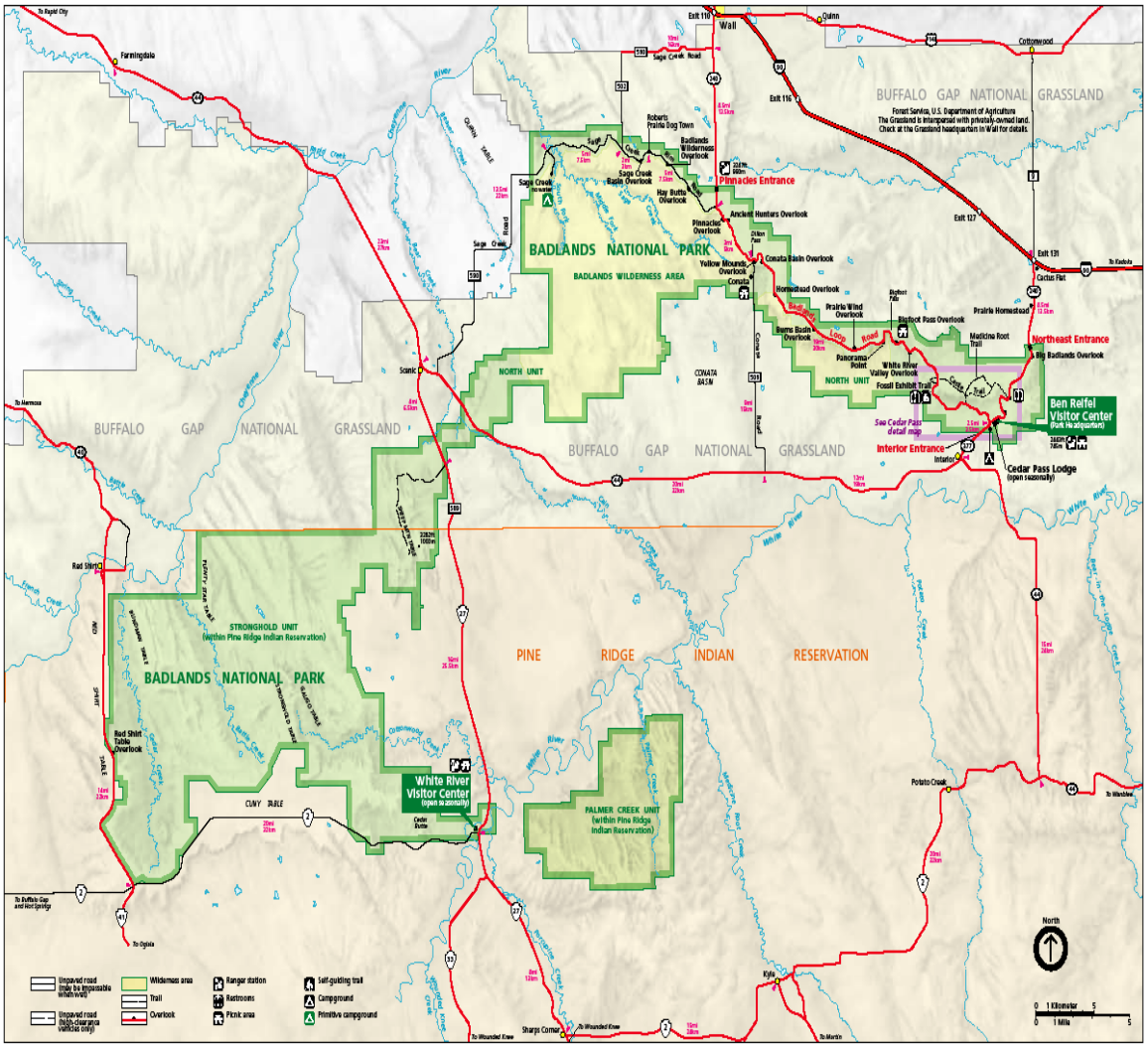
Figure 2-1 – Class I Areas in the United States

There are also national parks and wilderness areas considered Class I areas in our neighboring states. In Wyoming the Class I areas are located in the western part of the state. Montana's Class I areas are located throughout the state but none are located in the southeastern corner which borders South Dakota. North Dakota has probably the closest Class I area of any neighboring state. Minnesota's Class I areas are located in the northeastern corner of the state. Iowa and Nebraska do not have Class I areas.

2.1 Badlands National Park

The Badlands National Park is located in southwestern South Dakota and consists of 244,000 acres of sharply eroded buttes, pinnacles, and spires blended with the largest protected mixed grass prairie in the United States (see Figure 2-2). The closest industrial area from the park boundary is in Rapid City which is approximately 40 miles to the northwest. The general topography is plains; therefore this site is well exposed to regional scale transport winds. The surrounding terrain is predominantly mixed grass prairie and bare rock and sand.

Figure 2-2 –Badlands National Park's Boundary



It was established as the Badlands National Monument in 1939, and was redesignated as a national park in 1978. The area of the park that is actually considered a Class I area is the Badlands Wilderness Area, which consists of 64,000 acres in the north unit.

2.2 Wind Cave National Park

Wind Cave National Park lies approximately 10 miles north of Hot Springs in southwestern South Dakota (see Figure 2-3). It was the first cave to be designated a national park anywhere in the world and is currently the fourth longest cave in the world with 119.58 miles (192.45 kilometers) of explored cave passageways.

Figure 2-3 – Wind Cave National Park's Boundary

Aboveground, the park includes 28,295 acres of mixed-grass prairie, ponderosa pine forest, and associated wildlife (see Figure 2-4). The park's mixed-grass prairie is one of the largest remaining and home to bison, elk, pronghorn, mule deer, and prairie dogs. The view from

Lookout Tower on Rankin Ridge displays a spectacular view of the mixed-grass prairie and ponderosa pine forest (see Figure 2-5).

Figure 2-4 –Prairie, Forest, and Bison at Wind Cave (Courtesy of National Park Service)

Figure 2-5 – View from Lookout Tower (Courtesy of National Park Service)

3.0 Baseline, Natural and Uniform Rate of Improvement

In the mid-1980's, the IMPROVE (Interagency Monitoring of Protected Visual Environments) program was established to measure visibility impairment in Class I areas throughout the United States. The monitoring sites are operated and maintained through a formal cooperative relationship between the EPA, National Park Service, U.S. Fish and Wildlife, Bureau of Land Management, and U.S. Forest Service.

The objectives of the IMPROVE program include establishing the current visibility and aerosol conditions in Class I areas; identifying the chemical species and emission sources responsible for existing human-made visibility impairment; documenting long-term trends for assessing progress towards the national visibility goals; and support the requirements of the regional haze rule by providing regional haze monitoring representing all visibility-protected Class I areas where practical.

The data collected at the IMPROVE monitoring sites are used by federal land managers, industry planners, scientists, public interest groups, and air quality regulators to better understand and protect the visual air quality resource in Class I areas. Most importantly, the IMPROVE

program scientifically documents for American citizens, the visual air quality of their wilderness areas and national parks.

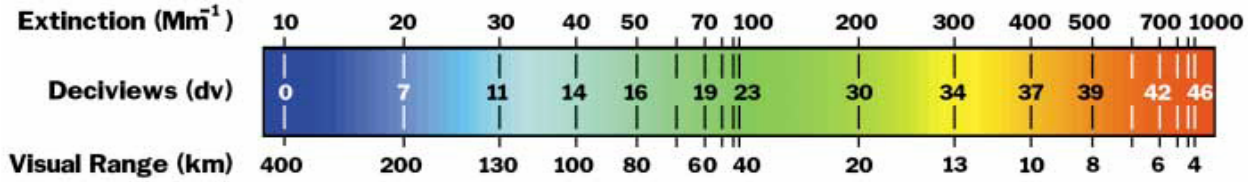
The IMPROVE network consists of aerosol and optical samplers. Every IMPROVE site deploys an aerosol sampler to measure speciated fine aerosols and coarse mass. Select sites also deploy a transmissometer and nephelometers to measure light extinction and scattering respectively, as well as automatic camera systems to visually measure the scenery. Particulate concentration data is obtained every 24 hours and converted into reconstructed light extinction through a complex calculation using the IMPROVE equation which may be viewed at:

http://vista.cira.colostate.edu/improve/Tools/ReconBext/reconBext.htm

Light extinction, the impairment of visibility, occurs due to particles and gases that reflect and absorb light. Reconstructed light extinction (denoted as b_{ext}) is expressed in units of inverse mega meters (1/Mm or Mm-1).

In accordance with 40 CFR 51.308(d)(2), states are required to track visibility conditions in terms of the Haze Index (HI) metric expressed in the deciviews. The relationship between light extinction in Mm-1, Haze Index in deciviews, and visual range in kilometers is indicted by the scale in Figure 3-1.

Figure 3-1 – Light Extinction-Haze Index-Visual Range Scale [1]



A comparison of the light extinction, haze index, and visual range at different levels may be viewed in Figure 3-2 for the Badlands National Park. Generally, a one deciview change in the Haze Index is likely humanly perceptible under ideal conditions regardless of background visibility conditions.

The IMPROVE data undergo quality assurance and control procedures and analyses by its contractors and the National Park Service before it is released. The aerosol and optical data are made publicly available approximately nine months after collection. In addition, seasonal analysis reports are prepared. IMPROVE program resources are available at:

http://vista.cira.colostate.edu/Improve.

There are two IMPROVE monitoring sites in South Dakota. One is located at the Badlands National Park and the other at Wind Cave National Park. The Badlands National Park operates an IMPROVE site (identified as "BADL1") located on a gently sloping flat in the eastern portion of the Badlands National Park, approximately two miles northeast of Interior, South Dakota. DENR operates an ambient air monitoring site at the same location (see Figure 3-3). The site

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elevation is 2,415 feet and the lowest elevation in the area is the White River at 2,320 feet, approximately two miles south of the monitoring site.

The Wind Cave National Park operates an IMPROVE site (identified as "WICA1") located near the park's visitors center (see Figure 3-4). Site elevation at the monitoring site is 4,240 feet and the general topography is hilly.

Figure 3-2 – Comparison at Different Levels

Deciview = 5; B_{ext} = 16; visual range = 240 km

Deciview = 19; B_{ext} = 65; visual range = 60 km

Deciview = 11; B_{ext} = 30; visual range = 130 km

Deciview = 23; B_{ext} = 98; visual range = 40 km

Figure 3-3 – Badlands' IMPROVE and State Monitoring Site

Figure 3-4 – Wind Caves' IMPROVE and State Monitoring Site

3.1 Baseline Visibility Conditions

In accordance with 40 CFR § 51.308(d)(2)(i), baseline visibility conditions for the most impaired and least impaired days are calculated using available monitoring data from calendar year 2000 to 2004. The rule requires the state to establish the average degree of visibility impairment for the most and least impaired days for each calendar year from 2000 to 2004 and average these annual values to determine the baseline visibility conditions.

DENR determined the baseline visibility conditions for the Badlands and Wind Cave National Parks based on IMPROVE data from the respective park. In the case where a day in the IMPROVE database did not have enough data to calculate a deciview value, the data was not considered in determining the baseline visibility conditions. The baseline visibility conditions was determined by calculating the average deciview value for the 20% least impaired (best) and most impaired (worst) days for each of the five years (2000 through 2004) and by averaging those five year values. The baseline visibility conditions for the Badlands and Wind Cave National Parks are summarized in Table 3-1.

Table 3-1 – Baseline Visibility Conditions in South Dakota's National Parks

	Badlands National Park		**Wind Cave National Park**	
	20% Least	**20% Most**	**20% Least**	**20% Most**
Calendar Year	**Deciviews**	**Deciviews**	**Deciviews**	**Deciviews**
2000	7.46	18.14	5.62	16.07
2001	7.45	17.63	5.11	15.47
2002	6.69	16.18	5.24	16.75
2003	6.34	17.81	5.02	16.12
2004	6.62	16.04	4.82	15.25
5-Year Average	**6.91**	**17.16**	**5.16**	**15.93**

The actual raw IMPROVE data used to determine the baseline visibility conditions may be viewed at the following website:

http://views.cira.colostate.edu/web/DataWizard/

3.2 Natural Visibility Conditions

In accordance with 40 CFR § 51.308(d)(2)(iii), a core requirement in the State Implementation Plan for the regional haze program is the establishment of natural visibility conditions for the 20% most impaired and 20% least impaired days. To assists states in determining natural visibility conditions, EPA published "*Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program*", in September 2003. The guidance identifies the primary cause of regional haze for many parts of the country is due to light scattering resulting from fine particles (e.g., particulate matter 2.5 microns in diameter or less). The fine particulate is composed of a variety of chemical species such as carbonaceous species (e.g., organics and

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elemental carbon) as well as ammonia, nitrate, sulfates, and soil. Coarse particulate which is particulate matter ranging in size from 2.5 to 10 microns in diameter can also contribute to light scattering. These components can occur both naturally and as the result of human activity.

The ultimate goal of the regional haze program is to remedy existing and prevent human-caused impairments of visibility and achieve natural conditions in each Class I area by 2064. It is recognized that natural conditions are not constant; but change over time. To compensate for varying natural processes, natural visibility conditions are based on a long term average condition analogous to the 5-year average conditions for the 20% most impaired and 20% least impaired days. In addition, as the difference between current and natural conditions become smaller and methods of estimating natural conditions improve, natural conditions may change as the regional haze program for each state is re-evaluated.

The natural condition for each Class I area is defined as the level of visibility (in deciviews) for the 20% most impaired days and 20% least impaired days that would exist if there were no manmade impairment. Since no visibility monitoring data exists from the pre-manmade impairment period, the EPA developed guidance on how to estimate natural conditions. Generally, for each Class I area in the western United States, the natural condition for the 20% most impaired days is determined by adding two standard deviations to the annual average of IMPROVE monitoring data. Similarly, the natural condition for the 20% least impaired days is determined by subtracting two standard deviations to the annual average of the IMPROVE monitoring data.

EPA's guidance on determining natural conditions provides two methods of estimating natural conditions. The first method is considered the default natural conditions. In this method, EPA provides estimates of natural conditions for each Class I area. In the second method, states may estimate site specific natural conditions if the state can provide sufficient evidence that supports refined natural conditions.

3.2.1 Default Natural Conditions

EPA developed default values for natural conditions to assist states in determining natural conditions. EPA's estimates for the natural levels of fine particulate constituents and of coarse particles were derived from the National Acid Precipitation Assessment Program (NAPAP) "*Acidic Deposition: State of Science and Technology: Report 24 – Visibility: Existing and Historical Conditions – Cause and Effects*", published in October 1990. The estimate of natural conditions presented in the NAPAP report separates the regions of the United States into the eastern half and western half. The eastern half consists of all states east of the Mississippi River, and up to one tier of states west of the Mississippi River. The western half includes the desert and mountain regions of the Mountain and Pacific Time zones. From this description, South Dakota is located in the western region; but should be evaluated to determine which natural conditions best represent South Dakota since it is on the border of the eastern and western half.

The NAPAP report estimated natural background concentrations for six major components of fine aerosols: sulfates, organics, elemental carbon, ammonium nitrate, soil dust, and water for the eastern and western regions of the United States. The NAPAP report also estimated the natural

background for coarse particulate matter. The estimates of natural concentration were based on the following:

1. Compilations of natural versus manmade emission levels;
2. Ambient measurements in remote areas (especially in the Southern hemisphere); and
3. Regressions studies using manmade and/or natural tracers.

EPA mentioned in the guidance the studies cited in the Appendix of the NAPAP report were conducted in relatively remote areas. Therefore, EPA believes it is reasonable to assume the contribution of fire to the particulate matter mass in the NAPAP estimates represents the natural regional contribution of fire. DENR is not sure it agrees with this assumption since fire suppression has occurred for many years disrupting the natural fire process even in remote areas.

Table 3-2 lists the average natural background levels of aerosols and light extinction and was derived from Table 2-1 of EPA's guidance, which is different then the natural background levels established in the NAPAP report. The reason for the difference is noted in the footnotes for Table 3-2. There was no value listed for sea salt.

Table 3-2 – Average Natural Background Concentration Levels

Aerosol Component	East (μg/m^3)	West (μg/m^3)
Ammonium sulfate [1]	0.23	0.12
Organic carbon mass [2]	1.40	0.47
Elemental carbon	0.02	0.02
Ammonium nitrate	0.1	0.1
Soil Dust	0.5	0.5
Coarse Mass	3.0	3.0

[1] – Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.1 micrograms per cubic meter (μg/m^3) and 0.2 μg/m^3 of ammonium bisulfate; and

[2] – Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.5 μg/m^3 and 1.5 μg/m^3 of organic compounds.

The average natural background concentrations levels in Table 3-2 were used in the formula displayed in Equation 3-1 to determine the natural light extinction (b_{ext}), which is used to characterize air pollution impacts on visibility. Light extinction is the fractional loss of the intensity of light per unit of distance caused by the scattering and absorption of gases and particles in the air.

Equation 3-1 – Natural Light Extinction Formula

$$b_{ext} = (3)f(RH)(sulfate) + (3)f(RH)(nitrate) + (4)(OCM) + (10)(LAC) + (soil) + (0.6)(CM) + 10$$

Where:

- b_{ext} = natural light extinction, in Mm^{-1};
- *f*(RH) = relative humidity correction factor;
- OCM = organic carbon mass, in μ/m^3;
- LAC = elemental carbon, in μ/m^3; and
- CM = coarse mass, in μ/m^3.

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The natural condition for South Dakota's Class I areas based on the formula in Equation 3-1 are listed in Table 3-3 and derived from Appendix B in EPA's guidance for estimating natural conditions.

Table 3-3 –Natural Background Conditions for South Dakota's Class I Areas

Class I Area	Bext [1]	Annual Average	20% Least Impaired Days	20% Most Impaired Days
Badlands	16.06	4.74 deciview	2.18 deciview	7.30 deciview
Wind Cave	15.97	4.68 deciview	2.12 deciview	7.24 deciview

[1] – Natural light extinction in inverse Mega meters (Mm^{-1}).

3.2.2 Improved Default Natural Conditions

Since EPA's guidance was written a revised natural light extinction formula was developed and adopted by EPA as the basis for the regional haze metric used to track progress in reducing haze levels in Class I areas. The new IMPROVE equation accounts for the effect of particle size distribution on light extinction of small and large size sulfate, nitrate and organic carbon mass. The revised formula is displayed in Equation 3-2.

Equation 3-2 – Revised Natural Light Extinction Formula

$$b_{ext} = 2.2 f_s(RH)[small\ sulfate] + 4.8 f_L(RH)[large\ sulfate] + 2.4 f_s(RH)[small\ nitrate]$$
$$+ 5.1 f_L(RH)[large\ nitrate] + 2.8[small\ organic\ mass] + 6.1[large\ organic\ mass]$$
$$+ 10[light\ absorbing\ carbon] + [soil] + 0.6[coarse\ matter] + 1.7 f_{ss}(RH)[sea\ salt]$$
$$+ Rayleigh\ Scattering + 0.33[NO_2(ppb)]$$

The total sulfate, nitrate and organic compound concentrations are split into two fractions representing small and large size distributions of each component. The formula for the large and small sulfate, nitrate and organic mass is displayed in Equation 3-3. In addition, the relative humidity correction factor in Equation 3-2 is also based on small size distribution (f_S(RH)) and large size distribution (f_L(RH)) for sulfate and nitrate and for sea salt (f_{SS}(RH)). The relative humidity correction factors were derived from the "*Federal Land Managers' Air Quality Related Values Workgroup (FLAG),*" drafted June 27, 2008, and can be viewed in Table 3-4.

Equation 3-3 – Large and Small Formulas

$$(Large) = \frac{(Total)}{20\frac{ug}{m^3}} \times (Total),\ for\ Total < 20\frac{ug}{m^3}$$

$$(Large) = (Total)\ for\ Total > 20\frac{ug}{m^3}$$

$$(Small) - (Total) - (Large)$$

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Table 3-4 – Relative Humidity Correction Factor (f(RH))

Class I Size	Month											
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Badlands												
Small	2.94	2.96	3.01	2.87	3.10	2.91	2.64	2.59	2.56	2.58	3.11	2.98
Large	2.31	2.31	2.31	2.21	2.34	2.25	2.08	2.05	2.02	2.05	2.38	2.33
Sea Salt	3.37	3.33	3.27	3.05	3.25	3.15	2.89	2.81	2.74	2.82	3.41	3.38
Wind Cave												
Small	2.81	2.81	2.86	2.82	3.06	2.81	2.50	2.46	2.44	2.52	2.97	2.83
Large	2.23	2.22	2.22	2.18	2.32	2.18	2.00	1.97	1.95	2.00	2.30	2.24
Sea Salt	3.25	3.20	3.13	3.01	3.22	3.06	2.75	2.68	2.63	2.75	3.28	3.24

The result of the revised light extinction is used in the formula displayed in Equation 3-4 to estimate the annual average of the haze index values (HI), in deciviews. DENR calculated the HI value for each month for each Class I area. The average HI value for each Class I area may be viewed in Table 3-5.

Equation 3-4 – Annual Average Haze Index

$$HI = 10\ln\left(b_{ext} \div 10\right)$$

Where:

- HI = annual average of the haze index values, in deciviews; and
- b_{ext} = natural light extinction, in Mm^{-1}.

In EPA's guidance, it was determined that the frequency distribution behaves normally (10th and 90th percentile HI) for Class I areas. This allows the 20% least impaired and 20% most impaired days to be determined using the annual average haze index and the formulas in Equation 3-5 and 3-6, respectively. In EPA's guidance, it was determined that the average standard deviation in the East is 3 deciviews and in the West it is 2 deciviews. DENR stayed consistent with using western values and used a standard deviation of 2 deciviews. The 10th and 90th percentile was calculated for each month for each Class I area. The results may be viewed in Table 3-5.

Equation 3-5 – Natural Least Impaired Days Formula

$$P10 = HI - 1.28sd$$

Equation 3-6 – Natural Most Impaired Days Formula

$$P90 = HI + 1.28sd$$

Where:

- P10 = Natural 20% least impaired days, in deciviews;
- P90 = Natural 20% most impaired days, in deciviews;
- HI = annual average haze index, in deciviews; and
- sd = standard deviation of the daily haze index values for that area, in deciviews.

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Table 3-5 –New Formula Natural Background Conditions for South Dakota's Class I Areas

Class I Area	Annual Average Haze Index	Natural Background	
		Least Impaired Days	Most Impaired Days
Badlands	**4.88 deciview**	2.32 deciview	7.44 deciview
Wind Cave	**4.85 deciview**	2.29 deciview	7.41 deciview

3.2.3 Baseline and Default Natural Conditions Comparison

The natural background concentration levels are estimated for long term average conditions. In some cases the natural background concentration level may have higher concentrations than the baseline concentrations or for any other 5-year period. If this occurs, EPA's guidance recommends that the natural background concentration level should be replaced with the corresponding measured value.

DENR used the IMPROVE data from each national park to determine the baseline concentration and compared the concentrations to the natural background concentrations in Table 3-2. Table 3-6 displays the comparison.

Table 3-6 – Comparison of Natural versus Baseline Concentrations [1]

Aerosol Component	Natural West ($\mu g/m^3$)	Background Badlands Least ($\mu g/m^3$)	Background Badlands Most ($\mu g/m^3$)	Background Wind Cave Least ($\mu g/m^3$)	Background Wind Cave Most ($\mu g/m^3$)
Ammonium sulfate	0.12 [2]	0.49	2.63	0.41	2.07
Organic carbon mass	0.47 [3]	0.62	3.17	0.50	3.55
Elemental carbon	0.02	0.08	0.26	0.07	0.30
Ammonium nitrate	0.10	0.16	0.76	0.12	0.98
Soil Dust	0.50	**0.33**	0.98	**0.24**	0.86
Coarse Mass	3.00	**2.53**	9.90	**1.78**	5.89

[1] – Units are in micrograms per cubic meter ($\mu g/m^3$);
[2] – Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimate was 0.1 $\mu g/m^3$ of ammonium bisulfate; and
[3] – Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimate was 0.5 $\mu g/m^3$ of organic compounds.

Based on the comparison, the aerosol components in the baseline data for 2000 through 2004 for the 20% least impaired days are less than the natural conditions for soil dust and coarse mass at both the Badlands and Wind Cave National Parks (see bolded values in Table 3-6). Although the soil dust and coarse mass for the baseline data is less than the values for natural conditions, DENR will use the values established in EPA's guidance for the initial Regional Haze State Implementation Plan and re-evaluate this in future State Implementation Plan reviews. Table 3-7 displays the natural conditions and compares it to the baseline data for 2000-2004.

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Table 3-7 – Baseline versus Natural Background (Deciviews)

Class I Area	Baseline	Natural	Difference	Baseline	Natural	Difference
	20% Least Impaired Days			20% Most Impaired Days		
Badlands	6.91	2.32	4.59	17.16	7.44	9.72
Wind Cave	5.16	2.29	2.87	15.93	7.41	8.52

3.2.4 Refined Natural Conditions

EPA identifies any refined approach for determining natural visibility conditions should be based on accurate, complete, and unbiased information and should be developed using a high degree of scientific rigor. The refined natural concentration estimates must retain the distinction between natural and anthropogenic components. For example, just like EPA's default natural concentrations, the refined natural concentrations should not exceed actual measured concentrations of that species over a 5-year period.

EPA indicates additional information will become available over the years to improve on the default natural concentrations such as the following:

1. Implementation of a coordinated fire data system or fire tracking system;
2. The collection of multiple years of speciated particulate matter data in mandatory Class I areas and the assessment of potential contributions by natural fire events using data from the fire tracking system;
3. Development of chemical analysis techniques to identify carbon attributed to fire versus other sources;
4. Development of improved emissions factors and tracking of fire activity levels; and
5. Improved regional scale fire modeling or remote sensing tools to retrospectively determine whether smoke from a fire impacted a Class I area air shed.

DENR agrees more refined natural species concentrations will be developed in the coming years that are more specific to a national park and will review this new information as it periodically reviews its Regional Haze State Implementation Plan.

3.3 Uniform Rate of Improvement

In accordance with 40 CFR § 51.308(d)(2)(iv)(A), the initial implementation plan shall address the difference between the baseline and natural conditions for the 20% most impaired and 20% least impaired days. In accordance with 40 CFR § 51.308(d)(1)(i)(B), the state is required to determine the rate of progress needed to attain natural visibility conditions by the year 2064. The rate of progress is based on the difference between the baseline visibility conditions and the natural visibility conditions for 20% most impaired days for each Class I area.

The uniform rate of visibility improvement, measured in deciviews, is determined by taking the difference between the baseline visibility conditions and the natural visibility conditions and dividing by 60 years, which is the time frame for attaining natural visibility conditions by 2064. The uniform rate of improvement is required to be considered as the state establishes its reasonable progress goals for attaining natural visibility conditions. The uniform rate of

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improvement for the Badlands and Wind Cave National Parks is based on the formula in Equation 3-7 and the baseline and natural background valued in Table 3-7. The results are displayed in Table 3-8. The uniform rate of improvement was calculated for the 20% most impaired days for each national park.

Equation 3-7 – Uniform Rate of Progress

$$Uniform\ Rate\ of\ \Pr ogress = (Baseline - Natural) \div 60$$

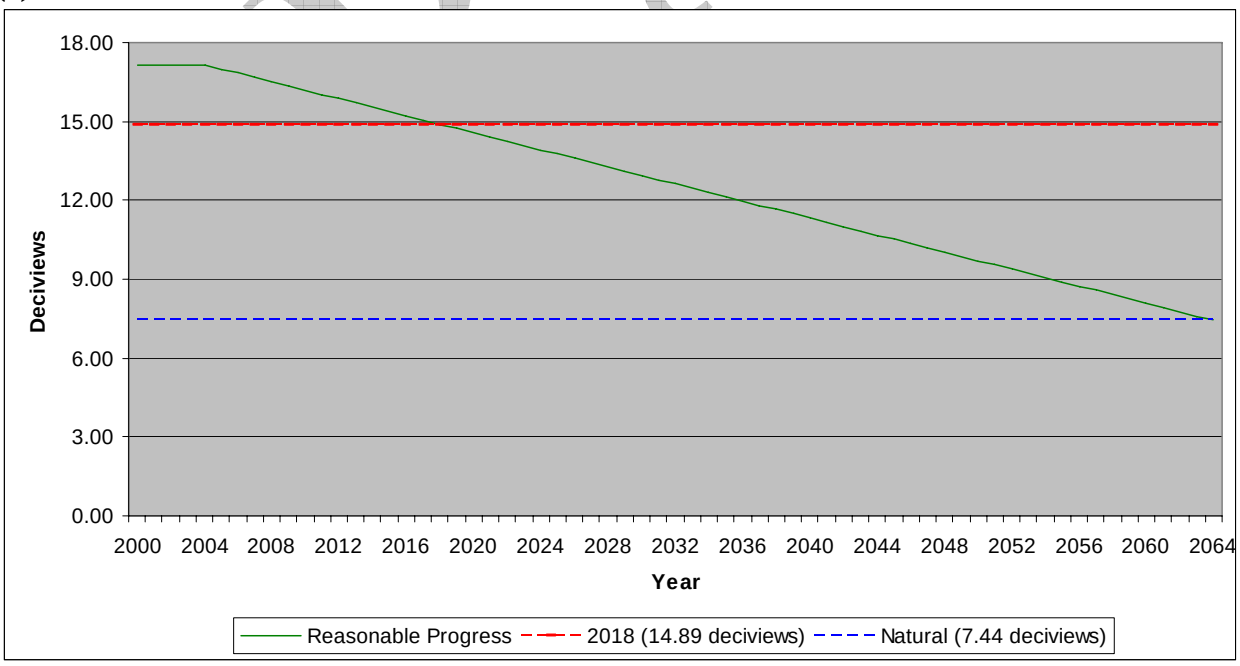
Table 3-8 – Annual Uniform Rate of Improvement

Description	Badlands	Wind Cave
Annual Improvement	0.1620 deciviews	0.1420 deciviews

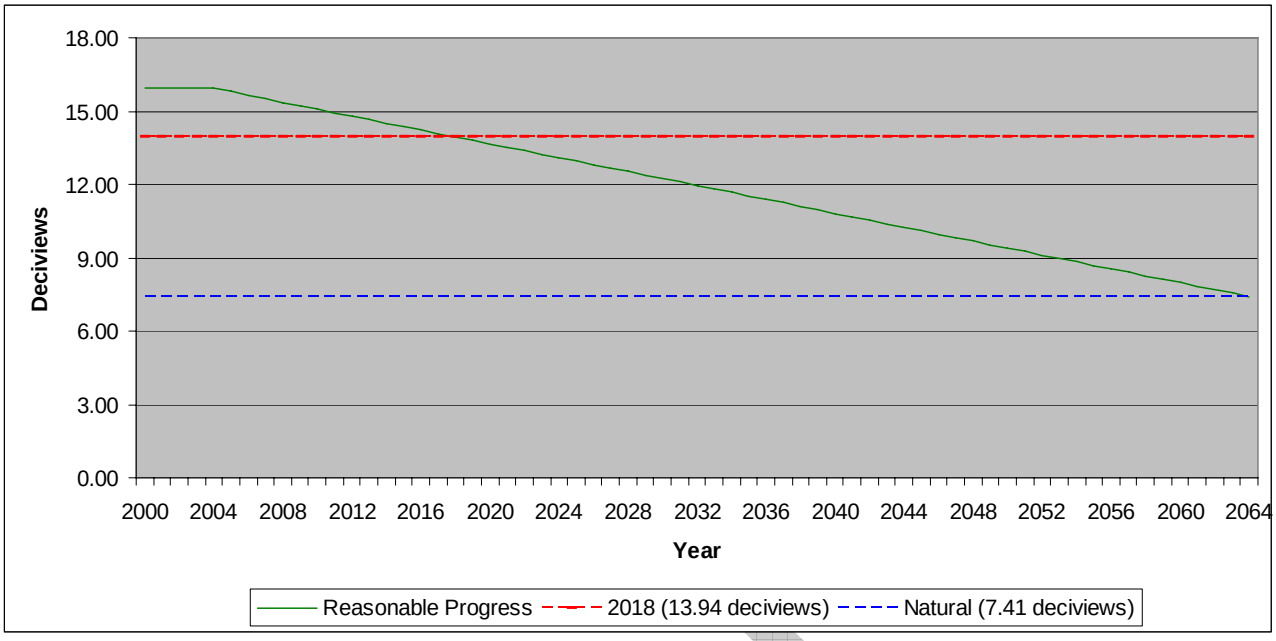
The uniform rate of improvement was used to establish the slope of reduction necessary to achieve the natural visibility conditions in 2064. The slope of reduction for the 20% most impaired days for the Badlands and Wind Cave National Parks are displayed in Figure 3-5.

The improvement needed by 2018 was calculated based on the annual uniform rate of improvement identified for each Class I area. The baseline is based on calendar years 2000 through 2004. Therefore, there are 14 years from the baseline to the first planning period or 2018. The improvement needed for the 20% most impaired days by calendar year 2018 for each Class I area was determined by multiplying the annual uniform rate of improvement by 14 years then subtracting that from the baseline value for the 20% most impaired days in Table 3-7. The result is displayed in Figure 3-5.

Figure 3-5 – Uniform Rate of Improvement
(a) Badlands National Park



(b) Wind Cave National Park



4.0 IMPROVE Data for Class I Areas

The data from the IMPROVE monitoring sites identifies the composition of the pollutants impacting our Class I areas and consists of ammonia sulfates fine (ammSO4f), ammonia nitrates fine (ammNO3f), organic mass carbon (OMC), elemental carbon fine (Ecf), soil, coarse mass (CM), and sea salt. The IMPROVE data has been collected at the Badlands National Park since 1988 and the Wind Cave National Park since 2000. DENR is using the IMPROVE data to help determine what air pollutants are causing or contributing to visibility impairment in the Class I areas and assist in evaluating if each state is achieving the reasonable progress goals.

4.1 Aerosol Concentrations

The average aerosol concentration (micrograms per cubic meter (ug/m^3)) and visibility (deciviews) per year during the baseline period (2000-2004) for the 20% least (P10) and 20% most (P90) impaired days are summarized in Table 4-1 for the Badlands National Park and Table 4-2 for the Wind Cave National Park. The last line in each Table provide the default natural conditions that should be achieved for the 20% most impaired days by 2064.

The baseline aerosol concentrations at the Badlands and Wind Cave National Parks during the 20% most impaired days are all similar and within 22% or less of each other except for the coarse mass and sea salt. If you neglect sea salt, the aerosol with the greatest dissimilarity is coarse mass with the Badlands National Park's coarse mass baseline concentrations being greater than at the Wind Cave National Park. This would be expected because of the drier conditions associated with the Badlands National Park. Coarse mass is typically generated from crushing or grinding operations, dust from paved or unpaved roads, windblown dust, etc.

Table 4-1 – Badlands National Park Baseline Aerosol Concentrations [1]

a) Aerosol Concentrations for 20% Least Impaired

Year	P10 (Deciview)	ammSO4f (u/m^3)	ammNO3f (u/m^3)	OMC (u/m^3)	Ecf (u/m^3)	SOIL (u/m^3)	CM (u/m^3)	Sea Salt (u/m^3)
2000	7.46	0.64	0.20	0.64	0.08	0.26	2.08	0.01
2001	7.45	0.57	0.21	0.64	0.09	0.39	2.60	0.00
2002	6.69	0.37	0.12	0.62	0.09	0.44	3.21	0.00
2003	6.34	0.44	0.11	0.61	0.06	0.25	2.38	0.00
2004	6.62	0.43	0.17	0.57	0.07	0.33	2.39	0.01
5-yr	**6.91**	**0.49**	**0.16**	**0.62**	**0.08**	**0.33**	**2.53**	0.00
Natural	**2.32**	**0.12**	**0.10**	**0.47**	**0.02**	**0.50**	**3.00**	**0.00**

b) Aerosol Concentrations for 20% Most Impaired

Year	P90 (Deciview)	ammSO4f (u/m^3)	ammNO3f (u/m^3)	OMC (u/m^3)	Ecf (u/m^3)	SOIL (u/m^3)	CM (u/m^3)	Sea Salt (u/m^3)
2000	18.14	2.72	0.50	4.78	0.40	1.00	10.14	0.00
2001	17.63	3.13	0.95	2.38	0.26	1.29	9.79	0.00
2002	16.18	2.45	0.63	2.22	0.19	1.14	12.17	0.10
2003	17.81	2.27	0.91	4.03	0.29	0.73	11.65	0.06
2004	16.04	2.55	0.83	2.43	0.16	0.74	5.77	0.02
5-yr	**17.16**	**2.63**	**0.76**	**3.17**	**0.26**	**0.98**	**9.90**	**0.04**
Natural	**7.44**	**0.12**	**0.10**	**0.47**	**0.02**	**0.50**	**3.00**	**0.00**

[1] – Units are in micrograms per cubic meter ($\mu g/m^3$), "P10" = 20% least impaired days, "P90" = 20% most impaired days, "ammSO4f" = ammonia sulfate fine; "ammNO3f" = ammonia nitrate fine, "OMC" = organic mass carbon, "Ecf" = Elemental carbon fine, and "CM" = coarse mass.

Table 4-2 – Wind Cave National Park Baseline Aerosol Concentrations [1]

a) Aerosol Concentrations for 20% Least Impaired

Year	P10 (Deciview)	ammSO4f (u/m^3)	ammNO3f (u/m^3)	OCM (u/m^3)	Ecf (u/m^3)	SOIL (u/m^3)	CM (u/m^3)	Sea Salt (u/m^3)
2000	5.62	0.49	0.15	0.59	0.09	0.18	1.24	0.00
2001	5.11	0.43	0.13	0.44	0.06	0.28	1.75	0.00
2002	5.24	0.36	0.10	0.48	0.07	0.30	2.57	0.01
2003	5.02	0.40	0.08	0.54	0.06	0.22	1.89	0.00
2004	4.82	0.38	0.12	0.44	0.07	0.22	1.44	0.00
5-yr	**5.16**	**0.41**	**0.12**	**0.50**	**0.07**	**0.24**	**1.78**	**0.00**
Natural	**2.29**	**0.12**	**0.10**	**0.47**	**0.02**	**0.50**	**3.00**	**0.00**

b) Aerosol Concentrations for 20% Most Impaired

Year	P90 (Deciview)	ammSO4f (u/m^3)	ammNO3f (u/m^3)	OCM (u/m^3)	Ecf (u/m^3)	SOIL (u/m^3)	CM (u/m^3)	Sea Salt (u/m^3)
2000	16.07	1.86	0.68	4.33	0.37	0.97	6.57	0.00
2001	15.47	2.25	1.26	2.48	0.23	0.82	5.99	0.00
2002	16.75	2.26	0.87	4.15	0.31	0.98	6.78	0.00

Year	P90 (Deciview)	ammSO4f (u/m^3)	ammNO3f (u/m^3)	OCM (u/m^3)	Ecf (u/m^3)	SOIL (u/m^3)	CM (u/m^3)	Sea Salt (u/m^3)
2003	16.12	2.03	0.86	4.00	0.24	0.75	6.60	0.01
2004	15.25	1.94	1.24	2.79	0.33	0.77	3.49	0.02
5-yr	**15.93**	**2.07**	**0.98**	**3.55**	**0.30**	**0.86**	**5.89**	**0.01**
Natural	**7.41**	**0.12**	**0.10**	**0.47**	**0.02**	**0.50**	**3.00**	**0.00**

[1] – Units are in micrograms per cubic meter ($\mu g/m^3$), "P10" = 20% least impaired days, "P90" = 20% most impaired days, "ammSO4f" = ammonia sulfate fine; "ammNO3f" = ammonia nitrate fine, "OMC" = organic mass carbon, "Ecf" = Elemental carbon fine, and "CM" = coarse mass.

The aerosol concentrations that appear to need to be reduced the most to achieve natural concentrations at both national parks are ammonia sulfate and elemental carbon. Ammonia sulfates are derived from fossil fuel combustion and the combustion of organic mass such as forest fires and the burning of grass. Elemental carbon is also generated from fossil fuel combustion; but is generally used as the main indicator of emissions from fires and other combustion sources such as diesel emissions.

Organic carbon mass and ammonia nitrate aerosol concentrations at the two national parks would also need to be reduced since current concentrations are approximately seven to 10 times greater than natural conditions. Organic carbon mass is derived from biomass burning, automobile emissions, fossil fuel combustion, gas-to-particle conversion of hydrocarbons, etc. Ammonia nitrates are generated from similar sources that generate ammonia sulfates along with organic decomposition.

4.2 Extinction Comparison

Extinction (inverse mega meters (Mm^{-1})) is useful in relating visibility directly to particle species concentrations. DENR took the IMPROVE data for the baseline period (2000-2004) for the 20% least and 20% most impaired days and summarized it in Table 4-3 for the Badlands National Park and Table 4-4 for the Wind Cave National Park, except for sea salt since the concentrations for sea salt are minimal.

Table 4-3 – Badlands National Park [1]
a) Baseline Aerosol Concentrations for 20% Least Impaired

Year	Extinction (bext) (Mm^{-1})	ammSO4f (Mm^{-1})	ammNO3f (Mm^{-1})	OMC (Mm^{-1})	Ecf (Mm^{-1})	SOIL (Mm^{-1})	CM (Mm^{-1})
2000	21.28	4.53	1.50	1.88	0.82	0.26	1.25
2001	21.15	3.85	1.58	1.87	0.89	0.39	1.56
2002	19.58	2.57	0.91	1.82	0.91	0.44	1.93
2003	18.90	3.00	0.81	1.78	0.63	0.25	1.43
2004	19.44	3.01	1.32	1.64	0.66	0.33	1.43
5-yr	**20.07**	**3.39**	**1.23**	**1.80**	**0.78**	**0.33**	**1.52**
% Without Rayleigh		**36%**	**14%**	**20%**	**9%**	**4%**	**17%**

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b) Baseline Aerosol Concentrations for 20% Most Impaired

Year	Extinction (bext) (Mm^{-1})	ammSO4f (Mm^{-1})	ammNO3f (Mm^{-1})	OMC (Mm^{-1})	Ecf (Mm^{-1})	SOIL (Mm^{-1})	CM (Mm^{-1})
2000	63.49	18.99	3.63	18.74	4.04	1.00	6.08
2001	59.32	23.25	7.41	7.93	2.56	1.29	5.87
2002	51.28	17.43	4.68	7.36	1.86	1.14	7.30
2003	61.53	16.19	7.18	16.22	2.90	0.73	6.99
2004	50.73	18.83	6.48	8.53	1.57	0.74	3.46
5-yr	**57.27**	**18.94**	**5.88**	**11.76**	**2.59**	**0.98**	**5.94**
% Without Rayleigh		**41%**	**13%**	**25%**	**6%**	**2%**	**13%**

[1] – Units are in inverse Mega meters (Mm^{-1}), "B_{ext}" = natural light extinction, "ammSO4f" = ammonia sulfate fine; "ammNO3f" = ammonia nitrate fine, "OMC" = organic mass carbon, "Ecf" = Elemental carbon fine, and "CM" = coarse mass.

Table 4-4 – Wind Cave National Park [1]

a) Aerosol Concentrations for 20% Least Impaired

Year	Extinction (bext) (Mm^{-1})	ammSO4f (Mm^{-1})	ammNO3f (Mm^{-1})	OMC (Mm^{-1})	Ecf (Mm^{-1})	SOIL (Mm^{-1})	CM (Mm^{-1})
2000	17.71	3.12	1.07	1.72	0.87	0.18	0.74
2001	16.75	2.65	0.88	1.27	0.63	0.28	1.05
2002	16.95	2.27	0.68	1.38	0.74	0.30	1.54
2003	16.58	2.48	0.53	1.58	0.63	0.22	1.14
2004	16.26	2.41	0.82	1.27	0.67	0.22	0.86
5-yr	**16.85**	**2.58**	**0.80**	**1.44**	**0.71**	**0.24**	**1.07**
% Without Rayleigh		**38%**	**12%**	**21%**	**10%**	**3%**	**16%**

b) Aerosol Concentrations for 20% Most Impaired

Year	Extinction (bext) (Mm^{-1})	ammSO4f (Mm^{-1})	ammNO3f (Mm^{-1})	OMC (Mm^{-1})	Ecf (Mm^{-1})	SOIL (Mm^{-1})	CM (Mm^{-1})
2000	51.94	11.60	4.69	17.00	3.74	0.97	3.94
2001	48.76	14.58	9.25	8.22	2.28	0.82	3.59
2002	56.18	14.98	6.06	16.95	3.14	0.98	4.07
2003	51.05	12.66	6.19	15.05	2.40	0.75	3.96
2004	47.94	12.80	9.19	9.73	3.25	0.77	2.09
5-yr	**51.18**	**13.32**	**7.07**	**13.39**	**2.96**	**0.86**	**3.53**
% Without Rayleigh		**32%**	**17%**	**33%**	**7%**	**2%**	**9%**

[1] – Units are in inverse Mega meters (Mm^{-1}), "B_{ext}" = natural light extinction, "ammSO4f" = ammonia sulfate fine; "ammNO3f" = ammonia nitrate fine, "OMC" = organic mass carbon, "Ecf" = Elemental carbon fine, and "CM" = coarse mass.

DENR included in each table the percentage of visibility impairment based on each aerosol's contribution to the extinction after subtracting out the Rayleigh affect. The Rayleigh affect is the scattering of light by particles much smaller than the wavelength of light. The percentages of extinction per aerosol for the 20% least and most impaired days for the Badlands and Wind Cave National Parks are displayed in Figure 4-1 and 4-2, respectively.

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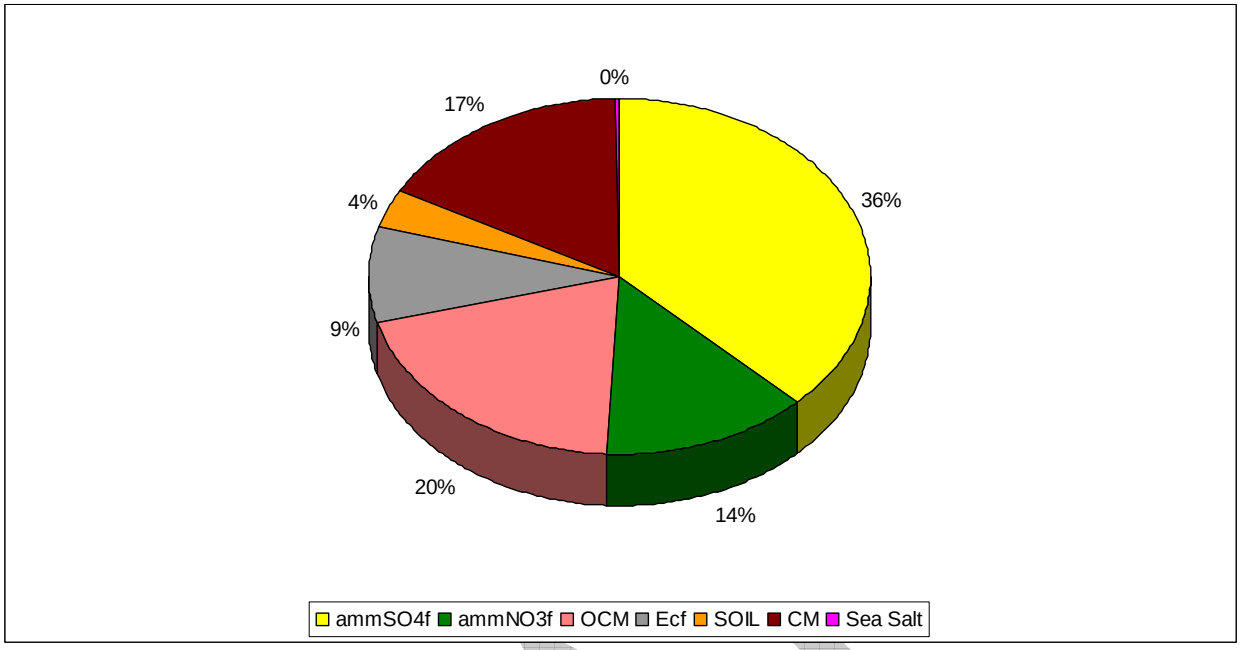
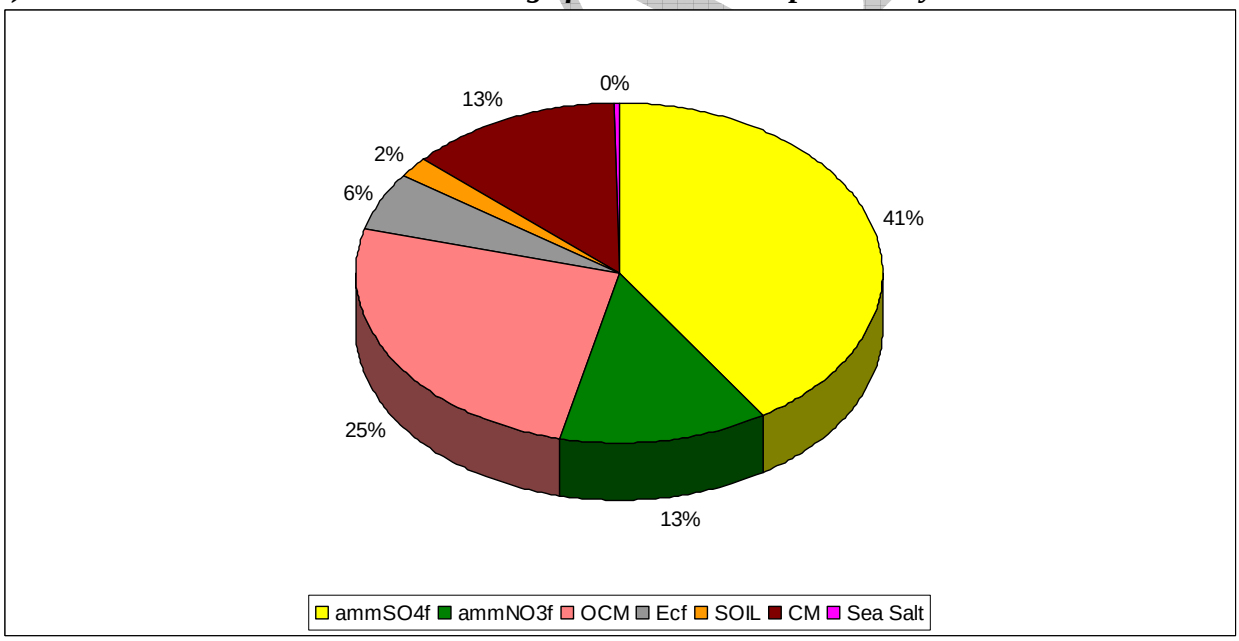
Figure 4-1 – Badlands National Park Baseline Aerosol Extinction Comparison [1]
a) Baseline Aerosol Extinction Percentage for 20% Least Impaired Days



b) Baseline Aerosol Extinction Percentage for 20% Most Impaired Days



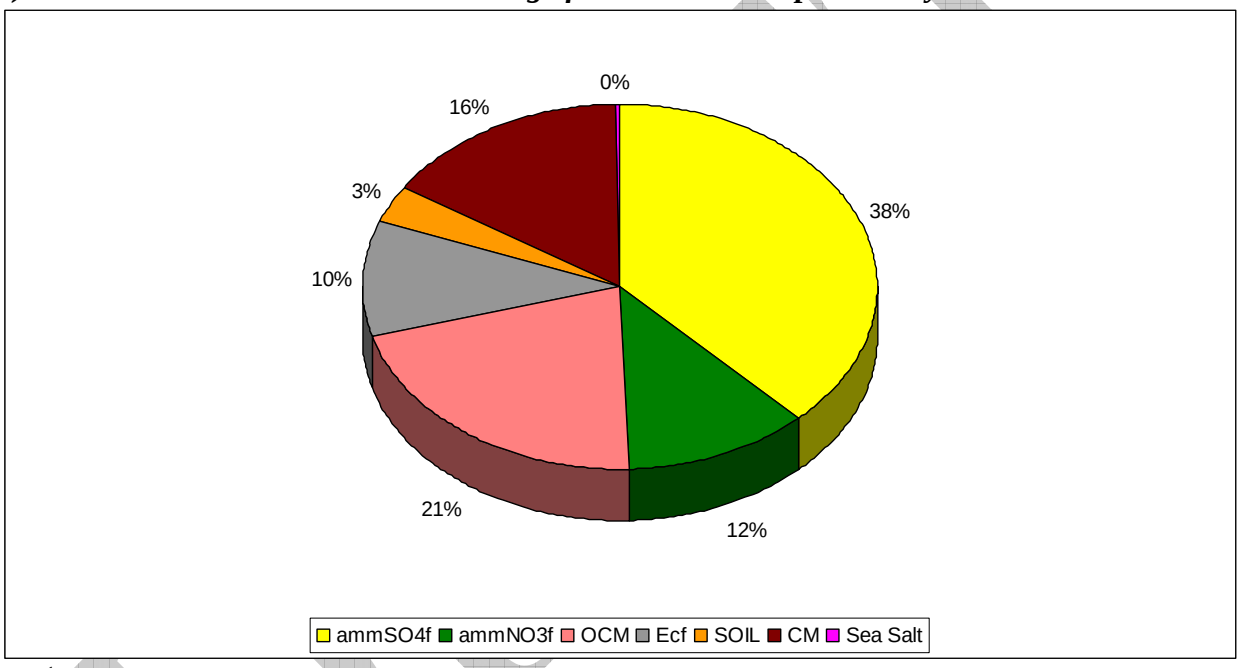
[1] – "ammSO4f" = ammonia sulfate fine; "ammNO3f" = ammonia nitrate fine, "OMC" = organic mass carbon, "Ecf" = Elemental carbon fine, and "CM" = coarse mass.

In the 20% least impaired days for the Badlands National Park, the aerosol that contributed the greatest visibility impairment is ammonia sulfate at 36%, which is almost double the percentage of the second greatest contributor. The second greatest contributor is organic carbon mass at 20%. The third greatest contributor is coarse mass at 17% followed closely by ammonia nitrates at 14%. Ammonia sulfate, organic carbon mass, coarse mass and ammonia nitrate represent 87%

of the aerosol concentrations impacting the 20% least impaired days in the Badlands National Park.

In the 20% most impaired days for the Badlands National Park, the aerosol that contributed the greatest visibility impairment again is ammonia sulfate at 41%. Its contribution is not double the percentage of the second greatest contributor; but is close. The second greatest contributor is organic carbon mass at 25%. The third greatest contributor is coarse mass and ammonia nitrates at 13%, each. Ammonia sulfate, organic carbon mass, coarse mass and ammonia nitrate represent 92% of the aerosol concentrations impacting the 20% most impaired days in the Badlands National Park.

Figure 4-2 – Wind Cave Baseline Aerosol Extinction Percentage
a) Baseline Aerosol Extinction Percentage for 20% Least Impaired Days [1]

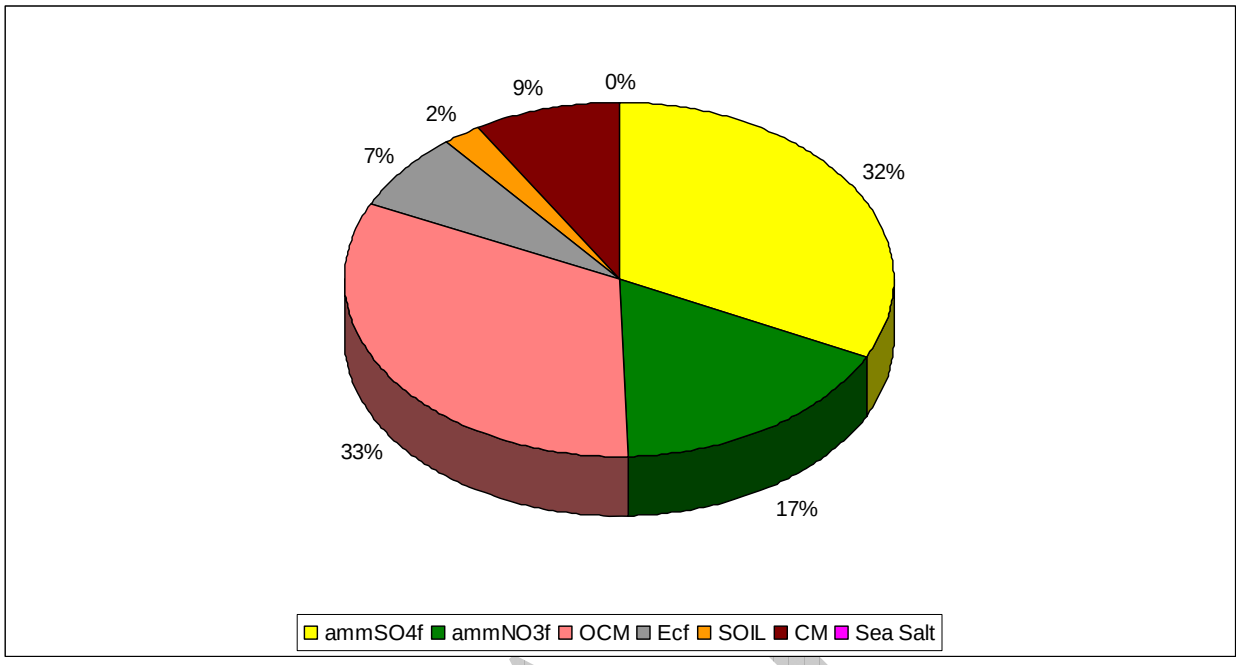


[1] – "ammSO4f" = ammonia sulfate fine; "ammNO3f" = ammonia nitrate fine, "OMC" = organic mass carbon, "Ecf" = Elemental carbon fine, and "CM" = coarse mass.

In the 20% least impaired days for the Wind Cave National Park, the aerosol that contributed the greatest visibility impairment is ammonia sulfate at 38%, which is almost double the percentage of the second greatest contributor. The second greatest contributor is organic carbon mass at 21%. The third greatest contributor is coarse mass at 16% followed by ammonia nitrates at 12%. Ammonia sulfate, organic carbon mass, coarse mass and ammonia nitrate represent 87% of the aerosol concentrations impacting the 20% least impaired days in the Wind Cave National Park.

In the 20% most impaired days for the Wind Cave National Park, the aerosol that contributed the greatest visibility impairment is organic carbon mass at 33%, followed closely by ammonia sulfate at 32%. The third greatest contributor is ammonia nitrates at 17% followed by coarse mass at 9%. Ammonia sulfate, organic carbon mass, coarse mass and ammonia nitrate represent 91% of the aerosol concentrations impacting the 20% most impaired days in the Wind Cave National Park.

b) Baseline Aerosol Extinction Percentage for 20% Most Impaired Days [1]



[1] – "ammSO4f" = ammonia sulfate fine; "ammNO3f" = ammonia nitrate fine, "OMC" = organic mass carbon, "Ecf" = Elemental carbon fine, and "CM" = coarse mass.

There is a good comparison between the 5-year average concentration for each aerosol at the Badlands and Wind Cave National Park during the 20% least impaired days (see Figure 4-3(a)). Although these concentrations represent the 20% least impaired days, the concentrations are still greater than natural conditions. DENR did not anticipate the two national parks to have similar concentrations since the Badlands National Park is predominantly mixed prairie grasses, bare rock and sand while the Wind Cave National Park is mixed prairie grasses and ponderosa pine forest.

Local influences on the 20% least impaired days would tend to influence just the park it is next to and not the other. If local influences were impacting the 20% least impaired days, concentrations at both parks would not be that similar. However, the 5-year averaging may smooth this out.

Depending on the distance, concentrations from regional influence would be well mixed and uniform as it impacts South Dakota's two Class I areas. A uniform regional influence would tend to influence both national parks similarly.

DENR will evaluate this in its long-term strategy to determine if there are any impacts from local sources hidden by the 5-year average and/or if regional influence is the main reason for the elevated concentrations on the 20% least impaired days.

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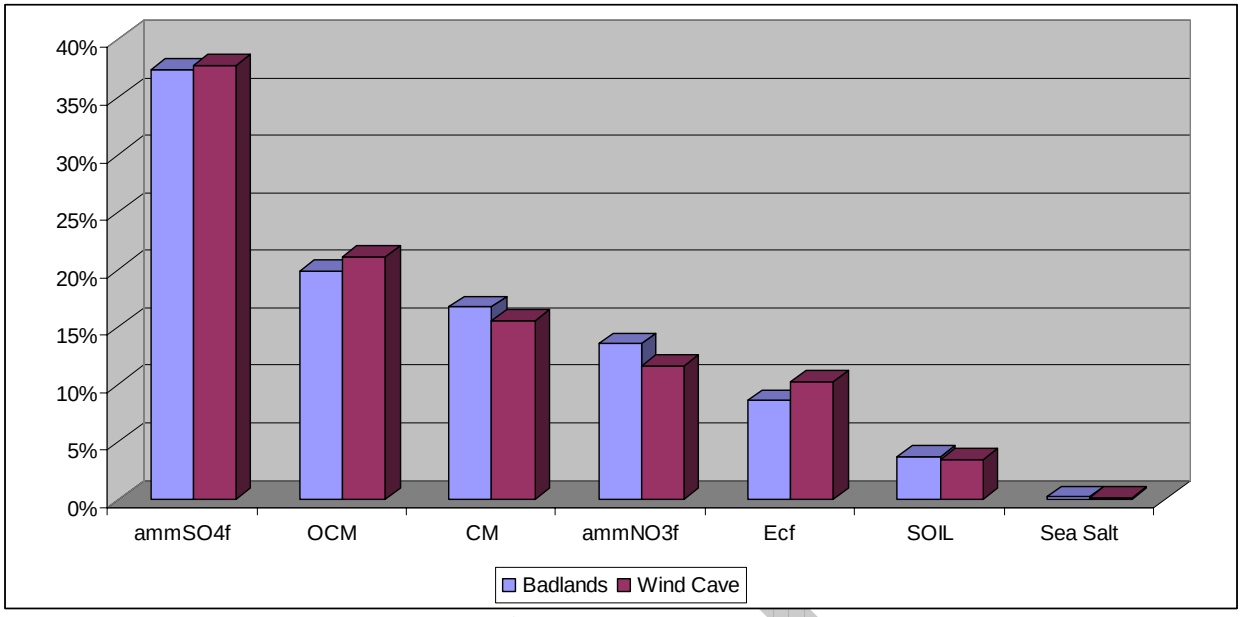
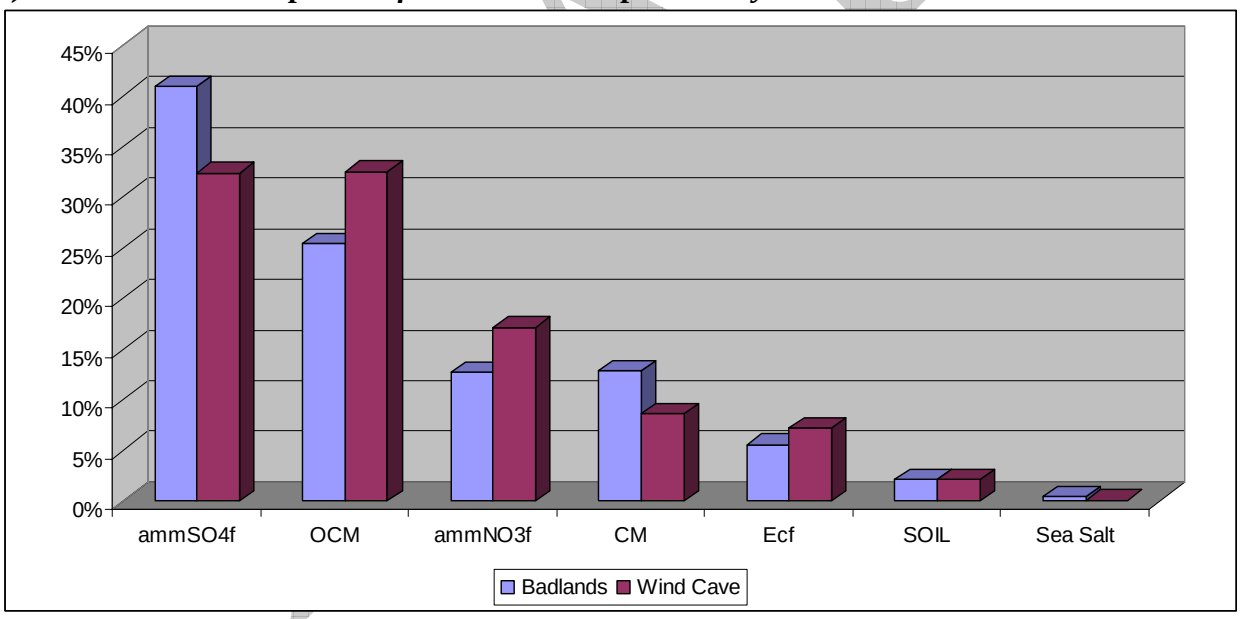
Figure 4-3 – National Park Extinction Comparison [1]

a) National Park Comparison for 20% Least Impaired Days



b) National Park Comparison for 20% Most Impaired Days



[1] – "ammSO4f" = ammonia sulfate fine; "ammNO3f" = ammonia nitrate fine, "OMC" = organic mass carbon, "Ecf" = Elemental carbon fine, and "CM" = coarse mass.

For the 20% most impaired days, the comparison is not as similar. From Figure 4.3(b), ammonia sulfate is impacting visibility at the Badlands National Park at a greater degree than it is at the Wind Cave National Park. At the Wind Cave National Park, organic carbon mass and ammonia sulfate have the greatest impact and provide approximately the same percentage of visibility impairment. This indicates that fires contribute more to visibility impairment at Wind Cave

National Park then at Badlands National Park because of the higher organic carbon mass contribution.

Ammonia sulfates and organic carbon mass are generated from similar sources. Ammonia sulfates are derived from fossil fuel combustion and the combustion of organic mass such as forest fires and the burning of grass. Organic carbon mass is derived from biomass burning, automobile emissions, fossil fuel combustion, gas-to-particle conversion of hydrocarbons, etc. The contribution of ammonia sulfates and organic carbon mass from fossil fuel combustion from industrial sources and mobile sources should tend to be constant throughout the year. The contribution from the burning of organic mass or from heating should tend to occur at certain times of the year and be evident by quarter.

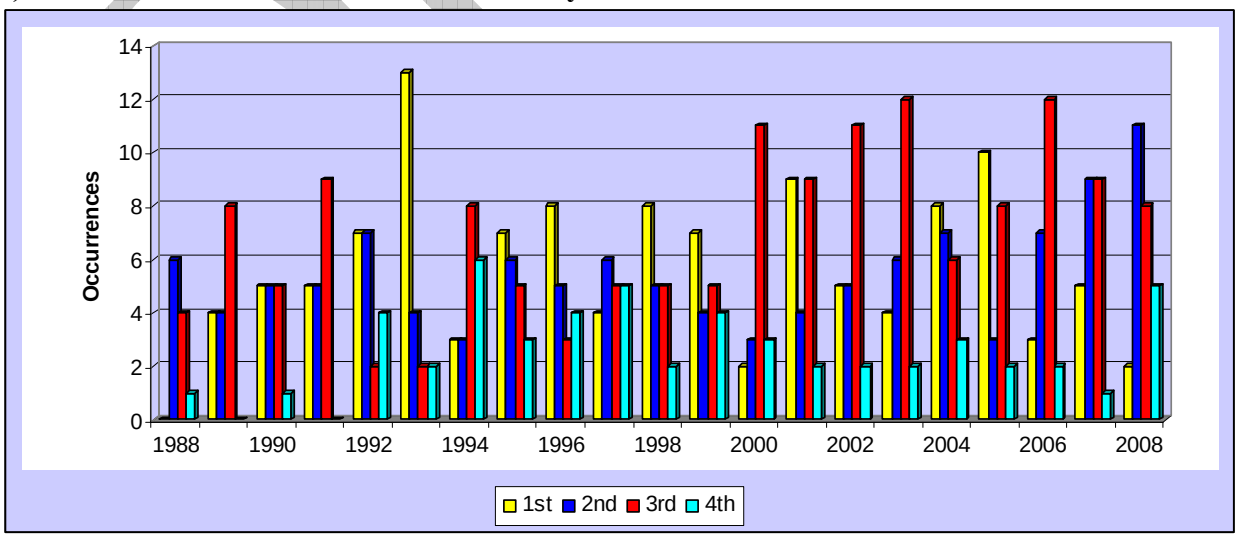
4.3 Visibility Impairment Quarterly Trends

Visibility impairment is impacted by the aerosol concentrations, type of aerosols, and time of year. DENR looked at various charts to determine if there were any trends based on the time of year for the 20% most impaired days. DENR reviewed the charts by quarter. For this review, the first quarter represents the winter months (January through March); the second quarter represents the spring months (April through June); the third quarter represents the summer months (July through September); and the fourth quarter represents the fall months (October through December).

4.3.1 Number of Occurrences per Quarter

The first type of chart DENR looked at was the number of occurrences per quarter for the 20% most impaired days. Figure 4-4 provides the quarterly comparison for the Badlands National Park and Wind Cave National Park.

Figure 4-4 –Number of Occurrences by Quarter – 20% Most Impaired Days
a) Badlands National Park Occurrences by Quarter



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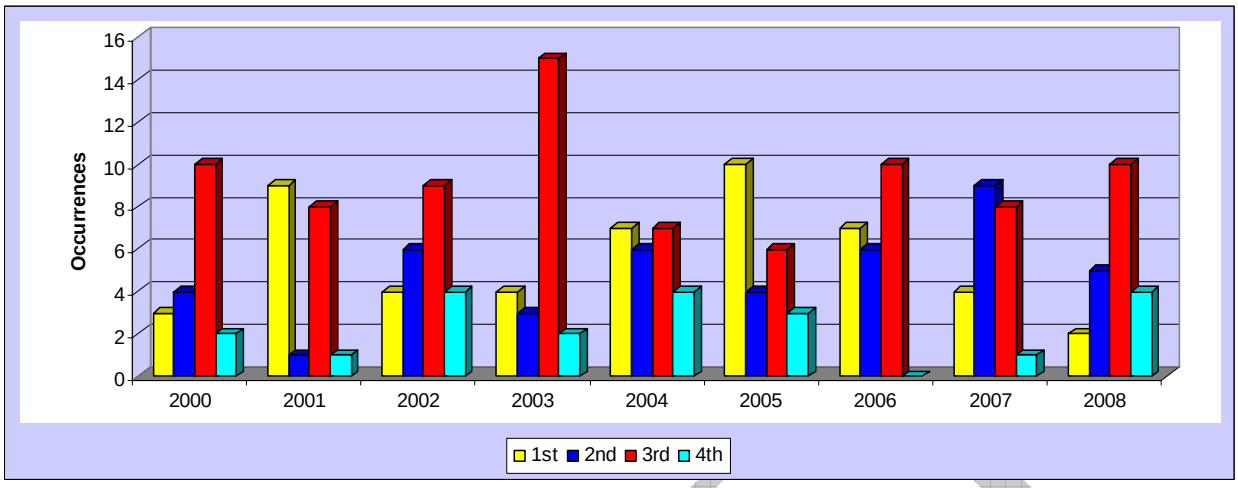
b) Wind Cave National Park Occurrences by Quarter



Based on the Badlands National Park data, the 4th quarter (fall months) consistently appear to have the least number of visibility impairment occurrences during the 20% most impaired days, especially for the baseline period (2000-2004). The 4th quarter did experience an increase in 2008, which will need to be reviewed in the future to see if the increase continues. The occurrences in the remaining quarters increase and decrease with the 3rd quarter (summer months) having the most occurrences in the baseline period and in the last four years of data. One thing to note is the 2nd quarter (spring months) is showing an increase in occurrences in the last three years, which will also need to be reviewed if this trend continues.

The number of occurrences ranged from zero to 13 occurrences per quarter. The greatest number of occurrences peaked in the 1st quarter of 1993 at 13. From 2000 to 2008, the greatest number of occurrences occurs in the 3rd quarter ranging from six to 12 occurrences per year. The 2nd and 4th quarter saw a rise in 2008 with the 1st quarter showing a decline.

Overall, in the last few years the 2nd and 3rd quarter tend to have the most occurrences while the 1st and 4th quarter have the least number of occurrences. The number of occurrences in the 2nd quarter has increased to where they had the most occurrences in 2008, followed by the 3rd quarter, 4th quarter and 1st quarter.

The number of occurrences in the Wind Cave National Park range from zero to 15 occurrences per quarter during the 20% most impaired days. The greatest number of occurrences occurred in the 3rd quarter during the baseline period (2000-2004) and peaked in 2003 at 15 occurrences. The 4th quarter consistently had the least number of occurrences in the baseline period and ranged from two to four occurrences per quarter. For the last four years, the greatest number of occurrences occurred in the 3rd quarter ranging from six to 10 occurrences per year. The 4th quarter appears to have the least amount of occurrences ranging from zero to four occurrences per year. However, in 2008 the number of occurrences in the 1st quarter dropped to where it has the least number of occurrences at two.

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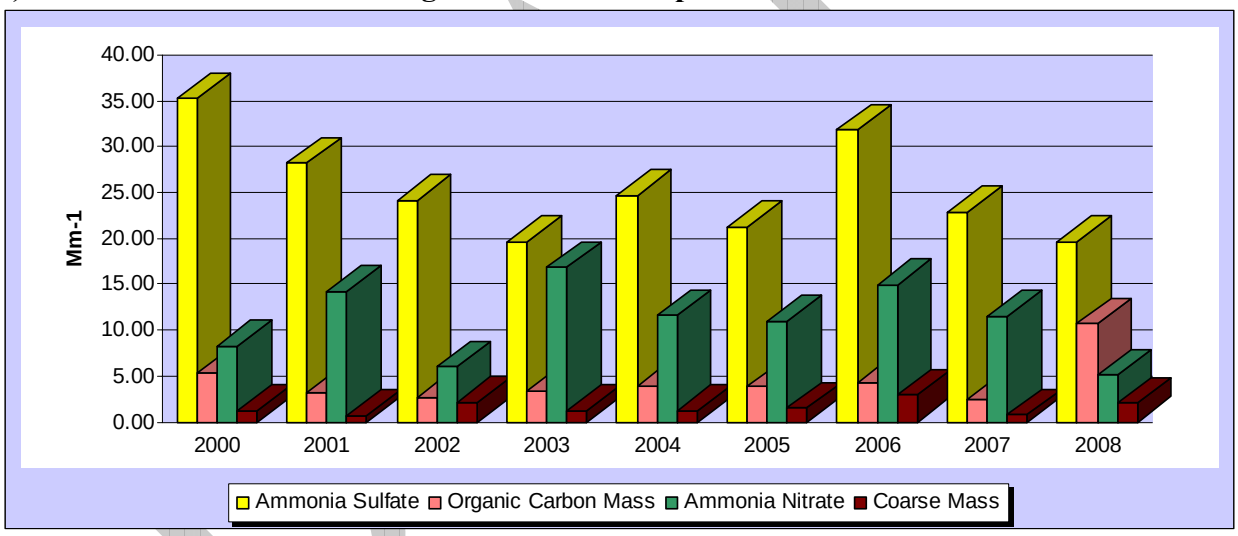
4.3.2 Extinction Trends by Quarter

DENR also charted the average extinction value for each quarter for ammonia sulfate, ammonia nitrate, organic carbon mass, and coarse mass during the 20% most impaired days for each national park since these four air pollutants comprise over 90% of the visibility impairment in each park. Figure 4-5 and 4-6 display the quarterly data from 2000, which is the start of the baseline period, to 2008 for the Badlands and Wind Cave National Parks, respectively. In some cases, there is no quarterly extinction value for a certain year, which means there were no days that contributed to the 20% most impaired days during that quarter.

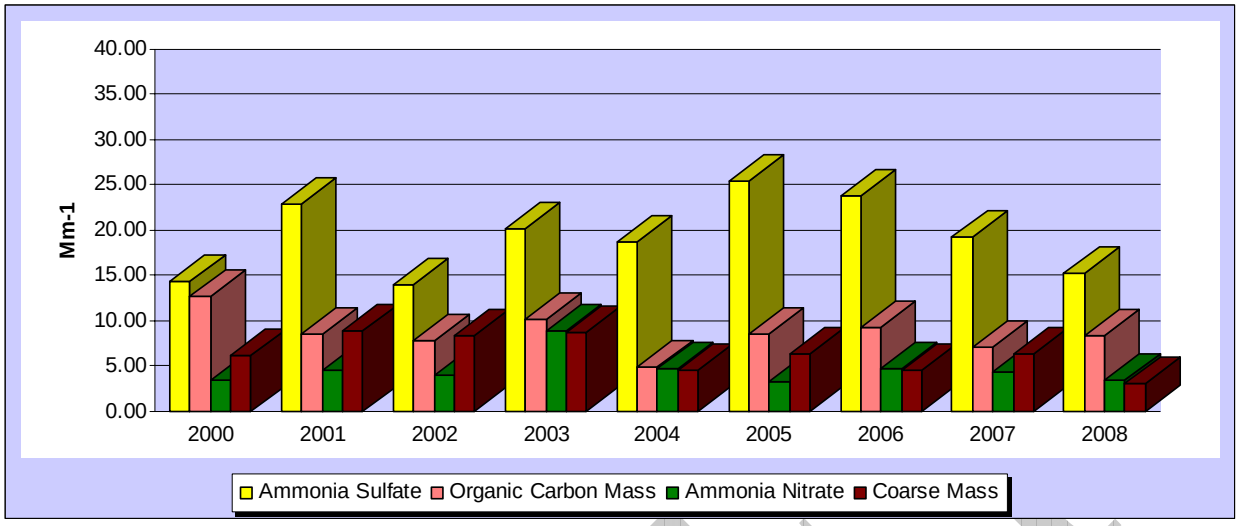
In the 1st quarter, ammonia sulfate followed by ammonia nitrate have the greatest impact on visibility impairment in the Badlands National Park. Organic carbon mass and coarse mass have minimal impact in the 1st quarter with an extinction value of approximately 5.0 inverse mega meters or less per pollutant. However, in 2008 organic carbon mass did increase from the normal trend to exceed ammonia nitrate in impacting visibility impairment but still had less impact then ammonia sulfate.

Figure 4-5 – Badlands' Quarterly Extinction Values for 20% Most Impaired Days
a) Badlands: 1st Quarter Average Extinction Comparison



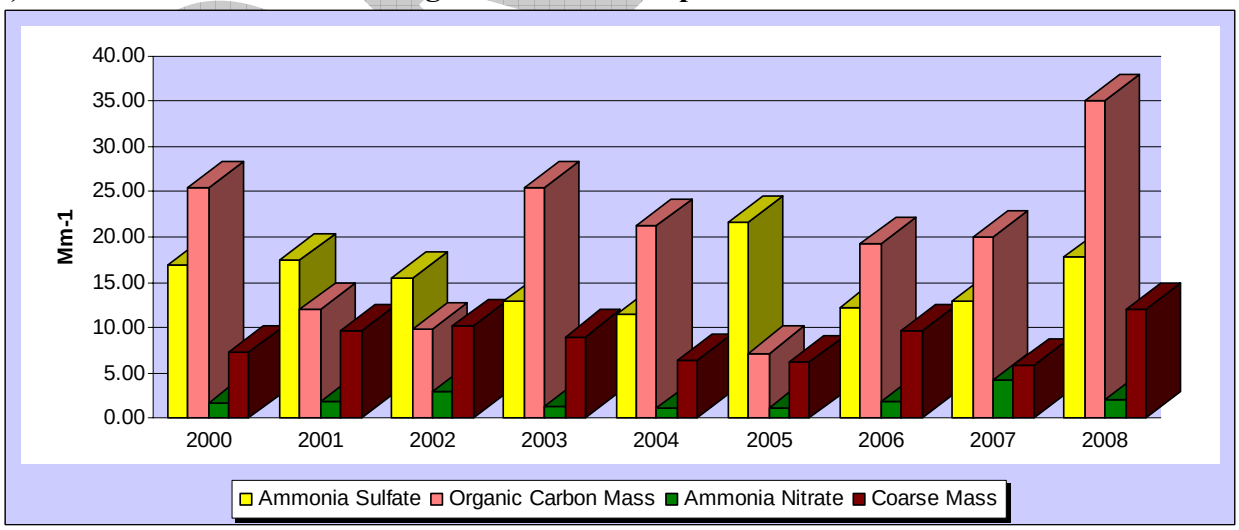
In the 2nd quarter, ammonia sulfate still has the greatest impact on visibility impairment in the Badlands National Park. The 2nd quarter differs from the 1st quarter with organic carbon mass tending to contribute more than ammonia nitrate. However, in some cases, organic carbon mass, ammonia nitrate, and coarse mass have approximately equal share in visibility impairment.

b) Badlands: 2nd Quarter Average Extinction Comparison

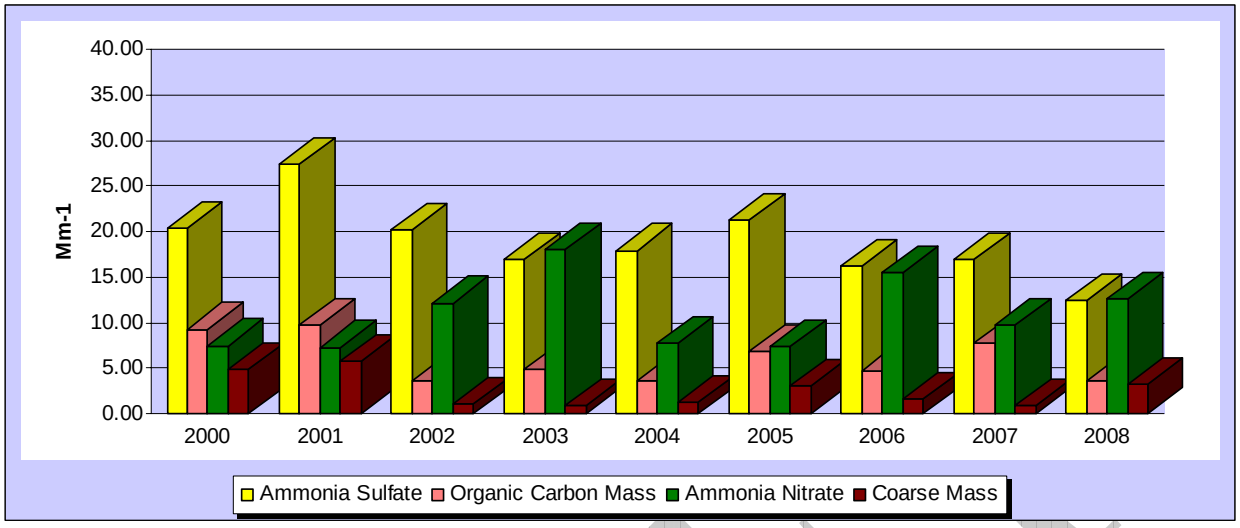


In the 3rd quarter, organic carbon mass tends to contribute the greatest impact on visibility impairment followed by ammonia sulfate. What is interesting is ammonia nitrate in the 3rd quarter consistently contributes the least to visibility impairment with coarse mass being consistently higher than ammonia nitrate. The 3rd quarter is typically the driest months in the Badlands National Park which would increase in coarse mass contributions from windblown dust and from traffic on paved and unpaved roads. In 2008, organic carbon mass increased dramatically due to a one day extinction value in the 3rd quarter of 192 inverse mega meters on July 2, 2008. Looking ahead to the 3rd quarter for the Wind Cave National Park (see Figure 4-6(d)), Wind Cave National Park experienced a high level of organic carbon mass on that same day.

c) Badlands: 3rd Quarter Average Extinction Comparison



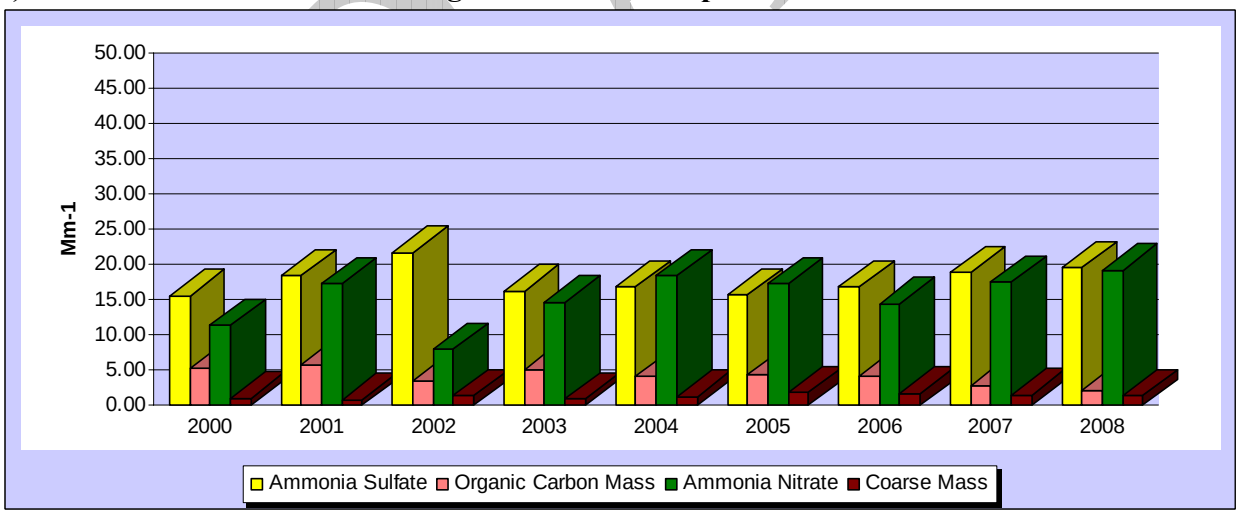
d) Badlands: 4th Quarter Average Extinction Comparison



In the 4th quarter, ammonia sulfate continues to contribute the greatest to visibility impairment in the Badlands National Park followed by ammonia nitrate. Organic carbon mass tends to be a significant contributor with extinction values greater than 5.0 inverse mega meters. Coarse mass extinction values were greater than 5.0 inverse mega meters in the early 2000 but have since dropped below that level and have minimal impacts on visibility in the 4th quarter.

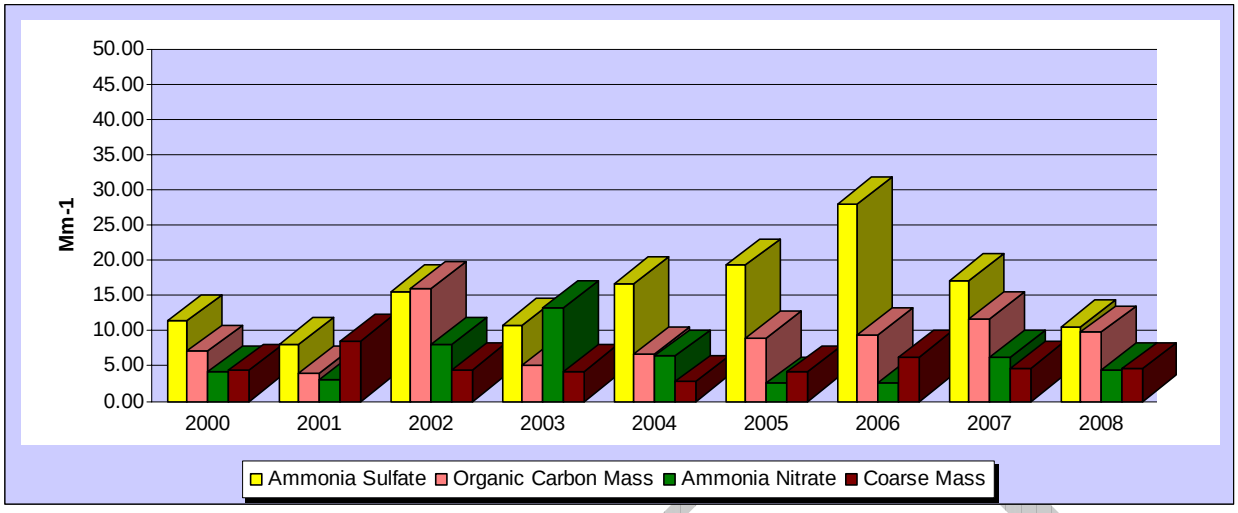
Figure 4-6 – Wind Cave's' Quarterly Extinction Values for 20% Most Impaired Days

a) Wind Cave: 1st Quarter Average Extinction Comparison



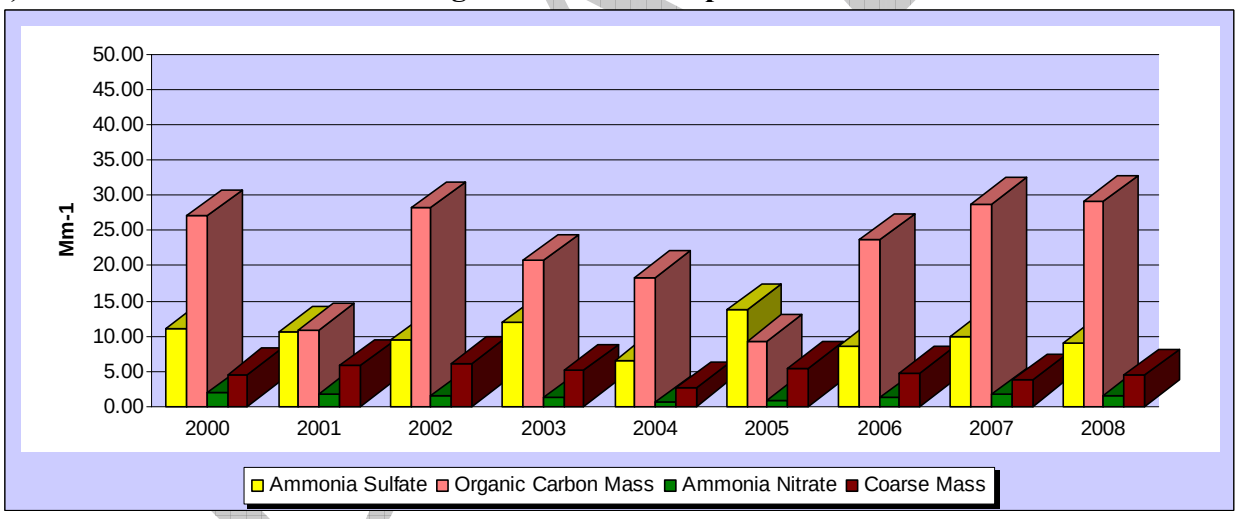
In the 1st quarter, ammonia sulfate and ammonia nitrate have the greatest impact on visibility impairment in the Wind Cave National Park. Organic carbon mass and coarse mass do not appear to have as much impact in the 1st quarter with extinction values of around 5.0 inverse mega meters or less.

b) Wind Cave: 2nd Quarter Average Extinction Comparison



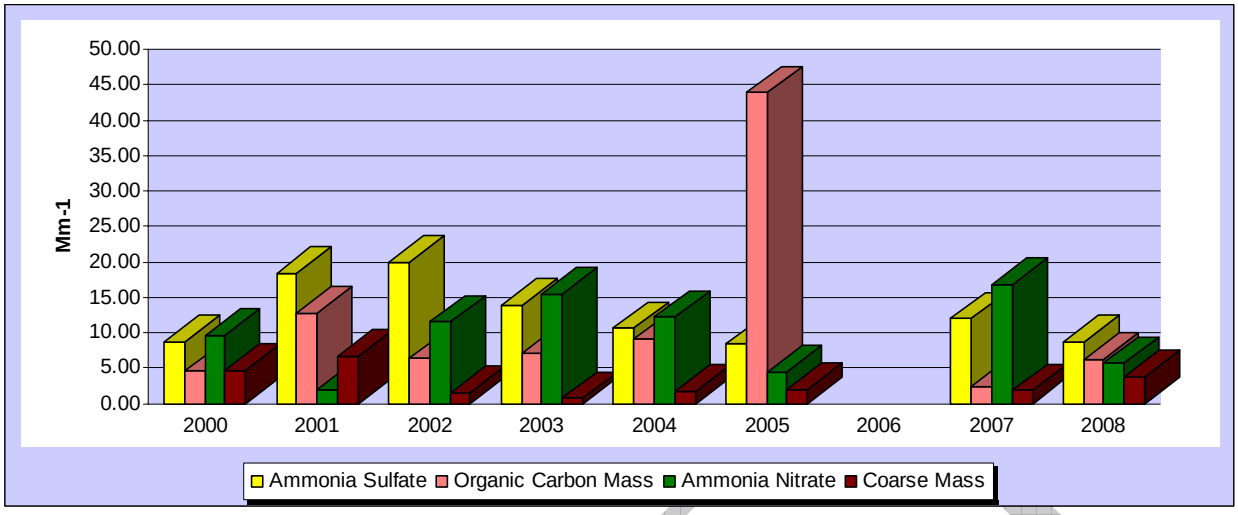
In the 2nd quarter, ammonia sulfate has the greatest impact on visibility impairment in the Wind Cave National Park in the last five years. Organic carbon mass increased during that period with ammonia nitrate and coarse mass having minimal impact.

c) Wind Cave: 3rd Quarter Average Extinction Comparison



In the 3rd quarter, organic carbon mass has the greatest impact on visibility impairment followed by ammonia sulfate. Coarse mass is next and consistently around 5.0 inverse mega meters. Ammonia nitrate tends to have minimal impact in the 3rd quarter. The high organic carbon mass average in 2008 was also due to a 179 inverse mega meter reading on July 2, 2008. This is the same date which resulted in a high reading at the Badlands National Park, which is indicative of regional transport. On June 28, 2008, smoke from Canada forest fires were observed in the Black Hills region and probably is the source of the organic carbon mass concentrations on July 2, 2008.

d) Wind Cave: 4th Quarter Average Extinction Comparison



In the 4th quarter, ammonia sulfates and ammonia nitrate continue to contribute the greatest with one exception in 2005. In 2005, organic carbon mass increased based on an October 25, 2005 extinction value of 109 inverse mega meters. In this case, the same high reading was not observed in the Badlands National Park, which means the higher level may be caused locally. After researching possible causes, it was discovered on October 25, 2005, a prescribed fire covering 1,215 acres was burned in the Wind Cave National Park which could be the contributor of the high organic carbon mass concentration.

This analysis indicates that ammonia sulfates and ammonia nitrate contributions are the greatest in the 1st and 4th quarter of each year at both national parks which is an indication the sources are being impacted by fuel combustion or even prescribed fires. Since it is occurring during the colder months, the sources of these emissions could also be caused by industrial and residential heating. Organic carbon mass tends to start contributing more in the 2nd quarter and is the greatest contributor in the 3rd quarter at both national parks. The driest months usually occur in the 3rd quarter, which is also when most wild fires typically occur.

Coarse mass contributions are the greatest during the 2nd and 3rd quarters. During these quarters, you would typically have greater coarse mass emissions from windblown dust, traffic on paved and unpaved roads, etc.

4.3.3 Visibility Impairment Trends

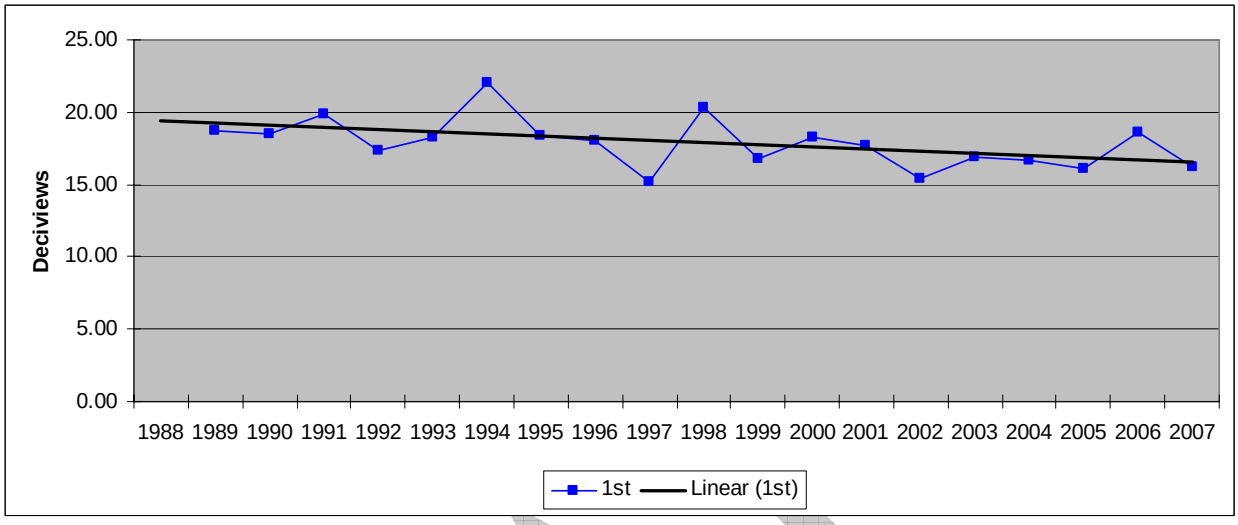
DENR charted the average visibility (deciviews) that occurred in each national park for each quarter during the 20% most impaired days. Figure 4-7 and 4-8 display the quarterly data for the Badlands and Wind Cave National Parks, respectively.

The average visibility impairment for the 20% most impaired days per quarter per year in the Badlands National Park, measured in deciviews, appears to be declining in every quarter except the 3rd quarter. In the 3rd quarter the slope appears to be flat. As seen in the quarterly extinction

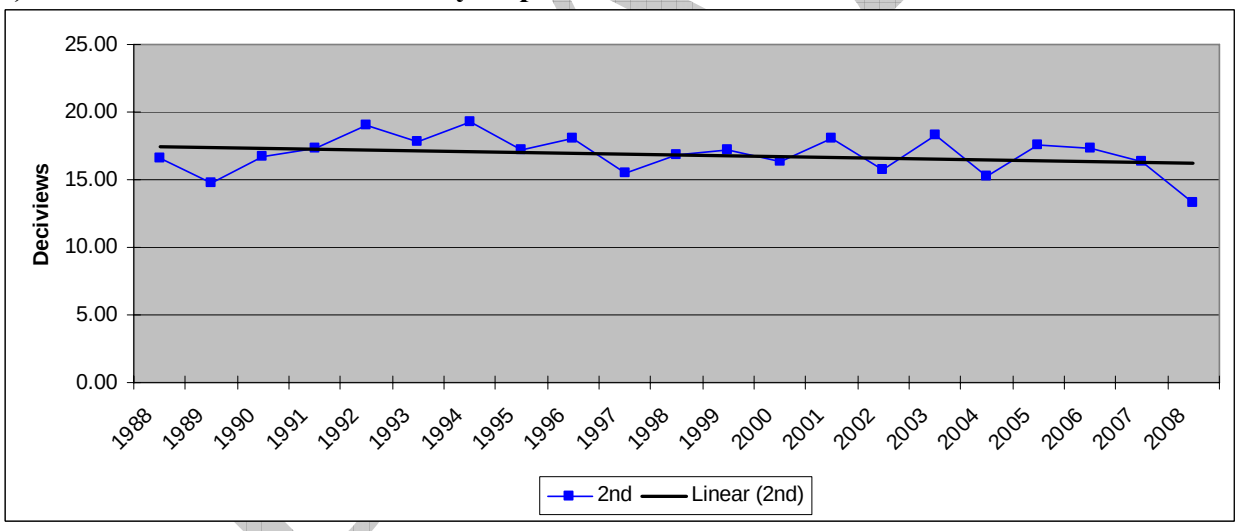
review, the aerosol with the greatest contribution in the 3rd quarter is organic carbon mass and may be the reason the deciview values in the 3rd quarter are flat.

Figure 4-7 – Badlands' Quarterly Data for 20% Most Impaired Days

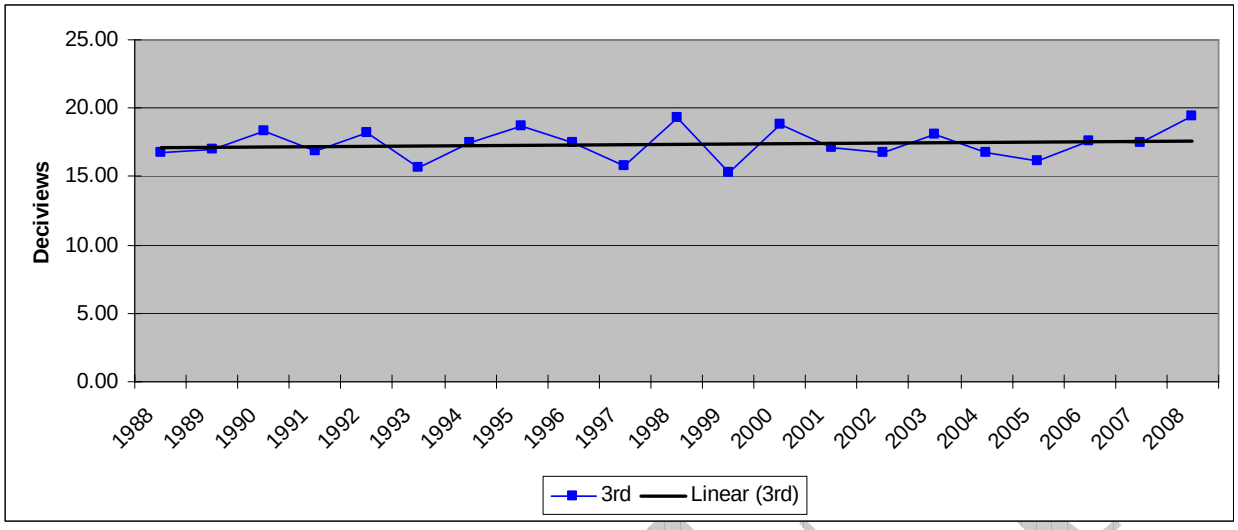
a) Badlands: 1st Quarter Visibility Impairment Trend



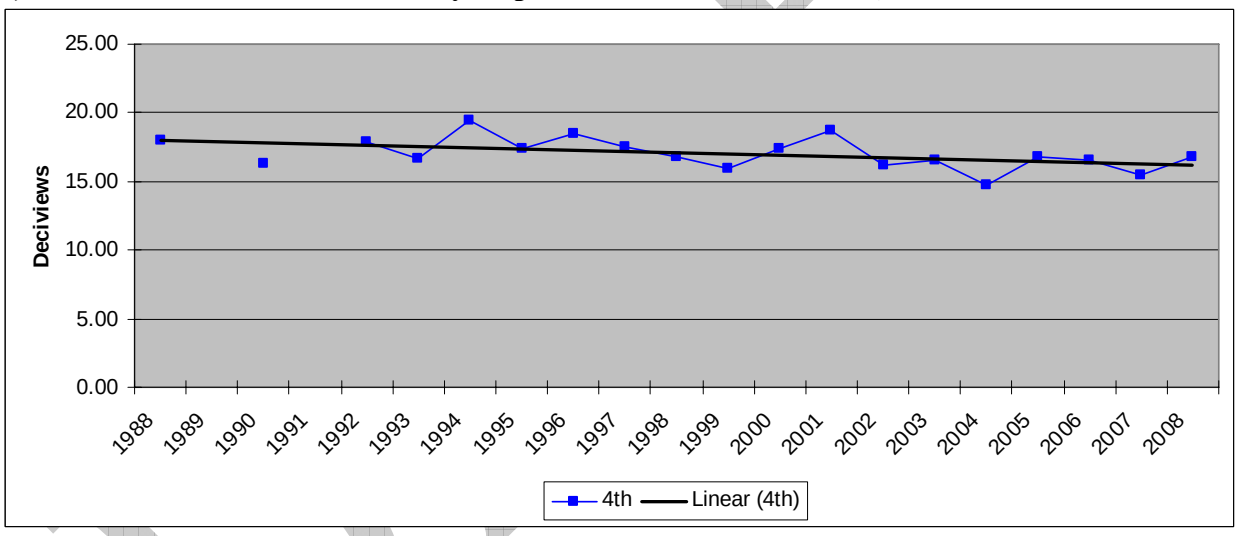
b) Badlands: 2nd Quarter Visibility Impairment Trend



c) Badlands: 3rd Quarter Visibility Impairment Trend



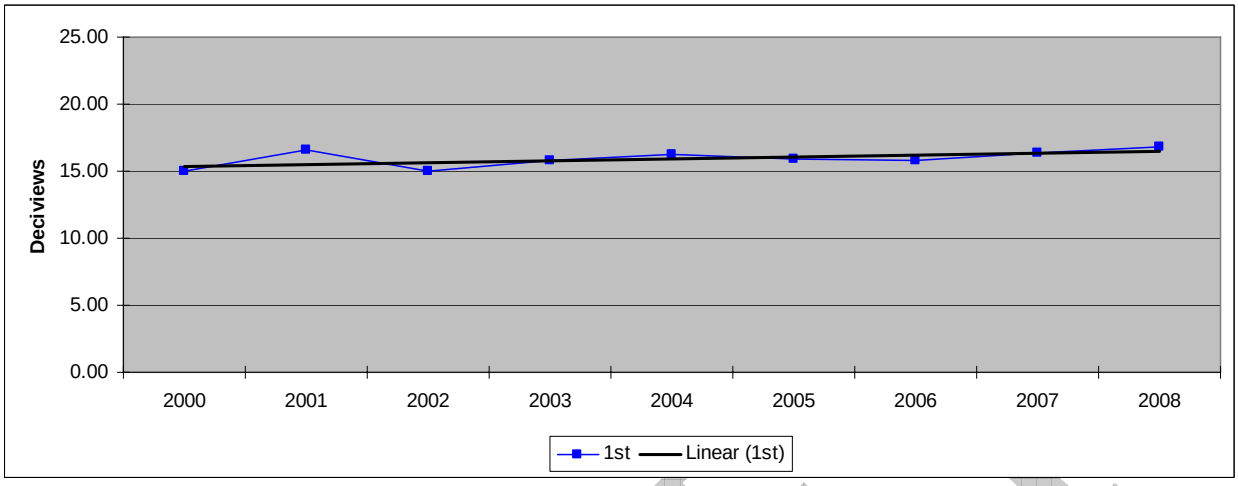
d) Badlands: 4th Quarter Visibility Impairment Trend



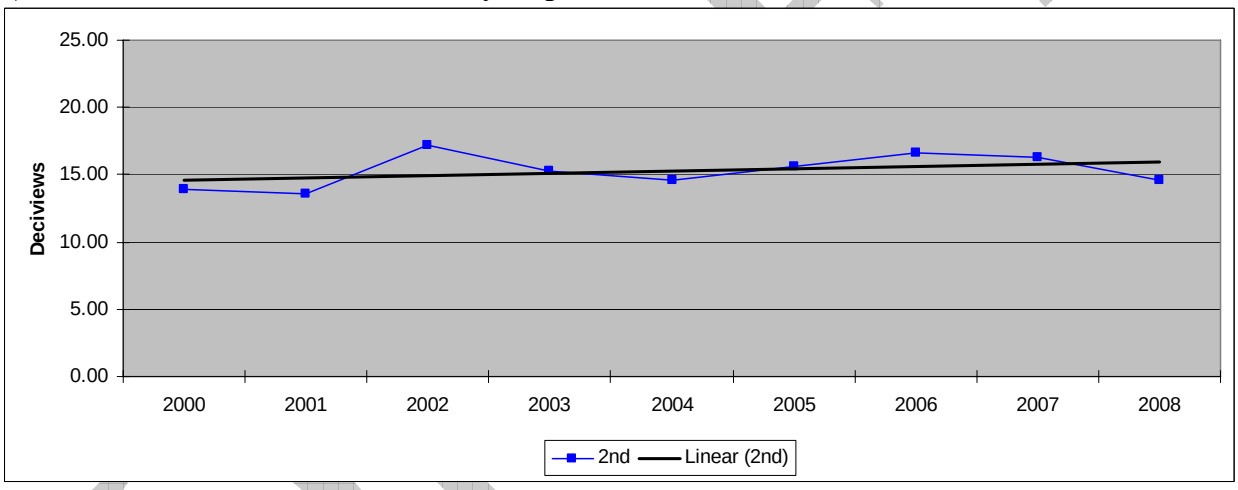
The average visibility impairment for the 20% most impaired days per quarter per year in the Wind Cave National Park, measured in deciviews, appear flat with a slight increase in the 1st and 2nd quarter. The slight increase in the 1st quarter appears to be the greatest. A review of the quarterly extinction data for the 1st quarter does not display an increase in any particular pollutant (see Figure 4.6(a)). There is some fluctuation in the ammonia sulfate and ammonia nitrate extinction values but that does not appear to be enough to result in such an increase in the slope. This will need to be reviewed in the future to see if the trend continues and what may be causing it.

Figure 4-8 – Wind Cave's Quarterly Data for 20% Most Impaired Days

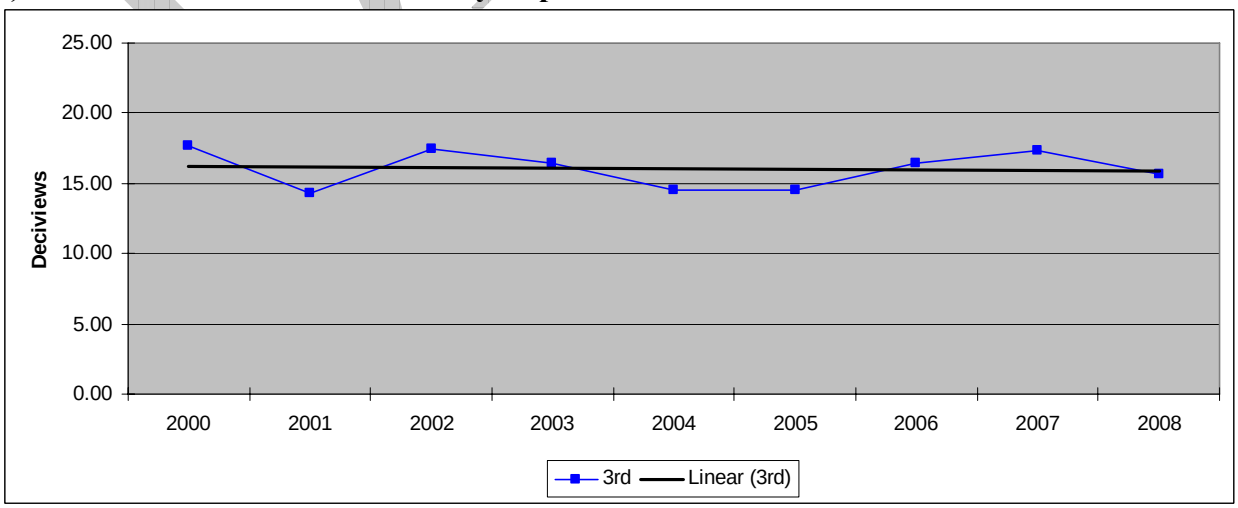
a) Wind Cave: 1st Quarter Visibility Impairment Trend



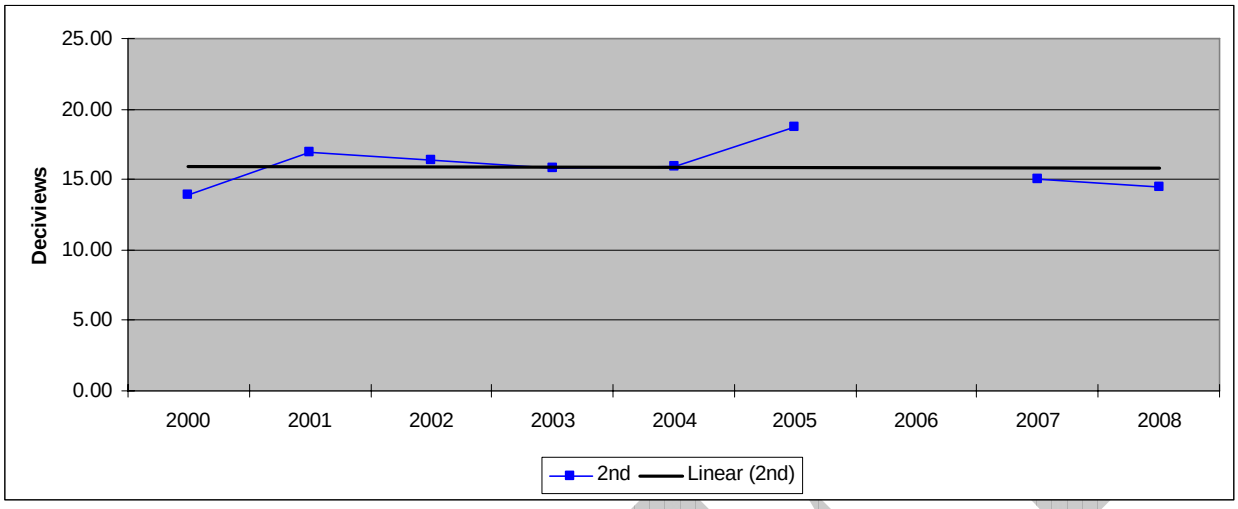
b) Wind Cave: 2nd Quarter Visibility Impairment Trend



c) Wind Cave: 3rd Quarter Visibility Impairment Trend



d) Wind Cave: 4th Quarter Visibility Impairment Trend



5.0 Source Apportionment

5.1 Air Emission Inventory

In accordance with 40 CFR § 51.308(d)(4)(v), a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any Class I area shall be included as part of the state's monitoring strategy. The inventory must include emissions for a baseline year, emissions for the most recent year for which data is available, and estimates of future projected emissions.

DENR and WRAP based the emission inventory on EPA's "*Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations*." The guidance establishes the baseline year as 2002. WRAP projected an emission inventory for 2018. The most current air emission inventory for South Dakota is 2009; but only contains air emissions from Title V air quality permitted sources.

The guidance specified what pollutants should be inventoried, which are reasonably anticipated to cause or contribute to visibility impairment in a mandatory Class I area. The air pollutants of concern are primary particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NO_x), volatile organic compounds (VOCs), and ammonia (NH_3). Particulate matter will be further separated into primary particulate matter coarse and fine. Primary particulate matter coarse is particulate matter 10 microns in diameter or less (PM10) minus primary particulate matter fine, which is particulate matter 2.5 microns in diameter or less (PM2.5). Where available, DENR will include primary organic aerosol (organic carbon) and elemental carbon (EC). The definition of VOC is defined in the Administrative Rules of South Dakota, Section 74:36:01:01(77), which is derived from 40 CFR § 51.100.

The pollutants that are reasonably anticipated to cause or contribute to visibility impairment are emitted by natural and anthropogenic sources. The goal of the regional haze program is to

minimize the impacts from anthropogenic sources and bring our Class I areas into their natural condition. Determining natural condition is difficult since anthropogenic activity has influenced our Class I areas for many years. This influence includes mobile sources, electric generation, prescribed burning, manufacturing activities, farming, preventing and fighting fires, and many other activities that result in the air emissions of the above pollutants.

In support of WRAP's regional haze air quality modeling efforts, the Regional Modeling Center developed annual emissions inventories for a 2002 actual emissions base case, a planning case to represent the 2000-04 regional haze baseline period using averages for key emissions categories, and a 2018 base case of projected emissions determined using factors known at the end of 2005. All emission inventories developed by WRAP used the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system. Each of these inventories has undergone a number of revisions throughout the development process to arrive at the final versions used in Community Multi-Scale Air Quality (CMAQ) and CAMx air quality modeling. The WRAP emission inventories developed by the Regional Modeling Center include:

1. The 2002 base case emissions scenario, referred to as "2002 Base Case" or "Base02". The purpose of the Base02 inventory is to represent the actual conditions in calendar year 2002 with respect to ambient air quality and the associated sources of criteria and particulate matter air pollutants. The Base02 emissions inventories are used to validate the air quality model and associated databases and to demonstrate acceptable model performance with respect to replicating observed particulate matter air quality.
2. The 2000-04 baseline period planning case emissions scenario is referred to as "Plan02". The purpose of the Plan02 inventory is to represent baseline emission patterns based on average, or "typical", conditions. This inventory provides a basis for comparison with the 2018 projected emissions as well as to gauge reasonable progress with respect to future year visibility.
3. The 2018 base case emissions scenario is referred to as "2018 Base Case" or "Base18". These emissions are used to represent conditions in 2018 with respect to sources of criteria and particulate matter air pollutants taking into consideration growth and controls. Modeling results based on this emission inventory are used to define the future year ambient air quality and visibility metrics.

5.1.1 Baseline Emission Inventory

WRAP developed a baseline emission inventory for point, all fires (anthropogenic and wild), biogenic sources, area, oil and gas, on-road mobile, off-road mobile, road dust, fugitive dust, and windblown dust sources for calendar year 2002. The emission inventories includes sulfur dioxide, sulfur dioxide and particulate, nitrogen oxide, nitrogen oxide and particulate, primary organic aerosol, elemental carbon, particulate matter 2.5 microns in diameter or less (fine), particulate matter 10 microns in diameter or less but greater than particulate matter 2.5 microns in diameter (coarse), ammonia, volatile organic compounds, and carbon monoxide. Information on how these inventories were developed and quality assurance measures may be reviewed at the following website:

http://vista.cira.colostate.edu/tss/results/Emissions.aspx

There were two versions of the baseline emission inventory conducted by WRAP. The two baseline versions were identified as “base 02a and 02b”. Version “a” of the 2002 base case inventory was developed based on preliminary 2002 modeling (Tonnesen et al., 2005). Improved 2002 emissions data for the United States, Mexico, and Canada were used to create a final base 2002 annual emissions database for use in the CMAQ and CAMx model performance evaluations. Sources for emissions inventory and ancillary modeling data included WRAP emissions inventory contractors, other regional planning organizations, and EPA. Building from the WRAP preliminary 2002 modeling cases completed earlier, several updates to the inventories and ancillary data were incorporated to create final 2002 emissions input files for the 2002 base case A, or Base02a. The purpose of the “base 02” scenario is to represent the actual conditions in calendar year 2002 with respect to ambient air quality and the associated sources of visibility-impairing air pollutants. The second versions, base 02b, represents updates to the first version and is summarized in Table 5-1 for each of the emission sources.

The 2000 through 2004 baseline period planning case emissions scenario is referred to as “plan 02”. As with the “base 02” inventories, “plan 02” underwent a number of revisions and enhancements to arrive at the final versions used in visibility and source apportionment modeling. The “plan 02”series of inventories was developed to represent baseline period emissions patterns based on average, or “typical” conditions. The “plan 02”inventory was developed from the “base 02”emissions modeling scenarios by incorporating:

1. Replacement of actual 2002 fire emissions inventories with the baseline typical fire emissions inventories;
2. Replacement of the temporal profiles for large stationary point sources with profiles developed from an average of several years surrounding 2002; and
3. Corrections to the off-road mobile, on-road mobile, offshore Pacific shipping lane and WRAP oil and gas inventories.

The “plan 02d” emission inventory was based on the minor changes to the “plan 02c”emission inventory. The revisions included:

1. Updating the current status of point sources related to the BART requirements under the regional haze rule; and
2. Correcting erroneous or missing Standard Industrial Classification and/or source classification codes (SCC).

Table 5-2 provides a summary of the 2002 South Dakota baseline planning emission inventory (plan 02d) for each of the emission sources. The base 02b and the plan 02d emissions data are similar except for the sulfur dioxide and nitrogen oxide emissions from area sources. Based on a Technical Memorandum from Paula Fields and Marty Wolf with ERG to WRAP Forums and Workgroups dated January 10, 2008, the South Dakota area source emissions from distillate fuel combustions was revised using data received during the PRP18 project. The end result was a reduction of just over 9,000 tons of sulfur dioxide and 3,000 tons of nitrogen oxide emissions. The January 10, 2008, memorandum may be viewed at:

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Table 5-1 – South Dakota's 2002 Baseline Emission Inventory Summary (Base 02b) [1, 2]

Source	SO_2	SO_2 [3]	NOx	NOx [3]	POA	EC	Particulate Matter		Ammonia	VOCs	CO
							Fine	Coarse			
Point	14,022	14,059	20,697	20,698	46	2	160	727	100	2,542	4,700
All Fires	278	318	1,371	1,388	3,172	409	1,338	544	494	3,135	49,109
Biogenic Sources	0	0	52,852	52,852	0	0	0	0	0	445,241	103,402
Area	10,159	10,387	5,978	5,987	1,887	317	2,129	2,177	118,920	42,372	24,239
Oil/Gas [4]	8	8	367	367	0	0	0	0	0	**33,721**	10
On-Road Mobile	872	922	29,224	29,224	472	632	180	169	842	13,741	221,726
Off-Road Mobile	5,733	6,066	39,039	39,039	942	3,234	0	0	25	12,764	92,508
Road Dust	0	4	0	5	255	18	4,061	38,164	0	0	0
Fugitive Dust	0	9	0	26	1,277	87	25,035	93,734	0	0	0
Wind Blown Dust	0	0	0	0	0	0	50,274	452,470	0	0	0
Total	**31,072**	**31,773**	**149,528**	**149,586**	**8,051**	**4,699**	**83,177**	**587,985**	**120,381**	**553,516**	**495,694**

[1] – Derived from WRAP's website at http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx. To get to the data, the individual needs to click on "Emissions and Source Apportionment", and click on "Emission Review Tool";
[2] – "SO_2" means sulfur dioxide, "NOx" means nitrogen oxide, "POA" means primary organic aerosol, "EC" means elemental carbon, "VOCs" means volatile organic compounds, and "CO" means carbon monoxide;
[3] – The emission total for sulfur dioxides and nitrogen oxides includes gas and particulate; and
[4] – VOC emissions from secondary oil and gas production were estimated based on an analysis of the gas and gas flow rates.

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Table 5-2 –South Dakota's 2002 Planning Emission Inventory Summary (Plan 02d) [1, 2]

Source	SO_2	SO_2 [3]	NOx	NOx [3]	POA	EC	Particulate Matter		Ammonia	VOCs	CO
							Fine	Coarse			
Point	14,024	14,037	20,698	20,699	10	0	216	727	100	2,542	4,700
Big Stone I [4]	11,171		14,552				209	209	29	107	490
All Fires	367	469	1,698	1,713	4,574	717	839	754	562	3,853	64,326
Biogenic Sources	0	0	52,852	52,852	0	0	0	0	0	445,241	103,402
Area	1,071	1,198	2,897	2,903	1,792	306	1,804	156	118,877	40,511	23,029
Oil/Gas [5]	6	6	361	361	0	0	0	0	0	**33,721**	11
On-Road Mobile	872	922	29,224	29,224	278	339	0	169	842	13,741	221,726
Off-Road Mobile	5,733	6,066	39,039	39,039	942	3,234	0	0	25	12,764	92,508
Road Dust	0	4	0	5	255	18	4,061	38,164	0	0	0
Fugitive Dust	0	24	0	27	1,317	89	25,220	122,914	0	0	0
Wind Blown Dust	0	0	0	0	0	0	50,274	452,470	0	0	0
Total	**22,073**	**22,726**	**146,769**	**146,823**	**9,168**	**4,703**	**82,414**	**615,354**	**120,406**	**552,373**	**509,702**

[1] – Derived from WRAP's website at http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx. To get to the data, the individual needs to click on "Emissions and Source Apportionment", and click on "Emission Review Tool";
[2] – "SO_2" means sulfur dioxide, "NOx" means nitrogen oxide, "POA" means primary organic aerosol, "EC" means elemental carbon, "VOCs" means volatile organic compounds, and "CO" means carbon monoxide;
[3] – The emission total for sulfur dioxides and nitrogen oxides includes gas and particulate;
[4] – Otter Tail Power Company's Big Stone I emissions are included in the "Point" emissions row but separated here for comparison to Table 5-4, 6-1 and 6-3; and
[5] – VOC emissions from secondary oil and gas production were estimated based on an analysis of the gas and gas flow rates.

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http://www.wrapair.org/forums/ssjf/documents/Pivot_Tables/2008-01_Plan02d_Tech_Memo%281-10%29.pdf

DENR revised the data for South Dakota for both the baseline and planning emission inventories to include oil and gas area source emissions. Through a compliance initiative in EPA's Region VIII, it was determined that secondary oil and gas production in northwestern South Dakota was generating volatile organic compound emissions from storage tanks that needed to be addressed.

The oil companies quantified the volatile organic compound emissions which resulted in air emissions of 33,433 tons. DENR added the volatile organic compound emissions from a secondary oil recovery field to the 2002 baseline and planning emission inventory calculated by WRAP to account for the area volatile organic compound emissions from the oil and gas fields.

The 33,433 tons of volatile organic compound emissions in Table 5-1 and 5-2 were not included in the modeling conducted by WRAP. However, the increase in criteria air pollutants (e.g., particulate matter, nitrogen oxide, and carbon monoxide) from the reduction in volatile organic compound emissions were used in the modeling for 2018 projections and reasonable progress purposes.

5.1.2 Current Emission Inventory

A complete air emission inventory is not available for the most recent year. DENR does calculate an annual air emission inventory for point sources that are required to pay fees under the Title V air quality permit program. The most current year is 2009. The point source data for 2009 is displayed in Table 5-3 and compared to the same data collected in WRAP's 2002 baseline emission inventory to compare air emission trends from point sources.

Table 5-3 – Comparison of 2002 and 2009 South Dakota Point Source Emissions [1]

Year	PM10 [2]	SO_2	NOx	VOCs	CO
2002 WRAP	887	14,022	20,697	2,542	4,700
2009 DENR	1,125	13,321	15,611	3,694	2,907
Difference	**238**	**-701**	**-5,086**	**1,152**	**-1,793**

[1] – "PM10" means particulate matter less than or equal to 10 microns in diameter or less, "SO2" means sulfur dioxide, "NOx" means nitrogen oxide, "VOCs" means volatile organic compounds, and "CO" means carbon monoxide; and

[2] - The PM10 emissions are based on coarse and fine particulate matter.

The comparison shows that air emissions increased from 2002 to 2009 for all pollutants except sulfur dioxide, nitrogen oxide and carbon monoxide.

5.1.3 WRAP's 2018 Projections

WRAP projected an air emissions inventory for 2018 (PRP18a) for the same source types and pollutants as the base year. The projection methodology included the following steps:

1. Adjustments: Emission increases for new facilities that have come on-line since 2002, deletion of emissions for facilities that retired in 2003 or 2004 and will not return to operation in the future; and other adjustments (e.g., ratios to correct certain PM10 and PM2.5 emission factors/Standard Classification Codes for combustion of natural gas);
2. Control Factors: Emission reductions due to known (e.g., on-the-books) controls, consent decrees reductions, State Implementation Plan control measures, and other relevant regulations that have gone into effect since 2002, or will go into effect before the end of 2018. These controls do not include impacts from any future control scenarios that have yet to be determined;
3. Growth Factors: Standard Classification Code specific growth factors developed from the Economic Growth and Analysis System projection factor model; special analysis of electric generating unit growth relative to unit capacity threshold;
4. Retirement & Replacement Rates: Effects of retirement estimates using annual retirement rates based on expected equipment lifetimes. Retired equipment replaced by lower-emitting new equipment. Unit lifetime examined for natural gas-fired electric generating units. No retirements assumed for coal-fired electric generating units;
5. Permit Limits: Used in the cases where the projected emissions may have inadvertently exceeded an enforceable emission limit (e.g., emissions were adjusted downward to the permit limit, as applicable); and
6. Section 309 Flags: Point sources in the Grand Canyon Visibility Transport States (e.g., AZ, CA, CO, ID, NV, NM, OR, UT, and WY) whose 2002 facility-level sulfur dioxide emissions are at least 100 tons per year.)

Just like the baseline inventory, WRAP improved on the projections and produced a second version. The objective of the "PRP 18b" version was to make a second revision to the 2018 emissions inventory projections for point and area sources in the WRAP region to provide a more current assessment of the reasonable progress toward visibility goals by the WRAP. The focus of this project was to address specific changes that have occurred since completion of the "PRP 18a" inventory in 2007. The resulting product is the second version of the WRAP region Preliminary Reasonable Progress emissions inventory for 2018, known as "PRP 18b".

The "PRP 18b" inventory revisions included the following elements:

1. Included all updated BART information available such as incorporating all available formal BART determinations; incorporating estimates of expected BART control levels where BART determinations had not been finalized (BART estimates made for both sulfur dioxide and nitrogen oxide); and addressing all "BART-eligible" or "Subject to BART" sources, both for electric generating units and for the non-electric generating unit universe;
2. Revised projections of "future" fossil-fuel plants needed to meet federal electrical generation demand forecasts in 2018 (e.g., used updated Energy Information Administration of the federal Department of Energy projections of 2018 energy requirements – for the first time incorporated Renewable Energy Portfolios where available – determined that existing WRAP region electric generating capacity, when added to existing State and Local agency electric generating unit permits, was sufficient to meet 2018 demand without addition of any new future electric generating units);

3. Incorporated all new rulemaking, permit limits, and consent decrees instituted since 2007; and
4. Corrected other outstanding issues that were identified by the federal, state, or local agencies within the WRAP domain as needing to be revised/updated such as modification of various inventory data to be consistent with the Plan 02d emissions inventory (e.g., name changes, updated stack parameters, new or removed sources); revision of a limited number of area source categories (e.g., fuel combustion emissions in South Dakota and California, gasoline distribution emissions in Idaho, residential wood combustion emissions in Washington, construction dust in Clark County, Nevada); revision of facility information (e.g., facility identifications, facility names, unit identifications, process identifications, Standard Classification Codes, Standard Industrial Classifications) based upon agency input; revision of stack parameters based upon agency input; and addition of WRAP Phase II oil and gas project emissions to "PRP 18a" area source emission summaries in order to provide relevant comparisons to the emission totals in "PRP 18b" which also contained oil and gas emission totals.

The 2018 projected air emissions for South Dakota included three large facilities that are currently permitted but not constructed or have submitted an application to construct. The first facility is Big Stone II, which was a proposed 600 megawatt coal-fired power plant located next to an existing coal-fired power plant (Big Stone I) in the northeast corner of the state. A Prevention of Significant Deterioration air quality permit was issued to Big Stone II on November 20, 2008. The increase in air emissions from this facility would be limited to particulate matter, volatile organic compounds, and possibly ammonia. There would be no increase of air emissions for sulfur dioxide and nitrogen oxide because of decreases in air emissions from the Big Stone I facility. The air emission increases from this facility are included in the 2018 projections and are shown in Table 5-4. However, on December 1, 2009, Otter Tail Power Company submitted a letter notifying DENR the Big Stone II facility will not be built and it relinquished all rights and obligations granted through and by the Prevention of Significant Deterioration permit. Therefore, the 2018 emission inventory will need to be updated.

The other facility that was issued a Prevention of Significant Deterioration air quality permit was the Hyperion Energy Center that received a permit on August 20, 2009. The Hyperion Energy Center will be located in Union County which is located in the southeastern corner of the state and is a 400,000 barrel per day oil refinery and integrated gasification combine cycle power plant. The air emission increases from this facility are included in the 2018 projections and are shown in Table 5-4.

The third facility involves Basin Electric Power Cooperative's NextGen application for another coal-fired power plant with a maximum capacity of 700 megawatts located in the north central area of the state. The application is currently on hold; but the air emission increases from this facility are included in the 2018 projections and are shown in Table 5-4.

DENR has also received a Prevention of Significant Deterioration permit application for a 300 megawatt natural gas fired combined cycle power generating facility in Brookings County, which is on eastern edge of South Dakota boarding Minnesota. The air emission increases from this facility will be included in the next 2018 projections and modeling analysis.

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Table 5-4 displays the 2018 projected air emissions for South Dakota using the "PRP 18b" inventory. The specific contribution from each project are displayed in Table 5-4 and derived from WRAP website at the following location:

http://www.wrapair.org/forums/ssjf/pivot.html

To review, click on the 2018 PRP 18b zip file to review the pivot tables that when clicked on will display each facilities contribution.

As discussed for the baseline, through a compliance initiative in EPA's Region VIII, it was determined that secondary oil and gas production in northwestern South Dakota was generating volatile organic compound emissions from storage tanks that needed to be addressed. The installation of four thermal oxidizers in the northwestern portion of South Dakota resulted from the compliance initiative. Each of the thermal oxidizers are permitted under South Dakota's minor air quality permit program and requires the thermal oxidizers to maintain a volatile organic compound destruction efficiency of 98.6% or greater. The installation of four thermal oxidizers did increase the emission of fine particulate matter, nitrogen oxide, and carbon monoxide. South Dakota's minor air quality permit program is included in its State Implementation Plan.

DENR added volatile organic compound emissions to Table 5-4 to account for the volatile organic compounds that are not destroyed by the thermal oxidizers. The fine particulate matter, nitrogen oxide and carbon monoxide emissions from the thermal oxidizers are included as area sources in WRAP's projected air emissions in the "PRP 18b" inventory.

5.1.4 Air Emission Inventories for Other States and Countries

The visibility in the Class I areas in South Dakota is influenced not only by air emissions from within South Dakota but from surrounding states, Canada, and sources outside WRAP's modeling domain. The six contiguous states are North Dakota, Minnesota, Iowa, Nebraska, Wyoming and Montana. The 2002 plan year emissions (Plan 02d) and 2018 projected emissions (PRP 18b) from the respective states are shown in Table 5-6 and 5-7, respectively.

For the base year, South Dakota's emissions when combined with the neighboring states' emissions represent only three to 17 percent of the total emissions for each type of pollutant. For 2018, South Dakota's emissions are similar at two to 18 percent of the total emissions for each type of pollutant. The small percentage for each type of pollutant is a good indication that South Dakota's Class I areas are being influenced by emissions from sources beyond South Dakota's borders. Based on WRAP's attribution analysis, which will be discussed further, South Dakota's Class I areas are also impacted by states beyond the contiguous states and other countries such as Canada. Emission inventory data for the states beyond the contiguous states and other countries are available on WRAP's website but were not included in this document.

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Table 5-4 –2018 South Dakota Projected Emission Inventory Summary (PRP 18b) [1, 2]

							Particulate Matter				
Source	**SO_2**	**SO_2** [3]	**NOx**	**NOx** [4]	**POA**	**EC**	**Fine**	**Coarse**	**Ammonia**	**VOCs**	**CO**
Point	11,986	11,996	30,185	30,186	8	0	205	9,847	102	4,510	16,632
Big Stone I	3,425		15,323					318		112	509
Big Stone II	3,942		2,891					6,758		96	3,947
Hyperion	627		455					1,041		438	954
NextGen	1,534		1,621					1,155		114	4,638
Existing	2,458		9,895					575		3,750	6,584
All Fires	365	465	1,679	1,694	4,531	715	821	751	553	3,808	63,843
Biogenic Sources	0	0	52,852	52,852	0	0	0	0	0	445,241	103,402
Area	1,662	1,789	3,303	3,309	1,769	314	1,920	190	118,992	49,659	23,773
Oil/Gas [5]	0	0	557	557	0	0	0	0	0	562	16
On-Road Mobile	108	129	8,059	8,059	270	86	0	188	1,075	5,101	120,041
Off-Road Mobile	50	199	23,785	23,785	386	1,072	0	0	36	7,686	95,276
Road Dust	0	5	0	6	325	23	5,190	48,773	0	0	0
Fugitive Dust	0	26	0	27	1,322	90	25,840	129,009	0	0	0
Wind Blown Dust	0	0	0	0	0	89	50,274	452,470	0	0	0
Total	**14,171**	**14,609**	**120,420**	**120,475**	**8,611**	**2,389**	**84,250**	**641,228**	**120,758**	**516,567**	**422,983**

[1] – Derived from WRAP's website at http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx. To get to the data, the individual needs to click on "Emissions and Source Apportionment" and click on "Emission Review Tool";
[2] – "SO_2" means sulfur dioxide, "NOx" means nitrogen oxide, "POA" means primary organic aerosol, "EC" means elemental carbon, "VOCs" means volatile organic compounds, and "CO" means carbon monoxide;
[3] – Sulfur oxides (gas and particulate);
[4] – Nitrogen oxides (gas and particulate); and
[5] – VOC emissions from secondary oil and gas production were estimated based on an analysis of the gas and gas flow rates.

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Table 5-5 provides the percent of difference between 2002 planned emission inventory (Table 5-6) and the 2018 projected emissions (Table 5-7). From this you can see that both South Dakota and the contiguous states will decrease air emissions for most pollutants from 2002 to 2018. This decrease will represent improvements in visibility in Class I areas in South Dakota and neighboring Class I areas.

Table 5-5 – Emission Changes projected for 2018 [1]

Pollutant	SD	Contiguous States
	% Difference	% Difference
SO_2	36% Decrease	26% Decrease
SO_2 [2]	36% Decrease	26% Decrease
NOx	18% Decrease	30% Decrease
NOx [3]	18% Decrease	30% Decrease
POA	6% Decrease	6% Decrease
EC	49% Decrease	29% Decrease
PM_{fine}	2% Increase	4% Increase
PM_{coarse}	4% Increase	1% Increase
Ammonia	No change	20% Increase
VOCs	6% Decrease	5% Increase
CO	17% Decrease	22% Decrease

[1] – "SO_2" means sulfur dioxide, "NOx" means nitrogen oxide, "POA" means primary organic aerosol, "EC" means elemental carbon, "PM" means particulate matter, "VOCs" means volatile organic compounds, and "CO" means carbon monoxide;
[2] – Sulfur oxides (gas and particulate); and
[3] – Nitrogen oxides (gas and particulate).

5.1.5 Future Emission Inventory by South Dakota

DENR conducts an annual air emission inventory for stationary sources that are required to pay air fees under the Title V air quality permit program. The air emission inventory consists of criteria air pollutants. The stationary sources required to report consist of major sources (actual air emissions that exceed 100 tons per year) and area sources. DENR will expand the air emission inventory to include all air emissions that impact visibility from these stationary sources.

DENR will continue to work with other organizations and states to ensure all inventory data used in future modeling will be accurate. The future emission inventories and the data provided by states in EPA's National Emission Inventory database will be used to track the progress of South Dakota and neighboring states on controlling and reducing air pollution that cause or contribute to visibility impairment in our Class I areas and neighboring Class I areas.

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Table 5-6 –2002 Contiguous State Planning Emission Inventory Summary (Plan 02d) [1, 2]

Source	SD	ND	Minnesota	Iowa	Nebraska	Wyoming	Montana	Total	SD %
SO_2	**22,073**	170,477	158,484	199,339	94,247	145,840	50,198	**840,658**	**3%**
SO_2 [3]	**22,726**	171,611	162,516	201,419	95,603	148,487	51,923	**854,285**	**3%**
NOx	**146,769**	229,460	522,727	378,150	322,915	287,974	242,978	**2,130,973**	**7%**
NOx [4]	**146,823**	229,536	523,008	378,306	323,015	288,095	243,142	**2,131,925**	**7%**
POA	**9,168**	8,840	33,414	13,953	10,709	29,194	48,089	**153,367**	**6%**
EC	**4,703**	4,847	13,034	7,790	6,312	8,066	11,873	**56,625**	**8%**
PM_{fine}	**82,414**	61,519	98,542	109,660	82,851	22,833	77,239	**535,058**	**15%**
PM_{coarse}	**615,354**	360,936	541,408	701,377	610,843	102,660	621,276	**3,553,854**	**17%**
Ammonia	**120,406**	120,493	194,699	272,173	177,774	33,032	66,229	**984,806**	**12%**
VOCs	**552,373**	334,020	1,127,795	574,151	561,172	816,904	1,181,318	**5,147,733**	**11%**
CO	**509,702**	470,129	2,644,613	1,809,356	1,054,477	909,702	1,639,949	**9,037,928**	**6%**

[1] – Derived from WRAP's website at http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx. To get to the data, the individual needs to click on "Emissions and Source Apportionment" and click on "Emission Review Tool";

[2] – "SO_2" means sulfur dioxide, "NOx" means nitrogen oxide, "POA" means primary organic aerosol, "EC" means elemental carbon, "PM" means particulate matter, "VOCs" means volatile organic compounds, and "CO" means carbon monoxide;

[3] – Sulfur oxides (gas and particulate); and

[4] – Nitrogen oxides (gas and particulate).

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Table 5-7 –2018 Contiguous State Emission Inventory Summary (PRP 18b) [1, 2]

Source	SD	ND	Minnesota	Iowa	Nebraska	Wyoming	Montana	Total	SD %
SO_2	**14,171**	66,942	111,532	198,444	60,473	122,446	44,269	**618,277**	**2%**
SO_2 [3]	**14,609**	67,810	115,735	200,953	61,912	125,692	45,794	**632,505**	**2%**
NOx	**120,420**	187,032	316,762	249,248	206,443	248,100	179,878	**1,507,883**	**8%**
NOx [4]	**120,475**	187,103	317,037	249,422	206,545	248,234	180,043	**1,508,859**	**8%**
POA	**8,611**	7,126	31,649	12,774	9,686	28,464	46,502	**144,812**	**6%**
EC	**2,389**	2,447	9,387	4,938	3,286	6,855	9,948	**39,250**	**6%**
PM_{fine}	**84,250**	62,731	97,229	114,324	83,456	28,055	83,047	**553,092**	**15%**
PM_{coarse}	**641,228**	373,428	517,566	697,526	591,464	116,054	675,985	**3,613,251**	**18%**
Ammonia	**120,758**	120,120	260,671	326,247	230,762	33,974	67,030	**1,159,562**	**10%**
VOCs	**516,567**	337,735	1,160,320	580,816	566,667	1,005,916	1,174,587	**5,342,608**	**10%**
CO	**422,983**	341,118	2,094,422	1,253,075	743,082	813,609	1,378,778	**7,047,067**	**6%**

[1] – Derived from WRAP's website at http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx. To get to the data, the individual needs to click on "Emissions and Source Apportionment" and click on "Emission Review Tool";

[2] – "SO_2" means sulfur dioxide, "NOx" means nitrogen oxide, "POA" means primary organic aerosol, "EC" means elemental carbon, "PM" means particulate matter, "VOCs" means volatile organic compounds, and "CO" means carbon monoxide;

[3] – Sulfur oxides (gas and particulate); and

[4] – Nitrogen oxides (gas and particulate).

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5.2 Source Apportionment Analysis

Visibility impairment occurs when pollutants emitted into the atmosphere scatter and absorb light thereby creating haze. These pollutants can remain suspended in the atmosphere for long periods and be transported long distances thereby contributing to regional-scale impacts on visibility in Class I areas. Air quality models are one of the tools that states can use to help understand how these impacts occur by identifying the sources contributing to haze and to select the most effective emissions reduction strategies to improve visibility.

In order to determine the significant sources contributing to haze in South Dakota's Class I areas, DENR relied on an apportionment analysis provided by WRAP, which can be reviewed on WRAP's website at:

http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx.

There were two techniques used by WRAP for analyzing source apportionment of regional haze. One was the Particulate Matter Source Apportionment Technology (PSAT) analysis used for the attribution of sulfate and nitrate sources only. The second was the Weighted Emissions Potential (WEP) analysis used for attribution of sources of sulfate, nitrate, organic carbon, elemental carbon, fine particulate matter and coarse particulate matter.

The Particulate Matter Source Apportionment Technology analysis used the CAMx air quality model to show nitrate-sulfate-ammonia chemistry and applies this chemistry to a system of tracers or "tags" to track the chemical transformations, transport and removal of nitrogen oxides and sulfur dioxide. These pollutants are important because they tend to originate from anthropogenic (human-caused) sources. Therefore, the results from this analysis can be useful in determining contributing sources that may be controllable, both in-state and in neighboring states. Emission scenarios used for the Particulate Matter Source Apportionment Technology analyses were the "plan02c" and "base 18b".

The Weighted Emissions Potential analysis is a screening tool that helps to identify sources in regions that have the potential to contribute to haze formation at specific Class I areas. Unlike the Particulate Matter Source Apportionment Technology analysis, this method does not account for chemistry or deposition. The Weighted Emissions Potential analysis combines emissions inventories, wind patterns, and residence time of air mass over each area where emissions occur to estimate the percent contribution of different pollutants. Like the Particulate Matter Source Apportionment Technology analysis, the Weighted Emissions Potential analysis compares baseline (2000-2004) to 2018, to show the improvement expected by the 2018 uniform rate of progress for sulfate, nitrate, organic carbon, elemental carbon, fine particulate matter, and coarse particulate matter.

DENR believes the Particulate Matter Source Apportionment Technology analysis is a better tool than Weighted Emissions Potential tool for identifying the contribution of sulfates and nitrates to South Dakota's Class I areas because it accounts for chemistry and deposition and is better at

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identifying regional contribution of sources from outside the WRAP region. For these reasons, DENR relied on the Particulate Matter Source Apportionment Technology results as the primary source for determining apportionment for sulfates and nitrates and thus the better tool for identifying anthropogenic sources. The results from the Weighted Emissions Potential analysis were used by DENR primarily to identify the pollutants more commonly associated with natural sources. Even though these sources are mostly uncontrollable, it is still important to consider their relative contribution to haze.

The primary tool utilized by DENR for modeling regional haze improvements by 2018 and for determining South Dakota's Reasonable Progress Goals was the CMAQ model. The CMAQ model was used by WRAP to estimate 2018 visibility conditions in South Dakota and all Western Class I areas based on application of the regional haze strategies presented by states to WRAP, including assumed controls on BART sources.

The modeling was conducted by the Regional Modeling Center (RMC) at the University of California Riverside under the oversight of WRAP's Modeling Forum. A more in depth description of the CMAQ model used to project 2018 visibility conditions by WRAP and the results of the modeling can be found on WRAP's website at:

http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx.

The CMAQ model was designed as a "one atmosphere" modeling system to encompass modeling of multiple pollutants and issues including ozone, particulate matter, visibility, and air toxics. This is in contrast to many earlier air quality models that focused on a single pollutant. CMAQ takes into account emissions, advection and dispersion, photochemical transformation, aerosol thermodynamics and phase transfer, aqueous chemistry, and wet and dry deposition of trace species. The model requires inputs of three-dimensional wind grids, temperature, humidity, cloud/precipitation, and boundary layer parameters. The current version of CMAQ can only utilize output fields from the MM5 meteorological model. MM5 meteorological model is a state-of-the-science atmosphere model that has proven useful for air quality applications and has been used extensively in past local, state, regional, and national modeling efforts. MM5 meteorological model has undergone extensive peer review, with all of its components continually undergoing development and scrutiny by the modeling community.

The Regional Modeling Center developed air quality modeling inputs including annual meteorology and emissions inventories for a 2002 actual emissions base case, a planning case to represent the 2000-2004 regional haze baseline period using averages for key emissions categories, and a 2018 base case of projected emissions determined using factors known at the end of 2005. All emission inventories were prepared for CMAQ using the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system. Each of these inventories underwent a number of revisions throughout the development process to arrive at the final versions used in CMAQ modeling. The development of each of these emission scenarios is documented under the emissions inventory sections on WRAP's website at:

http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx.

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The 2018 visibility projections were made using the planning case to represent the 2000-2004 regional haze baseline period (Plan02c) and base case projected emissions (Base18b). The CMAQ modeling grid design was established at 36-kilometers. Projections were made using relative response factors, which are defined as the ratio of the future-year modeling results to the current-year modeling results. The calculated relative response factors are applied to the baseline observed visibility conditions to project future-year observed visibility.

Generally, emissions inputs were prepared by individual states and tribes for point, area, and most dust emissions categories. The following WRAP forums were relied upon to summarize this data and provide it to the Regional Modeling Center:

1. Point source emissions were obtained from projects commissioned by the Stationary Sources Joint and Emissions forums;
2. Area source emissions were obtained from projects commissioned by the Stationary Sources Joint and Emissions forums;
3. Mobile source emissions were obtained from projects commissioned by the Emissions forum;
4. Fire (natural and anthropogenic) emissions were obtained from projects commissioned by the Fire Emissions Joint forum;
5. Ammonia, dust, and biogenic emissions were obtained from projects commissioned by the Dust Emissions Joint and Modeling forums;
6. Emissions from Pacific offshore shipping were obtained from a project conducted by the Regional Modeling Center;
7. Other emissions from North America were obtained from projects commissioned by the Emissions and Modeling forums. Mexico's emissions were based on a 1999 emission inventory and Canada's were based on a 2000 emission inventory. Both were held constant for 2018; and
8. Boundary conditions reaching North America from the rest of the world were obtained from a project commissioned by the VISTAS Regional Planning Organization on behalf of the five regional Planning organizations working on regional haze.

5.3 Regional Haze Contributions in South Dakota's National Parks

WRAP developed graphs showing the profile of the relative contribution of in-state versus out-of-state sources contributing to air pollutant concentrations in South Dakota's Class I areas for the 20% least and most impaired days during the 2002 baseline and 2018 projections using the Particulate Matter Source Apportionment Technology and Weighted Emissions Potential analyses.

As previously mentioned, there are several differences between the Particulate Matter Source Apportionment Technology analysis and Weighted Emissions Potential analysis. The Particulate Matter Source Apportionment Technology focuses on sulfate and nitrate contribution taking into account chemistry and deposition; but also estimates the contribution from all regions such as the WRAP states, CENRAP states, Canada, Mexico, Pacific offshore (shipping), and "outside the

domain" (global transport). CENRAP is a regional planning organization similar to the WRAP that is comprised of Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana.

The Weighted Emissions Potential analysis estimates the contribution from Canada and Pacific offshore regions; but does not include other regional contributions. Therefore, WRAP's apportionment analysis is based on the Particulate Matter Source Apportionment Technology results for identifying the contribution of sulfates and nitrates (the primary anthropogenic source pollutants) and Weighted Emissions Potential results for identifying the contribution of organic carbon mass, elemental carbon, fine particulate matter, and coarse particulate matter.

5.3.1 Sulfate Contributions

Based on the IMPROVE data, ammonia sulfate contributes to visibility impairment in both the Badlands and Wind Cave National Parks. At the Badlands National Park, ammonia sulfate has the greatest impact and at the Wind Cave National Park it has the second greatest impact during the 20% most impaired days. Figure 5-1 and 5-2 illustrates the state and regional contribution of sulfate during the 20% most and least impaired days in South Dakota's two Class I areas. The contributions are based on modeling of 2002 emission inventories of actual emissions and projected emissions in 2018. The pie chart in each figure displays the regional contribution to the total annual modeled sulfate mass at the respective sites for the 2002 base year and 2018 projections. The bar chart identifies what state or region is contributing, the amount of contribution, and what type of sources are contributing to sulfate concentrations in the 2002 base year and 2018 projections. There are five source categories listed: 1) point; 2) area; 3) mobile; 4) anthropogenic fires (controlled burns); and 5) natural fires and biogenic sources (mostly wildfire and windblown dust). In each figure, the first bar for each state and region is not labeled but represents the 2002 base year.

Based on the WRAP modeling, the sulfate concentrations for the 20% most impaired days (worst days) in the Badlands National Park will decrease from 1.8 micrograms per cubic meter in 2002 to 1.6 micrograms per cubic meter in 2018 (see Figure 5-1(a)). The decrease appears to be attributed to decreases of sulfate emission in the CENRAP region, Eastern U.S. region, South Dakota and Colorado.

The WRAP modeling indicates the greatest sulfate contribution for the 20% most impaired days at the Badlands National Park in 2002 is generated from the CENRAP region followed by Outside the Domain, Eastern U.S., Canada, and North Dakota. If you exclude Outside Domain because the source categories were not identified, a majority of the sulfate contribution is generated from point sources followed by area and mobile sources.

In 2018, the greatest sulfate contribution for the 20% most impaired days at the Badlands National Park switches from the CENRAP region to Outside the Domain. This occurs because Outside the Domain's sulfate contributions slightly increase while the CENRAP region's sulfate contribution decreases during the same period. Even with the decreases in sulfate emissions, the CENRAP region is the second greatest contributor followed by Canada, North Dakota and

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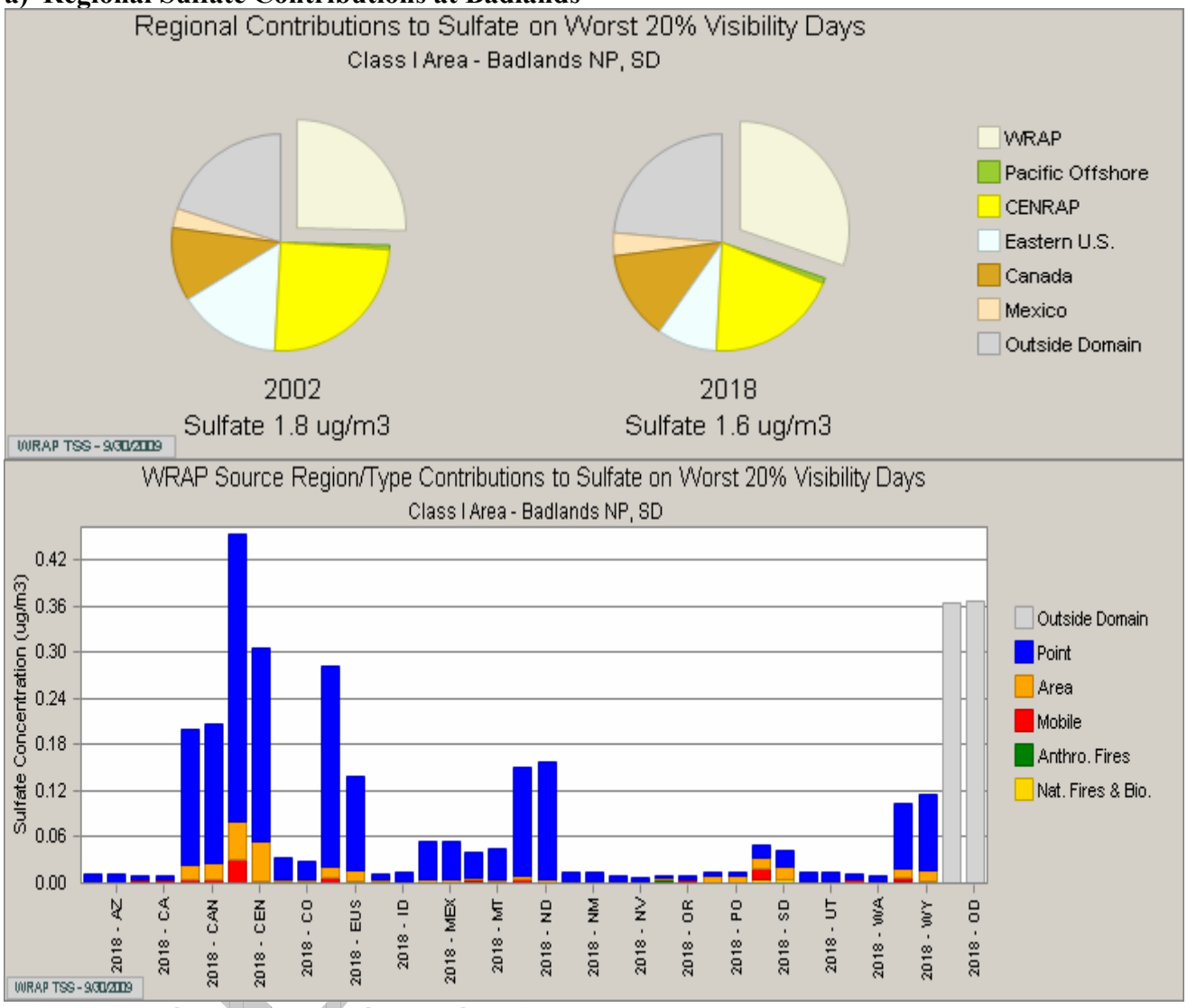
Eastern U.S. Again, point sources are the major contributor followed by area sources with mobile source contribution minimized in 2018.

Figure 5-1 – Sulfate Contribution for 20% Most Impaired Days
a) Regional Sulfate Contributions at Badlands



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

South Dakota's sulfate contribution in 2002 at the Badlands National Park is minimal at less than 0.06 micrograms per cubic meter. The sources of sulfate emissions in South Dakota are generated from point, area, and mobile sources evenly in 2002. In 2018, South Dakota's sulfate contribution switch mainly to point and area sources, and like other states and regions in the United States, mobile source contributions are minimal due to new changes in federal emission standards from mobile sources.

Based on the WRAP modeling, the sulfate concentrations for the 20% most impaired days (worst days) in the Wind Cave National Park will decrease from 1.4 micrograms per cubic meter in 2002 to 1.3 micrograms per cubic meter in 2018 (see Figure 5-1(b)). The decrease appears to be attributed to decreases of sulfate emission in the CENRAP region, Eastern U.S. region, South Dakota and Colorado.

The WRAP modeling indicates the greatest sulfate contribution for the 20% most impaired days at the Wind Cave National Park in 2002 is generated from Outside the Domain followed by the CENRAP region, Canada, Wyoming, and North Dakota. If you exclude Outside Domain because the source categories were not identified, a majority of the sulfate contribution is generated from point sources followed by area and mobile sources. The source category contribution is similar to what you see at the Badlands National Park

In 2018, the greatest sulfate contribution for the 20% most impaired days at the Wind Cave National Park remains from Outside the Domain. The next four greatest contributors is Canada, the CENRAP region, Wyoming and North Dakota. The CENRAP region's sulfate contribution decreases in 2018 which reduces its contribution lower than Canada; but continues to be greater than Wyoming and North Dakota. Again, point sources are the major contributor followed by area sources with mobile source contribution minimized in 2018.

South Dakota's sulfate contribution in 2002 at the Wind Cave National Park is minimal at approximately 0.04 micrograms per cubic meter. The sources of sulfate emissions in South Dakota are generated from point, area, and mobile sources evenly in 2002. In 2018, South Dakota's sulfate contribution switch mainly to point and area sources, and like other states and regions in the United States, mobile source contributions are minimal due to new changes in federal emission standards from mobile sources.

Point sources contribute a majority to the sulfate concentrations in South Dakota's two national parks during the 20% most impaired days. The state or region that contributes to the sulfate concentrations the greatest is dependent on where the national park is located. For example, in the WRAP region, North Dakota contributes more to the Badlands National Park while Wyoming contributes more to the Wind Cave National Park.

Based on the WRAP modeling, the sulfate concentrations for the 20% least impaired days (best days) in the Badlands National Park will increase from 0.6 micrograms per cubic meter in 2002 to 0.7 micrograms per cubic meter in 2018 (see Figure 5-2(a)). Although Wyoming is not the greatest sulfate contributor during the 20% least impaired days, the increase appears to be attributed to increases of sulfate emission in the Wyoming, Idaho, and Montana.

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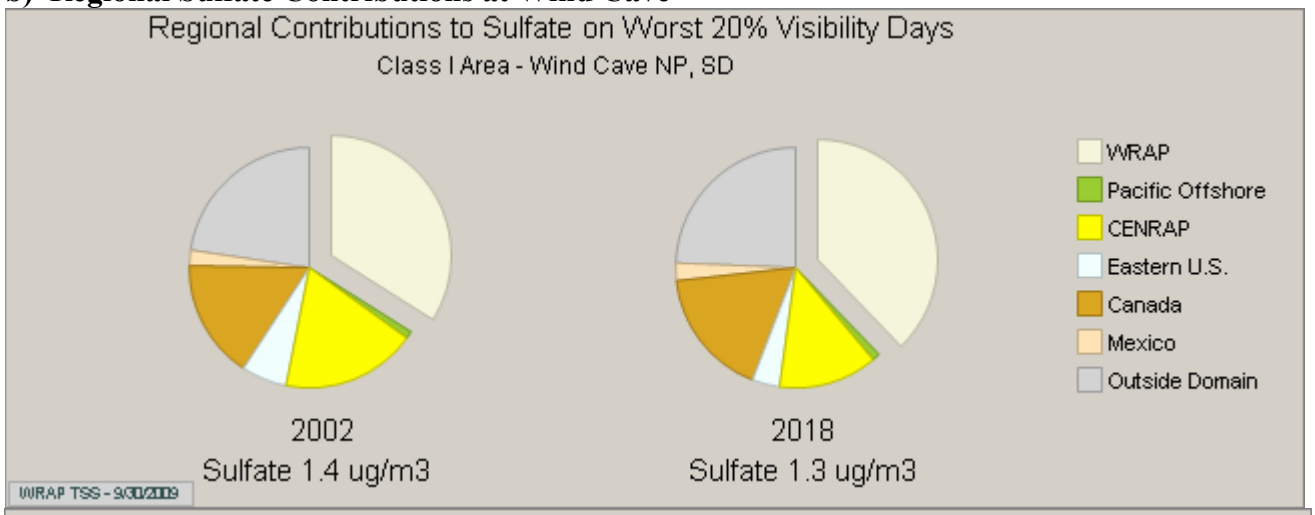
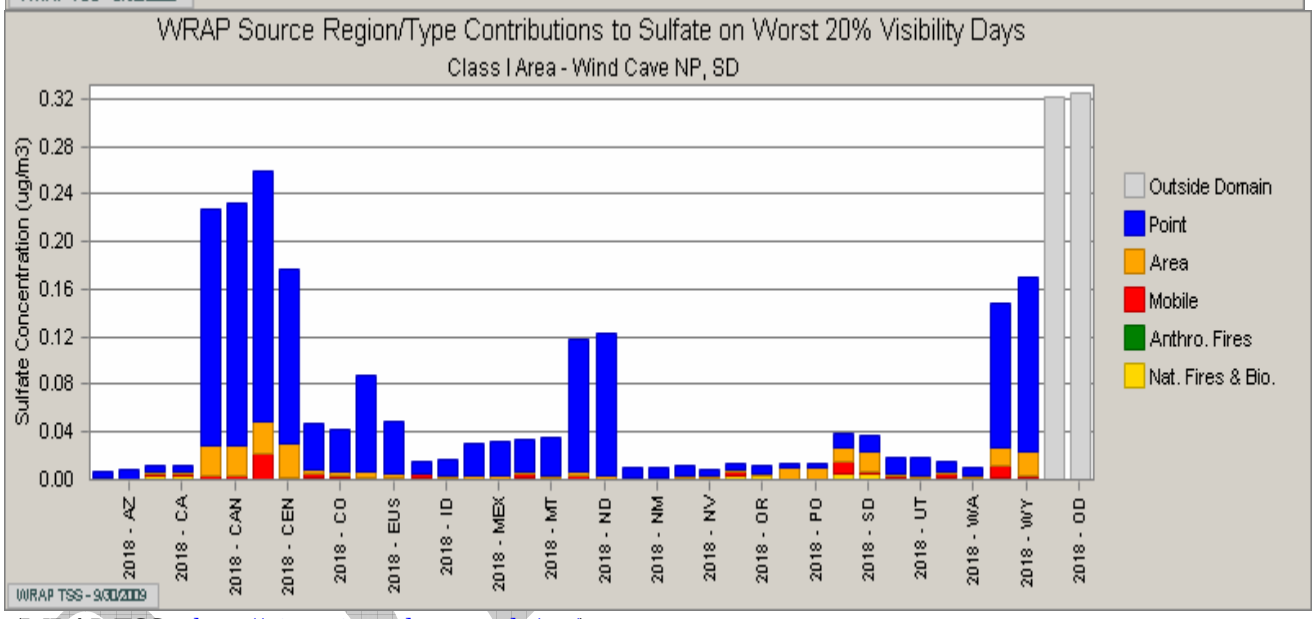
b) Regional Sulfate Contributions at Wind Cave



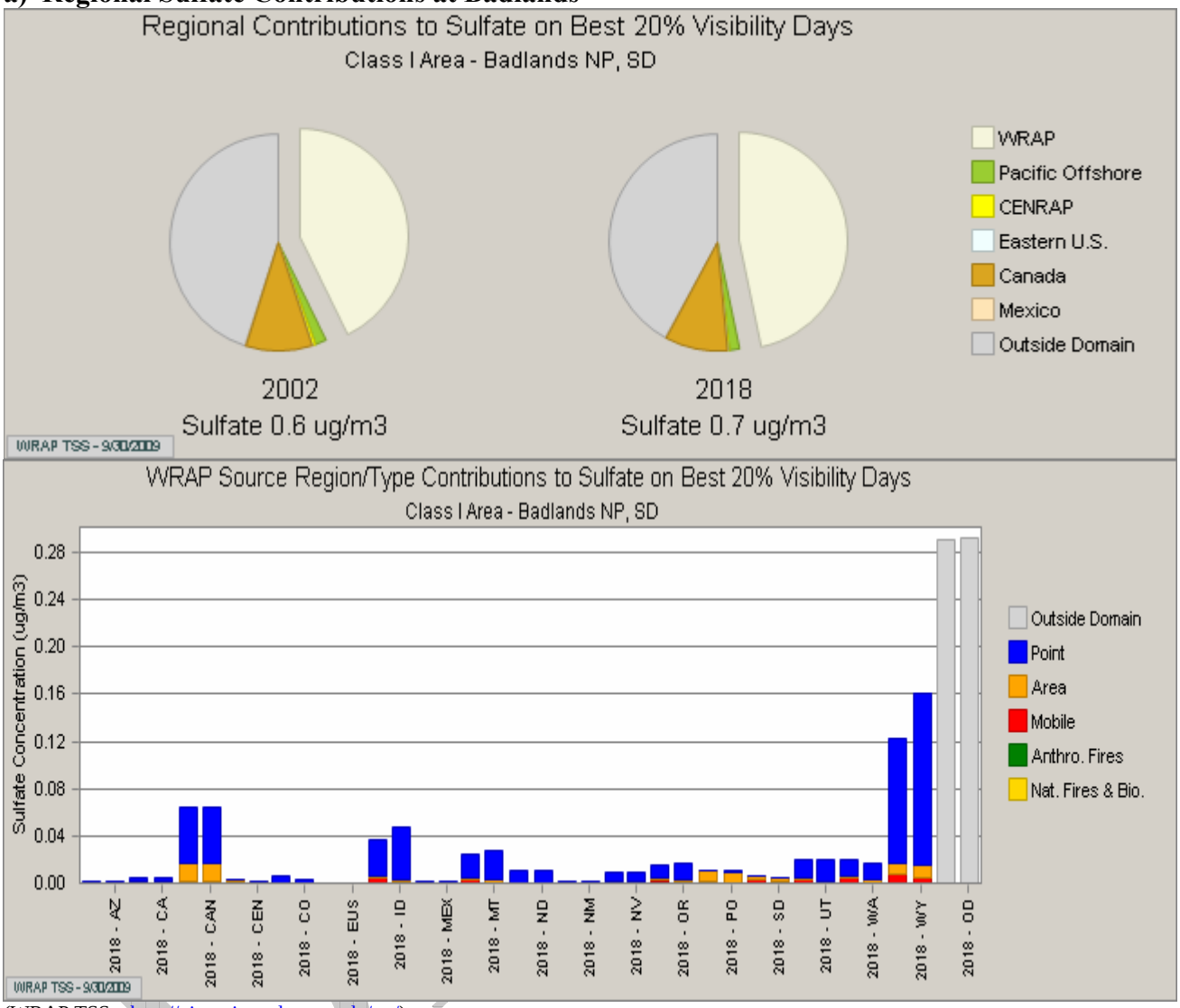


(WRAP TSS – http://vista.cira.colostate.edu/tss/)

The WRAP modeling indicates the greatest sulfate contribution for the 20% least impaired days at the Badlands National Park in 2002 is generated from Outside the Domain followed by Wyoming, Canada, Idaho, and Montana. If you exclude Outside Domain because the source categories were not identified, a majority of the sulfate contribution is generated from point sources.

In 2018, the greatest sulfate contribution for the 20% least impaired days at the Badlands National Park does not change from 2002. The five greatest sulfate contributors are Outside the Domain, Wyoming, Canada, Idaho, and Montana. Again, point sources are the major contributor of sulfate concentrations.

Figure 5-2 – Sulfate Contribution for 20% Least Impaired Days
a) Regional Sulfate Contributions at Badlands

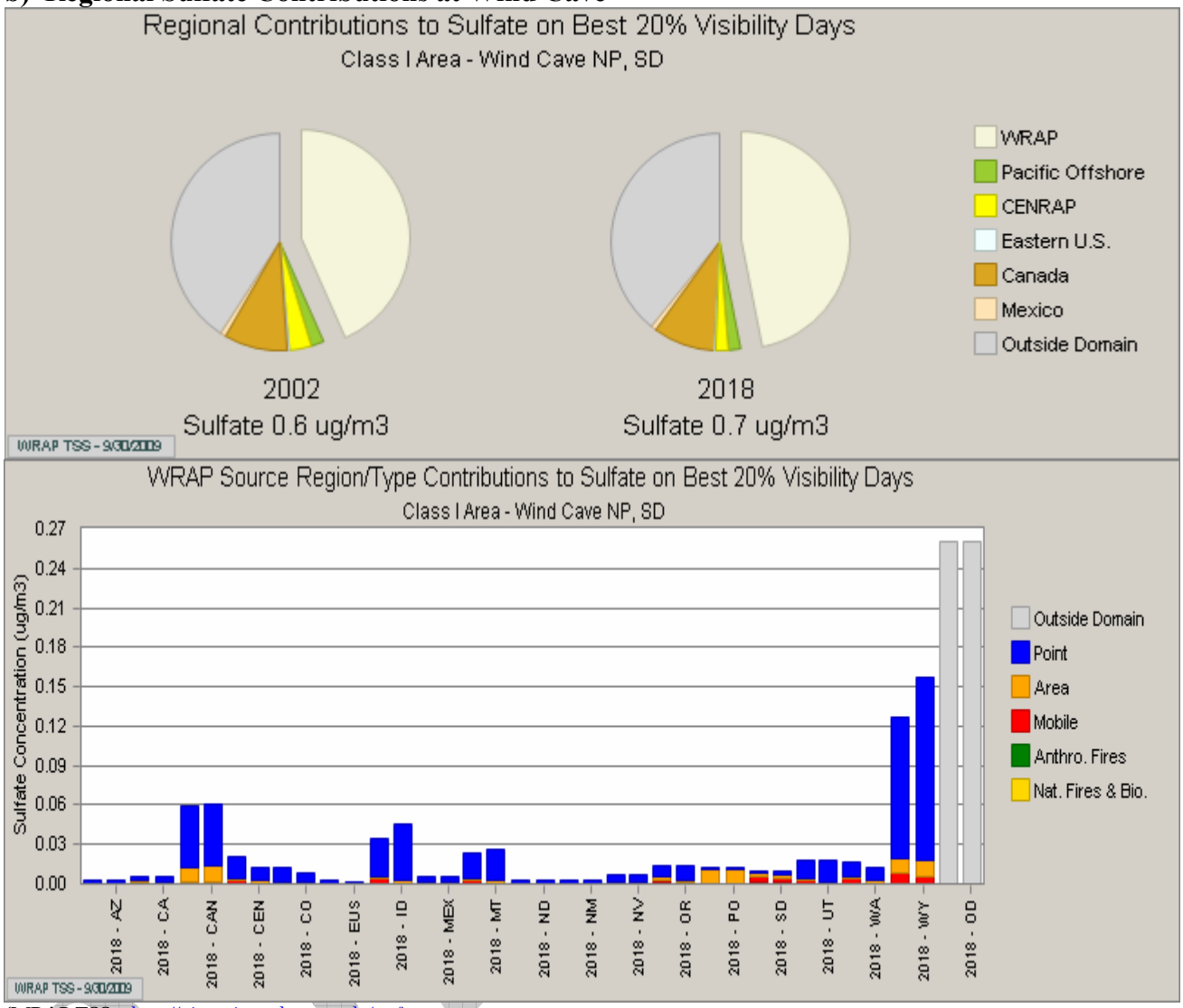


(WRAP TSS – http://vista.cira.colostate.edu/tss/)

South Dakota's sulfate contribution in 2002 at the Badlands National Park for the 20% least impaired days is minimal at approximately 0.01 micrograms per cubic meter. The sources of sulfate emissions in South Dakota are generated from point, area, and mobile sources in 2002. In 2018, South Dakota's sulfate contribution is less than 0.01 micrograms per cubic meter.

Based on the WRAP modeling, the sulfate concentrations for the 20% least impaired days (best days) in the Wind Cave National Park will also increase from 0.6 micrograms per cubic meter in 2002 to 0.7 micrograms per cubic meter in 2018 (see Figure 5-2(b)). Although Wyoming is not the greatest sulfate contributor during the 20% least impaired days, the increase appears to be attributed to increases of sulfate emission in the Wyoming, Idaho, and Montana, which is similar to what is predicted at the Badlands National Park.

b) Regional Sulfate Contributions at Wind Cave



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

The WRAP modeling indicates the greatest sulfate contribution for the 20% least impaired days at the Wind Cave National Park in 2002 is generated from Outside the Domain followed by Wyoming, Canada, Idaho, and Montana. If you exclude Outside Domain because the source categories were not identified, a majority of the sulfate contribution is generated from point sources.

In 2018, the greatest sulfate contribution for the 20% least impaired days at the Wind Cave National Park does not change from 2002. The five greatest sulfate contributors are Outside the Domain, Wyoming, Canada, Idaho, and Montana. Again, point sources are the major contributor of sulfate concentrations.

South Dakota's sulfate contribution in 2002 at the Wind Cave National Park for the 20% least impaired days is minimal at approximately 0.01 micrograms per cubic meter. The sources of

sulfate emissions in South Dakota are generated from point, area, and mobile sources in 2002. In 2018, South Dakota's sulfate contribution stays about the same.

Point sources contribute a majority to the sulfate concentrations in South Dakota's two national parks during the 20% least impaired days. The state or region that contributes to the sulfate concentrations the greatest is not dependent on where the national park is located. For each national park, the greatest contributors are the same.

5.3.2 Organic Carbon Mass Contributions

Based on the IMPROVE data, organic carbon mass also contributes to visibility impairment in both the Badlands and Wind Cave National Parks. At the Wind Cave National Park, organic carbon mass has the greatest impact and at the Badlands National Park it has the second greatest impact during the 20% most impaired days. Figure 5-3 and 5-4 illustrates the state and regional contribution of organic carbon mass during the 20% most and least impaired days in South Dakota's two Class I areas. The contributions are based on modeling of 2002 emission inventories of actual emissions and projected emissions in 2018. The bar chart identifies what state or region is contributing, the percentage of contribution, and what type of sources are contributing to organic carbon mass for the 2002 base year and 2018 projections. WRAP identified 12 source categories: 1) windblown dust; 2) fugitive dust; 3) road dust; 4) off-road mobile; 5) on-road mobile; 6) off-shore; 7) WRAP area oil and gas; 8) area; 9) biogenic; 10) natural fires; 11) anthropogenic fire; and 12) point sources.

The WRAP modeling indicates the greatest percentage of organic carbon mass contribution for the 20% most impaired days at the Badlands and Wind Cave National Park in 2002 and 2018 is generated from within South Dakota (see Figure 5-3). The percentage at the Badlands and Wind Cave National Park is approximately 30 and 41 percent, respectively. The CENRAP region contributes approximately 17 percent at the Badlands National Park; but only around eight percent at the Wind Cave National Park. Wyoming contributes approximately five percent at the Badlands National Park while up to eight percent at the Wind Cave National Park.

In all but the CENRAP region, the source of organic carbon mass contributions is generated from natural fires. For example, approximately 23 percent of South Dakota's 30 percent at the Badlands National Park is attributed to natural fires. South Dakota's natural fire percentage at the Wind Cave National Park is even greater at 33 percent. In the CENRAP region, organic carbon mass contributions are generated from area sources such as woodstoves or other urban related sources.

There appears to be slight decreases in organic carbon mass contributions from 2002 to 2018; but the reductions are minimal and mainly due to a decrease in off-road mobile and anthropogenic fires.

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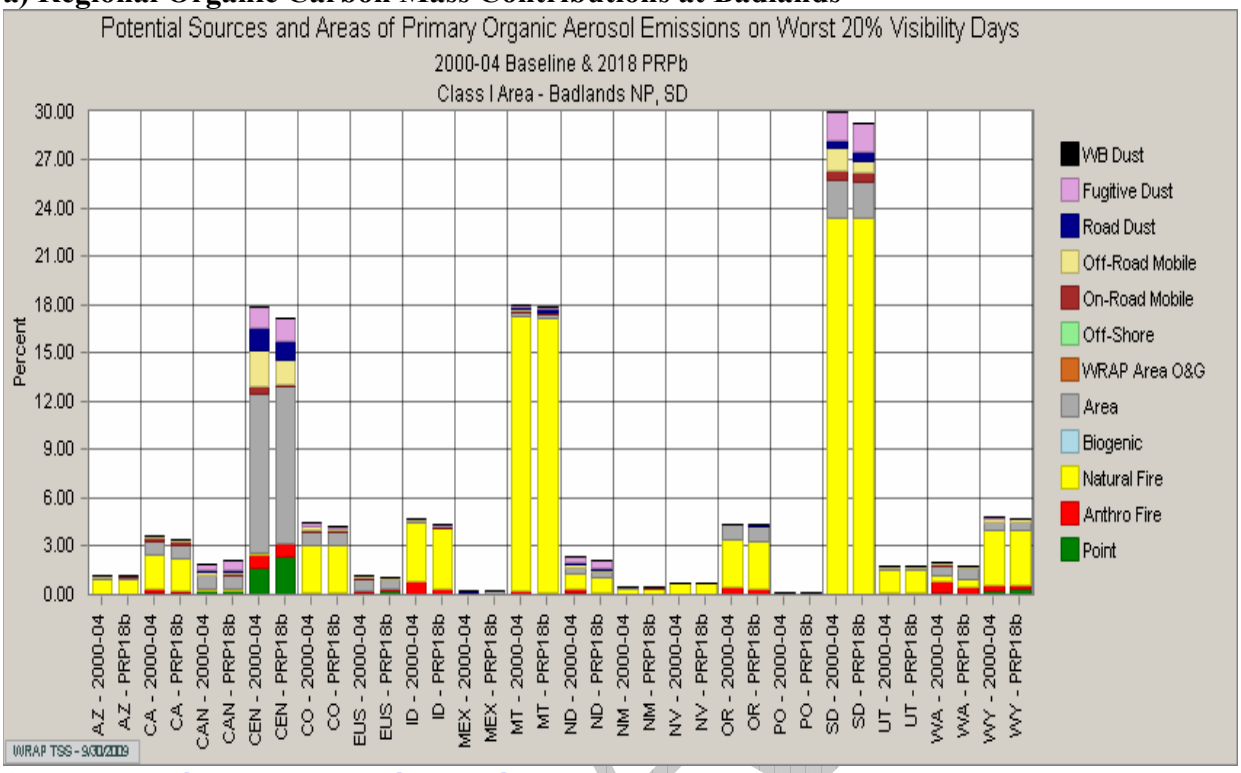
Figure 5-3 – Organic Carbon Mass Contribution for 20% Most Impaired Days
a) Regional Organic Carbon Mass Contributions at Badlands

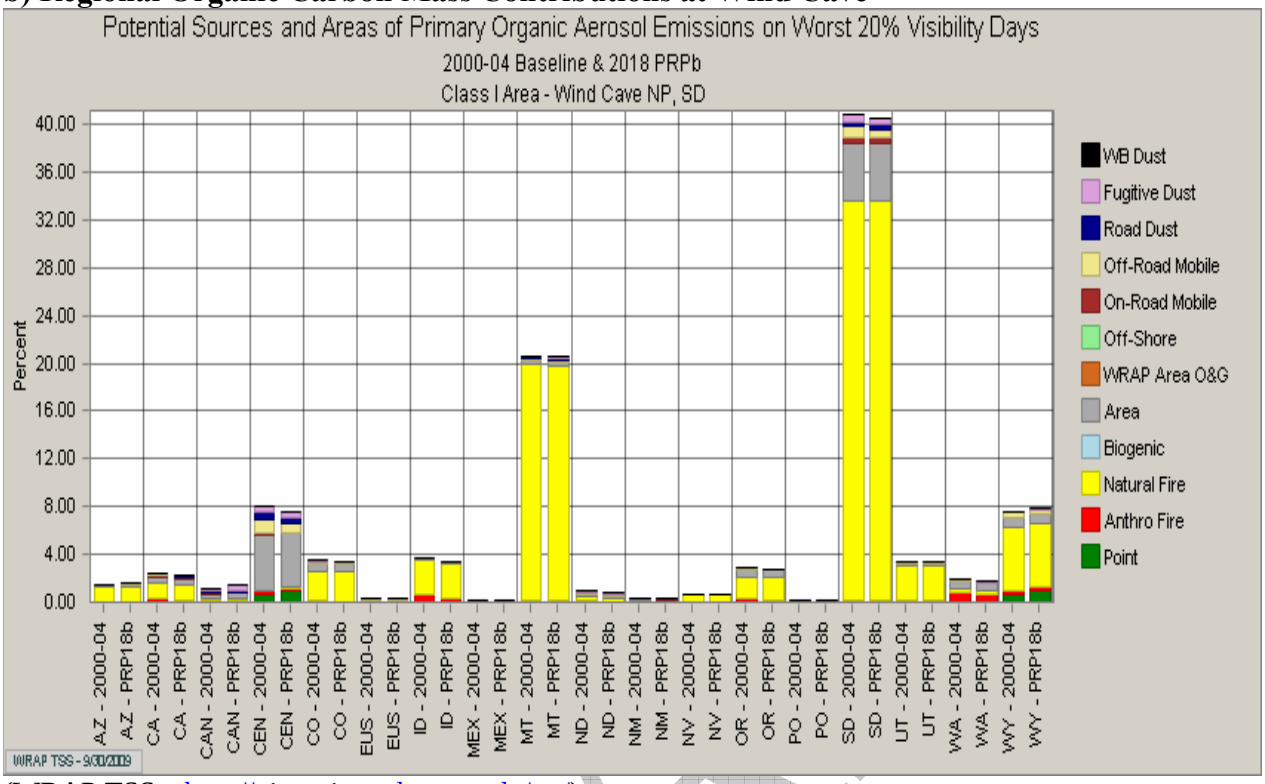


(WRAP TSS – http://vista.cira.colostate.edu/tss/)

It is interesting that the WRAP modeling indicates the greatest percentage of organic carbon mass contribution for the 20% least impaired days at the Badlands National Park in 2002 and 2018 is generated from Montana (see Figure 5-4(a)) at approximately 35 percent. South Dakota, Oregon, and Idaho contribute approximately 20 percent, 12 percent, and seven percent, respectively. The source of organic carbon mass contributions is generated mainly from natural fires. Natural fire generated organic carbon mass from Montana contributes approximately 34 percent of the organic carbon mass in the Badlands National Park. There appears to be slight decreases in organic carbon mass contributions from 2002 to 2018; but the reductions are minimal and mainly due to a decrease in off-road mobile and anthropogenic fire.

For the Wind Cave National Park, the WRAP modeling for the 20% least impaired days agrees better with the 20% most impaired days in that the greatest percentage of organic carbon mass contribution in 2002 and 2018 is generated from within South Dakota (see Figure 5-4(b)) at approximately 42 percent. Montana, Wyoming, Idaho, and Oregon all contribute over eight percent. The major source of organic carbon mass contribution is generated from natural fires. There appears to be slight decreases in organic carbon mass contributions from 2002 to 2018; but the reductions are minimal and mainly due to a decrease in off-road mobile and anthropogenic fire.

b) Regional Organic Carbon Mass Contributions at Wind Cave

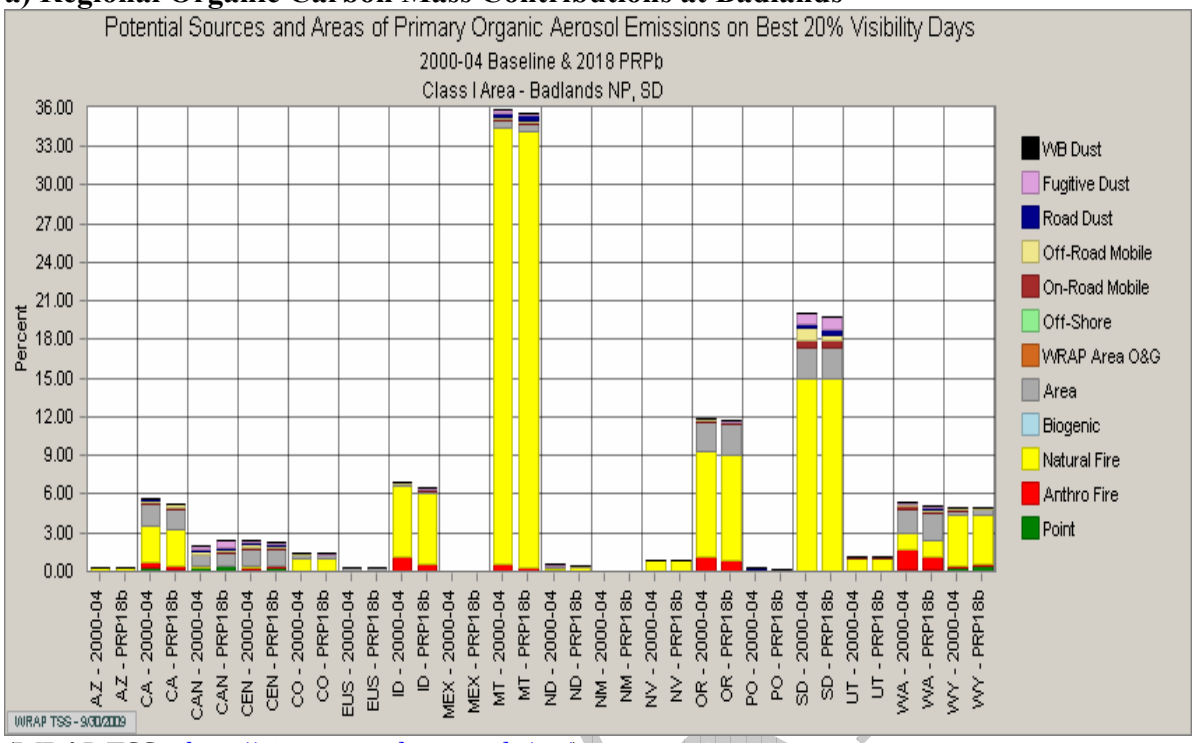


(WRAP TSS – http://vista.cira.colostate.edu/tss/)

It appears from this information that natural fires are the greatest contributor to visibility impairment from organic carbon mass in the two national parks. Based on South Dakota having the greatest contribution percentage for both the 20% most and least impaired days at the Wind Cave National Park, it appears natural fires within the Black Hills area have a greater impact on contributing to visibility impairment at the Wind Cave National Park then at the Badlands National Park. DENR believes this will have to be reviewed further to determine the best method for minimizing the impacts natural fires and prescribed fires have on South Dakota's two national parks.

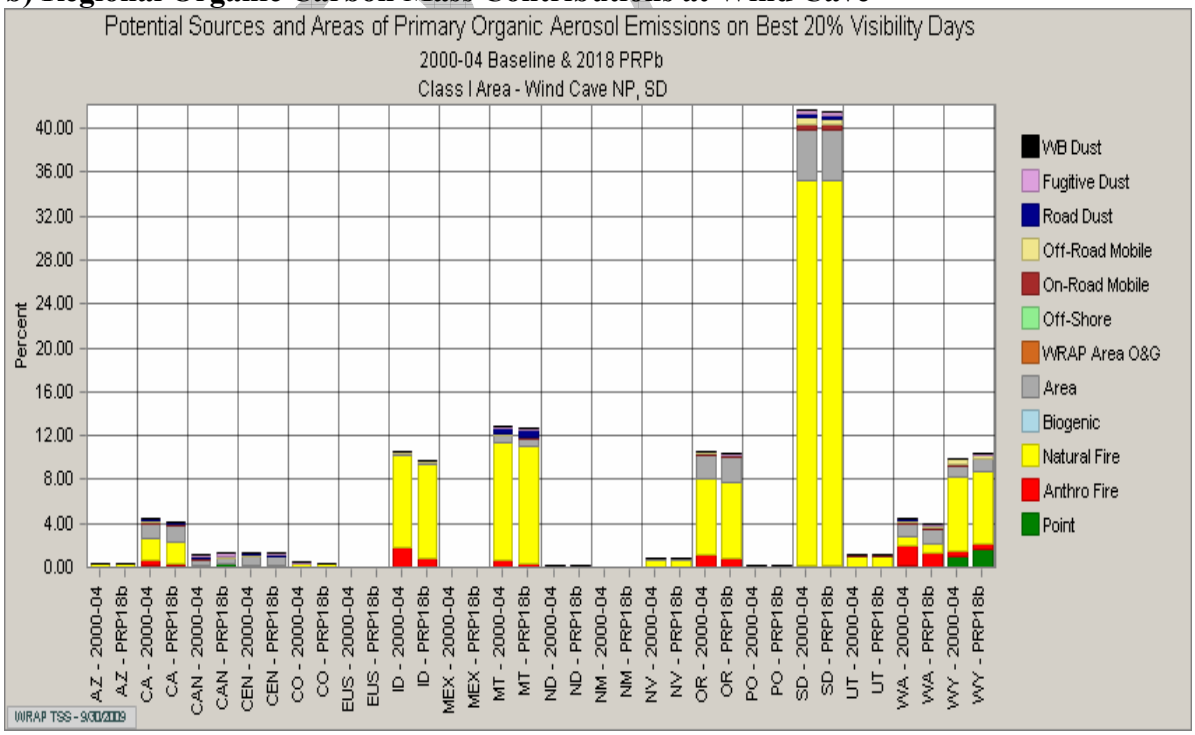
Figure 5-4 – Organic Carbon Mass Contribution for 20% Least Impaired Days

a) Regional Organic Carbon Mass Contributions at Badlands



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

b) Regional Organic Carbon Mass Contributions at Wind Cave



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

5.3.3 Nitrate Contributions

Based on the IMPROVE data, ammonia nitrate contributes to visibility impairment in both the Badlands and Wind Cave National Parks. Ammonia nitrate contributions are not as great as ammonia sulfate or organic carbon mass but are significant enough to determine where the nitrates are being generated. Figure 5-5 and 5-6 illustrates the state and regional contribution of sulfate during the 20% most and least impaired days in South Dakota's two Class I areas. The contributions are based on modeling of 2002 emission inventories of actual emissions and projected emissions in 2018. The pie chart in each figure displays the regional contribution to the total annual modeled nitrate mass at the respective sites for the 2002 base year and 2018 projections. The bar chart identifies what state or region is contributing, the amount of contribution, and what type of sources are contributing to nitrate concentrations in the 2002 base year and 2018 projections. There are five source categories listed: 1) point; 2) area; 3) mobile; 4) anthropogenic fires (controlled burns); and 5) natural fires and biogenic sources (mostly wildfire and windblown dust). In each figure, the first bar for each state and region is not labeled but represents the 2002 base year.

Based on the WRAP modeling, the nitrate concentrations for the 20% most impaired days (worst days) in the Badlands National Park will decrease from 1.3 micrograms per cubic meter in 2002 to 1.2 micrograms per cubic meter in 2018 (see Figure 5-5(a)). The decrease appears to be attributed to decreases of nitrate emission in the CENRAP region, South Dakota, Wyoming, and North Dakota from mobile sources.

The WRAP modeling indicates the greatest nitrate contribution for the 20% most impaired days at the Badlands National Park in 2002 is generated from Canada followed by Outside the Domain, the CENRAP region, South Dakota, and Wyoming. If you exclude Outside the Domain because the source categories were not identified, a majority of the nitrate contribution is generated from point, area, and mobile sources in 2002 from influences outside of South Dakota; and in South Dakota the nitrate contribution is from mobile, natural fires and biogenic, and point sources.

In 2018, the greatest nitrate contribution for the 20% most impaired days at the Badlands National Park remains from Canada followed by Outside the Domain, South Dakota, Wyoming, and North Dakota. The CENRAP region is no longer in the top five contributors because of nitrate decreases mainly due from mobile sources. The sources of nitrate contribution remain the same from 2002 to 2018.

South Dakota's nitrate contribution in 2002 at the Badlands National Park is approximately 0.18 micrograms per cubic meter. The sources of nitrates in South Dakota are generated from mobile, natural fires and biogenic, and point sources in 2002. In 2018, South Dakota's nitrate contribution drops to 0.14 micrograms per cubic meter due mainly to reduction in mobile contributions. The reduction in mobile source contributions is due to new changes in federal emission standards from mobile sources.

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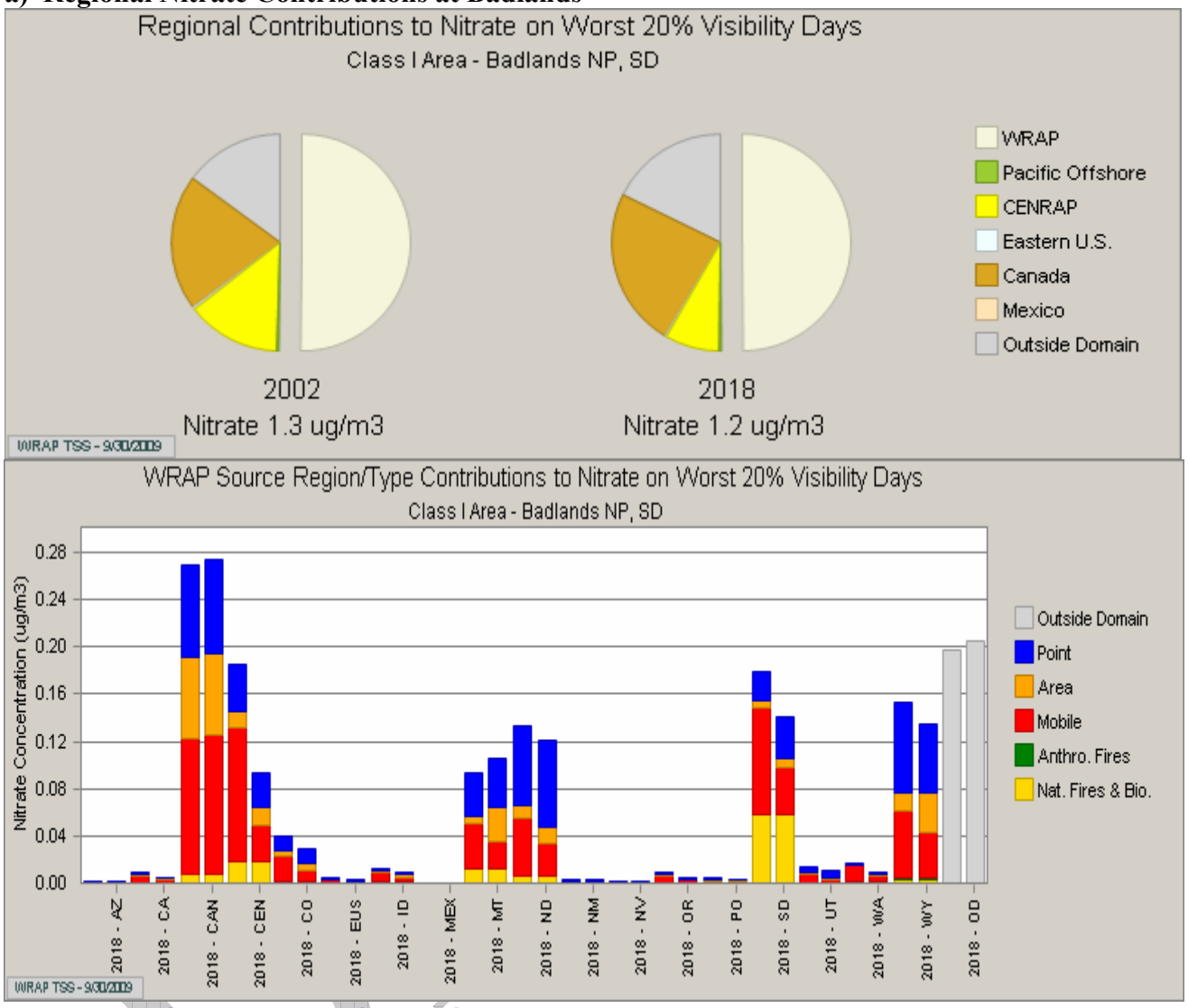
Figure 5-5 – Nitrate Contribution for 20% Most Impaired Days

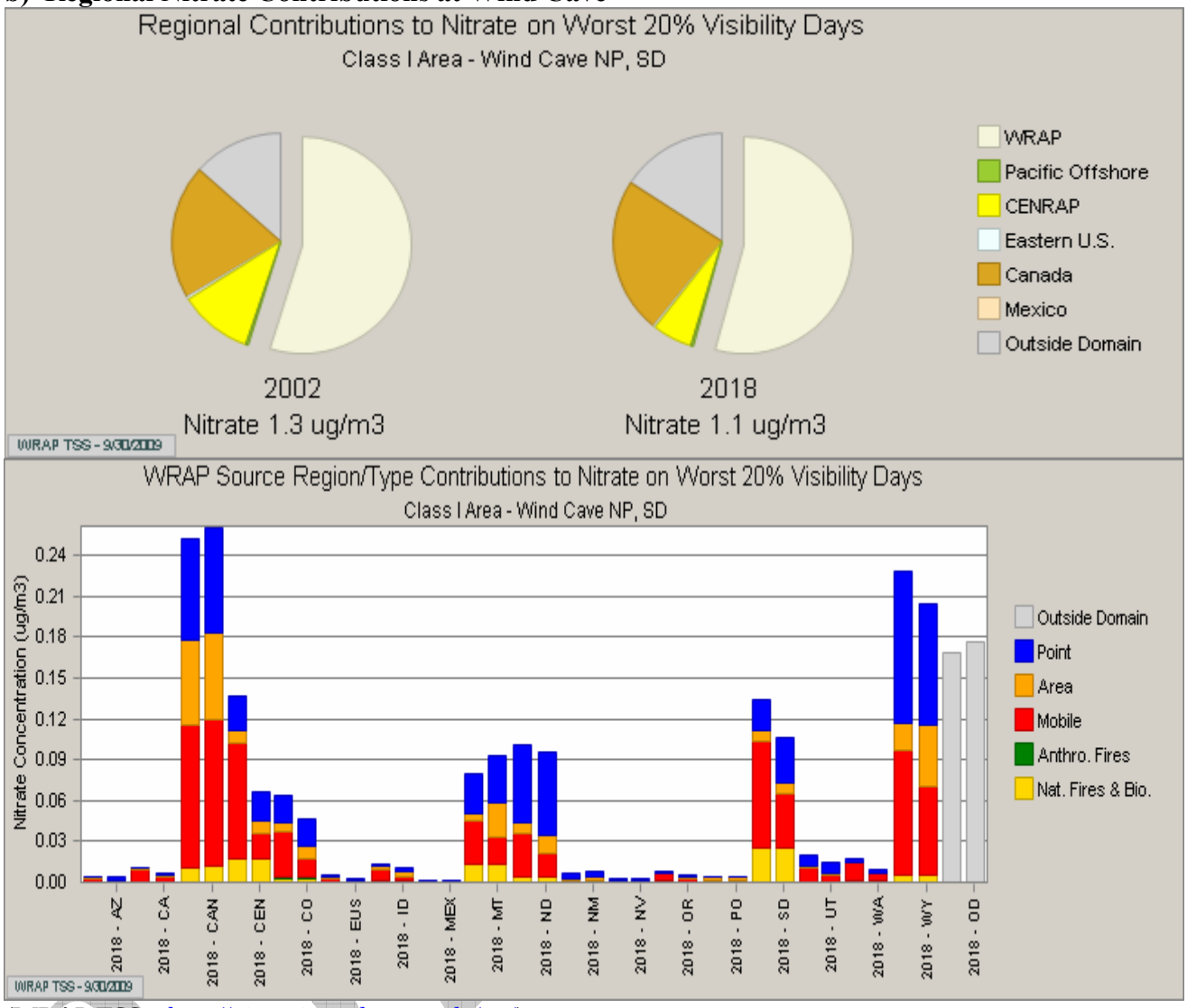
a) Regional Nitrate Contributions at Badlands



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

Based on the WRAP modeling, the nitrate concentrations for the 20% most impaired days (worst days) in the Wind Cave National Park will decrease from 1.3 micrograms per cubic meter in 2002 to 1.1 micrograms per cubic meter in 2018 (see Figure 5-5(b)). The decrease appears to be attributed to decreases of nitrate emission in Wyoming, the CENRAP region, South Dakota, North Dakota and Colorado from mobile sources.

b) Regional Nitrate Contributions at Wind Cave



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

The WRAP modeling indicates the greatest nitrate contribution for the 20% most impaired days at the Wind Cave National Park in 2002 is generated from Canada followed by Wyoming, Outside the Domain, the CENRAP region, and South Dakota. If you exclude Outside the Domain because the source categories were not identified, a majority of the nitrate contribution is generated from point, area, and mobile sources in 2002 from influences outside of South Dakota; and in South Dakota the nitrate contribution is from mobile, natural fires and biogenic, and point sources.

In 2018, the greatest nitrate contribution for the 20% most impaired days at the Wind Cave National Park remains from Canada followed by Wyoming, Outside the Domain, South Dakota, and North Dakota. The CENRAP region is no longer in the top five contributors because of

nitrate decreases mainly due from mobile sources. The sources of nitrate contribution remain the same from 2002 to 2018.

South Dakota's nitrate contribution in 2002 at the Wind Cave National Park is approximately 0.13 micrograms per cubic meter. The sources of nitrates in South Dakota are generated mainly from mobile sources followed by natural fires, biogenic and point sources in 2002. In 2018, South Dakota's nitrate contribution drops to 0.10 micrograms per cubic meter due mainly to reduction in mobile contributions. The reduction in mobile source contributions is due to new changes in federal emission standards from mobile sources.

Based on the WRAP modeling, the nitrate concentrations for the 20% least impaired days (best days) in the Badlands National Park will decrease from 1.7 micrograms per cubic meter in 2002 to 1.5 micrograms per cubic meter in 2018 (see Figure 5-6(a)). The decrease appears to be attributed to decreases of nitrate emission in the states and regions is due to reductions from mobile sources.

The WRAP modeling indicates the greatest nitrate contribution for the 20% least impaired days at the Badlands National Park in 2002 is generated from Wyoming followed by Outside the Domain, Canada, Montana, and South Dakota. If you exclude Outside the Domain because the source categories were not identified, a majority of the nitrate contribution is generated from point, area, and mobile sources in 2002 from influences outside of South Dakota; and in South Dakota the nitrate contribution is from mobile, natural fires and biogenic, and point sources.

In 2018, the greatest nitrate contribution for the 20% most impaired days at the Badlands National Park remains from Wyoming followed by Outside the Domain, Canada, Montana, and South Dakota. The sources of nitrate contribution remain the same from 2002 to 2018.

South Dakota's nitrate contribution in 2002 at the Badlands National Park is approximately 0.11 micrograms per cubic meter. The sources of nitrates in South Dakota are generated mainly from mobile sources followed by natural fires, biogenic and point sources in 2002. In 2018, South Dakota's nitrate contribution drops to 0.10 micrograms per cubic meter due mainly to reduction in mobile contributions. The reduction in mobile source contributions is due to new changes in federal emission standards from mobile sources.

Based on the WRAP modeling, the nitrate concentrations for the 20% least impaired days (best days) in the Wind Cave National Park will decrease from 1.0 micrograms per cubic meter in 2002 to 0.9 micrograms per cubic meter in 2018 (see Figure 5-6(b)). The decrease appears to be attributed to decreases of nitrate emission in the states and regions is due to reductions from mobile sources.

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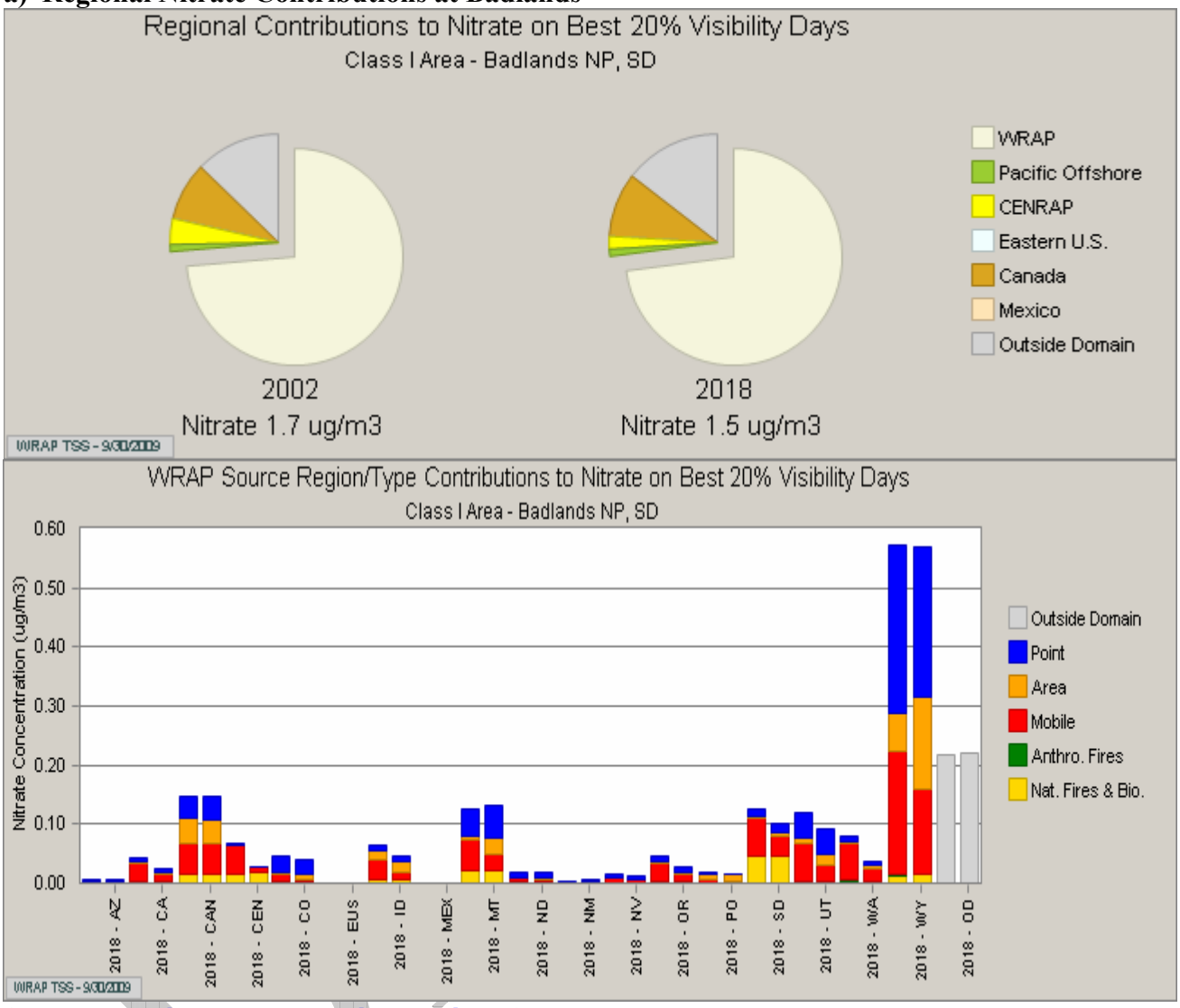
Figure 5-6 – Nitrate Contribution for 20% Least Impaired Days

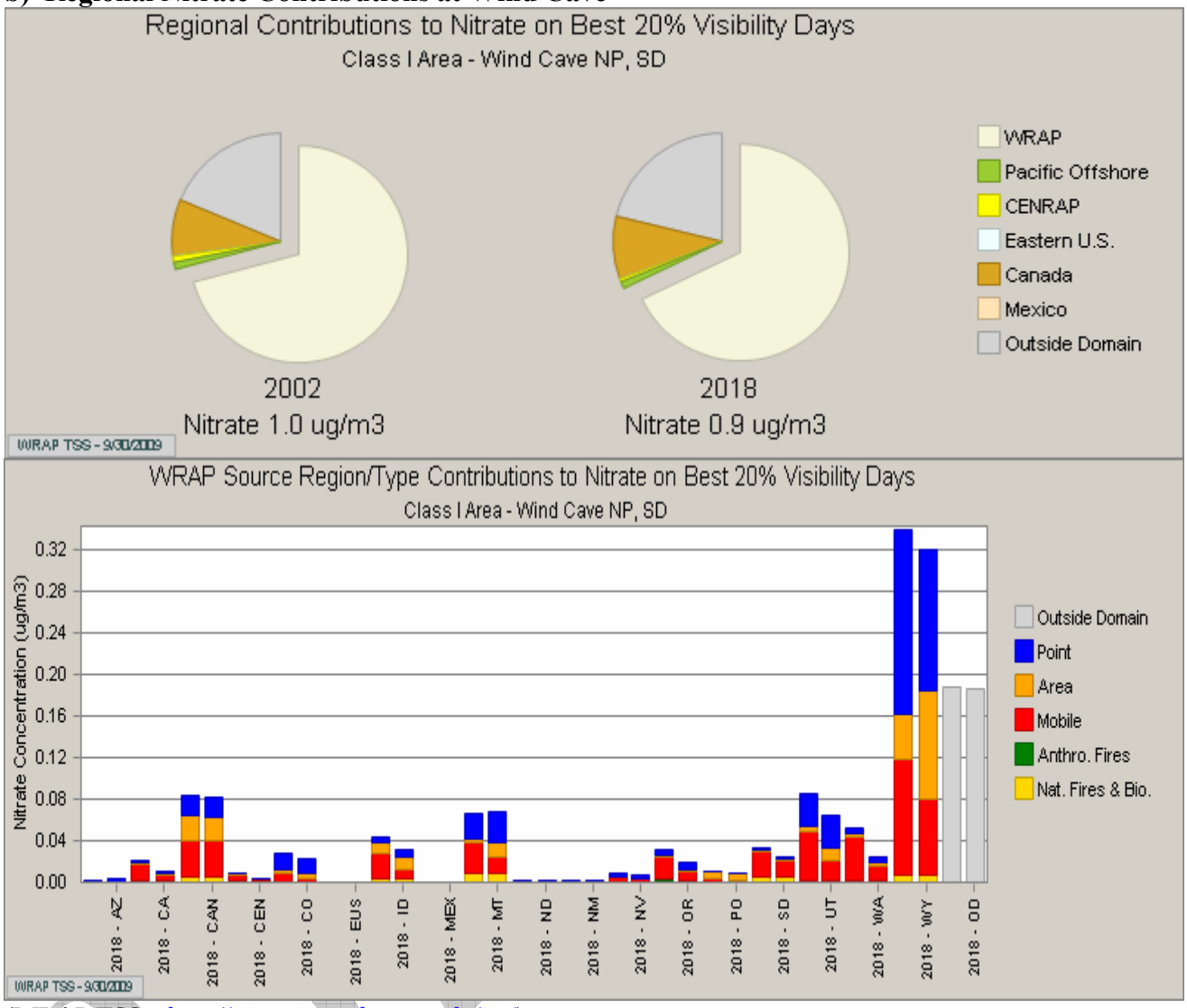
a) Regional Nitrate Contributions at Badlands



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

The WRAP modeling indicates the greatest nitrate contribution for the 20% least impaired days at the Wind Cave National Park in 2002 is generated from Wyoming followed by Outside the Domain, Canada, Utah, and Montana. If you exclude Outside the Domain because the source categories were not identified, a majority of the nitrate contribution is generated from point, area, and mobile sources in 2002.

b) Regional Nitrate Contributions at Wind Cave



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

In 2018, the greatest nitrate contribution for the 20% most impaired days at the Wind Cave National Park remains from Wyoming followed by Outside the Domain, Canada, Montana, and Utah. The sources of nitrate contribution remain the same from 2002 to 2018.

South Dakota's nitrate contribution in 2002 at the Wind Cave National Park is approximately 0.03 micrograms per cubic meter. The sources of nitrates in South Dakota are generated mainly from mobile sources in 2002. In 2018, South Dakota's nitrate contribution drops to 0.02 micrograms per cubic meter due mainly to reduction in mobile contributions. The reduction in mobile source contributions is due to new changes in federal emission standards from mobile sources.

5.3.4 Coarse Particulate Matter Contribution

Based on the IMPROVE data, coarse particulate matter contributes to visibility impairment in both the Badlands and Wind Cave National Parks. Coarse particulate matter contributions are not as great as ammonia sulfate or organic carbon mass but are significant enough to determine where the coarse particulate matter is being generated. Coarse particulate matter has the greater impact at the Badlands National Park then it does at the Wind Cave National Park during the 20% most impaired days. Figure 5-7 and 5-8 illustrates the state and regional contribution of coarse particulate matter during the 20% most and least impaired days in South Dakota's two Class I areas. The contributions are based on modeling of 2002 emission inventories of actual emissions and projected emissions in 2018. The bar chart identifies what state or region is contributing, the percentage of contribution, and what type of sources are contributing to coarse particulate matter for the 2002 base year and 2018 projections. WRAP identified 12 source categories: 1) windblown dust; 2) fugitive dust; 3) road dust; 4) off-road mobile; 5) on-road mobile; 6) off-shore; 7) WRAP area oil and gas; 8) area; 9) biogenic; 10) natural fires; 11) anthropogenic fire; and 12) point sources.

The WRAP modeling indicates the greatest percentage of coarse particulate matter contribution for the 20% most impaired days at the Badlands and Wind Cave National Park in 2002 and 2018 is generated from within South Dakota (see Figure 5-7). The percentage at the Badlands and Wind Cave National Park is approximately 62 and 44 percent, respectively. The CENRAP region contributes approximately 21 percent at the Badlands National Park; and almost 25 percent at the Wind Cave National Park. Montana contributes approximately four percent at the Badlands National Park while up to 12 percent at the Wind Cave National Park.

In all cases, the source of coarse particulate matter contributions is generated from windblown dust with some contribution from fugitive and road dust. For example, approximately 53 percent of South Dakota's 61 percent in 2002 at the Badlands National Park is attributed to windblown dust. South Dakota's windblown dust percentage at the Wind Cave National Park is less at 32 percent; but that is to be expected because of the dryer conditions and wide open areas in the Badlands National Park.

The WRAP modeling indicates the greatest percentage of coarse particulate matter contribution for the 20% least impaired days at the Badlands and Wind Cave National Park in 2002 and 2018 is also generated from within South Dakota (see Figure 5-8). The percentage at the Badlands and Wind Cave National Park is approximately 72 and 39 percent, respectively. The only other notable contributor at the Badlands National Park is Montana at approximately 12 percent. At the Wind Cave National Park, Montana's influence is greater at approximately 29 percent. Wyoming contributes approximately 11 percent at the Wind Cave National Park.

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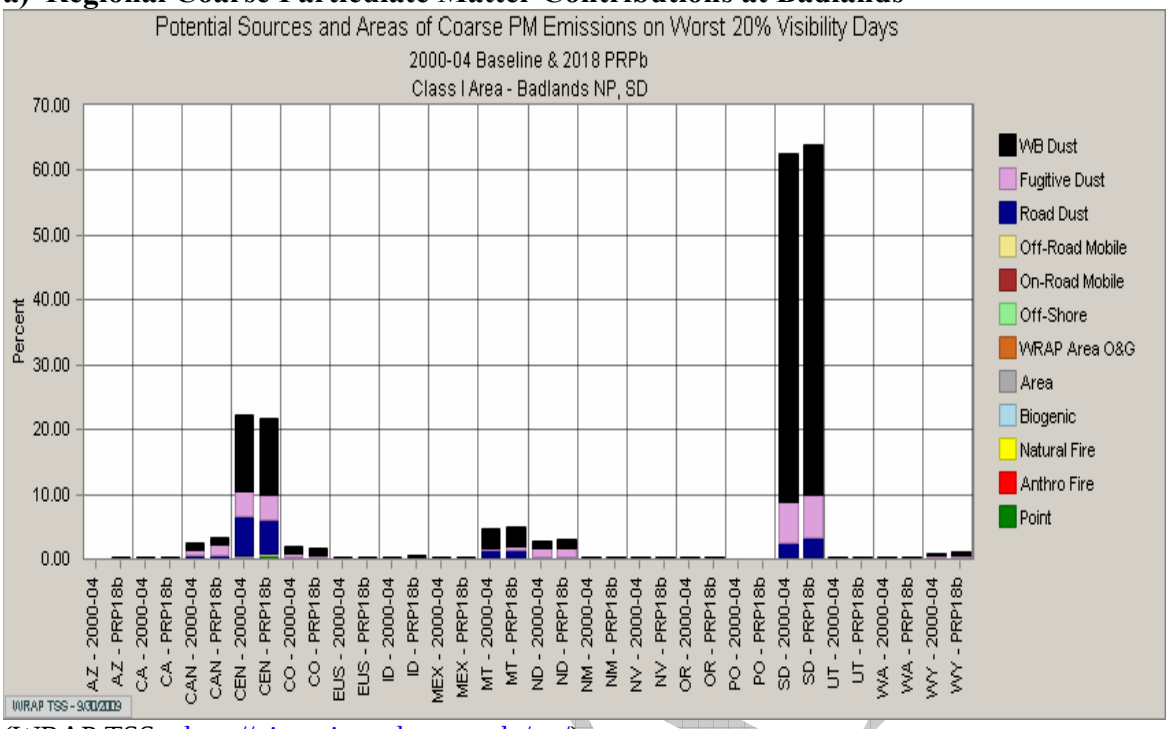
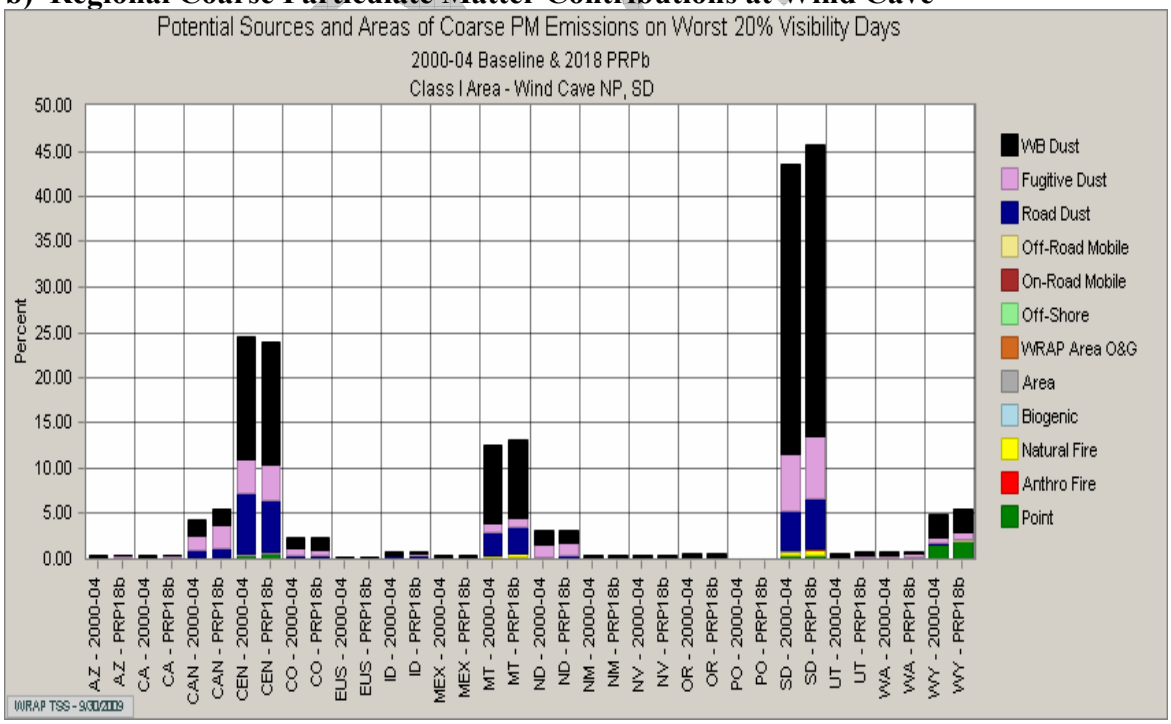
Figure 5-7 – Coarse Particulate Matter Contribution for 20% Most Impaired Days

a) Regional Coarse Particulate Matter Contributions at Badlands



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

b) Regional Coarse Particulate Matter Contributions at Wind Cave

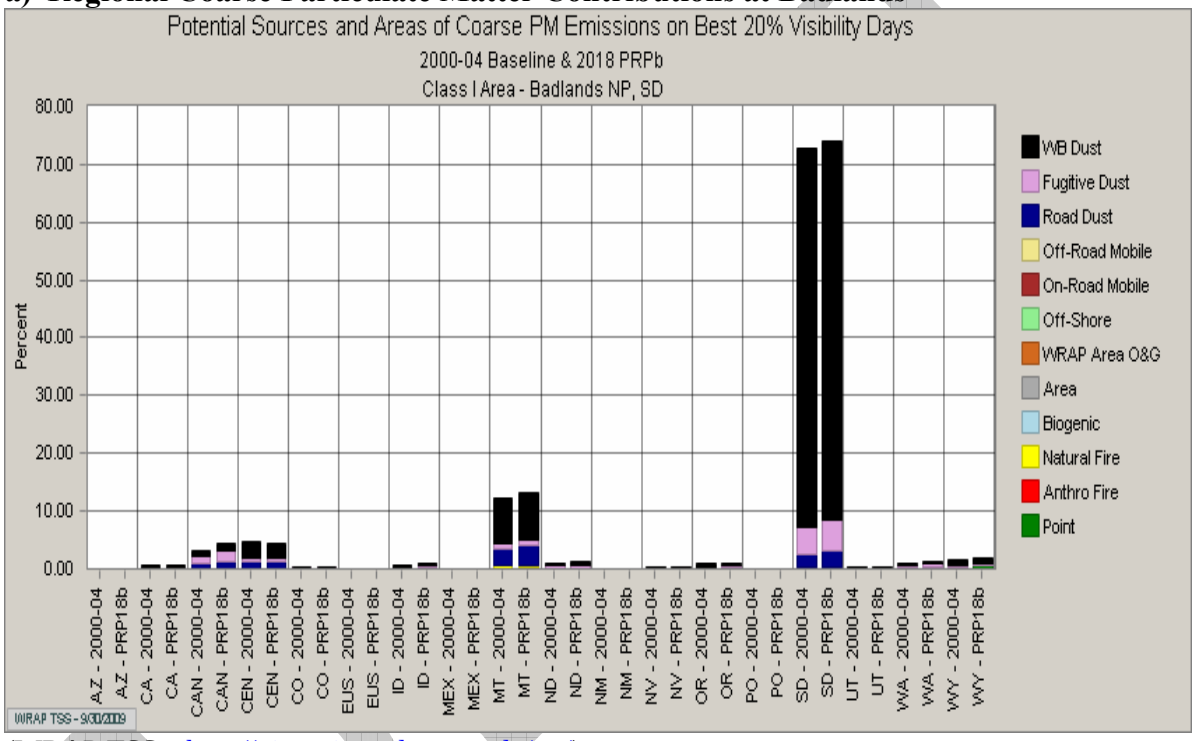


(WRAP TSS – http://vista.cira.colostate.edu/tss/)

In the Badlands National Park, the source of coarse particulate matter contributions is generated from windblown dust with some contribution from fugitive and road dust. For example, approximately 64 percent of South Dakota's 72 percent in 2002 at the Badlands National Park is attributed to windblown dust. At Wind Cave National Park, windblown dust is still the major contributor but fugitive and road dust have a greater role in South Dakota and Montana; while in Wyoming point sources have a greater role. South Dakota's windblown dust percentage at the Wind Cave National Park is less at 25 percent; but that is to be expected because of the dryer conditions and wide open areas in the Badlands National Park.

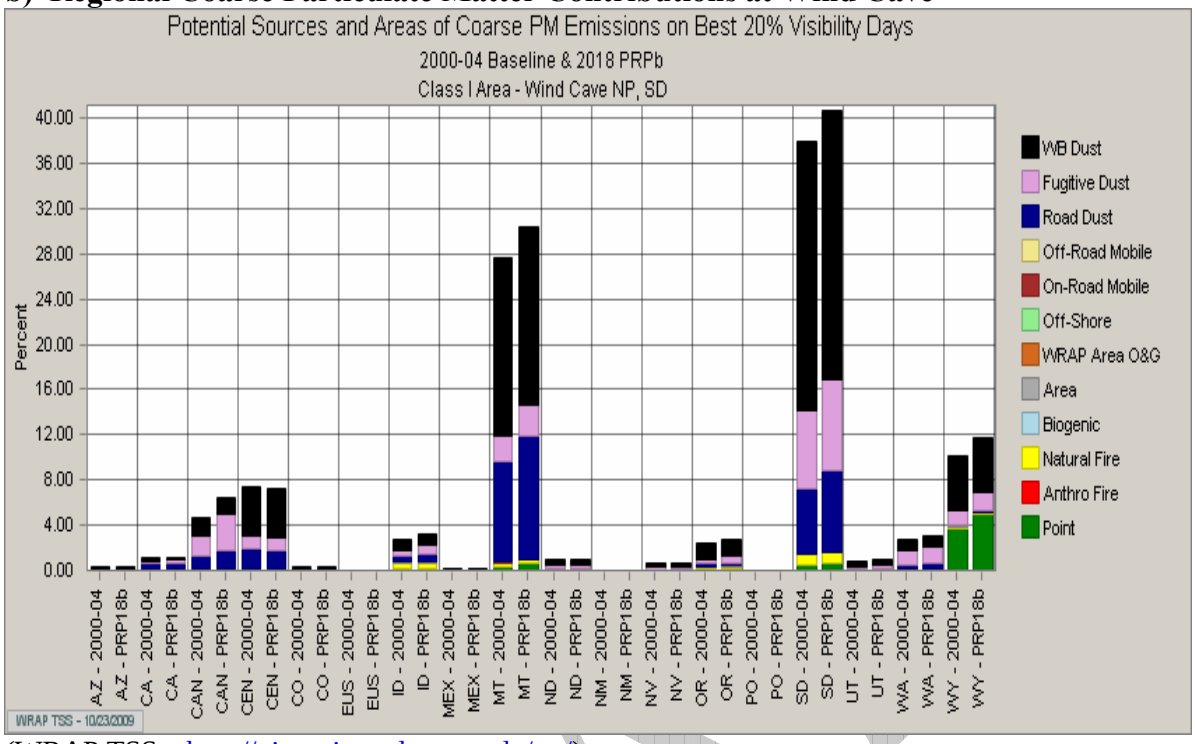
Figure 5-8 – Coarse Particulate Matter Contribution for 20% Least Impaired Days

a) Regional Coarse Particulate Matter Contributions at Badlands



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

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.

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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				BART Eligible
			TSP	SO_2	NOx	VOC	
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.

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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 $PM_{2.5}$;

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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.

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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

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Class I Area	State	Min Distance	Max Delta (dv)	99th (dv)	Days >0.5	Annual 98th percentile 2001	2002	2003
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**
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 then 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 98th 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.

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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).

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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

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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

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Rank	Control	Emission Rate		Control Efficiency	
		Otter Tail [1]	RBLC [3]	PFDR [4]	IEA [5]
		(lbs/MMBtus) [2]	(lbs/MMBtus) [2]	(%)	(%)
#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

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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.

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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

Rank	Control	Emission Rate			Control Efficiency
		Otter Tail [1] (lbs/MMBtus) [2]	RBLC [3] (lbs/MMBtus) [2]	Basin [4] (lbs/MMBtus) [2]	EPA [5] (%)
#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.

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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.

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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.

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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.

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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

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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] (%)
#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.

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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 catalystic 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.

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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 98th 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 98th 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 (98th 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.

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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

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[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 (98th 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)

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Option	Control Equipment	Class I Area	2002	2006	2007
		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)**
		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.

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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

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Option	Control Equipment	Class I Area	2002	2006	2007
		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
		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;

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[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 does not include 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	↓	↓	↓

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	Control Option	Class I Area	2002	2006	2007
#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
		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, which would include periods of startup and shutdown and 0.09 pounds per million Btus, which would not include startup and shutdown. Compliance with these emission limits shall be based on the continuous emission monitoring system and on a 30-day rolling average.

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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.

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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, which would include periods of startup and shutdown and 0.10 pounds per million Btus, which would not include startup and shutdown periods. 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

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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.

In accordance with 40 CFR § 51.308(d)(1)(i)(A), in establishing the reasonable progress goals for each mandatory Class I federal area within the state the state must consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potential affected sources. This consideration is also known as the 4-factor analysis. The 4-factor analysis must also include a demonstration showing how these factors were taken into consideration in selecting the goal.

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:
   a. Identify the key pollutants, sources and/or source categories that are contributing to visibility impairment at each Class I area. The sources of impairment for the most impaired and least impaired days may differ;
   b. Identify the control measures and associated emission reductions that are expected to result from compliance with existing rules and other available measurements for the sources and source categories that contribute significantly to visibility impairment;
   c. Determine what additional control measures would be reasonable based on the statutory factors and other relevant factors for the sources and/or source categories you have identified;
   d. Estimate through the use of air quality models the improvement in visibility that would result from implementation of the control measures you have found to be reasonable and compare this to the uniform rate of progress; and
4. Establish the reasonable progress goals.

DENR determined natural visibility conditions (see Table 3-7) and the uniform slope of reduction for each Class I area (see Figure 3-5).

7.1 State and Federal Rules

South Dakota's current air quality rules under Administrative Rules of South Dakota (ARSD) article 74:36 – Air Pollution Control Program, currently protects and improves visibility in Class I areas. Examples of existing rules that protect and improve visibility in Class I areas are listed below:

1. ARSD § 74:36:01:05 – Applicable requirements of Clean Air Act defined: Subsection (12) states "*Any national ambient air quality standard or increment or visibility requirement under Part C of Title I of the Clean Air Act, but only as it would apply to temporary sources permitted pursuant to § 504(e) of the Clean Air Act*";

2. ARSD § 74:36:01:10 – Modification defined: Subsection (3) states "*The change requires or changes a case-by-case determination of an emission limit or other standard, a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis*";
3. ARSD § 74:36:02:01 – Air quality goals: Subsection (3) states one of the goals is "*optimization of visibility*";
4. ARSD § 74:36:04 – Operating permits for minor sources and § 74:36:05 – Operating permits for Part 70 sources: The permits issued under these chapters require sources to meet all applicable emission limits, demonstrate compliance, monitoring, recordkeeping and reporting requirements to ensure compliance with all applicable requirements of the Clean Air Act;
5. ARSD §§ 74:36:06 – Regulated Air Pollutant Emissions; 74:36:07 – New Source Performance Standards; 74:36:08 – National Emission Standards for Hazardous Air Pollutants, and ARSD § 74:36:12 – Control of Visible Emissions: These chapters restrict air emissions from regulated entities that contribute to visibility impairment and prohibits certain open burning practices such as open burning waste oil, rubber, waste tires, asphalt shingles, railroad ties, etc.;
6. ARSD § 74:36:09 – Prevention of Significant Deterioration: This chapter requires a visibility analysis to prevent sources subject to these requirements from contributing to visibility impairment in Class I Areas;
7. ARSD § 74:36:10 – New Source Review: This chapter requires a visibility analysis to prevent sources subject to these requirements from contributing to visibility impairment in Class I Areas; and
8. ARSD § 74:36:18 – Regulations for State Facilities in the Rapid City Area: This chapter restricts visible emissions from fugitive sources.

The chapters and sections listed above are included in South Dakota's State Implementation Plan.

DENR is proposing rules that will establish BART emission limits, recordkeeping requirements, monitoring requirements, and reporting requirements for BART-eligible sources that will reduce their impacts on Class I areas. In addition, DENR is proposing rules that will require new major sources and a modification to an existing major source that are not subject to New Source Review to conduct a visibility impact analysis to ensure the proposal will not contribute to adverse impact on visibility in an mandatory Class I area.

On the federal side, gains in visibility should have already occurred from the implementation of the Acid Rain Program and future gains will occur from the implementation of federal emission standards established for mobile sources and federal fuel standards.

7.2 2018 Projected Visibility Conditions

The reasonable progress goals are interim goals that represent incremental improvement in visibility over time and are compared to the uniform rate of progress for achieving natural visibility by 2064. The first year in determining if states are meeting their reasonable progress

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goals is 2018. WRAP gathered the reductions that will occur through this timeframe from states and federal regulations and modeled the results to project where states will be at in 2018.

The information that WRAP gathered was entered into a CMAQ model for the Class I areas in the WRAP region to project visibility improvements. The CMAQ model was used to estimate 2018 visibility conditions in South Dakota and all Western Class I areas. DENR relied on the results of the CMAQ modeling in determining the reasonable progress achieved by South Dakota, surrounding states, and federal regulations in South Dakota's Class I areas.

Table 7-1 provides a summary of WRAP's modeling result and compares the results to the deciview level needed to achieve the 2018 uniform rate of progress for the 20% most impaired days and determine if there is any degradation in the 20% least impaired days in South Dakota's Class I areas. The modeling results indicate that the 2018 uniform rate of progress goal for the 20% most impaired days will not be achieved; but there will be no degradation of the 20% least impaired days.

Table 7-1– 2018 Reasonable Progress Summary for South Dakota's Class I Areas
(a) 20% Most Impaired Days

Class I Area	Baseline [1]	Uniform Progress [2]	Reasonable Progress [3]	Uniform Progress Achieved
Badlands	17.16 deciview	14.89 deciview	16.50 deciview	29%
Wind Cave	15.93 deciview	13.94 deciview	15.28 deciview	33%

(b) 20% Least Impaired Days

Class I Area	Baseline [1]	Reasonable Progress [3]	Degradation?
Badlands	6.91 deciview	6.58 deciview	No
Wind Cave	5.16 deciview	5.02 deciview	No

[1] – Baseline values derived from Table 3-7;
[2] – Uniform progress derived from Figure 3-5; and
[3] – Reasonable progress derived from WRAP's modeling results.

7.2.1 Breakdown of CMAQ Modeling Results

As indicated by the 2018 visibility projections using CMAQ modeling, the Class I areas in South Dakota are projected to not meet the uniform rate of progress goal for 2018 for the 20% most impaired days. The CMAQ modeling is conservative in several respects. The CMAQ modeling does not include the BART emissions limits for Otter Tail Power Company's Big Stone I facility. In addition, the CMAQ modeling includes Big Stone II and NextGen emissions, which are coal-fired power plants. The Big Stone II facility will no longer be constructed and the NextGen facility is on hold.

In order to determine if there are other contributors to not meeting the reasonable progress goals, it is necessary to break down these results to identify individual pollutants. Figures 7-1 provides a breakdown of individual pollutant contribution (measured by extinction) by showing the glide

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slope of each pollutant in South Dakota's Class I area from the baseline to 2018, and 2064, for the 20% most impaired days. Below each figure is a table that shows the 2018 projections for each pollutant, and whether the projection is under the 2018 uniform rate of progress goal and the percent improvement toward the 2018 uniform rate of progress goal.

The glide path for the Badlands National Park indicates the air pollutants not achieving the necessary levels for the 2018 uniform progress goal to be achieved are organic carbon mass, ammonia sulfate, and coarse mass. It's hard to see in the graph but the ammonia sulfate extinction level is equivalent to the organic carbon mass level of 14.7 Mm-1. Organic carbon mass appears to be the greatest concern since its extinction value is furthest from where it needs to be to achieve the uniform rate of progress goal for 2018.

The glide path for the Wind Cave National Park indicates the air pollutants not achieving the necessary levels for the 2018 uniform progress goal to be achieved are organic carbon mass, ammonia sulfate, and ammonia nitrates. At the Wind Cave National Park, it appears organic carbon mass and ammonia sulfate are the greatest concern since the extinction value for both are the furthest from where they need to be to achieve the uniform rate of progress goal for 2018.

7.2.2 Four Factor Analysis

In accordance with 40 CFR § 51.308(d)(1)(ii), if the state establishes a reasonable progress goal that provides for a slower rate of improvement in visibility than the rate that would be needed to attain natural conditions by 2064, the state must demonstrate based on the four factor analysis that the rate of progress for the state's implementation plan to attain natural conditions by 2064 is not reasonable; and the progress goal adopted by the state is reasonable. To determine if a four factor analysis is warranted, DENR looked at the air pollutants being emitted from point sources that were not meeting the glide path for each national park. Based on Figure 7-1(a), the air pollutant not meeting the glide path at the Badlands National Park is ammonia sulfate and organic carbon mass. Based on Figure 7-1(b), the air pollutant not meeting the glide path at the Wind Cave National Park is ammonia sulfate, organic carbon mass, and ammonia nitrate.

Next, DENR reviewed WRAP's attribution analysis to determine the major contributors of ammonia sulfate, organic carbon mass, and ammonia nitrate in South Dakota's two Class I areas. For the Badlands and Wind Cave National Parks, the major contributors of ammonia sulfate are from sources not in South Dakota. South Dakota's ammonia sulfate contribution for 2002 and 2018 is minimal at both national parks at approximately 0.04 micrograms per cubic meter. South Dakota's contribution represents 3% of the ammonia sulfate concentrations for 2018 at both national parks. Of the 3%, approximately 1.5% is generated from point sources and 1.5% is generated from mobile and other sources.

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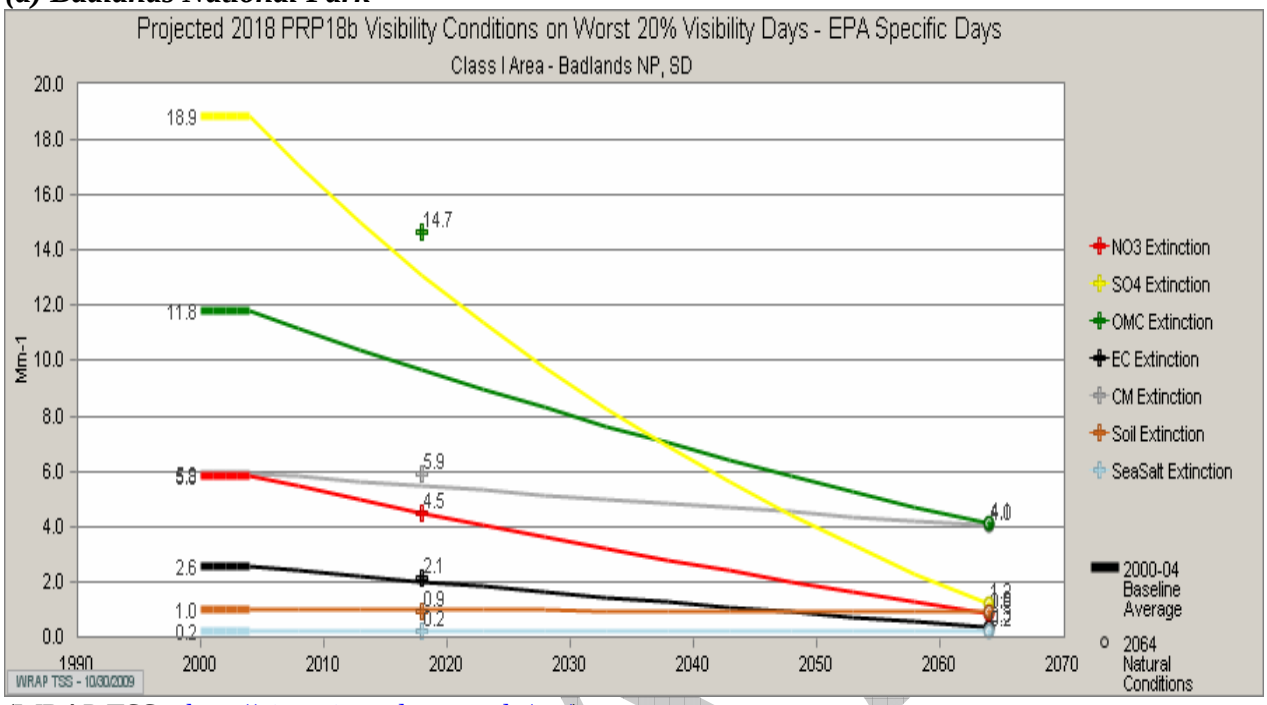
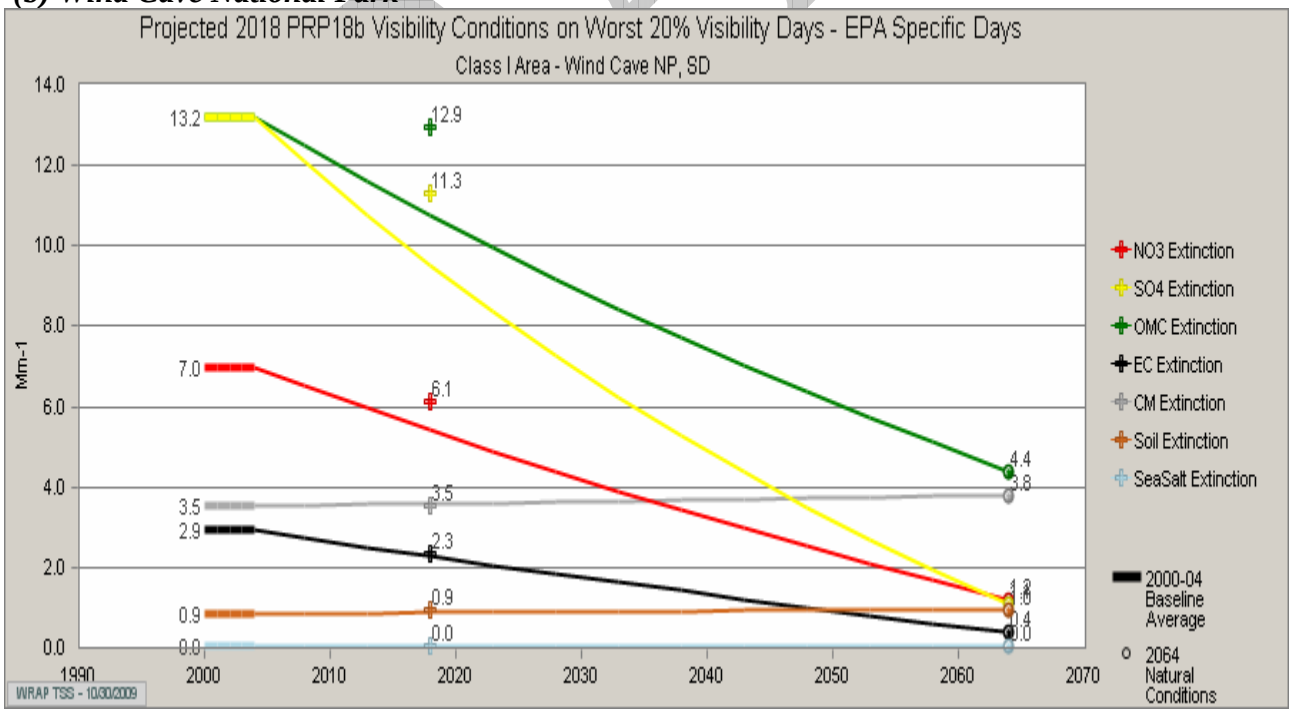
Figure 7-1 – Glide Slope by Pollutant for 20% Worst Visibility Days (Extinction) [1]

(a) Badlands National Park



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

(b) Wind Cave National Park



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

[1] – "NO_3" means nitrates, "SO_4" means sulfates, "OMC" means organic mass carbon, "EC" means elemental carbon, and "CM" means coarse mass.

The major contributor of organic carbon mass in both national parks is natural fires with point source contributions being minimal. Organic carbon mass emissions from natural and prescribed fires will be evaluated as part of a smoke management plan which is part of DENR's long term strategy.

Ammonia nitrate was only a concern for the Wind Cave National Park since it was on the glide path at the Badlands National Park. At the Wind Cave National Park, the major contributors to ammonia nitrate at the Wind Cave National Park are Canada followed by Wyoming, Outside the Domain, and South Dakota. South Dakota's ammonia nitrate contribution for 2002 and 2018 is approximately 0.135 and 0.105 micrograms per cubic meter, respectively. South Dakota's contribution represents 10% of the ammonia nitrate concentration for 2018 at the Wind Cave National Park. Of the 10%, approximately 4% is generated from point sources and 6% is generated from mobile and other sources.

DENR did not conduct a four factor analysis on businesses within South Dakota that contribute to ammonia sulfate, organic carbon mass, and ammonia nitrate concentrations because South Dakota's contribution is approximately 1.5% for ammonia sulfate, minimal for organic carbon mass, and 4% for ammonia nitrate. Therefore, minimal gain would be encountered from reduction in sulfur dioxide, organic carbon mass, and nitrogen oxide emissions from point sources within South Dakota. DENR has determined that a four factor analysis at this time is not warranted; but will be re-consider a four factor analysis in future periodic reviews.

8.0 Long Term Strategy

In accordance with 40 CFR § 51.308(d)(3), each state must submit a long term strategy to address regional haze visibility impairments for each Class I area within the state and for each Class I area outside the state which may be affected by emissions from the state. The long term strategy must include enforceable emission limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by the state for each Class I area.

The long term strategy must meet the following requirements:

1. Where the state has emissions that are reasonably anticipated to contribute to visibility impairment in any Class I area located in another state or states, the state must consult with the other state(s) in order to develop coordinated emission management strategies. The state must also consult with any other state having emissions that are reasonably anticipated to contribute to visibility impairment in any mandatory Class I area within the state;
2. Where other states cause or contribute to impairment in a Class I area, the state must demonstrate that it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the area. If the state has participated in a regional planning process, the state must ensure it has

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included all measures needed to achieve its apportionment of emission reduction obligations agreed upon through that process;

3. The state must document the technical basis, including modeling, monitoring and emissions information, on which the state is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I area it affects. The state may meet this requirement by relying on technical analyses developed by the regional planning organization and approved by all state participants. The state must identify the baseline emissions inventory on which its strategies are based. The baseline emissions inventory year is presumed to be the most recent year of the consolidate periodic emissions inventory;
4. The state must identify all anthropogenic sources of visibility impairment considered by the state in developing its long term strategy. The state should consider major and minor stationary sources, mobile sources, and area sources; and
5. The state must consider, at a minimum, the following factors in developing its long term strategy:
    a. Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
    b. Measures to mitigate the impacts of construction activities;
    c. Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
    d. Source retirement and replacement schedules;
    e. Smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for these purposes;
    f. Enforceability of emissions limitations and control measures; and
    g. The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

8.1 Class I Areas in Other States Impacted by South Dakota

In accordance with 40 CFR § 51.308(d)(3)(i), the long term strategy for each state that causes or contributes to impairment in a Class I area is required to demonstrate that it has included in its State Implementation Plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goals for the Class I area. If the state has participated in a regional planning process, the state must ensure it has included all measures needed to achieve its apportionment of emission reduction obligations agreed upon through that process.

DENR participated in WRAP and worked with other states that are not members of WRAP in developing its State Implementation Plan. Otter Tail Power Company's Big Stone I facility is the only source in South Dakota that is reasonable anticipated to contribute to visibility impairment at the Badlands National Park in South Dakota; Theodore National Park in North Dakota; Boundary Waters and Voyageurs Class I areas in northern Minnesota and the Isle Royale federal Class I area in Michigan. Otter Tail Power Company developed a case-by-case BART analysis which DENR reviewed to establish the BART emission limits for Big Stone I. The case-by-case BART analysis and DENR's review was submitted to the appropriate states for their comments.

DENR will establish the BART procedures in the Administrative Rules of South Dakota that are equivalent to federal regulation in 40 CFR Part 51, adopt the BART emission limits for Big Stone I in the rule, and adopt the BART emission limits in an air quality construction permit and eventually in Otter Tail Power Company's Title V air quality operating permit for the Big Stone I facility. DENR believes the BART requirements represents South Dakota's emission reductions for those Class I areas impacted by Big Stone I.

8.2 States Impacting South Dakota's Class I Areas

In accordance with 40 CFR § 51.308(d)(3)(ii), the long term strategy for each state that causes or contributes to impairment in a Class I area is required to demonstrate that it has included in its State Implementation Plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goals for the Class I area. If the state has participated in a regional planning process, the state must ensure it has included all measures needed to achieve its apportionment of emission reduction obligations agreed upon through that process.

DENR has worked with states contributing to visibility impairment in South Dakota's Class I areas through WRAP and also with those states that are not part of WRAP. DENR believes at this time that the controls they are adopting under their BART analysis, State Implementation Plan, and other measures states are taking will minimize their impacts on South Dakota's Class I areas. Based on WRAP's emission inventory for 2002 and 2018, these control measures will reduce sulfur dioxide emissions by 26%, nitrogen oxide emissions by 29%, organic carbon mass by 6% and elemental carbon by 31% (derived from Table 5-6 and 5-7).

8.3 Technical Basis for Modeling, Monitoring and Emissions Information

In accordance with 40 CFR § 51.308(d)(3)(iii), as part of the long term strategy, each state is required to document the technical basis, including modeling, monitoring and emissions information, on which the state is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I area it affects. The state may meet this requirement by relying on technical analyses developed by the regional planning organization and approved by all state participants. The state must identify the baseline emissions inventory on which its strategies are based. The baseline emissions inventory year is presumed to be the most recent year of the consolidated periodic emissions inventory.

South Dakota is a member of WRAP and relied on the modeling, monitoring and emissions information and technical analyses developed by WRAP to accomplish this requirement. DENR relied on the use of CALPUFF for single source BART screening modeling and WRAP's CMAQ and Particulate Matter Source Apportionment Technology modeling in its cumulative impact analyses. The BART modeling conformed to the requirements of the BART guidelines. The WRAP CMAQ and Particulate Matter Source Apportionment Technology modeling conformed with EPA's modeling guidelines. On the monitoring side, DENR used the IMPROVE monitoring data available on the IMPROVE website for its Class I areas.

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DENR used WRAP's Plan02d emissions inventory for the baseline emissions year 2002 which reflects a composite interpretation of emissions for the base 2000-2004 period; and WRAP's CMAQ PRP18b (Preliminary Reasonable Progress 2018 Scenario A) emissions inventory which reflects projected year 2018 emissions. The projected year 2018 emissions represents base period emissions projected to 2018, accounting for estimates of the effect of BART controls and assuming other growth and control factors.

Currently, WRAP is maintaining this documentation at the following website:

http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx

DENR will continue to work with WRAP in its effort to update emission inventories and run models to determine if South Dakota is meeting its reasonable progress and long term strategy goals.

8.4 Identification of Anthropogenic Sources of Visibility Impairment

In accordance with 40 CFR § 51.308(d)(3)(iv), as part of the long term strategy, each state must identify all anthropogenic sources of visibility impairment considered by the state in developing its long term strategy. The state should consider major and minor stationary sources, mobile sources and area sources.

DENR worked through WRAP and through a BART analysis to identify major and minor stationary sources. WRAP was also used to consider mobile and area source emissions. One item that does appear to be the greatest contributor is activities contributing to organic mass carbon emissions such as wild fires and prescribed fires.

8.5 Factors in Developing Long Term Strategy

In accordance with 40 CFR § 51.308(d)(3)(v), states must consider, at a minimum, the following factors in developing its long term strategy:

1. Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
2. Measures to mitigate the impacts of construction activities;
3. Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
4. Source retirement and replacement schedules;
5. Smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the state for these purposes;
6. Enforceability of emissions limitations and control measures; and
7. The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

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It is expected that for some areas of the country, such as parts of the eastern United States, emission reductions achieved for the acid rain program and for meeting the PM2.5 NAAQS, will lead to substantial improvements in visibility as well. Subsection 1 in this section makes clear that states must take these other emission reductions into account in developing their long-term strategies for regional haze.

8.5.1 Emission Reductions from Ongoing Air Pollution Control Programs

In accordance with 40 CFR § 51.308(d)(3)(v)(A), an assessment of emission reductions due to ongoing air pollution control programs is required. Existing air pollution control programs in place which assist in reducing air emissions and help achieve reasonable progress toward the national visibility goal include the following South Dakota air quality rules under ARSD § 74:36 – Air Pollution Control Program are listed below:

1. ARSD § 74:36:01:05 – Applicable requirements of Clean Air Act defined: Subsection (12) states "*Any national ambient air quality standard or increment or visibility requirement under Part C of Title I of the Clean Air Act, but only as it would apply to temporary sources permitted pursuant to § 504(e) of the Clean Air Act*";
2. ARSD § 74:36:01:10 – Modification defined: Subsection (3) states "*The change requires or changes a case-by-case determination of an emission limit or other standard, a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis*";
3. ARSD § 74:36:02:01 – Air quality goals: Subsection (3) states one of the goals is "*optimization of visibility*";
4. ARSD § 74:36:04 – Operating permits for minor sources and § 74:36:05 – Operating permits for Part 70 sources: The permits issued under these chapters require sources to meet all applicable emission limits, demonstrate compliance, monitoring, recordkeeping and reporting requirements;
5. ARSD §§ 74:36:06 – Regulated Air Pollutant Emissions; 74:36:07 – New Source Performance Standards; 74:36:08 – National Emission Standards for Hazardous Air Pollutants, and ARSD § 74:36:12 – Control of Visible Emissions: These chapter restricts air emissions from regulated entities that cause visibility impairment and prohibits certain open burning practices such as open burning waste oil, rubber, waste tires, asphalt shingles, railroad ties, etc.;
6. ARSD § 74:36:09 – Prevention of Significant Deterioration: This chapter requires a visibility analysis to prevent sources subject to these requirements from contributing to visibility impairment in Class I Areas;
7. ARSD § 74:36:10 – New Source Review: This chapter requires a visibility analysis to prevent sources subject to these requirements from contributing to visibility impairment in Class I Areas; and
8. ARSD § 74:36:18 – Regulations for State Facilities in the Rapid City Area: This chapter restricts visible emissions from fugitive sources.

The chapters and sections listed above are included in South Dakota's State Implementation Plan.

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8.5.2 Measures to Mitigate Impacts of Construction Activities

In accordance with 40 CFR § 51.308(d)(3)(v)(B), states are required to consider measures to mitigate the impacts of construction activities. States, for example, should include these activities in emission inventories used for long-term strategy development. South Dakota regulates fugitive emissions by rule in ARSD § 74:36:18 – Regulations for State Facilities in the Rapid City Area. This chapter restricts visible emissions from fugitive sources in the Rapid City area.

In addition, as part of South Dakota's State Implementation Plan, DENR is proposing rules that will require new major sources and modifications to major sources to conduct a visibility analysis. A new major source or modification to a major source will have to determine what controls will be necessary to maintain emissions at a level that will not cause visible emission equal to or greater than 0.5 deciviews at a Class I area. The new major source or modification to a major source will be required to install the control equipment, establish emission limits, recordkeeping requirements, and reporting requirements.

8.5.3 Emission Limitations and Schedules to Achieve Reasonable Progress Goals

In accordance with 40 CFR § 51.308(d)(3)(v)(C), states are required to consider air emissions limitations and schedules for compliance to achieve the reasonable progress goal in developing its long terms strategy. This requirement impacts South Dakota's only BART-eligible source (Otter Tail Power Company's Big Stone I). The BART requirements, BART emission limits, and compliance deadlines for Otter Tail Power Company's Big Stone I facility will be established in South Dakota's rules. The evaluation of non-BART sources as part of the long term strategy will be reviewed in the next planning period since WRAP's attribution analysis indicates South Dakota's sources have minimal impact on our Class I areas.

8.5.4 Retirement and Replacement Schedules

In accordance with 40 CFR § 51.308(d)(3)(v)(D), states are required to consider any source retirement and replacement schedules in developing its long term strategy, particularly, where these schedules would have a significant impact on regional emission loadings and on a state's ability to achieve reasonable progress.

DENR is not aware of any anticipated major source retirements or replacements that would have a significant impact on regional emissions loadings and on a state's ability to achieve reasonable progress. The replacement of existing units at facilities will be managed in conformance with the state's existing State Implementation Plan.

The 2018 modeling conducted by WRAP included two new coal-fired electric power plants and one oil refinery to be located in South Dakota. Although the PSD permit has been issued for one of the new coal-fired electric power plants, the applicant notified DENR that it is no longer going to build the plant. The second coal-fired power electric power plant requested that DENR put its

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application on hold until further notice. Therefore, the next modeling exercise for determining visibility in 2018 will need to be adjusted to reflect this development and the current modeling results for 2018 are probably conservative.

8.5.5 Smoke Management

In accordance with 40 CFR § 51.308(d)(3)(v)(E), states are required to consider smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the state for these purposes in developing its long term strategy. As part of the long term strategy, DENR will investigate the impacts a smoke management plan for wild fires and prescribed burns will have on the 20% most impaired days within the first planning period of 2013.

Currently very little agricultural burning takes place in South Dakota and the majority of agricultural land lies in the eastern two-thirds of the state, while both Class I areas are in the western third. In addition, DENR did not observe any of the 20% most impaired days that were attributed to agricultural burning in the eastern half of South Dakota. Therefore, agricultural burning does not appear to have much of an impact at our Class I areas. However, there is some burning of grass in and around the Class I areas which will be investigated to determine if this practice warrants being covered under a smoke management plan.

Over the years the National Park Service and U.S. Forest Service have conducted planned prescribed burns on federal lands at both Class I areas, which have affected the air quality in both parks. The last prescribed burn at the Wind Cave National Park is one example in which the smoke from the fire had a negative impact on DENR's air monitoring equipment. DENR is currently waiting to review the IMPROVE data for those days to see what kind of impact the fire had on the organic carbon mass concentration and to some extent the ammonia sulfide and ammonia nitrate levels. In addition, DENR has observed there is evidence that large fires contribute to the 20% most impaired days during the baseline period.

DENR has taken the initial steps in developing a smoke management plan by contacting those groups that DENR believes would need to be involved, including the South Dakota Department of Agriculture, National Park Service and U.S. Forest Service, among others. The response from these agencies has been positive and all have offered to assist in developing a smoke management plan for South Dakota. More recently, DENR has been in contact with the South Dakota Division of Wildland Fire Suppression, which maintains a prescribed fire database of fires throughout South Dakota and along our borders in neighboring states. DENR will use this database to track fires and compare the fire data (e.g., size of fire, material being burned, distance from the Class I areas, dates) to the IMPROVE data from our Class I areas to see what the impacts are to the visibility.

It is DENR's intention to investigate these prescribed burns as well as other wildfires and planned prescribed burns to determine at what level (e.g., size of burn, distance from the Class I areas, combustible material) should a wildfire or prescribed fire be included in the smoke management plan and what best management practices can be used to minimize their impacts on

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the 20% most impaired days in the Class I areas. The results of this analysis will be adopted in the Regional Haze State Implementation Plan as part of our long term strategy. DENR will work with the federal land managers, other state agencies, and local governments during the development and implementation of the smoke management plan.

8.5.6 Enforceable Emission Limits and Control Measures

In accordance with 40 CFR § 51.308(d)(3)(v)(F), states are required to consider the enforceability of emission limits and control measures in developing its long term strategy. In developing enforceable emissions limits and control measures, the state should ensure they are written in a way that EPA and citizens may enforce them as a practical matter.

The BART requirements, including the BART emission limits for Big Stone I, will be established in South Dakota's rules and adopted into South Dakota's State Implementation Plan. This will allow states, the public, and any interested party to comment on the rules to ensure the BART requirements are enforceable in a practical matter. In addition, the BART emission limits and specific control measures that will be established in Otter Tail Power Company's Big Stone I air quality permit will be open to states, the public, and any interested party for comment and ensure the BART permit requirements are enforceable in a practical matter.

Currently, DENR developed a Title V air quality permit program which is required prior to construction for new sources and modifications to existing sources. DENR established a construction permit program that separates the construction permit from the Title V air quality permit program. The construction permit program was submitted to EPA to be included in South Dakota's State Implementation Plan. The BART emission limits and control measures will be included in a construction permit and eventually in the Title V air quality permit.

DENR is also establishing requirements under the Regional Haze Program to require new major sources and modifications to major sources to demonstrate through a visibility analysis that the new major source or modification to a major source will not contribute to visibility impairment in any mandatory Class I area. Contribute to visibility impairment is defined by a change in visibility impairment in a mandatory Class I area of 0.5 deciviews or more, based on a 24-hour average, above the average natural visibility baseline. A source exceeds the threshold with the 98th 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. The emission limits and control measures used in the visibility analysis are required to be included in the sources permit which will include an opportunity for states, the public, and any interested party to comment on to ensure the requirements are enforceable in a practical matter. The rules will assist DENR in ensuring the sources in South Dakota will not contribute to visibility impairment in any Class I area.

8.5.7 Anticipated Net Effect on Visibility Due to Projected Changes

In accordance with 40 CFR § 51.308(d)(3)(v)(G), when developing its long term strategy states are required to consider the anticipated net effect on visibility due to projected changes in point,

area, and mobile source emissions over the period addressed by the long term strategy. WRAP projected the net effect on visibility from emission reductions and increases by point, area and mobile sources throughout the WRAP region through 2018. The first emission projection inventory was compiled in 2006. The inventory was revised in 2007 to make preliminary evaluations of reasonable progress towards Class I areas visibility goals. The 2007 inventory focused on the most significant point and area sources of visibility impairing pollution. This effort included updating projections of electric generating units and incorporating known and presumed BART emission levels.

During the spring of 2009, the WRAP once again updated emission inventory projections for point and area sources in the WRAP region to give the most current assessment of reasonable progress towards visibility goals. Again, the updated projection inventory reflected new information about BART determinations and projection of future fossil fuel plants needed to achieve 2018 federal electrical generation demands.

The results of the CMAQ modeling which has already been discussed shows anthropogenic emissions sources generally declining across the West through 2018. However, natural sources such as wildfires and dust, international sources in Mexico and Canada, global transport of emissions and off shore shipping in the Pacific Ocean all appear to offset improvements in visibility from controls on manmade sources. In spite of the large number of growing uncontrollable sources in the WRAP region, however, South Dakota does see a net visibility improvement at the South Dakota Class I areas through 2018. The net effect of all of the reductions in the WRAP region, known at the time of the most recent model run is demonstrated in the WRAP Class I Summary Tables shown below for each of the Class I areas in South Dakota. Figure 8-1 provides a summary of the results for each Class I area for the 20% most impaired days.

Table 8-1– CMAQ Modeling Visibility Summary for 20% Most Impaired Days
(a) Badlands National Park

	RRF Calculations Method: Specific Days (EPA) Emissions Scenarios: 2000-04 Baseline (plan02d) and 2018 PRPb (prp18b)						
	Monitored	**Estimated**		**Projected**			
	2000-04 Baseline Conditions (Mm-1) [1]	**2064 Natural Conditions (Mm-1) [2]**	**2018 Uniform Rate of Progress Target (Mm-1) [3]**	**2018 Visibility Conditions (Mm-1)**	**Baseline to 2018 Change In Statewide Emissions (tons/%)**	**Baseline to 2018 Change In Upwind Weighted Emissions [4] (%)**	**Baseline to 2018 Change In Anthropogenic Upwind Weighted Emissions [4] (%)**
Sulfate	18.94	1.19	13.13	14.66	-8,115 -36%	-30%	-30%
Nitrate	5.88	0.86	4.51	4.49	-26,347 -18%	-27%	-37%

	RRF Calculations Method: Specific Days (EPA) Emissions Scenarios: 2000-04 Baseline (plan02d) and 2018 PRPb (prp18b)						
	Monitored	Estimated		Projected			
	2000-04 Baseline Conditions (Mm-1) [1]	2064 Natural Conditions (Mm-1) [2]	2018 Uniform Rate of Progress Target (Mm-1) [3]	2018 Visibility Conditions (Mm-1)	Baseline to 2018 Change In Statewide Emissions (tons/%)	Baseline to 2018 Change In Upwind Weighted Emissions [4] (%)	Baseline to 2018 Change In Anthropogenic Upwind Weighted Emissions [4] (%)
Organic Carbon	11.76	4.10	9.68	14.66	-555 -6%	-3%	-7%
Elemental Carbon	2.59	0.34	2.02	2.13	-2,404 -51%	-30%	-45%
Fine Soil	0.98	0.95	0.97	0.94	1,837 6%	3%	9%
Coarse Material	5.94	4.04	5.48	Not Applicable [5]	25,873 16%	2%	8%
Sea Salt	0.00	0.19	0.19	Not Applicable [5]	Not Applicable	Not Applicable	Not Applicable
Total Light Extinction	57.27	22.67	45.98	54.01	Not Applicable	Not Applicable	Not Applicable
Deciview	17.16	7.44	14.89	16.47	Not Applicable	Not Applicable	Not Applicable

[1] – Baseline values derived from Table 4.3(b), except for the deciview values. The deciview value was derived from Table 3-7;
[2] – Deciview value derived from Table 3-7;
[3] – 2018 Uniform Rate of Progress Target for Best 20% Days is not defined. The Deciview value was derived from Figure 3-5(a);
[4] – Results based on Weighted Emissions Potential analysis using the 2000-04 Baseline (plan02d) & 2018 PRPb (prp18b) emissions scenarios; and
[5] – Visibility projections not available due to model performance issues.

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(b) Wind Cave National Park

	RRF Calculations Method: Specific Days (EPA) Emissions Scenarios: 2000-04 Baseline (plan02d) and 2018 PRPb (prp18b)						
	Monitored	**Estimated**		**Projected**			
	2000-04 Baseline Conditions (Mm-1) [1]	**2064 Natural Conditions (Mm-1) [2]**	**2018 Uniform Rate of Progress Target (Mm-1) [3]**	**2018 Visibility Conditions (Mm-1)**	**Baseline to 2018 Change In Statewide Emissions (tons/%)**	**Baseline to 2018 Change In Upwind Weighted Emissions [4] (%)**	**Baseline to 2018 Change In Anthropogenic Upwind Weighted Emissions [4] (%)**
Sulfate	13.32	1.09	9.53	11.33	-8,115 -36%	-21%	-22%
Nitrate	7.07	1.21	5.41	6.12	-26,347 -18%	-24%	-30%
Organic Carbon	13.39	4.4	10.77	12.93	-555 -6%	-1%	-5%
Elemental Carbon	2.96	0.4	2.28	2.32	-2,404 -51%	-21%	-41%
Fine Soil	0.86	0.97	0.88	0.93	1,837 6%	8%	16%
Coarse Material	3.53	3.8	3.59	Not Applicable [5]	25,873 16%	5%	13%
Sea Salt	0.00	0.03	0.03	Not Applicable [5]	Not Applicable	Not Applicable	Not Applicable
Total Light Extinction	51.18	21.90	41.71	47.19	Not Applicable	Not Applicable	Not Applicable
Deciview	15.84	7.41	13.94	15.12	Not Applicable	Not Applicable	Not Applicable

[1] – Baseline values derived from Table 4.4(b), except for Deciview. The Deciview value was derived from Table 3-7;
[2] – Deciview value derived from Table 3-7;
[3] – 2018 Uniform Rate of Progress Target for Best 20% Days is not defined. The Deciview value was derived from Figure 3-5(b);
[4] – Results based on Weighted Emissions Potential analysis using the 2000-04 Baseline (plan02d) & 2018 PRPb (prp18b) emissions scenarios; and
[5] – Visibility projections not available due to model performance issues.

9.0 Monitoring Strategy

In accordance with 40 CFR § 51.308(d)(4), the State Implementation Plan for the Regional Haze Program is required to include a monitoring strategy for measuring, characterizing and reporting of regional haze visibility impairment that is representative of all Class I areas within the state.

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The monitoring strategy must be coordinated with the monitoring strategy required in 40 CFR § 51.305. In accordance with 40 CFR § 51.305, the monitoring strategy must take into account current and anticipated visibility monitoring research, the availability of appropriate monitoring techniques, and such guidance as provided by EPA. In addition, the monitoring strategy must provide for the consideration of available visibility data and must provide a mechanism for its use in decisions making. Compliance with this requirement may be met through the participation in the IMPROVE network.

DENR has been and will continue to participate in the IMPROVE network for both of its Class I areas. The IMPROVE network currently collects and reports aerosol monitoring data which will be used to track long term reasonable progress. Because the long term tracking program with an implementation period nominally set for 60 years, the state expects that the IMPROVE network will provide data based on the following goals:

1. Maintain a stable configuration of the individual monitors and sampling sites and stability in network operations for the purpose of continuity in tracking reasonable progress trends;
2. Assure sufficient data capture at each site of all visibility-impairing species;
3. Comply with EPA quality control and assurance requirements; and
4. Prepare and disseminate periodic reports on IMPROVE network operations.

DENR is relying on the IMPROVE network to meet these monitoring operation and data collection goals, with the fundamental assumption that network data collection operations will not change, or if changed, will remain directly comparable to those operated by the IMPROVE network during the 2000 to 2004 baseline period. Technical analyses and reasonable progress goals in this implementation plan are based on data from these sites. As such, DENR will work with EPA and the Federal Land Managers to ensure these monitors continue to operate and any changes to the IMPROVE network will not jeopardize the use of the data in the monitoring strategy.

The state of South Dakota depends on the following IMPROVE program-operated monitors at the following sites listed in Table 9-1 for tracking reasonable progress:

Table 9-1–* IMPROVE *Monitoring Sites at Class I areas in South Dakota

IMPROVE Monitoring Sites	Class I Area
BAD1	Badlands National Park
WICA1	Wind Cave National Park

In accordance with 40 CFR § 51.308(d)(4)(i), DENR will also operate additional non-IMPROVE monitors that may be used in assessing if reasonable progress goals in South Dakota's Class I areas are being met. These may include PM2.5 speciation or Federal Reference Methods, and/or more portable monitoring systems than operated at an IMPROVE site. This data is collected throughout the state but the ambient air quality monitoring sites of particular interest are the ones located next to the IMPROVE sites in the Class I areas in South Dakota. The data collected by these sites, along with data from the others sites throughout the state are reported to EPA's AIRS

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database. Table 9-2 provides a summary of what DENR is currently monitoring next to the IMPROVE sites in the Class I area in South Dakota.

Table 9-2– Ambient Air Monitoring Site Parameters Next to IMPROVE Sites

Monitoring Site	Parameter	Sampling &Analysis Method	Operating Schedule
Badlands National Park AQS#	Sulfur Dioxide	Instrumental pulsed florescent	Continuous
	Nitrogen Dioxide	Instrumental chemiluminescence	Continuous
	Ozone	Instrumental ultra violet	Continuous
	$PM_{2.5}$	Met One BAM – 1020 Very Sharp Cut Cyclone Gravimetric	Continuous
	PM_{10}	Thermal Anderson Series FH62 C14 BETA Gravimetric	Continuous
	Wind Speed	Electronic signal	Continuous
	Wind Direction	Electronic signal	Continuous
	Ambient Temperature	Electronic signal	Continuous
	Delta Temperature	Electronic signal	Continuous
	Ambient Pressure	Barometric pressure transducer	Continuous
	Solar Radiation	Pyranometer	Continuous
	Relative Humidity	Hygroscopic Plastic Film	Continuous
Wind Cave National Park AQS#	Sulfur Dioxide	Instrumental Pulsed Florescent	Continuous
	Nitrogen Dioxide	Instrumental Chemiluminescence	Continuous
	Ozone	Instrumental Ultra Violet	Continuous
	$PM_{2.5}$	Met One BAM – 1020 Very Sharp Cut Cyclone Gravimetric	Continuous
	PM_{10}	Thermal Anderson Series FH62 C14 BETA Gravimetric	Continuous
	Wind Speed	Electronic signal	Continuous
	Wind Direction	Electronic signal	Continuous
	Ambient Temperature	Electronic signal	Continuous
	Ambient Pressure	Barometric Pressure Transducer	Continuous

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Monitoring Site	Parameter	Sampling &Analysis Method	Operating Schedule
	Relative Humidity	Hygroscopic Plastic Film	Continuous

In accordance with 40 CFR § 51.308(d)(4)(ii), DENR will use data reported by the IMPROVE program as part of the regional technical support analysis tools found at the Visibility Information Exchange Web System (VIEWS), as well as other analysis tools that are available. DENR will participate in the ongoing regional analysis activities to collectively assess and verify the progress toward reasonable progress goals, also supporting interstate consultation as the regional haze rules are implemented and collaborate with EPA, states, tribes, and federal land managers to ensure the continued operation of these technical support analysis tools and systems .

In accordance with 40 CFR § 51.308(d)(4)(iv), DENR will depend on the routine timely reporting of haze monitoring data by the IMPROVE program for the reasonable progress tracking sites to the EPA air quality data system and VIEWS. DENR will collaborate with EPA, states, tribes, and federal land managers to ensure the continued operation of these technical support analysis tools and systems.

In accordance with 40 CFR § 51.308(d)(4)(vi), DENR will track data related to the regional haze plan implementation for sources for which the state has regulatory authority and will depend on the IMPROVE program and working with states and other organizations to collect and analyze efforts and data support systems for monitoring and emissions inventory data, respectively. To ensure the availability of data and analyses to report on visibility conditions and progress toward Class I area visibility goals, the state of South Dakota will collaborate with EPA, states, tribes, and FLMs to ensure the continued operation of the IMPROVE program.

10.0 Consultation Requirements

10.1 Federal Land Manager Consultation

In accordance with 40 CFR § 51.308(i)(1), a state is required to provide written notification to the federal land managers the title of the official to which the federal land managers of any Class I area can submit any recommendations on the implementation of the state's Regional Haze Program. DENR provided the state's contact to the federal land managers through its involvement with WRAP.

WRAP represents a conglomeration of stakeholders representing federal land managers, industry, states, tribes, environmental groups and the general public. Through participation in this process, a significant portion of the consultation process with federal land managers and other states has been met. In the WRAP process these stakeholders participated in various forums to help develop a coordinated emissions inventory and analysis of the impacts sources have on regional haze in the west. Coordination and evaluation of monitoring data and modeling processes were also overseen by WRAP participants. Through these coordinated technical evaluations, a regional haze oriented evaluation of South Dakota's Class I areas was constructed.

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South Dakota has been a participating member of the WRAP since its inception. The WRAP completed a long-term strategic plan in 2003. The Strategic Plan provides the overall schedule and objectives of the annual work plans and may be revised as appropriate. Among other things, the Strategic Plan (1) identifies major products and milestones; (2) serves as an instrument of coordination; (3) provides the direction and transparency needed to foster stakeholder participation and consensus-based decision making, which are key features of the WRAP process; and (4) provides guidance to the individual plans of WRAP forums and committees.

Much of the WRAP's effort is focused on regional technical analysis that serves as the basis for developing strategies to meet the regional haze rule requirements to demonstrate reasonable progress towards natural visibility conditions in Class I areas. This includes the compilation of emission inventories, air quality modeling, and ambient monitoring and data analysis. The WRAP is committed to using the most recent and scientifically acceptable data and methods. The WRAP does not sponsor basic research, but WRAP committees and forums interact with the research community to refine and incorporate the best available tools and information pertaining to western haze.

In accordance with 40 CFR § 51.308(i)(2), a state is required to provide the federal land managers with an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on the state's regional haze program or revisions to the program. The consultation shall include an opportunity to discuss the following:

1. Assessment of impairment of visibility in any mandatory Class I area; and
2. Recommendations on the development of the reasonable progress goal and on the development and implementation of strategies to address visibility impairment.

DENR is committed to providing the federal land managers opportunities to provide input as South Dakota' State Implementation Plan for the regional haze program is developed and implemented. This includes providing the federal land managers with at least 60 days prior notice to any public hearing. On January 15, 2010, DENR fulfilled this obligation and submitted South Dakota's draft Regional Haze Program to the following Federal Land Managers:

1. Tim Allen, U.S. Fish & Wildlife Service, Lakewood, Colorado;
2. Trent Wickman, USDA Forest Service, Great Lakes National Forests – Eastern Region;
3. John Bunyak, National Park Service, Air Resources Division, Lakewood, Colorado;
4. John Notar, National Park Service, Air Resources Division, Lakewood, Colorado;
5. Brian Kenner, National Park Service, Badlands National Park; and
6. Ken Hyde, National Park Service, Wind Cave National Park.

In addition, DENR took this opportunity to solicit comments from the following:

1. Laurel Dygowski, EPA Region VIII;
2. Amy Platt, EPA Region VIII;
3. Monica Morales, EPA Region VIII;

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4. Catherine Nueschler and Anne Jackson, State of Minnesota;
5. Teresa Cooper and Asad Khan, State of Michigan;
6. Shelley Schneider and Katryna Schaf, State of Nebraska;
7. Dana Mount and Tom Bachman, State of North Dakota;
8. Curtis Taipale, State of Colorado;
9. Dave Klemp, State of Montana;
10. Tina Anderson, State of Wyoming;
11. Jim Strain, South Dakota Department of Agriculture;
12. Gene Nelson, GCC Dacotah, Rapid City, SD;
13. Tim Rogers, Black Hills Corporation, Rapid City, SD;
14. Danielle Weibers, Pete Lien and Sons, Rapid City, SD;
15. Clint Allen, Hills Materials Company, Rapid City, SD; and
16. Terry Graumann, Otter Tail Power Company, Big Stone I.

DENR requested comments by March 16, 2010. DENR received comments from the United States Department of Agriculture – Forest Service, United States Department of Interior – National Park Service, Otter Tail Power Company, and the United States Environmental Protection Agency (EPA) – Region 8.

10.1.1 Addressing Federal Land Manager Recommendations

In accordance with 40 CFR § 51.308(i)(3), in developing any implementation plan or revision, the state must include a description of how it addressed any comments provided by federal land managers. The comments from the federal land managers, Otter Tail Power Company, and EPA and DENR response to those comments may be reviewed in Appendix D.

10.1.2 Continued Consultation with Federal Land Managers

In accordance with 40 CFR § 51.308(i)(4), DENR must provide procedures for continuing consultation between the state and federal land managers on the implementation of the visibility protection program including the development and review of implementation plan revisions and 5-year progress reports and on the implementation of other programs having the potential to contribute to impairment of visibility in a Class I area. DENR is committed to working with the federal land managers to protect the Class I areas in South Dakota and in neighboring states. This will be accomplished with our continued involvement in regional organizations and through our contacts with the federal land managers.

DENR has already involved the federal land managers on other programs that may impact visibility in a Class I area through our PSD air quality permit program. Again, DENR has an open door policy in which the federal land managers can submit recommendations in an ongoing basis.

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10.2 Consultation with Other States

In accordance with 40 CFR § 51.308(d)(1)(iv), in developing reasonable progress goals the state must consult with those states which may reasonably be anticipated to cause or contribute to visibility impairment in a Class I area within the state. In accordance with 40 CFR § 51.308(d)(3)(i), where a state's emissions are reasonably anticipated to cause or contribute to impairment in a Class I area located in another state or states, that state must consult with the other state or states in order to develop coordinated emission management strategies. DENR accomplished these requirements through WRAP and by contacting and working with states that are not part of WRAP.

As noted previously, DENR has been a participant in WRAP since its inception and considers its involvement as fulfilling part of the requirements for consultation. Within WRAP, the Implementation Work Group (IWG) was formed to address states' issues regarding Regional Haze and conducted numerous face-to-face meetings and monthly calls. All western states, EPA, Tribes and Federal Land Mangers participated in the WRAP activities and were involved throughout the process.

DENR accomplished the requirement of working with states impacting Class I areas in South Dakota through WRAP and by contacting and working with states that are not part of WRAP to develop emission reductions. WRAP gathered information from what states were doing to reduce air emissions that contribute to visibility impairment and provided that information to other states. The same information was used by WRAP in the 2018 projection models to determine the impacts those reductions will have on each Class I area.

Beyond WRAP, South Dakota was involved with the Northern Class I Areas workgroup which had monthly conference calls and included Minnesota, Michigan, Iowa, along with other Midwestern states. In addition, South Dakota consulted with Minnesota directly starting in August of 2007 through emails and phone calls, which continued through December of 2009 when Minnesota submitted its Regional Haze State Implementation Plan to EPA. DENR also consulted directly with the State of Nebraska over the past few years through email and phone calls, mostly in regards to impacts the Gerald Gentleman Power Plant has on visibility impairment in Class I areas in South Dakota and their plans to control emissions from the Gerald Gentlemen Power Plant. As noted in a Public Notice dated May 28, 2009, the Nebraska Department of Environmental Quality determined BART shall be the replacement of the existing burner equipment system on Unit 2, a coal-fired electric generating unit, with a new Low NOx burner equipment system including overfire air ports.

Otter Tail Power Company's Big Stone I facility is the only source in South Dakota that is reasonably anticipated to contribute to visibility impairment of a Class I area in another state. Otter Tail Power Company's BART analysis for Big Stone I demonstrated that its air emissions were reasonably anticipated to contribute to impairment at the Badlands National Park in South Dakota; Theodore National Park in North Dakota; Boundary Waters and Voyageurs Class I areas in northern Minnesota and the Isle Royale federal Class I area in Michigan. DENR notified these states and submitted Otter Tail Power Company's case-by-case BART analysis and

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DENR's review of the BART analysis for their comments. DENR did not receive any comments from Minnesota or Michigan.

DENR reviewed the BART analysis and determined the proper air emission limits for the regulated air pollutants that are reasonably anticipated to contribute to impairment in the Class I areas. DENR will established the BART procedures in the Administrative Rules of South Dakota that are equivalent to federal regulation in 40 CFR Part 51 and will adopt the BART emission limits in an air quality construction permit and eventually in Otter Tail Power Company's Title V air quality operating permit for the Big Stone I facility. DENR believes the BART requirements for Big Stone I meets South Dakota's obligation for emission reductions for those Class I areas impacted by Big Stone I.

As stated above, DENR also sent South Dakota's draft Regional Haze State Implementation Plan to the following states on January 15, 2010:

1. Catherine Nueschler and Anne Jackson, State of Minnesota;
2. Teresa Cooper and Asad Khan, State of Michigan;
3. Shelley Schneider and Katryna Schaf, State of Nebraska;
4. Dana Mount and Tom Bachman, State of North Dakota;
5. Curtis Taipale, State of Colorado;
6. Dave Klemp, State of Montana; and
7. Tina Anderson, State of Wyoming.

DENR did not receive any comments from these states.

DENR did not experience any situation in which we disagreed with another state on a reasonable progress goal. DENR will continue to work with states to ensure South Dakota's Class I areas achieve natural conditions by 2064 and air emissions from within South Dakota do not impair other state's progress in achieving natural condition in their Class I areas by 2064.

10.3 Public Input

In accordance with 40 CFR § 51.308(d)(1)(ii), if the state establishes a reasonable progress goal that provides a slower rate of improvement in visibility than the rate that would be needed to attain natural condition by 2064, the state must provide the public an opportunity to review as part of the implementation plan an assessment of the number of years it would take to attain natural conditions if visibility improvement continues at the rate of progress selected by the state as reasonable.

Based on the modeling analysis WRAP conducted on visibility improvement in 2018, the reasonable progress goal will not be met for organic carbon mass, ammonia nitrates, ammonia sulfates, and coarse particulates. The major contributor of ammonia sulfates and ammonia nitrates emissions at the two national parks is transported in from out of state. DENR has worked with other states through WRAP or individually to ensure their contribution in South Dakota is minimized. However, until all of the states implement their approved regional haze

rules it is hard to determine if the modeling assumptions used by WRAP in the analysis are correct. For instance, the WRAP analysis does not reflect the BART emission limits that will be implemented by Big Stone I or the BART emission limits other states are still developing for their BART sources. DENR believes as states start implementing the Regional Haze Programs, the ammonia sulfate and ammonia nitrate concentrations will be reduced to meet the glide path sometime between now and 2018. Therefore, DENR believes that South Dakota can still meet its reasonable progress goals and achieve natural conditions by 2064. DENR will evaluate the progress on a periodic basis.

DENR has also committed through this document to develop and implement a Smoke Management Plan by 2013. DENR will use the time from now until then to evaluate wildfires and prescribed fires to determine which size, distance, fuel material, etc. needs to be included in the Smoke Management Plan and the Best Management Practices for minimizing the impacts of wildfires and prescribed fires on South Dakota's two Class I areas.

DENR is also required to provide public input when adopting rules. DENR will provide the public an opportunity to comment on the proposed regional haze program and provide testimony at a public hearing that will be held in front of the Board of Minerals and Environment. The comments from the public and others and DENR response to those comments may be reviewed in Appendix E.

11.0 Periodic Review

11.1 Evaluation and Reassess Every 10 Years

In accordance with 40 CFR § 51.308(f), DENR will review, revise, and submit revisions to South Dakota's State Implementation Plan by July 31, 2018, and every ten years thereafter. The review shall consist of DENR evaluating and reassessing all of the elements required in 40 CFR § 51.308(d), taking into account improvements in monitoring data collection and analysis techniques, control technologies, and other relevant factors. The evaluation and reassessing shall address at least the following:

1. In accordance with 40 CFR § 51.308(d)(2)(iv)(B), current visibility conditions for the 20% most impaired and 20% least impaired days, and actual progress made towards natural conditions during the previous implementation period. The period for calculating current visibility conditions is the most recent five year period preceding the required date of the implementation plan submittal for which data are available. Current visibility conditions must be calculated based on the annual average level of visibility impairment for the most and least impaired days for each of these five years. Current visibility conditions are the average of these annual values;
2. The effectiveness of the long-term strategy for achieving reasonable progress goals over the prior implementation period(s); and
3. Affirmation of, or revision to, the reasonable progress goal in accordance with the procedures set forth in 40 CFR § 51.308(d)(1). If DENR established a reasonable progress goal for the prior period which provided a slower rate of progress than that

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needed to attain natural conditions by the year 2064, DENR must evaluate and determine the reasonableness, based on the factors in 40 CFR § 51.308(d)(1)(i)(A), of additional measures that could be adopted to achieve the degree of visibility improvement projected by the analysis contained in the first implementation plan described in 40 CFR § 51.308(d)(1)(i)(B).

11.2 Report Every 5 Years

In accordance with 40 CFR § 51.308(g), DENR will evaluate and report its progress towards the reasonable progress goal for each mandatory Class I federal area located within South Dakota and in each mandatory Class I federal area located outside the state which may be affected by emissions from within the state. The first progress report is due 5 years from submittal of DENR's initial implementation plan for South Dakota's Regional Haze Program and every 5 years thereafter. The progress reports will be in the form of an implementation plan revision that complies with the procedural requirements of 40 CFR §§ 51.102 and 51.103. The periodic progress reports shall contain at a minimum the following elements:

1. A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class I federal areas both within and outside South Dakota;
2. A summary of the emissions reductions achieved throughout South Dakota through implementation of the measures described in 40 CFR § 51.308(g)(1);
3. For each mandatory Class I federal area within South Dakota, DENR will assess the following visibility conditions and changes with values for most impaired and least impaired days expressed in terms of 5-year averages of these annual values:
   a. The current visibility conditions for the most impaired and least impaired days;
   b. The difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions;
   c. The change in visibility impairment for the most impaired and least impaired days over the past 5 years;
4. An analysis tracking the change over the past 5 years in emissions of pollutants contributing to visibility impairment from all sources and activities within South Dakota. Emissions changes should be identified by type of source or activity. The analysis must be based on the most recent updated emissions inventory, with estimates projected forward as necessary and appropriate, to account for emissions changes during the applicable 5-year period;
5. An assessment of any significant changes in anthropogenic emissions within or outside South Dakota that have occurred over the past 5 years that have limited or impeded progress in reducing pollutant emissions and improving visibility;
6. An assessment of whether the current implementation plan elements and strategies are sufficient to enable South Dakota, or other states with mandatory Class I federal areas affected by emissions from South Dakota, to meet all established reasonable progress goals.
7. A review of DENR's visibility monitoring strategy and any modifications to the strategy as necessary.

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DENR will coordinate with EPA as it develops its long term strategy for reasonably attributable visibility impairment under 40 CFR § 51.306(c).

11.3 Determination of Adequacy

In accordance with 40 CFR § 51.308(h), at the same time that DENR is required to submit any 5-year progress report to EPA in accordance with 40 CFR § 51.308(g), DENR will also take one of the following actions based upon the information presented in the progress report:

1. If DENR determines the existing implementation plan requires no further substantive revision at this time in order to achieve established goals for visibility improvement and emissions reductions, DENR must provide EPA with a negative declaration that further revision of the existing implementation plan is not needed at this time;
2. If DENR determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another state(s) which participated in a regional planning process, DENR must provide notification to EPA and to the other state(s) which participated in the regional planning process with DENR. DENR must also collaborate with the other state(s) through the regional planning process for the purpose of developing additional strategies to address the plan's deficiencies;
3. Where DENR determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another country, DENR shall provide notification, along with available information, to EPA; and
4. Where DENR determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources within South Dakota, DENR shall revise its implementation plan to address the plan's deficiencies within one year from the date the progress report is due.

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Appendix A

Otter Tail Power Company's BART Modeling Protocol and Approval Letter

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DEPARTMENT of ENVIRONMENT and NATURAL RESOURCES
PMB 2020
JOE FOSS BUILDING
523 EAST CAPITOL
PIERRE, SOUTH DAKOTA 57501-3182
www.state.sd.us/denr

September 18, 2009

Terry Graumann, Manager
Environmental Services
Otter Tail Power Company
PO Box 496
Fergus Falls, MN 56538-0496

Re: BART Modeling Protocol

Dear Mr. Graumann:

The South Dakota Department of Environment and Natural Resources (DENR) has been working with Otter Tail Power Company; the Environmental Protection Agency (EPA), Region 8; Fish and Wildlife Service; Forest Service; and National Park Service to determine if Otter Tail Power Company's Big Stone I facility near Big Stone City, South Dakota is reasonably anticipated to cause or contribute to any impairment of visibility at a federal Class I area in South Dakota or in a neighboring state. This evaluation is required since DENR determined that Big Stone I is a BART eligible source.

Otter Tail Power Company submitted an individual source analysis on March 19, 2008, which was not acceptable by all parties. The end result was the request for a BART modeling protocol that was approval by everyone and once that was achieved, Otter Tail Power Company would run the model using the approved protocol and submit the results to DENR. Otter Tail Power Company submitted a modeling protocol for Big Stone I dated June 2009 (see Attachment A). 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 (see Attachment B):

- 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.

- 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.
- 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.
- 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 then 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:

- "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.
- "NSE" – Number of species emitted. The EPA default is 3 and Otter Tail Power Company is proposing 9.
- "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.
- "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.
- "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.

It appears that Otter Tail Power Company has addressed all of DENR concerns and the concerns DENR received from EPA and the federal land managers. Therefore, DENR approves the modeling protocol as described above.

It is DENR's understanding that Otter Tail Power Company has already run the CALPUFF modeling using the modeling protocol DENR is approving today. Otter Tail Power Company determined that Big Stone I is 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 98th percentile at the three federal Class I areas. DENR is requesting that Otter Tail Power Company submit a report describing this analysis, summarizing the results, and include the input and output files for all of the preprocessor, CALMET, CALPUFF, and postprocessor runs.

It is also DENR's understanding that Otter Tail Power Company is in the process of conducting a Case-by-Case BART analysis, which includes determining the visibility improvements expected at each of these Class I areas. In this evaluation, any modeling should follow the modeling protocol that DENR is approving today. Once Otter Tail Power Company has completed its analysis, a report outlining the steps and summarizing the results must be submitted and include all modeling inputs and outputs for all of the preprocessor, CALMET, CALPUFF, and postprocessor runs.

I want to thank everyone for their time and effort in developing an approvable BART modeling protocol for Big Stone I. If there are any questions, please contact me at 605-773-3151.

Sincerely,

Brian Gustafson, PE
Administrator
Air Quality Program

cc: Kevin Golden, EPA Region 8
Amy Platt, EPA Region 8
Tim Allen, Fish and Wildlife Service
John Notar, National Park Service

Modeling Protocol for a BART Assessment of the Big Stone I Coal-Fired Power Plant, Big Stone City, South Dakota

June 2009

Prepared For:

Big Stone I
Otter Tail Power Company,
Big Stone City, South Dakota

Prepared By:

TRC Environmental Corporation
650 Suffolk Street
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1. INTRODUCTION

TRC Environmental Corporation will be conducting a site-specific BART (Best Available Retrofit Technology) modeling assessment of the Big Stone I coal-fired power plant facility located near Milbank and Big Stone City in South Dakota to determine if any sources of this facility are subject to BART. The current document is a modeling protocol for this BART assessment, which is specific to the Big Stone I power plant facility. This document has been prepared to address comments in an EPA memo dated May 15, 2009 (Fox, 2009).

On July 6, 2005 the USEPA produced the Federal Register document, 40 CFR Part 51 in order to introduce new National Regional Haze Regulations for Best Available Retrofit Technology. The regional haze rule requires States to submit implementation plans (SIPs) to address regional haze visibility impairment in 156 Federally-protected parks and wilderness areas, commonly referred to as "Class 1 Areas". The final rule included a requirement for BART for certain large stationary sources that were put in place between 1962 and 1977. The regional haze rule uses the term "BART-eligible source" to describe those sources which have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were put in place between August 7, 1962 and August 7 1977 and whose operations fall within one or more of 26 specifically listed source categories, of which Coal-Fired Power Plants are one.

BART review is required when the source emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class 1 area. In identifying a level of control of BART, States are required by section 169A(g) of the CAA to consider; (a) the costs of compliance, (b) the energy and non-air quality environmental impacts of compliance, (c) any existing pollution control technology in use at the source, (d) the remaining useful life of the source and (e) the degree of visibility improvement which may reasonably be anticipated from the use of BART.

The purpose of the modeling will be to assess the visibility impacts of sulfur dioxide (SO_2), particulate matter (PM) and nitrogen oxides (NO_x) emissions from the sources which are BART-eligible and compare their impacts to the 0.5 change in deciview threshold at all the federally mandatory Class I areas. Since there is no Class I areas within the 300 km radius usually applied, the South Dakota Department of Environment and Natural Resources requested that the Class I areas between 300 km and up to 625 km away from the Big Stone I facility sources be modeled. A total of eight Class I areas are located between these distances: two wilderness areas: Boundary Waters Canoe Area Wilderness and Rainbow Lake Wilderness, one National Wildlife Refuge (NWR): Lostwood and five National Parks: Voyageurs NP, Theodore Roosevelt NP, Badlands NP, Wind Cave NP and Isle Royale NP. However, Rainbow Lake Wilderness is one of two Class I areas where the visibility analysis is not required (http://www.dnr.state.wi.us/org/aw/air/modeling/psd.htm), so it will not be included in the modeling analysis. Although the MM5 datasets distributed by WRAP did not extend far enough in the East to include the Isle Royale NP or cover all of the Boundary Waters Class I area, the proposed new MM5 domains will include these areas.

The CALMET and CALPUFF non-steady-state models (Scire et al., 2000a,b) are recommended by the USEPA (*Federal Register*, 6 July 2005) to perform source-specific subject-to-BART screening. The CALPUFF system will therefore be used for this modeling analysis. The USEPA has promulgated the CALPUFF modeling system as a *Guideline Model* for Class I impact assessments and other long range transport applications or near field applications involving complex flows (USEPA, 2000), and the model is recommended by both the Federal Land Managers (FLM) Air Quality Workgroup (FLAG, 2000) and the Interagency Workgroup on Air Quality Modeling (IWAQM, 1998). The CALPUFF modeling system is also recommended in new proposed guidance by the FLMs (FLAG, 2008). A partially completed draft of proposed revisions to the IWAQM guidance dated May 27, 2009 has been released by EPA (EPA, 2009). The draft document does not contain a complete list of recommended switch settings but does contain some information on several model inputs which will be discussed in this protocol.

The Big Stone I BART modeling analysis will be performed with the EPA-approved Version 5.8 of the CALMET and CALPUFF models. Version 6.221 of CALPOST is proposed because it contains the FLM-approved implementation of Method 8 (FLAG, 2008), but in other respects is identical to the EPA-approved Version 5.6394.

CALMET is a diagnostic meteorological model that produces three-dimensional wind fields based on parameterized treatments of terrain effects such as slope flows and terrain blocking effects. Normally, meteorological observations are blended with gridded data from the NCAR-PSU Mesoscale Model, Version 5 (MM5). In this application MM5 data will be generated by TRC with a 4-km grid spacing for three years (2002, 2006 and 2007) to define the initial guess wind fields. A quantitative evaluation of the MM5 datasets will be conducted using the statistical measures outlined in EPA (2009) to demonstrate the 4-km datasets have equal (or better) technical merit than the 36-km MM5 datasets recommended by WRAP (2006) in their approach to BART modeling in this area. In addition, two configurations of CALMET will be tested quantitatively – one using CALMET at 4-km resolution using EPA (2009) switch settings and recommendations (except as described below) and in a second configuration using 2-km CALMET resolution with the traditional weighting factors given to the surface observations. The results of the meteorological model evaluations will be submitted to the SD DENR, FLMs and EPA for their review. The exceptions to the EPA (2009) configuration in the 4-km CALMET simulation includes the use of 4-km rather than 36-km MM5 data and the use of a fixed set of vertical layers in CALMET because it is not possible to set the layers exactly to the MM5 values as recommended by EPA because CALMET and MM5 use different vertical layer structures. The two CALMET configurations will allow an quantitative test of many of the conclusions in the EPA memo regarding grid resolution and model switch settings.

CALPUFF is a non-steady-state puff dispersion model. It accounts for spatial changes in the CALMET-produced meteorological fields, variability in surface conditions (elevation, surface roughness, vegetation type, etc.), chemical transformation, wet removal due to rain and snow, dry deposition, and terrain influences on plume interaction with the surface. CALPUFF contains a module to compute visibility effects, based on a humidity-dependent relationship between

particulate matter concentrations and light extinction, as well as wet and dry acid deposition fluxes. The screening and refined meteorological and dispersion modeling simulations will be conducted for three years (2002, 2006 and 2007). SO_2, PM, and NO_x, emissions and their secondary products resulting from chemical conversions from the Big Stone I facility will be modeled at receptors in the Class I areas and their impacts on visibility evaluated. Visibility impacts will be estimated with the new FLM-recommended visibility algorithm and monthly average relative humidity adjustment factors (Method 8 in Version 6.221).

This protocol outlines the techniques and data sources that will be used in the BART analyses. In Section 2, a general description of the source configuration is provided. Descriptions of the site characteristics and data bases (meteorological, geophysical, and aerometric) are provided in Section 3. Section 4 includes an overview of the CALMET and CALPUFF models settings and parameters that will be used in the analysis.

2. SOURCE DESCRIPTION

The 450-megawatt Big Stone I facility is a coal-fired power plant situated close to Big Stone City and Milbank in Grant County, South Dakota, at the border of Minnesota State. A BART applicability analysis was completed for the facility to determine those sources subject to the BART controls. The BART-eligible sources include one stack approximately 152 meters high.

Table 2-1 shows the source parameters and emission rates for the source considered in this application. The highest 24-hour average actual emission rates of SO_2, NO_x and PM under normal conditions over the 2001-2003 period will be used for this analysis. As shown in Table 2-2, the filterable PM_{10} will be divided into a particle size distribution based on AP-42, Table 1.1-6 for baghouse controlled emissions because the facility currently uses a fabric filter for PM control. Approximately 57.6% of the filterable mass is in the fine ($PM_{2.5}$) size category, and 42.4% in the coarse (2.5 to 10 μm diameter) size range. Each of the particle size categories will be modeled as a separate PM species in CALPUFF. The filterable PM_{10} emission rate is reported by the facility at 10.48 g/s (83.2 lb/hr). Based on AP-42 Table 1.1-5, the total condensable PM_{10} would be approximately 0.01 lb/mmBtu based on approximately 0.4% sulfur coal or 7.07 g/sec (56.1 lb/hr) assuming an heat input of 5609 mmBtu/hr. This estimate is consistent with the stack test data (August, 2006) at Otter Tail Power's Hoot Lake Plant, Unit 2, (which burns PRB coal) where the ratio of the filterable/total PM_{10} ratio was 0.66, resulting in a 2/3 filterable and 1/3 condensable split to the total PM_{10}.[1]

Elemental Carbon (EC) emissions will be assumed to be 3.7% of the fine filterable fraction based on EPA (2002) and will be assigned to the smallest particle size category. The primary H_2SO_4 emissions are 0.454 g/s (3.604 lb/hr) based on annual emission inventories and Toxic Release Inventory reports. The remaining condensable emissions will be assigned to organic carbon and distributed equally into the two smallest particle size categories.

Note that since all Class I areas are more than 50 km away from the facility, as recommended by the Federal Land Managers (FLMs) (US Fish and Wildlife, National Park Service and U.S. Forest Service), no downwash computations will be performed.

[1] AP-42 Table 1.1-8 was not used to estimate the particulate matter size distribution for Big Stone I because the emission factors were derived for cyclones burning bituminous coal, not sub-bituminous coal which is burned at Big Stone I.

Table 2-1. Point Source Parameters and Emission Rates

Source	LCC[1] East (km)	LCC[1] North (km)	Stack Ht (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	H_2SO_4 Emission Rate (g/s)	NO_x Emission Rate (g/s)	Filterable PM_{10} Emission Rate (g/s)	Condensable PM_{10} Emission Rate (g/s)
Main Stack	38.141	587.875	151.79	328.90	7.37	20.14	423.00	608.9	0.454	611.7	10.48	7.07

[1] Lambert Conformal Projection with an origin of 40.0N, 97.0W and standard parallels at 33N and 45N. Datum is NWS-84.

Table 2-2. PM_{10} Size Distribution[1]

Particle Size[2] (μm)	Cumulative Mass (PM) (%)	Cumulative Mass (PM_{10}) (%)
15	97	-
10	92	100
6	77	83.7
2.5	53	57.6
1.25	31	33.7
1.00	25	27.2
0.625	14	15.2

[1] From AP-42, Table 1.1-6, Cumulative particle size distribution and size-specific emission factors for dry bottom boilers burning pulverized bituminous and subbituminous coal.

[2] Expressed as aerodynamic equivalent diameter.

3. GEOPHYSICAL AND METEOROLOGICAL DATA

The South Dakota Department of Environment and Natural Resources requested that the eight Class I areas shown in Figure 3-1 be considered in the BART analysis. Rainbow Lake Wilderness is one of two Class I areas where the visibility analysis is not required so it is has been removed from the present analysis (see http://www.dnr.state.wi.us/org/aw/air/modeling/psd.htm). The MM5 dataset for this analysis will be extended to include the Isle Royale National Park as well as all of the Boundary Waters Class I area.

3.1 Terrain

The topography of the domain areas consists of terrain increasing toward the southwest from approximately 300 meters at the facility to 900 meters at Badlands NP and 1200 meters at Wind Cave NP, resulting in 900 meters (~3,000 feet) of terrain relief. The terrain relief also increases towards the northeast. The terrain gets mountainous on the west side of the facility near Badlands and Wind Cave National Parks.

The MM5 simulations will be conducted at 4-km grid spacing covering the modeling domain. CALMET will be run at the same 4-km resolution as MM5 using the EPA (2009) modeling options. A second simulation of CALMET using 4-km MM5 data as its initial guess field and 2-km CALMET grid spacing will be conducted and evaluated quantitatively. The results of the model performance at the two grid resolutions will be presented in a separate summary report.

Gridded terrain elevations for the refined modeling domain will be derived from 3 arc-second digital elevation models (DEMs) produced by the United States Geological Survey (USGS). Data are provided in files covering 1 degree by 1 degree blocks of latitude and longitude. The 1-degree DEMs are produced by the Defense Mapping Agency using cartographic and photographic sources. USGS 1:250,000 scale topographic maps are the primary source of 1-degree DEMs.

One degree DEM data consists of an array of 1201 by 1201 elevations referenced on the geographic (latitude/longitude) coordinate system of the World Geodetic System 1972 Datum. Elevations are in meters relative to mean sea level, and the spacing of the elevations along each profile is 3 arc-seconds, which corresponds to a spacing of approximately 90 meters. For the North part of the east domain and north west domain covering the south side of Manitoba and Ontario, Canada, SRTM-3 data with also an approximate resolution of 90 meters will be used.

The USGS elevation records located within each grid cell in the computational domain are averaged to produce a mean elevation at each grid point. The CALPUFF computational domain is the same as the CALMET domain. The CALMET and CALPUFF domains extend at least 50 km beyond the Class I areas in order to provide an adequate buffer zone at the boundaries, and to allow the effects of flow curvature and possible small-scale recirculation to be evaluated.

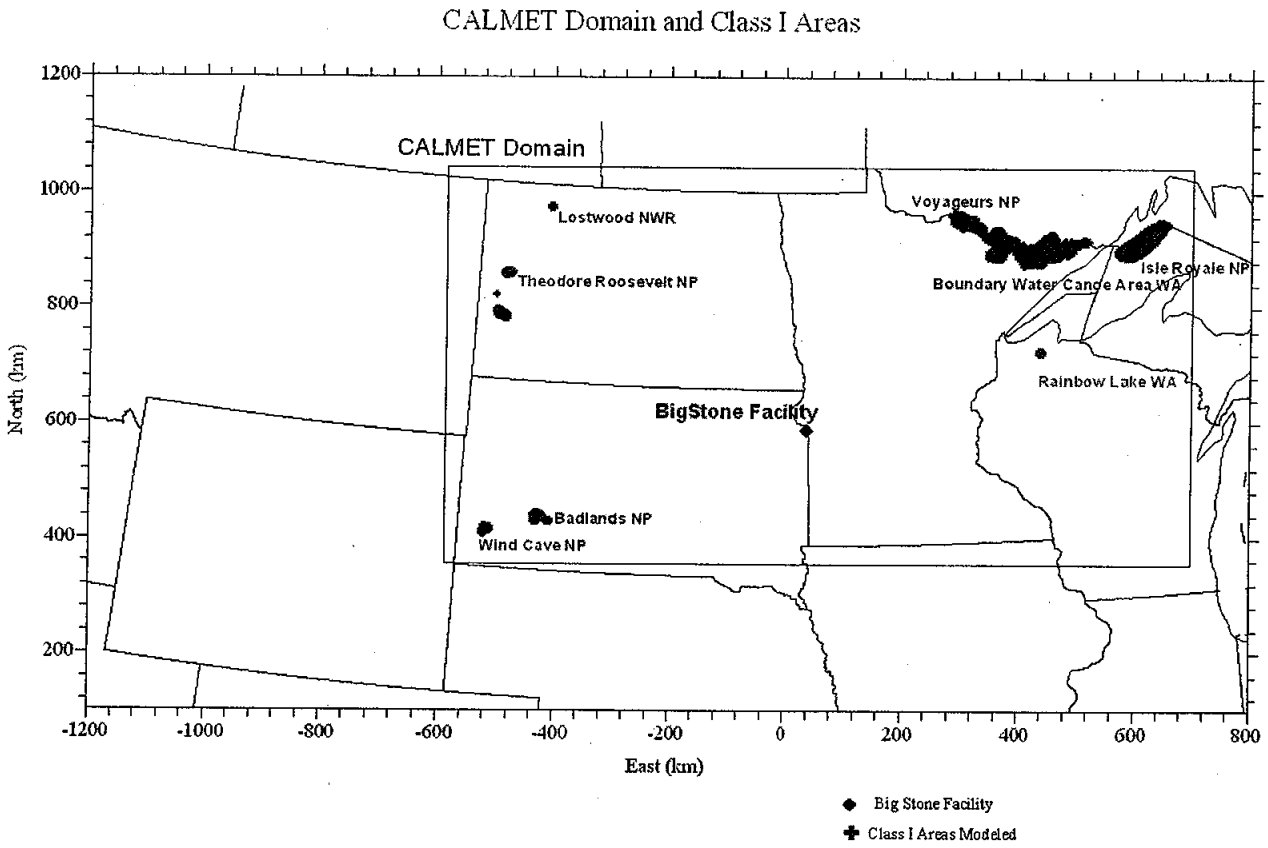

Figure 3-1. Proposed CALMET and CALPUFF modeling domain. The locations of the Class I areas are also shown.

3.2 Land Use

The Composite Theme Grid (CTG) land use data from the USGS, at a resolution of approximately 90m, will be processed to produce gridded fields of dominant land use categories for each grid cell. For the northern part of the domain covering Canada (south part of Manitoba and Ontario), 900 meters Global USGS land use data will also be incorporated using a mesh density for sampling of 2.

Land use data are first processed to produce fractional land use categories. The 37 USGS land use categories are then be mapped into 14 CALMET land use categories. Surface properties such as albedo, Bowen ratio, roughness length, and leaf area index are computed proportionally to the fractional land use. The USGS land use categories are described in Table 3-1. Table 3-2 displays the 14 CALMET land use categories and their associated geophysical parameters for summer conditions. Seasonal variations in surface properties will be considered as appropriate.

Table 3-1. U.S. Geological Survey Land Use and Land Cover Classification System

	Level I		Level II
10	Urban or Built-up Land	11	Residential
		12	Commercial and Services
		13	Industrial
		14	Transportation, Communications and Utilities
		15	Industrial and Commercial Complexes
		16	Mixed Urban or Built-up Land
		17	Other Urban or Built-up Land
20	Agricultural Land	21	Cropland and Pasture
		22	Orchards, Groves, Vineyards, Nurseries, and Ornamental Horticultural Areas
		23	Confined Feeding Operations
		24	Other Agricultural Land
30	Rangeland	31	Herbaceous Rangeland
		32	Shrub and Brush Rangeland
		33	Mixed Rangeland
40	Forest Land	41	Deciduous Forest Land
		42	Evergreen Forest Land
		43	Mixed Forest Land
50	Water	51	Streams and Canals
		52	Lakes
		53	Reservoirs
		54	Bays and Estuaries
		55	Oceans and Seas
60	Wetland	61	Forested Wetland
		62	Non-Forested Wetland
70	Barren Land	71	Dry Salt Flats
		72	Beaches
		73	Sandy Areas Other than Beaches
		74	Bare Exposed Rock
		75	Strip Mines, Quarries, and Gravel Pits
		76	Transitional Areas
		77	Mixed Barren Land
80	Tundra	81	Shrub and Brush Tundra
		82	Herbaceous Tundra
		83	Bare Ground
		84	Wet Tundra
		85	Mixed Tundra
90	Perennial Snow or Ice	91	Perennial Snowfields
		92	Glaciers

Table 3-2. Default CALMET Land Use Categories and Associated Geophysical Parameters based on the U.S. Geological Survey Land Use Classification System (14-Category System)

Land Use Type	Description	Surface Roughness (m)	Albedo	Bowen Ratio	Soil Heat Flux Parameter	Anthropogenic Heat Flux (W/m^2)	Leaf Area Index
10	Urban or Built-up Land	1.0	0.18	1.5	.25	0.0	0.2
20	Agricultural Land - Unirrigated	0.25	0.15	1.0	.15	0.0	3.0
-20*	Agricultural Land - Irrigated	0.25	0.15	0.5	.15	0.0	3.0
30	Rangeland	0.05	0.25	1.0	.15	0.0	0.5
40	Forest Land	1.0	0.10	1.0	.15	0.0	7.0
50	Water	0.001	0.10	0.0	1.0	0.0	0.0
54	Small Water Body	0.001	0.10	0.0	1.0	0.0	0.0
55	Large Water Body	0.001	0.10	0.0	1.0	0.0	0.0
60	Wetland	1.0	0.10	0.5	.25	0.0	2.0
61	Forested Wetland	1.0	0.1	0.5	0.25	0.0	2.0
62	Nonforested Wetland	0.2	0.1	0.1	0.25	0.0	1.0
70	Barren Land	0.05	0.30	1.0	.15	0.0	0.05
80	Tundra	.20	0.30	0.5	.15	0.0	0.0
90	Perennial Snow or Ice	.05	0.70	0.5	.15	0.0	0.0

* Negative values indicate "irrigated" land use

3.3 Meteorological Data Base

The CALMET model has the ability to assimilate meteorological information from surface stations, precipitation stations and upper air stations. Specifically, CALMET uses surface observations of wind speed, wind direction, temperature, cloud cover, ceiling height, surface pressure, relative humidity, and precipitation type (e.g., snow, rain, etc.). These variables are routinely measured at the National Weather Service (NWS) surface stations and will be directly included on an hourly basis into CALMET. Upper air observations however are only available twice-daily at a few stations throughout the domain. The locations of the upper air stations in and around the region of interest is displayed in Figure 3-2.

As described in Section 4, CALMET will be run in two modes. The first mode is as described in Section 2.7 of the EPA (2009) draft report in IWAQM Phase 2 and with 4-km grid resolution. In this model the observed surface and upper air wind data are essentially not used because of the low weighting factors suggested by EPA. Because the EPA (2009) does not contain a complete list of recommended switch settings, additional clarification on EPA recommendations will be requested. In the second mode, the model will be run at higher resolution (2-km) and with more weight given to the observational data as has been the traditional mode of running CALMET in Class I analyses.

The surface and precipitation stations that will be included in the modeling are displayed in Figure 3-3. For 2002, there are 272 surface stations and 265 precipitation stations available with similar numbers in 2006 and 2007. As recommended in the WRAP Protocol (2006) observed cloud cover and ceiling height from the surface meteorological stations will be used instead of cloud cover computed from relative humidity from MM5 (ICLOUD = 0).

The three-dimensional gridded data from the prognostic numerical model MM5 with nested grids of 36-km, 12-km and 4-km grid spacing will be conducted by TRC. An existing 12-km MM5 dataset for 2006 will be used along with a new nested 4-km nest over the area of interest. Information about the existing MM5 model configuration is provided in Appendix B.

Table 3-3. Meteorological Data Sources and Parameters Available

Type of Dataset	Frequency	Source	Parameters available
Surface Observations	Hourly	NWS	Wind speed, wind direction, temperature, ceiling height, cloud cover, relative humidity, surface pressure, precipitation type
Precipitation Observations	Hourly	NWS	Precipitation rate
Modeled Profiles MM5 for 2002, 2006 and 2007	Hourly	TRC	Hourly, gridded fields of winds, temperature, pressure, and humidity and liquid water content on 4-km grid.

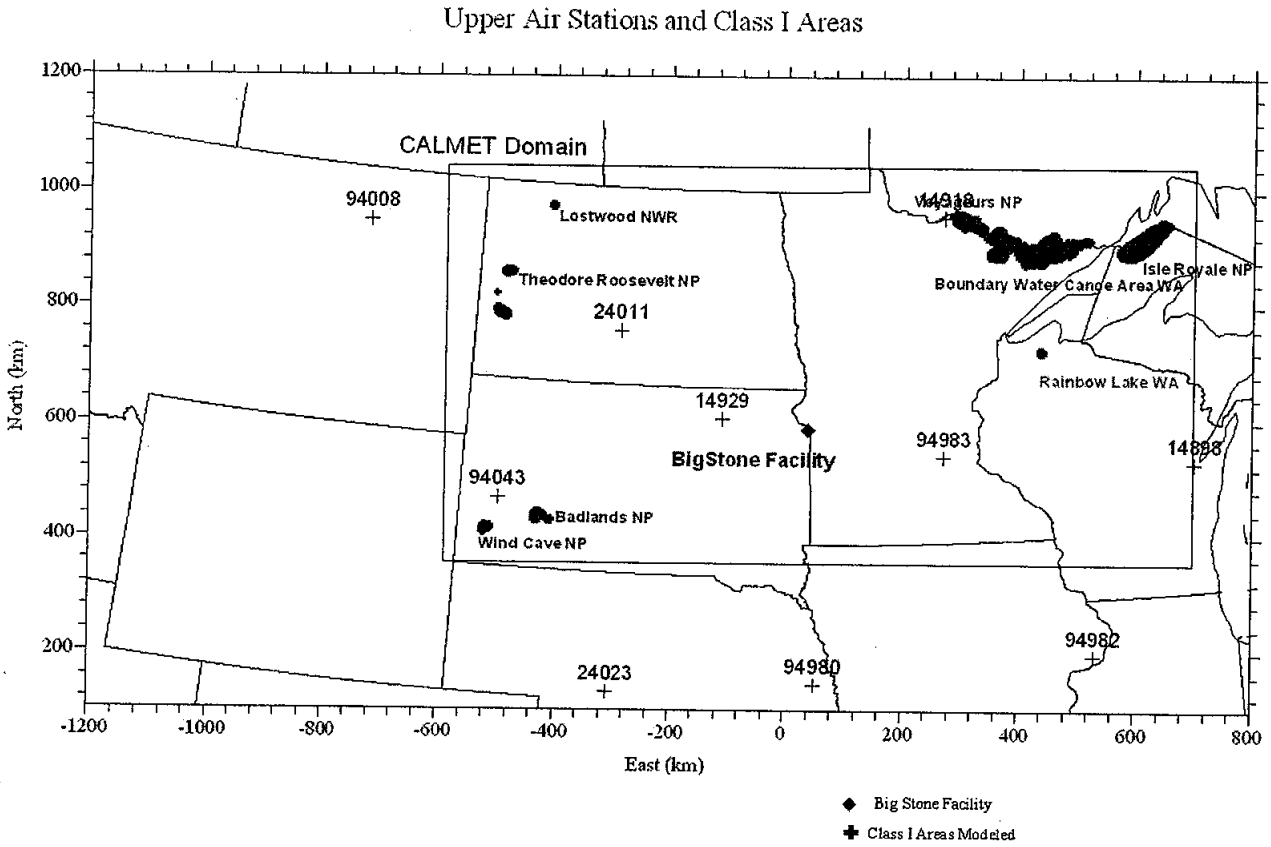

Figure 3-2. Plot of upper air stations available in the modeling domain.

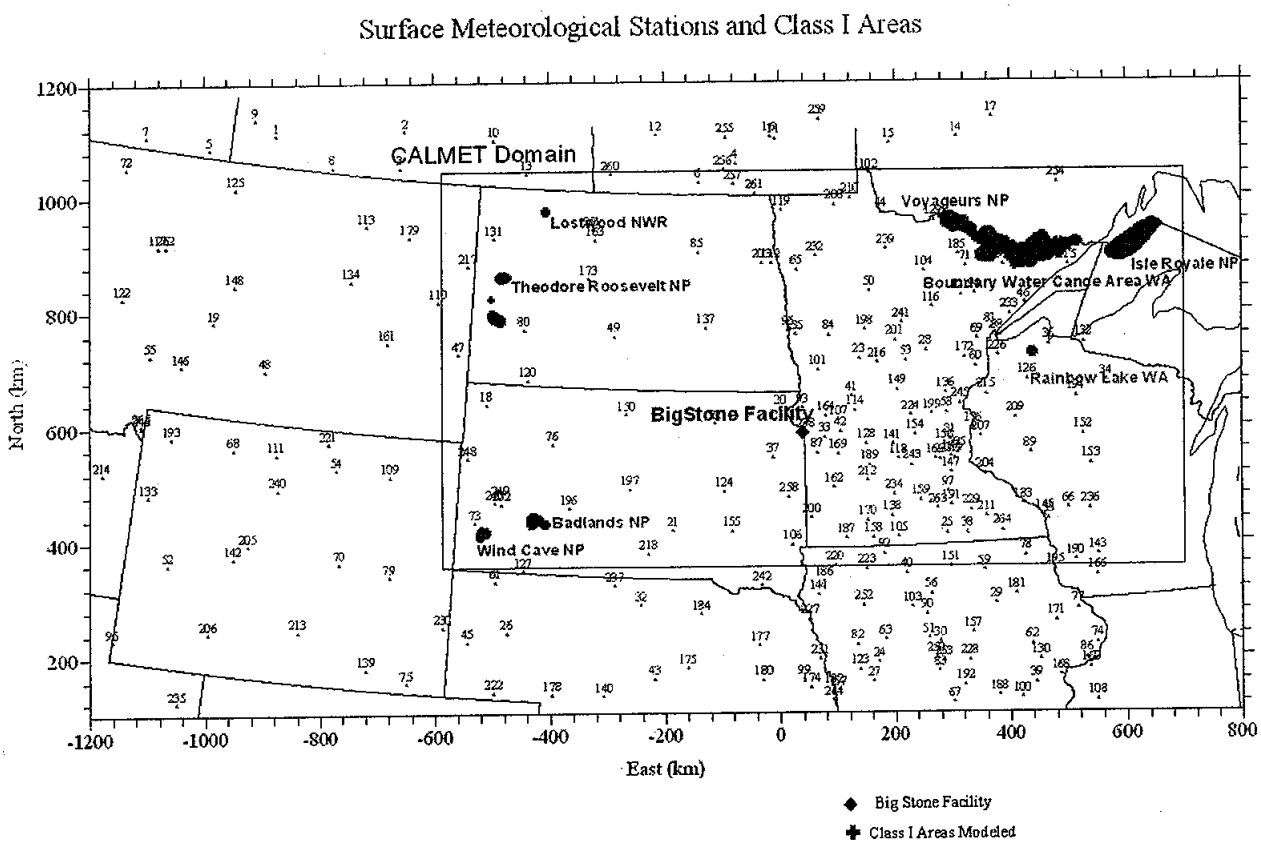

Figure 3-3. Plot of surface stations available in the modeling domain.

3.4 Air Quality Monitoring Data

CALPUFF will use hourly ozone concentration measurements in the chemical transformation rates (SO_2 to SO_4, NO_x to HNO_3/NO_3). The ambient ozone measurements are used in determining SO_2 loss rates due to chemical transformation to sulfate and in determining NO_x loss rates to nitrate. Ambient ozone hourly concentrations from EPA AIRS and CASTNet networks for 2002, 2006 and 2007 will be processed into OZONE.DAT files and used as ozone background in CALPUFF. An 80 parts per billion (ppb) concentration will be used as backup when hourly ozone concentrations are missing, which given the number of ozone stations is unlikely to be used.

A constant background ammonia concentration of 1 parts per billion (ppb) as recommended by the FLMs and EPA will be used in the CALPUFF runs. The output of CALPUFF will be postprocessed with POSTUTIL using the MNITRATE=1 switch. This eliminates the potential for double counting of ammonia by overlapping puffs from the modeled Big Stone source.

A second postprocessing simulation will be conducted using full ammonia limiting calculations based on data from background monthly average sulfate, total nitrate and total ammonia data from the 2002 CMAQ model using the POSTUTIL option MNITRATE=2. This second option accounts for both overlapping puffs from the modeled source as well as spatial and monthly variability of ammonia and background sulfate and nitrate from sources not included in the CALPUFF simulations. The results from both sets of simulations will be presented.

4. AIR QUALITY MODELING OPTIONS

4.1 Modeling Domain

CALMET and CALPUFF use terrain-following coordinates. In order to cover a large enough area for the refined analysis covering all seven Class I areas within a single domain, and including a buffer of at least 50 km around each Class I area, the domain dimensions of 1300 km x 700 km will be used. For a 4-km grid spacing, this amounts to 325 x 175 grid cells. In the vertical, the CALMET domain will be designed to match the MM5 model parameters up to the 4000 meters above the ground to the extent possible. Because MM5 uses a sigma coordinate system in the vertical and CALMET uses a fixed terrain following system, it is not possible to match the layers in the two models exactly as indicated should be done in the EPA (2009) guidance. However, the vertical grid spacing at the location of the source will be used in determining the CALMET vertical layer structure. Approximately 25 vertical levels will be used to match the number of MM5 layers below 4000 meters.

CALMET and CALPUFF will be run for three years, 2002, 2006 and 2007. A network of discrete receptors derived from the list of receptors developed by the National Park Service (NPS) are located within the boundaries of the seven Class I areas modeled: Boundary Water Canoe Area Wilderness, Voyageur National Park, Badlands National Park, Wind Cave National Park, Lostwood National Wildlife Refuge, Theodore Roosevelt National Park and Isle Royale National Park.

4.2 Meteorological Modeling Options

4-km Simulation. EPA-approved Version 5.8 Level 070623 of CALMET will be run using the recommendations described in Section 2.7 of EPA (2009), except as noted above regarding vertical layer structure. This includes using the regulatory set of options, including Maul-Carson convective mixing height over land only (IMIXH= - 1), OCD delta-T method for overwater fluxes (ICOARE=0), and no convective heat flux threshold overland (THRESHL= 0 W/m^3). These values of IMIXH, ICOARE and THRESHL, differ from the settings in the CALMET input files provided for sources located in South Dakota state on the WRAP Regional Modeling Center web page http://pah.cert.ucr.edu/aqm/308/bart.shtml. , but follow regulatory guidance set by EPA. In addition, NOOBS will be set to 0 and the MM5 data will be used as the initial guess field. Diagnostic adjustments will be turned off in the 4-km simulation and small values (i.e., 0.001 km) will be used for the RMAX1, RMAX2, R1 and R2 parameters, effectively minimizing the use of the surface and upper air wind observations. The EPA document references additional CALMET parameters in Appendix A of the document, but that section is missing from the draft EPA report. Some additional guidance from EPA may be necessary on the switch settings that will conform to EPA recommendations.

Initial Guess Field

MM5 data will be used to define the initial guess field for the CALMET simulations (IPROG=14). For all three years hourly MM5 data with a grid spacing of 4 km will be used in

the modeling. The CALMET horizontal grid specifications will be set to match those of the MM5 grid.

2-km Simulation. As a test of the performance of the EPA (2009) recommended model switch setting, a simulation of CALMET at higher grid resolution (2-km grid spacing) will be conducted using the traditional model options including diagnostic adjustments for terrain effects, more weight to surface observations with the typical 2:1 ratio of RMAX1/R1 and RMAX2/R2. The switch settings will be similar to those used previously except because these new runs will have higher resolution MM5 data available (4-km vs 36-km resolution), smaller RMAX1, RMAX2, R1 and R2 parameters will be developed to allow the higher resolution data to be retained. In the previous simulations, RMAX1=100 km and RMAX2=200 km were used with the 36-km MM5 data. Values between ½ to ¼ of these values will be evaluated in the 2-km simulation to strike a balance between smooth transitions from the observations to the MM5 data without completely eliminating the influence of the observations. It is proposed that NOOBS=1 be used in the 2-km simulations. As with the 4-km CALMET run, precipitation rates will be determined based on precipitation station measurements. Also, as with the 4-km runs, cloud amount and ceiling height will be derived from the surface station measurements. Overwater air-sea temperature difference will be derived from the MM5 data (ITWPROG=2) and prognostic temperature data will determined based on the 3-D temperature fields from the high resolution MM5 output. The performance of the CALMET simulations will be compared to that from the 4-km runs and presented to the regulatory agencies.

Step 1 Field: Terrain Effects

In developing the Step 1 wind field, CALMET adjusts the initial guess field to terrain effects, including slope flows and blocking effects. Slope flows are a function of the local slope and altitude of the nearest crest. The crest is defined as the highest peak within a radius TERRAD around each grid point. A value of TERRAD of 10 km will be used in the CALMET simulations as it is recommended by the WRAP Protocol (2006) and in agreement with an analysis of the scale of the terrain. The Step 1 field produces a flow field consistent with the fine-scale CALMET terrain resolution (2 km).

Step 2 Field: Objective Analysis

In Step 2, observations are incorporated into the Step 1 wind field to produce a final wind field. Each observation site influences the final wind field within a radius of influence (parameters RMAX1 at the surface and RMAX2 aloft). Observations and Step 1 wind fields are weighted by means of parameters R1 at the surface and R2 aloft: at a distance R1 from an observation site, the Step 1 wind field and the surface observations are weighted equally. As noted above, RMAX1/R1 and RMAX2/R2 will retain 2:1 ration, although the values of RMAX1 and RMAX2 will be reduced to25-50% of the values used when 36-km MM5 was used. This more typical use of a 2:1 ratio with R1 *smaller* than RMAX1 is a deviation from the WRAP CALMET setting where R1 was set to 100 km and RMAX1 to 50km. The WRAP setting with RMAX1 being larger than R1 inevitably creates bull-eye effects around each meteorological stations at the surface and thus should be avoided. Also vertical extrapolation for the surface meteorological

stations will be activated (IEXTRP=-4), which is a deviation from the WRAP protocol but in agreement with the EPA BART guidance. This setting will insure that the surface observations, vertically extrapolated within the boundary layer, are blended with the MM5-based Step 1 field aloft.

4.3 Dispersion Modeling Options

CALPUFF simulations will be conducted generally following the WRAP Protocol 2006 guidance, but with the EPA-approved Version 5.8 Level 070623 rather than Version 6 of the model. List of options to be used includes:

- Gaussian near-field vertical distribution
- Partial plume path adjustment method for terrain
- Transitional plume rise will be modeled
- Partial plume penetration of elevated inversion option will be activated
- Stack tip downwash will be used
- MESOPUFF II scheme will be used for the chemical transformation
- Pasquill-Gifford (PG) dispersion coefficients (rural areas) and McElroy-Pooler coefficients (urban areas) will be used to compute dispersion coefficients. The probability density function (PDF) for convective conditions will not be used because this is available only with the turbulence-based dispersion option.)
- Transition of σ_y to time-dependent (Heffter) growth rates will be set to 550 meters
- The switch for using Heffter equation for sigma z will not be activated
- PG sigma-y, z adjustment for roughness will not be selected
- Puff splitting (MSPLIT=1) will be activated
- Wet deposition, dry deposition will be applied
- The minimum turbulence velocities sigma-v for each stability class will be set to 0.5 m/s over land and 0.37 m/s over water.

The CALPUFF computational grid will be the same as the meteorological grid. The modeling domain include a buffer zone of 50 km around the source area and beyond the borders of the Class I areas. This minimizes edge effects and allows pollutants involved in flow reversals to be brought back into the Class I areas. Note that the CALMET modeling domain from previous studies will be extended to include the Isle Royale National Park

Two important computational parameters in CALPUFF are XMXLEN (maximum length of an emitted puff, in grid units) and XSAMLEN (maximum travel distance of a puff, in grid units, during one time step). Both of these variables will be set to 1.0 in the CALPUFF simulations in order to allow the strong wind channeling effects to be accounted for in the puff trajectory calculations. The first parameter ensures that the length of an emitted puff does not become so large so that it cannot respond to changes in the wind field on the scale of the meteorological grid. The model automatically increases the frequency of puff releases to ensure the length of a single

puff is not larger than the grid size. The second parameter decreases the internal time step to ensure the travel distance during one time step does not exceed the grid size.

The partial plume path adjustment option will be used in CALPUFF for this analysis (MCTADJ=3). The CALMET wind field incorporates the effect of the terrain on the plume trajectories. The plume path coefficient is used to characterize the local effect on ground-level concentrations. The default plume path coefficients (PPC) will be used for this analysis as listed below:

Stability Class	A	B	C	D	E	F
PPC	0.5	0.5	0.5	0.5	0.35	0.35

Deposition and chemical transformation effects will be modeled using the default dry deposition model, the scavenging coefficient wet removal module, and the default chemical transformation mechanism.

A total of five chemically active species will be modeled with CALPUFF for this analysis: SO_2, SO_4, NO_x, HNO_3 and NO_3. The chemical mechanism computes transformation rates of SO_2 to SO_4 and NO_x to NO_3/HNO_3. Hourly measured ozone concentrations will be provided in an external file for use with the chemical transformation module. These ozone concentrations, along with radiation intensity, are used as surrogates for the OH concentration during the day when the gas phase free radical chemistry is active.

Six additional PM_{10} species will be modeled corresponding to the midpoint of each particle size bin shown in Table 2-2. The fine, coarse, elemental carbon and organic carbon species will be constructed in postprocessing steps using the POSTUTIL program from these six PM species according to the appropriate size weights for size bin as discussed in Section 2.

4.4 Visibility Calculations

Calculations of the impact of the simulated plume particulate matter component concentrations on light extinction will be carried out with the CALPOST postprocessor following the new proposed FLAG (2008) guidance. The procedure deviates from the WRAP protocol (2006). The original IMPROVE/EPA equation (1) described below was recommended to determine the change in light extinction due to changes in component concentrations. Using the notations of CALPOST:

$$B_{ext} = 3f(RH)[(NH_4)2SO_4] + 3f(RH)[NH_4NO_3] + 4[OC] + 1[Soil] + 0.6[Coarse\ Mass] + 10[EC] + b_{ray} \quad (1)$$

The concentrations, in square brackets, are in $\mu g/m^3$ and b_{ext} is in units of Mm^{-1}.

But a revised new IMPROVE algorithm to compute the extinction (1/Mm) has been developed by the IMPROVE steering committee for estimating light extinction from particulate matter as described in equation (2) below. This algorithm provides a better correspondence between the

measured visibility and that calculated from particulate matter component concentrations (Tombach, 2006):

$$
\begin{aligned}
b_{ext} = {} & 2.2 f_S(RH) \bullet [small\ sulfate] + 4.8 f_L(RH) \bullet [large\ sulfate] \\
& + 2.4 f_S(RH) \bullet [small\ nitrate] + 5.1 f_L(RH) \bullet [large\ nitrate] \\
& + 2.8 \bullet [small\ organics] + 6.1 \bullet [large\ organics] \\
& + 10 \bullet [elemental\ carbon] \\
& + 1 \bullet [fine\ soil] \\
& + 1.7 f_{SS}(RH) \bullet [sea\ salt] \\
& + 0.6 \bullet [coarse\ matter] \\
& + Rayleigh\ scattering\ (site - specific) \\
& + 0.17 \bullet [NO_2]
\end{aligned}
\tag{2}
$$

All of the brackets [] denote concentrations in $\mu g/m^3$.

In CALPOST, the new IMPROVE algorithm as proposed by FLAG (2008) is implemented as CALPOST Method 8. The implementation of this method in CALPOST is described in more details in Appendix A. The proposed FLAG (2008) methodology is included in CALPOST V6.221 Level 080724, which has been reviewed and approved by the FLMs. This version of CALPOST is publicly available on the TRC's CALPUFF website (http://www.src.com/calpuff/calpuff1.htm) and will be used for this analysis.

The Rayleigh scattering term (b_{ray}) will be site-specific and computed as a function of the elevation as shown in Table 4-1, following FLAG(2008) guidance. Note that organic carbon (OC), which consists of condensable particulates and elemental carbon (EC) for soot particulates will be modeled along with fine and coarse particulate matter as described in Section 2.

To represent background natural conditions, monthly background concentrations must be entered into the CALPOST input control file for all aerosols defining the background. The WRAP Protocol (2006) recommendations are to use as natural conditions background, all three types of EPA default Natural Conditions: Best 20% Days, Annual Average and Worst 20% Days. In "Guidance for Estimating Visibility Conditions Under the Regional Haze Rule" (EPA2003), these three default values are defined only by their extinction coefficient in Mm^{-1}. For CALPOST Method 8, explicit background concentrations are required to allow the computation of the small and large sulfate particulates, nitrate particulates and organic carbon. So, in this analysis, the annual averaged background conditions will be used to define the natural background for each of the six Class I areas, following FLAG(2008). The concentrations used as background for each of the six Class I areas are summarized in Table 4-2. These concentrations will be used to compute a natural background light extinction following the revised IMPROVE formulae described above, for each of the Class I areas.

Tables 4-3, 4-4, and 4-5, provide the monthly f(RH) values for each of the 6 Class I areas, that are used to compute extinction coefficients for hygroscopic species, respectively for small

Table 4-1. Rayleigh Scattering Term (Mm^{-1}) for each Class I area as a Function of Elevation

Class I Area	Highest Elevation in feet (meters)	Rayleigh Scattering Term (Mm^{-1})
Boundary Water Canoe Area Wilderness	1998.0 (609)	11
Voyageurs NP	1335.3 (407)	12
Badlands NP	3031.5 (924)	11
Wind Cave NP	4796.6 (1462)	10
Lostwood NWR	2427.8 (740)	11
Theodore Roosevelt NP	2900.3 (884)	11

Source: FLAG (2008)

Table 4-2. Annual Averaged Conditions Levels of Aerosol Components ($\mu g/m^3$) to Define Natural Background (FLAG 2008 – Method 8 values per Class I Area)

Class I Area	SO_4	NO_3	OC	EC	Soil	Coarse Mass
Boundary Water Canoe Area Wilderness	0.23	0.10	1.71	0.02	0.31	2.53
Voyageurs NP	0.23	0.10	1.75	0.02	0.26	2.73
Badlands NP	0.12	0.10	0.60	0.02	0.50	3.00
Wind Cave NP	0.12	0.10	0.60	0.02	0.49	2.98
Lostwood NWR	0.12	0.10	0.60	0.02	0.50	3.00
Theodore Roosevelt NP	0.12	0.10	0.60	0.02	0.50	3.00
Isle Royale NP	0.23	0.10	1.55	0.02	0.24	2.89

Source: FLAG (2008)

Table 4-3. Monthly Site-Specific RH adjustment factors f(RH) values for hygroscopic species – Small ammonium sulfate and ammonium nitrate particles. Method 8 (FLAG (2008))

Class I area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Boundary Water Canoe Area Wilderness	3.23	2.81	2.93	2.63	2.89	3.22	3.44	3.71	3.83	3.08	3.49	3.49
Voyageurs NP	3.16	2.77	2.82	2.59	2.65	3.28	3.25	3.48	3.66	3.02	3.37	3.32
Badlands NP	2.94	2.96	3.01	2.87	3.1	2.91	2.64	2.59	2.56	2.58	3.11	2.98
Wind Cave NP	2.81	2.81	2.86	2.82	3.06	2.81	2.5	2.46	2.44	2.52	2.97	2.83
Lostwood NWR	3.21	3.15	3.36	2.6	2.54	2.86	2.89	2.6	2.53	2.72	3.6	3.52
Theodore Roosevelt NP	3.17	3.11	3.22	2.71	2.74	2.85	2.73	2.49	2.48	2.66	3.42	3.37

Source: FLAG (2008)

Table 4-4. Monthly Site-Specific RH adjustment factors f(RH) values for hygroscopic species – Large ammonium sulfate and ammonium nitrate particles – Method 8 (FLAG(2008))

Class I area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Boundary Water Canoe Area Wilderness	2.5	2.25	2.28	2.09	2.2	2.43	2.57	2.71	2.78	2.38	2.64	2.64
Voyageurs NP	2.46	2.22	2.22	2.07	2.09	2.46	2.46	2.59	2.7	2.35	2.58	2.55
Badlands NP	2.31	2.31	2.31	2.21	2.34	2.25	2.08	2.05	2.02	2.05	2.38	2.33
Wind Cave NP	2.23	2.22	2.22	2.18	2.32	2.18	2	1.97	1.95	2	2.3	2.24
Lostwood NWR	2.51	2.45	2.54	2.06	2.03	2.221	2.23	2.05	2.02	2.13	2.69	2.67
Theodore Roosevelt NP	2.47	2.42	2.45	2.12	2.14	2.21	2.14	1.99	1.99	2.1	2.58	2.57

Source: FLAG (2008)

Table 4-5. Monthly Site-Specific RH adjustment factors f(RH) values for hygroscopic species – Sea salt particles - Method 8 (FLAG(2008))

Class I area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Boundary Water Canoe Area Wilderness	3.73	3.35	3.29	2.91	3.0	3.44	3.68	3.88	3.98	3.45	3.89	3.91
Voyageurs NP	3.69	3.31	3.2	2.9	2.89	3.46	3.55	3.71	3.87	3.42	3.83	3.8
Badlands NP	3.37	3.33	3.27	3.05	3.25	3.15	2.89	2.81	2.74	2.82	3.41	3.38
Wind Cave NP	3.25	3.2	3.13	3.01	3.22	3.06	2.75	2.68	2.63	2.75	3.28	3.24
Lostwood NWR	3.77	3.66	3.67	2.86	2.79	3.07	3.11	2.82	2.8	2.99	3.93	3.95
Theodore Roosevelt NP	3.67	3.56	3.51	2.93	2.97	3.09	2.96	2.72	2.72	2.93	3.75	3.78

Source: FLAG (2008)

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U. S. Environmental Protection Agency (EPA), 2005: Regional Haze Regulations and Guidelines for Best Available Technology (BART) Determinations. Fed. Reg./Vol. 70, No. 128/Wed. July 6, 2005, Rules and Regulations, pp. 39104-39172. 40 CFR Part 51, FRL-7925-9, RIN AJ31.

The revised visibility algorithm developed for the IMPROVE Steering Committee (IMPROVE 2005) as recommended by FLAG (2008) has been implemented in CALPOST. It differs from the previous IMPROVE algorithm as used in Methods 2 and 6 in six areas:

- Extinction efficiencies of sulfates, nitrates, and organics vary with concentration, as there are distinct efficiencies for "small" and "large" particles and the ratio of small-to-large particle fraction decreases as the concentration increases. Furthermore, the extinction efficiency for sulfates no longer equals that for nitrates.
- A separate hygroscopic humidity enhancement factor curve is prescribed for "small" and "large" particles, $f_S(RH)$ and $f_L(RH)$. These curves apply to sulfates and nitrates.
- Light extinction due to scattering by sea salt (with its own hygroscopic humidity enhancement factor $f_{SS}(RH)$) is included.
- Light absorption by NO_2 gas is included in the extinction.
- Background particulate organic matter concentration is taken to be 1.8 times measured organic carbon concentrations.
- Rayleigh scattering extinction varies with site elevation and mean temperature.

Items 5 and 6 remain direct inputs to CALPOST, and require no structural changes to the postprocessor. The user must confirm that appropriate values are provided.

Item 4, the introduction of light extinction due to NO_2 gas absorption, has been added to CALPOST as a discrete component independent of the visibility method chosen. New control file inputs associated with NO_2 are:

```
Modeled species to be included in computing the light extinction
Include NO2 absorption?   (LVNO2) -- Default: F   ! LVNO2  = T  !
         With Visibility Method 8 -- Default: T

Source of NO2 (when LVNO2=T) may be from CALPUFF NO2 concentrations
and from a fraction of CALPUFF NOx concentrations.  Specify the
fraction of NOx that is treated as NO2.
                         (FNO2NOX) -- Default: 1.0 ! FNO2NOX = 0.75 !

Extinction Efficiency (1/Mm per ug/m**3)
----------------------------------------
           NO2 GAS          (EENO2) -- Default: .17 ! EENO2  = .17 !
```

Items 1 through 3 are implemented as visibility method 8 in CALPOST, along with the specific choice of the new f(RH) curves. Selection of the revised IMPROVE algorithm requires the following new control file selections:

```
Particle growth curve f(RH) for hygroscopic species
                          (MFRH) -- Default: 2   ! MFRH   = 4  !
     1 =  IWAQM (1998) f(RH) curve (originally used with MVISBK=1)
     2 =  FLAG (2000) f(RH) tabulation
     3 =  EPA (2003) f(RH) tabulation
     4 =  IMPROVE (2006) f(RH) tabulations for sea salt, and for
          small and large SULFATE and NITRATE particles;
          Used with Visibility Method 8 (MVISBK = 8)

Method used for background light extinction
                        (MVISBK) -- Default: 2   ! MVISBK =  8  !
     1 =  Supply single light extinction and hygroscopic fraction
     2 =  Compute extinction from speciated PM measurements (A)
     3 =  Compute extinction from speciated PM measurements (B)
     4 =  Read hourly transmissometer background extinction measurements
     5 =  Read hourly nephelometer background extinction measurements
     6 =  Compute extinction from speciated PM measurements
     7 =  Use observed weather or prognostic weather information for
          background extinction during weather events; otherwise, Method 2
     8 =  Compute extinction from speciated PM measurements using the
          IMPROVE (2006) variable extinction efficiency formulation
          (MFRH must be set to 4)
          - Split between small and large particle concentrations of
            SULFATES, NITRATES, and ORGANICS is a function of concentration
            and different extinction efficiencies are used for each
          - Source-induced change in visibility includes the increase in
            extinction of the background aerosol due to the change in the
            extinction efficiency that now depends on total concentration.
          - Fsmall(RH) and Flarge(RH) adjustments for small and large
            particles are applied to observed and modeled sulfate and
            nitrate concentrations
          - Fsalt(RH) adjustment for sea salt is applied to background
            sea salt concentrations
          - F(RH) factors are capped at F(RHMAX)
          - RH for Fsmall(RH), Flarge(RH), and Fsalt(RH) may be
            obtained from hourly data as in Method 2 or from the FLAG
            monthly RH adjustment factor used for Method 6 where EPA
            F(RH) tabulation is used to infer RH, or monthly Fsmall,
            Flarge, and Fsalt RH adjustment factors can be directly
            entered. Furthermore, a monthly RH factor may be applied
            to either hourly concentrations or daily concentrations
            to obtain the 24-hourextinction.

            These choices are made using the M8_MODE selection.
```

```
Additional inputs used for MVISBK = 8:
-------------------------------------
 Extinction coefficients for hygroscopic species (modeled and
 background) may be computed using hourly RH values and hourly
 modeled concentrations, or using monthly RH values inferred from
 the RHFAC adjustment factors and either hourly or daily modeled
 concentrations, or using monthly RHFSML, RHFLRG, and RHFSEA
 adjustment factors and either hourly or daily modeled
 concentrations.

  (M8_MODE) -- Default: 5      ! M8_MODE=  5   !
               FLAG (2008)

       1 = Use hourly RH values from VISB.DAT file with hourly
           modeled and monthly background concentrations.
       2 = Use monthly RH from monthly RHFAC and EPA (2003) f(RH)
           tabulation with hourly modeled and monthly background
           concentrations.
           (VISB.DAT file is NOT needed).
       3 = Use monthly RH from monthly RHFAC with EPA (2003) f(RH)
           tabulation with daily modeled and monthly background
           concentrations.
           (VISB.DAT file is NOT needed).
       4 = Use monthly RHFSML, RHFLRG, and RHFSEA with hourly
           modeled and monthly background concentrations.
           (VISB.DAT file is NOT needed).
       5 = Use monthly RHFSML, RHFLRG, and RHFSEA with daily modeled
           and monthly background concentrations.
           (VISB.DAT file is NOT needed).
```

The last of these selections, M8_MODE, provides options for how concentrations are averaged, and how the relative humidity enhancement factors for hygroscopic species are determined. M8_MODE has a default value of 5, which is consistent with the new FLAG (2008) guidance

1. MM5 Domain Configuration (36-km, 12-km Resolution)

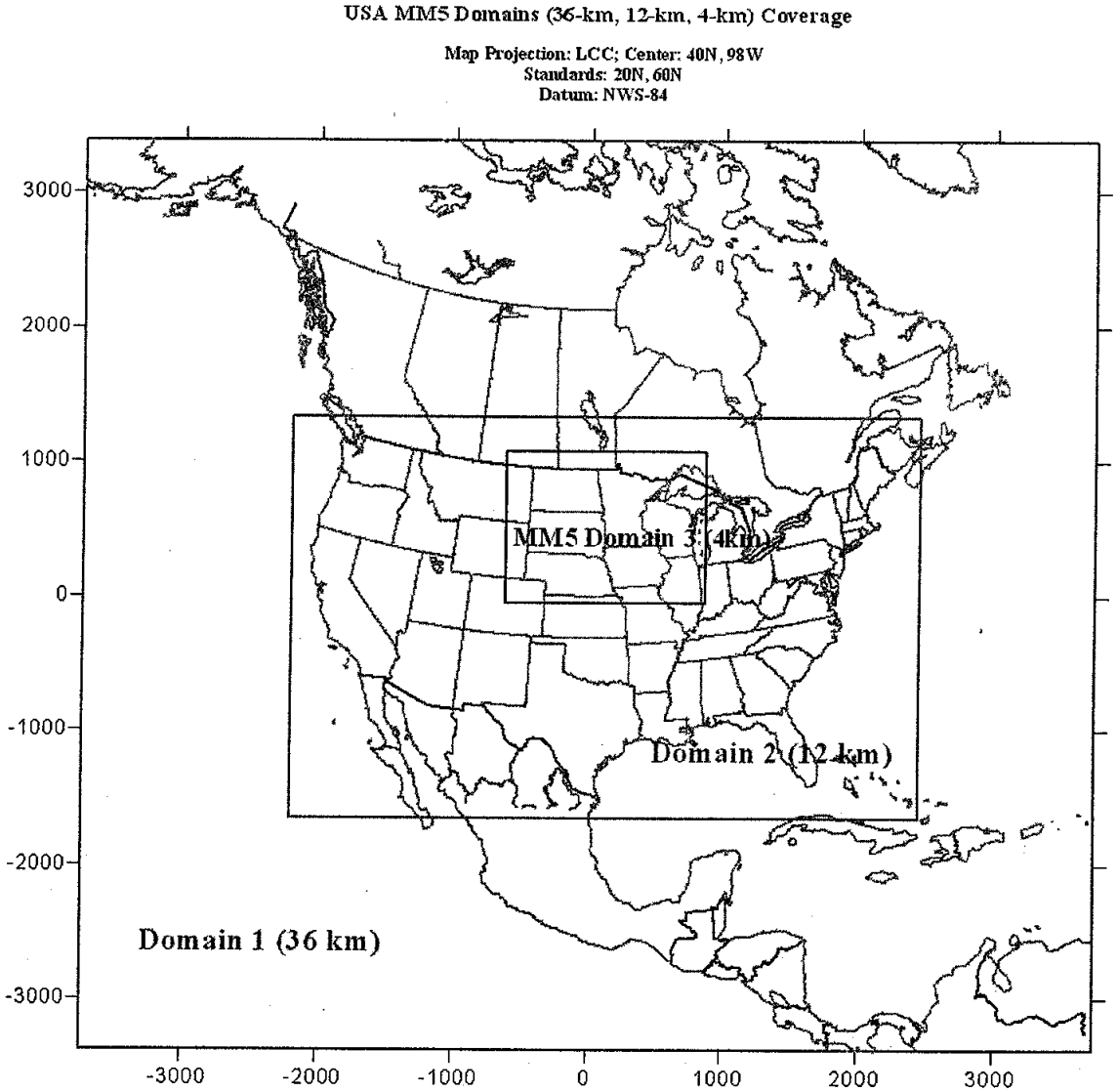
MM5 simulations have been run for 1996 for North America for two domains: a coarse Domain 1 (36-km resolution), and a nested Domain 2 (12-km resolution). The Lambert Conical Conformal (LCC) mapping projection is used in modeling. The center of the coordinate system is located at the center of Domain 1 at 40°N and 98°W. Two standard latitudes of LCC are set to 20°N and 60°N. The coarse domain (Domain 1) covers an area of 7488 km in the west-east (X) direction by 6768 km in the south-north (Y) direction with grid spacing of 36 km (Table B-1).

An additional nest at 4 km grid spacing will be developed to cover the modeling area of interest for the Big Stone BART modeling. One way nesting will be used as in the other nests. Figure B-1 shows the two initial modeling domains and the new 4-km inner nest (Domain 3).

There are forty-one sigma levels in the vertical direction from the surface up to 100 hPa (Table B-2). The first sigma level is about 11 m above the ground, very close to the anemometer height at operational weather stations. The vertical spatial resolution varies from the surface to the model top. About twenty levels are below 1500 m above the ground for better resolving the atmospheric boundary layer in the model.

Table B-1 Domain Configuration and Parameterizations for 2006 MM5 Simulations. The Lambert Conical Conformal (LCC) map projection is used in the MM5 modeling.

Settings	Domain 1	Domain 2
Grid number	209 x 189	388 x 250
Grid size (km)	36	12
Nesting	NA	One-way
Sigma levels	41	41
Moisture	Reisner 2	Reisner 2
Cumulus	Kain-Fritsch 2	Kain-Fritsch 2
Boundary layer	ETA	ETA
Radiation	RRTM	RRTM
Soil model	NOAH LSM	NOAH LSM
FDDA	3D and Surface Analysis	3D and Surface Analysis
Run Length	2.5 days	2.5 days
Spin-up time	12 hours	12 hours
Terrain and land-use data	USGS 10-minute (~19 km)	USGS 5-minute (~9 km)



MM5 Domains:
D1: X: -3744 - 3744 km, Y: -3384 - 3384 km; dxy= 36 km; 209 x 189 i1= 1,j1= 1
D2: X: -2196 - 2448 km, Y: -1656 - 1332 km; dxy= 12 km; 388 x 250 i1= 44,j1= 49
D3: X: -612 - 864 km, Y: -48 - 1080 km; dxy= 4 km; 370 x 283 i1=133,j1=135

Figure B-2. Map showing the MM5 Domain 1 (36-km) and Domain 2 (12-km) and the new Domain 3 (4-km).

Table B-2. Sigma Levels used in the North American MM5 Simulations for 2006.

Level	Sigma	Half Sigma	Ref. Pressure (mb)	Height (m)
surface	1.0000	-	1010.0	0.0
1	0.9970	0.9985	1008.6	10.9
2	0.9936	0.9953	1005.7	34.1
3	0.9898	0.9917	1002.4	60.3
4	0.9856	0.9877	998.8	89.6
5	0.9808	0.9832	994.7	122.5
6	0.9754	0.9781	990.1	160.0
7	0.9694	0.9724	984.9	202.1
8	0.9626	0.9660	979.1	249.6
9	0.9549	0.9588	972.5	303.7
10	0.9463	0.9506	965.0	364.8
11	0.9367	0.9415	956.8	433.5
12	0.9258	0.9313	947.4	511.5
13	0.9136	0.9197	936.9	600.1
14	0.8999	0.9068	925.1	700.4
15	0.8845	0.8922	911.9	814.4
16	0.8672	0.8759	897.0	944.1
17	0.8477	0.8575	880.3	1092.1
18	0.8258	0.8368	861.4	1261.5
19	0.8012	0.8135	840.3	1455.3
20	0.7736	0.7874	816.5	1677.7
21	0.7425	0.7581	789.8	1934.1
22	0.7076	0.7251	759.8	2230.9
23	0.6683	0.6880	726.0	2576.1
24	0.6242	0.6463	688.1	2980.0
25	0.5746	0.5994	645.5	3455.7
26	0.5188	0.5467	597.5	4021.9
27	0.4688	0.4938	549.4	4628.0
28	0.4284	0.4486	508.2	5180.4
29	0.3879	0.4082	471.4	5705.6
30	0.3474	0.3677	434.6	6265.0
31	0.3065	0.3270	397.5	6866.0
32	0.2620	0.2843	358.7	7545.5
33	0.2175	0.2398	318.2	8317.4
34	0.1675	0.1925	275.2	9224.7
35	0.1175	0.1425	229.7	10311.2
36	0.0783	0.0979	189.1	11426.7
37	0.0588	0.0686	162.4	12261.6
38	0.0392	0.0490	144.6	12875.1
39	0.0196	0.0294	126.8	13547.3
40	0.0000	0.0098	108.9	14290.2

2. Model Parameterizations and Schemes

The MM5 model was run in the non-hydrostatic mode using the upper radiative boundary condition. MM5 physical schemes and parameterizations are listed in Table B-1. The Reisner graupel scheme was used for the explicit moisture parameterization. It predicts all five water contents in the atmosphere. This scheme includes additional equation to predict graupel. It is an expansive scheme compared with simple ice scheme, but it is affordable with the improved computer power at TRC. The cumulus scheme used in MM5 is the Kain-Fritsch 2 scheme (Kain, 2002). This scheme includes shallow convection. For planetary boundary layer (PBL) scheme, the Mellor-Yamada scheme used in the ETA model (Janjic, 1990, 194) was used in this MM5 modeling. This scheme was implemented in the NCEP MRF model. It is efficient and suitable for high-resolution PBL. The Rapid Radiative Transfer Model was used for the radiation scheme in both Domains (Malwer et al., 1997). This scheme is a highly accurate and efficient method developed by AER Inc. Multiple-layer soil temperatures were computed using the NOAH land surface model (National Centers for Environmental Prediction, Oregon State University, Air Force, and Hydrologic Research Laboratory). Additional geographical data, such as soil types, vegetation fraction, and annual deep soil temperatures are needed for the land surface model; and these data were obtained from NCAR.

One way nesting is used in the MM5 simulation, meaning that the mother domain is not affected by its child-domain. Such nesting allows adding new domains later without re-running all the other domains.

Analysis Four Dimensional Data Assimilation (FDDA) was applied to both Domain 1 and Domain 2, but it will not be applied to the Domain 3. Typically the effect of assimilated data is passed into high resolution domains such as the 4-km domain through the lower resolution nests, rather than directly in the high resolution domain.

3. Initial Data and Simulation

MM5 is initialized using the 1° x 1° Final Analysis (FNL) data from NCEP at NCAR. It is an improvement of the original 2.5-degree by 2.5-degree data set. The FNL data were archived at NCAR with temporal resolution of six hours at the surface and 26 standard pressure levels under 10 hPa: 1000, 975, 950, 925, 900, 850, 800, 750, 700, 650, 600, 550, 500, 450, 400, 350, 300, 250, 200, 150, 100, 70, 50, 30, 20, and 10 hPa. The data set includes two-dimensional variables of snow cover, sea surface temperature (SST), sea level pressure, and three-dimensional variables of temperature, geopotential height, U and V components, and relative humidity.

The SST spatial resolution of 1° x 1° in FNL data is too coarse in the coastal area. To improve SST in MM5, a better SST data set, the daily 4-km MODIS SSTs, is ingested into the simulation. The MODIS (MODerate Resolution Imaging Spectroradiometer) SSTs are derived from the sensors onboard the NASA Terra and Aqua platforms. The MODIS SSTs include from both the sensors of mid-infrared (IR) and thermal IR channels. The product used in the simulation is the MODIS Global Level 3 Mapped mid-IR SSTs.

MM5 is run for 2.5-day periods with 12 hours for spin-up time. The initial FNL data are model output and already in the dynamically-consistent state. The spin-up time of 12 hours is enough to allow MM5 reach dynamical balance in its domains. The 2.5-day simulation length can reduce the divergence between forecasts and analyses. MM5 output covers the period from 2005123112 to 2007010111, so that any conversion between local and UTC times can be properly processed. There are 183 2.5-day simulations in total for the annual period.

Gustafson, Brian

From: TGraumann@otpco.com

Sent: Monday, August 31, 2009 12:40 PM

To: Gustafson, Brian

Cc: pshamblin@hunton.com

Subject: Big Stone Plant - Proposed BART Modeling Protocol - 8.31.2009

Brian,

Otter Tail Power Company has considered the questions and concerns expressed by the participants on the July 22, 2009 conference call regarding the Big Stone I BART modeling protocol, and EPA Region 8's July 30th summary of that call.

In an effort to move the process along on a schedule that will enable the Department of Environment and Natural Resources to complete its Regional Haze State Implementation Plan in a timely manner, Otter Tail offers the following revisions to its "Modeling Protocol for a BART Assessment of the Big Stone I Coal-Fired Power Plant, Big Stone City, South Dakota June 2009", which Penny Shamblin submitted to you electronically on July 1, 2009 (copy attached).

During the July 22, 2009 call, EPA and the Federal Land Managers requested that Big Stone provide a detailed justification for using our proposed 4 km MM5 grid and a 4 km CALMET grid. While it is our opinion that our proposal could be justified, we are concerned that the demonstration could evolve into a research project that would not be satisfactorily resolved with all parties in a timeframe necessary to complete the modeling. Consequently, Otter Tail proposes to use a 12 km MM5 grid and a 4 km CALMET grid rather than the 4 km MM5 grid and the 4 km CALMET grid. Our proposal is consistent with those modeling proposals adopted by Wyoming, North Dakota, VISTAS and WRAP. The 2-km simulation as described in section 4.2 page 4-2 will be eliminated from the Big Stone modeling protocol. Consistent with Section 3.4 page 3-10, we may however perform additional supplemental modeling using full ammonia limiting calculations using the POSTUTIL option MNITRATE=2. The results from both the approved modeling protocol and the supplemental modeling simulations will be presented.

The proposed CALMET and CALPUFF switch settings are attached. Otter Tail has accepted the EPA-FLM Recommended CALMET Input File Values dated August 20, 2009. The proposed CALPUFF Inputs are those that we had initially proposed to you on August 19, 2009.

We look forward to moving forward with the modeling on an expedited schedule. Thank you for your review and approval of these revisions.

Regards,

Terry

Terry Graumann

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

AUG 3 1 2009

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

MEMORANDUM

SUBJECT: Clarification on EPA-FLM Recommended Settings for CALMET

TO: Regional Modeling Contacts

FROM: Tyler J Fox, Group Leader
Air Quality Modeling Group, C439-01

The purpose of this memorandum is to update the draft recommendations for CALMET settings that were provided previously with the draft *Reassessment of the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report: Revisions to Phase 2 Recommendations* (EPA, 2009).

On May 15, 2009, the EPA Model Clearinghouse issued a memorandum addressing a number of issues related to the operation of the CALMET diagnostic meteorological model in regulatory modeling applications for long-range transport (LRT). Additionally, a draft version of revisions to the existing IWAQM Phase 2 guidance was released on May 27, 2009 to provide technical context for the Clearinghouse memorandum. This draft document outlined a series of recommendations for CALMET settings that were intended to facilitate the direct "pass-through" of prognostic meteorological data to the CALPUFF modeling system using the same horizontal and vertical grid structure of the parent prognostic data set. This purpose is consistent with one of our overarching goals expressed at the 8th Conference on Air Quality Modeling promoting the use of prognostic meteorological model products in regulatory dispersion modeling applications.

Due to the time sensitive nature of the Clearinghouse memorandum, it was not possible to complete extensive testing of the recommended CALMET operational settings prior to release of the memorandum and draft IWAQM reassessment report. Subsequent testing of the CALMET model with the proposed settings against mesoscale tracer databases indicates that CALMET/CALPUFF performance using the draft recommendations deteriorates somewhat in comparison to other MM5/CALMET horizontal grid configurations that were tested. Specifically, testing against the Cross-Appalachian Tracer Experiment (CAPTEX) mesoscale tracer study dataset showed that when MM5 and CALMET were run on the same horizontal grid resolution, performance was poorer than other MM5/CALMET grid configurations tested. While the performance deterioration was not drastic, it was significant. These results have caused us to reconsider our interim guidance because it is inconsistent with our desire to promote the use of both the best meteorological products and prognostic data in general. The use of

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CALMET as a vehicle to "pass-through" MM5 or other numerical weather prediction (NWP) model data is no longer considered viable.

The EPA has dedicated considerable time and resources to the evaluation of the use of NWP data in conjunction with the CALMET/CALPUFF modeling system. As discussed in the draft IWAQM reassessment report, there are technical limitations to the applicability of diagnostic wind field models that together with advances in NWP model technology and resolution make the fuller use of NWP model data an attractive alternative. The draft IWAQM reassessment document also discusses EPA's intention to transition to the full use of NWP model data rather than continue reliance upon wind fields from DWMs for LRT applications. Therefore, rather than continue to dedicate time and resources to evaluating configurations for CALMET that would facilitate a direct "pass-through" of NWP data, EPA will focus its efforts toward expediting the testing and review of its MM5/WRF-to-CALPUFF software prototype discussed at the 9th Conference on Air Quality Modeling in anticipation of an early 2010 release.

In the interim, a revised series of recommendations for CALMET settings were agreed upon during a recent meeting with modelers from EPA and the Federal Land Manager (FLM) community. Therefore, as discussed during the EPA modelers' conference call on August 19th, the EPA Model Clearinghouse is providing all of the Regional Modeling Contacts with the attached revised list of recommended switch settings for CALMET. These recommendations are based in large part upon the understanding we have developed from the numerous tracer evaluations we have conducted in addition to the collective experience of the National Park Service, Forest Service, and US Fish and Wildlife from the BART process. In general the recommendations are based upon values from the VISTAS BART modeling protocol with limited modifications based on our internal testing.

As attached, these updated recommendations supersede the recommendations from the draft IWAQM reassessment report. While the draft IWAQM recommendations intended to configure CALMET to facilitate a direct "pass-through" of MM5 data are no longer considered viable, our position regarding grid resolution presented in the May 15, 2009, Model Clearinghouse memorandum have not changed. In particular, we wish to call to your attention that in most circumstances it is considered inappropriate to consider CALMET horizontal grid resolutions of less than four (4) kilometers, consistent with our discussion in the May 15, 2009 Model Clearinghouse memorandum. It is anticipated that the FLMs will likewise require adherence to these recommendations for modeling conducted pursuant to the Class I AQRV requirements of the PSD program. In those cases, it is important to remember that the FLMs have the affirmative responsibility for AQRV related studies, and usually take the lead in negotiating the protocol for model settings (per Section 6.2.3 of the *Guideline on Air Quality Models*, Appendix W to 40 CFR Part 51).

REFERENCES

USEPA, 2009: Reassessment of the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report: Revisions to Phase 2 Recommendations (Draft). EPA- EPA-454/B-09-XXX, Research Triangle Park, NC, 56 pp.

cc: Richard Wayland
Bill Harnett
Raj Rao
Dan Deroeck
Roger Brode
Bret Anderson
John Vimont
Tim Allen
John Notar
Rick Graw

EPA-FLM Recommended CALMET Input File Values

August 28, 2009

Input Group	Subgroup	Variable	Description	Default	EPA-FLM
0 - Input and output file names	a	GEODAT	Input filename of geophysical data	GEO.DAT	User defined
		SRFDAT	Input filename of hourly meteorological data	SURF.DAT	User defined
		CLDDAT	Input filename of gridded cloud data	CLOUD.DAT	
		PRCDAT	Input filename of hourly precipitation data	PRECIP.DAT	User defined
		WTDAT	Input filename of gridded fields of terrain weighting factors	WT.DAT	
		METLST	Output filename of list file	CALMET.LST	User defined
		METDAT	Output filename of generated gridded met fields	CALMET.DAT	User defined
		PACDAT	Output filename of generated gridded met files (MESEOPUFF II)	PACOUT.DAT	
		LCFILES	Convert names to upper or lower case	User defined	T
		NUSTA	Number of upper air stations	User defined	User defined (>0)
		NOWSTA	Number of over water met stations	User defined	User defined
		NM3D	Number of MM4/MM5/3D.DAT files	User defined	User defined (>0)
		NIGF	Number of coarse grid CALMET fields as initial guess fields	User defined	0
	b	UPDAT	Input filenames of upper air data	UPn.DAT (n=1,2,3...)	User defined
	c	SEADAT	Input filename of over water stations	SEAn.DAT (n=1,2,3;..)	User defined
	d	M3DDAT	Input filename of MM4/MM5/3D.DAT	MM50n.DAT	User defined
	e	IGFDAT	Input filename of IGF-CALMET files	IGFn.DAT (n=1,2,3...)	
	f	DIADAT	Input filename of preprocessed sfc/UA data	DIAG.DAT	
		PRGDAT	Input filename of prognostic gridded wind fields	PROG.DAT	
		TSTPRT	Output filename of intermediate winds, and misc...etc	TEST.PRT	

Input Group	Subgroup	Variable	Description	Default	EPA-FLM
		TSTOUT	Output filename of final wind fields	TEST.OUT	
		TSTKIN	Output filename of wind fields after kinematic winds	TEST.KIN	
		TSTFRD	Output filename of winds after Froude Number effects	TEST.FRD	
		TSTSLP	Output filename winds after slope effects	TEST.SLP	
		DCSTGD	Output filename of distance land internal variables	DCST.GRD	
1 - General run and control parameters		IBYR	Beginning year	User defined	User defined
		IBMO	Beginning month	User defined	User defined
		IBDY	Beginning day	User defined	User defined
		IBHR	Beginning hour	User defined	User defined
		IBTZ	Base time zone	User defined	User defined
		IRLG	Length of run (hours)	User defined	User defined
		IRTYPE	Output type to create	1	1
		LCALGRD	Require fields for CALGRID	T	T
		ITEST	Flag to stop run after setup phase	2	2
		MREG	Conformity to regulatory values	User defined	1
2 - Map projection and grid control parameters		PMAP	Map projection	UTM	LCC
		FEAST	False Easting at projection origin (km)	0.0	0.0
		FNORTH	False northing at projection origin (km)	0.0	0.0
		IUTMZN	UTM zone	User defined	-999
		UTMHEM	Hemisphere of UTM projection	N	N
		RLAT0	Latitude of projection origin (decimal degrees - N)	User defined	User defined
		RLON0	Longitude of projection origin (decimal degrees - W)	User defined	User defined
		XLAT1	Matching latitude for projection (decimal degrees - N)	User defined	User defined

Input Group	Subgroup	Variable	Description	Default	EPA-FLM
		XLAT2	Matching latitude of projection (decimal degrees - N)	User defined	User defined
		Datum	Datum-region of output coordinates	WGS-84	User defined
		NX	Number of east to west or X grid cells	User defined	User defined
		NY	Number of north to south or Y grid cells	User defined	User defined
		DGRIDKM	Grid spacing in kilometers (km)	User defined	User defined (≥4km)
		XORIGKM	Southwest corner of grid cell (1,1), X-coordinate (km)	User defined	User defined
		YORIGKM	Southwest corner of grid cell (1,1), Y-coordinate (km)	User defined	User defined
		NZ	Number of vertical layers	User defined	10
		ZFACE	Cell face heights in arbitrary vertical grid (ZFACE (NZ+1)) (m)	User defined	0,20,40,80,160,320, 640,1200,2000,3000, 4000
3 - Output options		LSAVE	Save met fields in unformatted file	T	T
		IFORMO	Type of unformatted output file	1	1
		LPRINT	Print met fields	F	F
		IPRINF	Print interval in hours	1	1
		IUVOUT	Layers of U, V wind components to print (IUVOUT (NZ))	NZ*0	10*0
		IWOUT	Levels of W wind component to print (IWOUT (NZ))	NZ*0	10*0
		ITOUT	Levels of 3-D temps to print (ITOUT (NZ))	NZ*0	10*0
		STABILITY	Print PGT Stability	0	0
		USTAR	Print friction velocity	0	0
		MONIN	Print Monin-Obukhov	0	0
		MIXHT	Print mixing height	0	0
		WSTAR	Print convective velocity scale	0	0
		PRECIP	Print precipitation rate	0	0

Input Group	Subgroup	Variable	Description	Default	EPA-FLM
		SENSHEAT	Print sensible heat flux	0	0
		CONVZI	Print convective mixing height (Zic)	0	0
		LDB	Print met data and internal variables)	F	F
		NN1	Test and debug print options: first time step	1	1
		NN2	Test and debug print options: last time step	1	1
		LDBCST	Test and debug print options: distance to land internal variables	F	F
		IOUTD	Test and debug print options: control variables for writing winds	0	0
		NZPRN2	Test and debug print options: number of levels starting at sfc	1	0
		IPR0	Test and debug print options: interpolated winds	0	0
		IPR1	Test and debug print options: terrain adjusted surface wind	0	0
		IPR2	Test and debug print options: smoothed wind and diverge fields	0	0
		IPR3	Test and debug print options: final wind speed and direction	0	0
		IPR4	Test and debug print options: final divergence	0	0
		IPR5	Test and debug print options: winds after Kinematic effects	0	0
		IPR6	Test and debug print options: winds after Froude No. adjustment	0	0
		IPR7	Test and debug print options: winds after slope flow	0	0
		IPR8	Test and debug print options: final winds	0	0
4 - Meteorological data options		NOOBS	No observation mode	0	0
		NSSTA	Number of surface stations	User defined	User defined (>0)
		NPSTA	Number of precipitation stations	User defined	User defined (>0)
		ICLOUD	Gridded cloud fields	0	0
		IFORMS	Surface met data file format	2	2
		IFORMP	Precipitation data file format	2	2

Input Group	Subgroup	Variable	Description	Default	EPA-FLM
		IFORMC	Cloud data format	2	2
5 - Wind field options and parameters		IWFCOD	Wind model options	1	1
		IFRADJ	Compute Froude number adjustment effects	1	1
		IKINE	Compute Kinematic effects	0	0
		IOBR	Use O'Brien procedures for adjust vertical velocity	0	0
		ISLOPE	Compute slope effects	1	1
		IEXTRP	Extrapolate sfc wind obs to upper levels	-4	-4
		ICALM	Extrapolate sfc winds even if calm	0	0
		BIAS	Surface/upper weighting factors (BIAS (NZ))	NZ*0	10*0
		RMIN2	Minimum distance for extrapolation of winds	4	-1
		IPROG	Use prognostic model winds as input to diagnostic wind model	0	14
		ISTEPPG	Timestep (hours) of prognostic model data	1	1
		IGFMET	Use coarse CALMET fields as initial guess	0	0
		LVARY	Use varying radius of influence	F	F
		RMAX1	Maximum radius of influence in surface layer (km)	User defined	100
		RAMX2	Maximum radius of influence over land aloft (km)	User defined	200
		RMAX3	Maximum radius of influence over water (km)	User defined	200
		RMIN	Minimum radius of influence in wind field interpolation (km)	0.1	0.1
		TERRAD	Radius of influence of terrain features (km)	User defined	15
		R1	Relative weight at surface of 1st guess fields and obs (km)	User defined	50
		R2	Relative weight aloft of 1st guess fields and obs (km)	User defined	100
		RPROG	Weighting factors of prognostic wind field data (km)	User defined	0
		DIVLIM	Maximum acceptable divergence	5.0E-06	5.0E-06

Input Group	Subgroup	Variable	Description	Default	EPA-FLM
		NITER	Maximum number of iterations in divergence minimum	50	50
		NSMTH	Number of passes in smoothing (NSMITH (NZ))	2, (nxnz-1)*4	2, 9*4
		NINTR2	Maximum number of stations for interpolation (NINTR2(NZ))	99	10*99
		CRITFN	Critical Froude Number	1	1
		ALPHA	Empirical factor controlling influence of kinematic effects	0.1	0.1
		FEXTR2	Multiplicative scaling factor for extrap of sfc obs to upper layers (FEXTRS(NX))	NZ*0.0	10*0
		NBAR	Number of barriers to interpolation of wind fields	0	0
		KBAR	Level (1 to NZ) up to which barriers apply	NZ	10
		XBBAR (NBAR>0)	X coordinate of beginning of each barrier (km)	User defined	0
		YBBAR (NBAR>0)	Y coordinate of beginning of each barrier (km)	User defined	0
		XEBAR (NBAR>0)	X coordinate of ending of each barrier (km)	User defined	0
		YEBAR (NBAR>0)	Y coordinate of ending of each barrier (km)	User defined	0
		IDIOPT1	Compute surface temperature	0	0
		ISURFT [b]	Sfc met station to use for sfc temp	User defined	User defined
		IDIOPT2	Domain-averaged temp lapse rate	0	0
		IUPT (IDIOPT2=0) [b]	UA station to use for the domain-scale lapse rate	User defined	User defined
		ZUPT (IDIOPT2=0)	Depth through which domain-scale lapse rate is computed (m)	200	200
		IDIOPT3	Domain-averaged wind component	0	0
		IUPWIND (IDIOPT3=0)	UA station to use for domain-scale winds	-1	-1
		ZUPWIND (IDIOPT3=0)	Bottom and top of layer thru which domain winds computed (m)	1., 1000	1., 1000
		IDIOPT4	Read observed surface wind components	0	0
		IDIOPT5	Read observed upper wind components	0	0

Input Group	Subgroup	Variable	Description	Default	EPA-FLM
		LLBREZE	Use lake breeze module	F	F
		NBOX	Number of lake breeze regions	User defined	0
		XG1	X grid line 1 defining the region of interest	User defined	0
		XG2	X grid line 2 defining the region of interest	User defined	0
		YG1	Y grid line 1 defining the region of interest	User defined	0
		YG2	Y grid line 2 defining the region of interest	User defined	0
		XBCST	X point defining the coastline (km)	User defined	0
		YBCST	Y point defining the coastline (km)	User defined	0
		XECST	X point defining the coastline (km)	User defined	0
		YECST	Y point defining the coastline (km)	User defined	0
		NLB	Number of stations in the region (sfc + upper air)	User defined	0
		METBXID	Station ID's in the region (METBXID (NLB))	User defined	0
6 - Mixing height, temperature and precipitation parameters		CONSTB	Mix ht constant: neutral, mechanical equation	1.41	1.41
		CONSTE	Mix ht constant: convective equation	0.15	0.15
		CONSTN	Mix ht constant: stable equation	2400	2400
		CONSTW	Mix ht equation: over water	0.16	0.16
		FCORIOL	Absolute value of Coriolis parameter	1.0E-04	1.0E-04
		IAVEZI	Spatial averaging of Mix ht: conduct spatial averaging	1	1
		MNMDAV	Spatial averaging of Mix ht: Max search radius (# of grid cells)	1	1
		HAFANG	Spatial avg'n of Mix ht: 0.5-angle of upwind cone for avg (deg)	30	30
		ILEVZI	Spatial averaging of Mix ht: Layer of winds used in upwind	1	1
		IMIXH	Zic Mix Ht Options: Method to compute Mix ht	1	-1

Input Group	Subgroup	Variable	Description	Default	EPA-FLM
		THRESHL	Zic Mix Ht Options: Threshold buoyancy flux reqrd to sustain over land (W/m3)	0.05	0.0
		THRESHW	Zic Mix Ht Options: Threshold buoyancy flux reqrd sustain over water (W/m3)	0.05	0.05
		ITWPROG	Zic Mix Ht Options: Overwater lapse rates used in Zic growth	0	0
		ILUOC3D	Zic Mix Ht Options: Land use category in 3D.DAT	16	16
		DPTMIN	Min potential Temp lapse rate in stable layer above Zic (deg-K/m)	0.001	0.001
		DZZI	Depth of computing capping lapse rate (m)	200	200
		ZIMIN	Minimum over land mixing height (m)	50	50
		ZIMAX	Maximum over land mixing height (m)	3000	3000
		ZIMINW	Minimum over water mixing height (m)	50	50
		ZIMAXW	Maximum over water mixing height (m)	3000	3000
		ICOARE	Over water surface fluxes methods and parameters	10	0
		DSELF	Coastal/shallow water length scale (km)	0	0
		IWARM	COARE warm layer computation	0	0
		ICOOL	COARE cool skin layer computation	0	0
		ITPROG	3D temp from obs or from prognostic data	0	0
		IRAD	Temp interpolation type	1	1
		TRADKM	Radius of influence of temp interpolation (km)	500	500
		NUMTS	Max number of stations to include in interpolation	5	5
		IAVET	Conduct spatial averaging of temp	1	1
		TGDEFB	Default temp gradient below mix ht over water (deg-K/m)	-0.0098	-0.0098
		TGDEFA	Default temp gradient above mix ht over water (deg-K/m)	-0.0045	-0.0045

Input Group	Subgroup	Variable	Description	Default	EPA-FLM
		JWAT1	Beginning land use categories for temp interpolation over water	User defined - 999	55
		JWAT2	Ending land use categories for temp interpolation over water	User defined - 999	55
		NFLAGP	Method of precipitation interpolation	2	2
		SIGMAP	Radius of influence for precipitation (km)	100	100
		CUTP	Minimum precipitation rate cutoff (mm/hr)	0.01	.01
7 -Surface meteorolo-gical station parameters		CSNAM	Station name	User defined	User defined
		IDSSTA	Station identification number	User defined	User defined
		XSSTA	X-coordinate (km)	User defined	User defined
		YSSTA	Y-coordinate (km)	User defined	User defined
		XSTZ	Time zone	User defined	User defined
		ZANEM	Anemometer height (m)	User defined	User defined
8- Upper air meteorolo-gcal station parameters		CUNAM	Station name	User defined	
		IDUSTA	Station identification number	User defined	
		XUSTA	X-coordinate (km)	User defined	
		YUSTA	Y-coordinate (km)	User defined	
		UUTZ	Time zone	User defined	
9 - Precipitation station parameters		CPNAM	Station name	User defined	User defined
		IDPSTA	Station identification number	User defined	User defined
		XPSTA	X-coordinate (km)	User defined	User defined
		YPSTA	Y-coordinate (km)	User defined	User defined

CALMET Inputs

Variable	Description	EPA Default	WRAP Values	IWAQM 09	Big Stone	Notes
GEO.DAT	Name of Geophysical data file	GEO.DAT	GEO.DAT		GEO.DAT	WRAP
SURF.DAT	Name of Surface data file	SURF.DAT	SURF.DAT		SURF.DAT	WRAP
PRECIP.DAT	Name of Precipitation data file	PRECIP.DAT	PRECIP.DAT		PRECIP.DAT	WRAP
NUSTA	Number of upper air data sites	User Defined	0		0	WRAP
UPN.DAT	Names of NUSTA upper air data files	UPN.DAT	NA		NA	WRAP
IBYR	Beginning year	User Defines	User Defines		User Defines	Based on 12 Km MM5 data availability
IBMO	Beginning month	User Defines	User Defines		User Defines	
IBDY	Beginning day	User Defines	User Defines		User Defines	
IBHR	Beginning hour	User Defines	User Defines		User Defines	
IBTZ	Base time zone	User Defines	User Defines		User Defines	
IRLG	Number of hours to simulate	User Defines	User Defines		User Defines	
IRTYPE	Output file type to create (must be 1 for CALPUFF)	1	1		1	WRAP
LCALGRD	Are w-components and temperature needed?	T	T		T	WRAP
NX	Number of east-west grid cells	User Defines	Table 3-1		313	Domain specific based on MM5 grid spacing resolution
NY	Number of north-south grid cells	User Defines	Table 3-1		181	Domain specific based on MM5 grid spacing resolution
DGRIDKM	Grid spacing	User Defines	4		4	WRAP
XORIGKM	Southwest grid cell X coordinate	User Defines	Table 3-1		-506	Domain specific based on MM5 data
YORIGKM	Southwest grid cell Y coordinate	User Defines	Table 3-1		298	Domain specific based on MM5 data
XLATO	Southwest grid cell latitude	User Defines	Table 3-1		User Defines	Domain specific based on MM5 data
YLONO	Southwest grid cell longitude	User Defines	Table 3-1		User Defines	Domain specific based on MM5 data
IUTMZN	UTM Zone	User Defines	NA		NA	WRAP
LLCONF	When using Lambert Conformal map coordinates, rotate winds from true north to map north?	F	F		F	WRAP
XLAT1	Latitude of 1st standard parallel	30	33		33	WRAP
XLAT2	Latitude of 2nd standard parallel	60	45		45	WRAP
RLON0	Longitude used if LLCONF = T	90	97		97	WRAP
RLAT0	Latitude used if LLCONF = T	40	40		40	WRAP
NZ	Number of vertical Layers	User Defines	11	~24	~24	IWAQM 09
ZFACE	Vertical cell face heights (NZ+1 values)	User Defines	0, 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, and 5000		0, 20, 46, 72, 104, 136, 178, 220, 272, 326, 394, 460, 548, 636, 746, 860, 1002, 1152, 1336, 1534, 1774, 2040, 2358, 2720, 3154, 3656	IWAQM, based on MM5 levels
LSAVE	Save met. Data fields in an unformatted file?	T	T		T	WRAP
IFORMO	Format of unformatted file (1 for CALPUFF)	1	1		1	WRAP
NSSTA	Number of stations in SURF.DAT file	User Defines	Domain dependent, see Figure 3-1 for locations		2002 - 204 2006 - 250 2007 - 250	Domain specific
NPSTA	Number of stations in PRECIP.DAT	User Defines	Domain dependent, see Figure 3-1 for locations		2002 - 263 2006 - 267 2007 - 267	Domain specific
ICLOUD	Is cloud data to be input as gridded fields? 0=No)	0	0		0	WRAP
IFORMS	Format of surface data (2 = formatted)	2	2		2	WRAP
IFORMP	Format of precipitation data (2= formatted)	2	2		2	WRAP
IFORMC	Format of cloud data (2= formatted)	2	2		2	WRAP
IWFCOD	Generate winds by diagnostic wind module? (1 = Yes)	1	1	1	1	WRAP
IFRADJ	Adjust winds using Froude number effects? (1= Yes)	1	1	0	1	WRAP, VISTAS, Montaha, North Dakota
IKINE	Adjust winds using Kinematic effects? (1 = Yes)	0	0	0	0	WRAP
IOBR	Use O'Brien procedure for vertical winds? (0 = No)	0	0	0	0	WRAP

Variable	Description	EPA Default	WRAP Values	IWAQM 09	Big Stone	Notes
ISLOPE	Compute slope flows? (1 = Yes)	1	1	0	1	WRAP, VISTAS, Montana, North Dakota
IEXTRP	Extrapolate surface winds to upper layers? (4 = use similarity theory and ignore layer 1 of upper air station data)	-4	1	1	-4	VISTAS, Montana
ICALM	Extrapolate surface calms to upper layers? (0 = No)	0	0	0	0	WRAP
BIAS	Surface/upper-air weighting factors (NZ values)	NZ*0	NZ*0		NZ*0	WRAP
IPROG	Using prognostic or MM-FDDA data? (0 = No)	0	14	14	14	WRAP
LVARY	Use varying radius to develop surface winds?	F	F		F	WRAP
RMAX1	Max surface over-land extrapolation radius (km)	User Defines	50	0.001	25	Domain specific based on MM5 grid spacing resolution
RMAX2	Max aloft over-land extrapolations radius (km)	User Defines	100	0.001	50	Domain specific based on MM5 grid spacing resolution
RMAX3	Maximum over-water extrapolation radius (km)	User Defines	100	0.001	100	WRAP
RMIN	Minimum extrapolation radius (km)	0.1	0.1		0.1	WRAP
RMIN2	Distance (km) around an upper air site where vertical extrapolation is excluded (Set to – 1 if IEXTRP = ±4)	4	4		NA	Not relevant if not using upper air stations
TERRAD	Radius of influence of terrain features (km)	User Defines	10		10	WRAP
R1	Relative weight at surface of Step 1 field and obs	User Defines	100	0.001	12.5	R1 half of RMAX1 consistent with Montana
R2	Relative weight aloft of Step 1 field and obs	User Defines	200	0.001	25	R2 half of RMAX2 consistent with Montana
DIVLIM	Maximum acceptable divergence	5.00E-06	5.00E-06		5.00E-06	WRAP
NITER	Max number of passes in divergence minimization	50	50		50	WRAP
NSMTH	Number of passes in smoothing (NZ values)	2,4*(NZ-1)	2,4*(NZ-1)		2,4*(NZ-1)	WRAP
NINTR2	Max number of stations for interpolations (NA values)	99	99		99	WRAP
CRITFN	Critical Froude number	1	1		1	WRAP
ALPHA	Empirical factor triggering kinematic effects	0.1	0.1		0.1	WRAP
IDIOPT1	Compute temperatures from observations (0 = True)	0	0		0	WRAP
ISURFT	Surface station to use for surface temperature (between 1 and NSSTA)	User Defines	1		211	most representative
IDIOPT2	Compute domain-average lapse rates? (0 = True)	0	0		0	WRAP
IUPT	Station for lapse rates (between 1 and NUSTA)	User Defines	1		NA	Not relevant if not using upper air stations
ZUPT	Depth of domain-average lapse rate (m)	200	200		200	WRAP
IDIOPT3	Compute internally initial guess winds? (0 = True)	0	0		0	WRAP
IUPWND	Upper air station for domain winds (-1 = 1/r**2 interpolation of all stations)	-1	-1		-1	WRAP
ZUPWND	Bottom and top of layer for 1st guess winds (m)	1., 1000.	1., 1000.		1., 1000.	WRAP
IDIOPT4	Read surface winds from SURF.DAT? (0 = True)	0	0		0	WRAP
IDIOPT5	Read aloft winds from UPn.DAT? (0 = True)	0	0		0	WRAP
CONSTB	Neutral mixing height B constant	1.41	1.41		1.41	WRAP
CONSTE	Convective mixing height E constant	0.15	0.15		0.15	WRAP
CONSTN	Stable mixing height N constant	2400	2400		2400	WRAP
CONSTW	Over-water mixing height W constant	0.16	0.16		0.16	WRAP
FCORIOL	Absolute value of Carioles parameter	1.00E-04	1.00E-04		1.00E-04	WRAP
IAVEZI	Spatial averaging of mixing heights? (1 = True)	1	1		1	WRAP
MNMDAV	Max averaging radius (number of grid cells)	1	1		1	WRAP
HAFANG	Half-angle for looking upwind (degrees)	30	30		30	WRAP
ILEVZI	Layer to use in upwind averaging (between 1 and NZ)	1	1		1	WRAP
DPTMIN	Minimum capping potential temperature lapse rate	0.001	0.001		0.001	WRAP
DZZI	Depth for computing capping lapse rate (m)	200	200		200	WRAP
ZIMIN	Minimum over-land mixing height (m)	50	50		50	WRAP

Variable	Description	EPA Default	WRAP Values	IWAQM 09	Big Stone	Notes
ZIMAX	Maximum over-land mixing height (m)	3000	4500		4500	WRAP
ZIMINW	Minimum over-water mixing height (m)	50	50		50	
ZIMAXW	Maximum over-water mixing height (m)	3000	4500		4500	WRAP
IRAD	Form of temperature interpolation (1 = 1/r)	1	1		1	WRAP
TRADKM	Radius of temperature interpolation (km)	500	500		500	WRAP
NUMTS	Max number of stations in temperature interpolations	5	5		5	WRAP
IAVET	Conduct spatial averaging of temperature? (1 = True)	1	0		0	WRAP
TGDEFB	Default over-water mixed layer lapse rate (K/m)	-0.0098	-0.0098		-0.0098	WRAP
TGDEFA	Default over-water capping lapse rate (K/m)	-0.0045	-0.0045		-0.0045	WRAP
JWAT1	Beginning landuse type defining	999	51		51	WRAP
JWAT2	Ending landuse type defining water	999	55		55	WRAP
NFLAGP	Method for precipitation interpolation (2= 1/r**2)	2	2		2	WRAP
SIGMAP	Precip radius for interpolations (km)	100	100		100	WRAP
CUTP	Minimum cut off precip rate (mm/hr)	0.01	0.01		0.01	WRAP
SSn	NSSTA input records for surface stations	User Defines	Figure 3-1		2002 - 204 2006 - 250 2007 - 250	Specific to meteorology year modeled
Usn	NUSTA input records for upper-air stations	User Defines	NA		NA	WRAP
PSn	NPSTA input records for precipitations stations	User Defines	Figure 3-1		2002 - 263 2006 - 267 2007 - 267	Specific to meteorology year modeled
NOOBS		0	1	0	1	WRAP
ITWPROG	Option for overwater lapse rates used in convective mixing height growth	0			2	Addresses lack of bouy data over water
ITPROG	3D temperature from observations or from prognostic data?	0			2	Maximizes use of MM5 data

CALPUFF Inputs

Variable	Description	EPA Default	WRAP Values	IWAQM 09	Big Stone	Notes
METDAT	CALMET input data filename	CALMET.DAT	CALMET.DAT		CALMET.DAT	WRAP
PUFLST	Filename for general output from CALPUFF	CALPUFF.LST	CALPUFF.LST		CALPUFF.LST	WRAP
CONDAT	Filename for output concentration data	CONC.DAT	CONC.DAT		CONC.DAT	WRAP
DFDAT	Filename for output dry deposition fluxes	DFLX.DAT	DFLX.DAT		DFLX.DAT	WRAP
WFDAT	Filename for output wet deposition fluxes	WFLX.DAT	WFLX.DAT		WFLX.DAT	WRAP
VISDAT	Filename for output relative humidities (for visibility)	VISB.DAT	VISB.DAT		VISB.DAT	WRAP
METRUN	Do we run all periods (1) or a subset (0)?	0	0		0	WRAP
IBYR	Beginning year	User Defined	User Defined		User Defined	Based on 12 km MM5 data availability
IBMO	Beginning month	User Defined	User Defined		User Defined	
IBDY	Beginning day	User Defined	User Defined		User Defined	
IBHR	Beginning hour	User Defined	User Defined		User Defined	
IRLG	Length of runs (hours)	User Defined	User Defined		User Defined	
NSPEC	Number of species modeled (for MESOPUFF II chemistry)	5	5-9		11	Following FLM guidance on particle speciation and size to address comments
NSE	Number of species emitted	3	2-9		9	WRAP
MRESTART	Restart options (0 = no restart), allows splitting runs into smaller segments	0	2 or 3		2 or 3	WRAP
METFM	Format of input meteorology (1 = CALMET)	1	1		1	WRAP
AVET	Averaging time lateral dispersion parameters (minutes)	60	60		60	WRAP
MGAUSS	Near-field vertical distribution (1 = Gaussian)	1	1		1	WRAP
MCTADJ	Terrain adjustments to plume path (3 = Plume	3	3		3	WRAP
MCTSG	Do we have subgrid hills? (0 = No), allows CTDM-like treatment for subgrid scale hills	0	0		0	WRAP
MSLUG	Near-field puff treatment (0 = No slugs)	0	0		0	WRAP
MTRANS	Model transitional plume rise? (1 = Yes)	1	1		1	WRAP
MTIP	Treat stack tip downwash? (1 = Yes)	1	1		1	WRAP
MSHEAR	Treat vertical wind shear? (0 = No)	0	0		0	WRAP
MSPLIT	Allow puffs to split? (0 = No)	0	0		1	EPA Region 8 recommendation; necessary due to distance from source to Class I areas
MCHEM	MESOPUFF-II Chemistry? (1 = Yes)	1	1		1	WRAP
MWET	Model wet deposition? (1 = Yes)	1	1		1	WRAP
MDRY	Model dry deposition? (1 = Yes)	1	1		1	WRAP

Variable	Description	EPA Default	WRAP Values	IWAQM 09	Big Stone	Notes
MDISP	Method for dispersion coefficients (3 = PG & M	3	3		3	WRAP
MTURBVW	Turbulence characterization? (Only if MDISP =	3	3		3	WRAP
MDISP2	Backup coefficients (Only if MDISP = 1 or 5)	3	3		3	WRAP
MROUGH	Adjust PG for surface roughness? (0 = No)	0	0		0	WRAP
MPARTL	Model partial plume penetration? (0 = No)	1	1		1	WRAP
MTINV	Elevated inversion strength (0 = compute from	0	0		0	WRAP
MPDF	Use PDF for convective dispersion? (0 = No)	0	0		0	WRAP
MSGTIBL	Use TIBL module? (0 = No) allows treatment o	0	0		0	WRAP
MREG	Regulatory default checks? (1 = Yes)	1	1		1	WRAP
CSPECn	Names of species modeled (for MESOPUFF II, must be SO2, SO4, NOx, HN03, NO3)	User Defined	5		11	
Species Names	Species that will be modeled	User Defined	SO2, SO4, NOX, NO3, HNO3, PM25 (depends on emissions data provide by States)		SO2, SO4, NOX, NO3, HNO3, PM800, PM425, PM187, PM112, PM081, PM056	Following FLM guidance on particle speciation and size to address comments
Specie Groups	Grouping of species, if any.	User Defined			NA	No grouping
NX	Number of east-west grids of input meteorolog	User Defined	Table 3-1		313	Domain specific
NY	Number of north-south grids of input meteorol	User Defined	Table 3-1		181	Domain specific
NZ	Number of vertical layers of input meteorology	User Defined	11	24	24	IWAQM 09
DGRIDKM	Meteorology grid spacing (km)	User Defined	4		4	WRAP
ZFACE	Vertical cell face heights of input meteorology	User Defined	Table 3-2		User Defined	Domain specific
XORIGKM	Southwest corner (east-west) of input meteoro	User Defined	Table 3-1		User Defined	Domain specific
YORIGIM	Southwest corner (north-south) of input meteo	User Defined	Table 3-1		User Defined	Domain specific
IUTMZN	UTM zone	User Defined	NA		User Defined	Domain specific
XLAT	Latitude of center of meteorology domain	User Defined	Table 3-1		User Defined	Domain specific
XLONG	Longitude of center of meteorology domain	User Defined	Table 3-1		User Defined	Domain specific
XBTZ	Base time zone of input meteorology	User Defined	MST		User Defined	Domain specific
IBCOMP	Southwest of Xindex of computational domain	User Defined	Table 3-1		User Defined	Domain specific
JBCOMP	Southwest of Y-index of computational domain	User Defined	Table 3-1		User Defined	Domain specific
IECOMP	Northeast of Xindex of computational domain	User Defined	Table 3-1		User Defined	Domain specific
JECOMP	Northeast of Y- index of computational domain	User Defined	Table 3-1		User Defined	Domain specific
LSAMP	Use gridded receptors (T -= Yes)	F	F		F	WRAP
IBSAMP	Southwest of Xindex of receptor grid	User Defined	NA		User Defined	Domain specific
JBSAMP	Southwest of Y-index of receptor grid	User Defined	NA		User Defined	Domain specific
IESAMP	Northeast of Xindex of receptor grid	User Defined	NA		User Defined	Domain specific
JESAMP	Northeast of Y-index of receptor grid	User Defined	NA		User Defined	Domain specific
MESHDN	Gridded receptor spacing = DGRIDKM/MESHI	1	NA		NA	WRAP
ICON	Output concentrations? (1 = Yes)	1	1		1	WRAP
IDRY	Output dry deposition flux? (1 = Yes)	1	1		1	WRAP
IWET	Output wet deposition flux? (1 = Yes)	1	1		1	WRAP
IVIS	Output RH for visibility calculations (1 = Yes)	1	1		1	WRAP
LCOMPRS	Use compression option in output? (T = Yes)	T	T		T	WRAP
ICPRT	Print concentrations? (0 = No)	0	0		0	WRAP
IDPRT	Print dry deposition fluxes (0 = No)	0	0		0	WRAP
IWPRT	Print wet deposition fluxes (0 = No)	0	0		0	WRAP
ICFRQ	Concentration print interval (1 = hourly)	1	1		1	WRAP
IDFRQ	Dry deposition flux print interval (1 = hourly)	1	1		1	WRAP
IWFRQ	Wet deposition flux print interval (1 = hourly)	1	1		1	WRAP
IPRTU	Print output units (1 = g/m**3; g/m**2/s)	1	1		1	WRAP
IMESG	Status messages to screen? (1 = Yes)	1	1		1	WRAP
Output Specie	Where to output various species	User Defined	Default		Default	WRAP
LDEBUG	Turn on debug tracking? (F = No)	F	F		F	WRAP
Dry Gas Dep	Chemical parameters of gaseous deposition s	User Defined	Default		Default	WRAP
Dry Part. Dep	Chemical parameters of particulate deposition	User Defined	Default		Default	WRAP
RCUTR	Reference cuticle resistance (s/cm)	30	30		30	WRAP
RGR	Reference ground resistance (s/cm)	10	10		10	WRAP
REACTR	Reference reactivity	8	8		8	WRAP
NINT	Number of particle-size intervals	9	9		9	WRAP
IVEG	Vegetative state (1 = active and unstressed)	1	1		1	WRAP
Wet Dep	Wet deposition parameters	User Defined	TBD		Default	Default
MOZ	Ozone background? (1 = read from ozone.dat)	1	1		1	WRAP
BCKO3	Ozone default (ppb) (Use only for missing data	80	80		80	WRAP
BCKNH3	Ammonia background (ppb)	10	1		1	WRAP
RNITE1	Nighttime SO2 loss rate (%/hr)	0.2	0.2		0.2	WRAP
RNITE2	Nighttime NOx loss rate (%/hr)	2	2		2	WRAP
RNITE3	Nighttime HNO3 loss rate (%/hr)	2	2		2	WRAP
SYTDEP	Horizontal size (m) to switch to time dependen	550	550		550	WRAP
MHFTSZ	Use Heffter for vertical dispersion? (0 = No)	0	0		0	WRAP
JSUP	PG Stability class above mixed layer	5	5		5	WRAP
CONK1	Stable dispersion constant (Eq. 2.7-3)	0.01	0.01		0.01	WRAP
CONK2	Neutral dispersion constant (Eq. 2.7-4)	0.1	0.1		0.1	WRAP
TBD	Transition for downwash algorithms (0.5 = ISC	0.5	0.5		0.5	WRAP
IURB1	Beginning urban landuse type	10	10		10	WRAP
IURB2	Ending urban landuse type	19	19		19	WRAP

Appendix B

Otter Tail Power Company's Visibility Impact Analysis

DRAFT

Modeling Report for a BART Assessment of the Big Stone I Coal-Fired Power Plant, Big Stone City, South Dakota

October 2009

Prepared For:

Big Stone I
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1. INTRODUCTION

TRC Environmental Corporation has conducted a site-specific BART (Best Available Retrofit Technology) modeling assessment of the Big Stone I coal-fired power plant facility located near Milbank and Big Stone City in South Dakota to determine if this facility is subject to BART controls on emissions. This report is a modeling assessment of baseline impacts from the Big Stone I power plant facility to determine whether the Big Stone I cyclone-fired boiler is subject to BART.

On July 6, 2005 the U.S. Environmental Protection Agency (U.S. EPA) published in the Federal Register the "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations" (40 CFR Part 51). The regional haze rule requires States to submit implementation plans (SIPs) to address regional haze visibility impairment in 156 Federally-protected parks and wilderness areas, commonly referred to as "Class 1 Areas". The final rule addresses BART-eligible sources, which are defined as sources that have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were put in place between August 7, 1962 and August 7, 1977 and whose operations fall within one or more of 26 specifically listed source categories, of which Coal-Fired Power Plants are one.

In January 2009, a modeling protocol was submitted by TRC for the Big Stone I BART modeling based on the use of fine scale meteorological modeling, MM5 data and hourly surface meteorological observations. In response to comments received from Environmental Protection Agency (EPA) and the Federal Land Managers (FLMs), a revised protocol was submitted in June 2009, proposing the use of higher resolution MM5 data with the EPA-recommended modeling input parameters. Based on further discussions with EPA, the FLMs and South Dakota Department of Environment and Natural Resources (DENR), subsequent revisions were made to the June protocol on August 31, 2009. DENR approved the revised protocol in a letter dated September 18, 2009. The modeling described in this report is consistent with the DENR's approved protocol (except as noted below) and is based on the emissions data described in the June 2009 TRC protocol along with the August 2009 revisions to incorporate EPA-recommended model switch settings and meteorological configuration. The exceptions to the protocol include the use of MNITRATE=0 instead of MNITRATE=1 in POSTUTIL for the baseline runs and the use of MNITRATE=3 for a set of alternative runs. See Section 3.4 for a more detail discussion. Also, the variable IUTMZN referred to in the EPA-recommended list of variables was not assigned because that variable is not used when using a Lambert Conformal projection.

The purpose of the modeling is to assess the visibility impacts of sulfur dioxide (SO_2), particulate matter (PM) and nitrogen oxides (NO_x) emissions from the Big Stone I boiler and compare the impacts to the 0.5 change in deciview threshold at all the federally mandatory Class I areas. Since there is no Class I area within the 300 km radius usually applied, the South Dakota Department of Environment and Natural Resources requested that the Class I areas between 300 km and up to 625 km away from the Big Stone I facility sources be modeled. A total of eight Class I areas are located between these distances: two wilderness areas: Boundary Waters Canoe Area Wilderness

and Rainbow Lake Wilderness, one National Wildlife Refuge (NWR): Lostwood and five National Parks: Voyageurs NP, Theodore Roosevelt NP, Badlands NP, Wind Cave NP and Isle Royale NP. However, Rainbow Lake Wilderness is one of two Class I areas where the visibility analysis is not required (http://www.dnr.state.wi.us/org/aw/air/modeling/ psd.htm), so it is not included in the modeling analysis. The MM5 datasets distributed by WRAP did not extend far enough in the East to include the Isle Royale NP or cover all of the Boundary Waters Class I area. The re-extracted MM5 data for 2002 and new MM5 domains for 2006 and 2007 include these areas.

The CALMET and CALPUFF non-steady-state models (Scire et al., 2000a,b) are recommended by the U.S. EPA (*Federal Register*, 6 July 2005) to perform source-specific subject-to-BART screening. The CALPUFF system was therefore used for this modeling analysis. The U.S. EPA has promulgated the CALPUFF modeling system as a *Guideline Model* for Class I impact assessments and other long range transport applications or near field applications involving complex flows (U.S. EPA, 2000), and the model is recommended by both the Federal Land Managers (FLM) Air Quality Workgroup (FLAG, 2000) and the Interagency Workgroup on Air Quality Modeling (IWAQM, 1998). The CALPUFF modeling system is also recommended in new proposed guidance by the FLMs (FLAG, 2008). On August 31, 2009 EPA issued new recommendations on CALMET switch settings. The current modeling is based on the August 2009 recommendations.

The Big Stone I BART modeling analysis was performed with the EPA-approved Version 5.8 of the CALMET and CALPUFF models. Version 6.221 of CALPOST was used because it contains the FLM-approved implementation of Method 8 (FLAG, 2008), but in other respects is identical to the EPA-approved Version 5.6394.

CALMET is a diagnostic meteorological model that produces three-dimensional wind fields based on parameterized treatments of terrain effects such as slope flows and terrain blocking effects. Normally, meteorological observations are blended with gridded data from the NCAR-PSU Mesoscale Model, Version 5 (MM5). For this evaluation, MM5 data were generated by TRC with a 12-km grid spacing for two years (2006 and 2007) to define the initial guess wind fields. For 2002, 12-km MM5 data were re-extracted from the EPA MM5 dataset to cover entire region including the Isle Royale NP to the east.

CALPUFF is a non-steady-state puff dispersion model. It accounts for spatial changes in the CALMET-produced meteorological fields, variability in surface conditions (elevation, surface roughness, vegetation type, etc.), chemical transformation, wet removal due to rain and snow, dry deposition, and terrain influences on plume interaction with the surface. CALPUFF contains a module to compute visibility effects, based on a humidity-dependent relationship between particulate matter concentrations and light extinction, as well as wet and dry acid deposition fluxes. The meteorological and dispersion modeling simulations were conducted for three years (2002, 2006 and 2007). SO_2, SO_4, PM, and NO_x, emissions and their secondary products resulting from chemical conversions from the Big Stone I facility were modeled and their impacts on visibility evaluated at receptors in the Class I areas. Visibility impacts were estimated with the new

FLM-recommended visibility algorithm and monthly average relative humidity adjustment factors (Method 8 in Version 6.221).

This report outlines the techniques and data sources used in the BART analyses. In Section 2, a general description of the source configuration is provided. Descriptions of the site characteristics and data bases (meteorological, geophysical, and aerometric) are provided in Section 3. Section 4 includes an overview of the CALMET and CALPUFF models settings and parameters that were used in the analysis. The results are summarized in Section 5.

2. SOURCE DESCRIPTION

The 450-megawatt Big Stone I facility is a coal-fired power plant situated close to Big Stone City and Milbank in Grant County, South Dakota, at the border of Minnesota State. A BART applicability analysis was completed for the facility to determine those sources subject to the BART controls. The BART-eligible source is the Big Stone I cyclone-fired boiler with one stack 152 meters (498 feet) high.

The proposed emissions for the BART analysis were described in a Modeling Protocol dated June 2009. These emissions were reviewed and approved by SD DENR. Table 2-1 shows the source parameters and emission rates for the source considered in this report. The highest 24-hour average actual emission rates of SO_2, NO_x and PM under normal conditions over the 2001-2003 period were used for this analysis. As shown in Table 2-2, the filterable PM_{10} are divided into a particle size distribution based on AP-42, Table 1.1-6 for baghouse controlled emissions because the facility currently uses a fabric filter for PM control. Approximately 57.6% of the filterable mass is in the fine ($PM_{2.5}$) size category, and 42.4% in the coarse (2.5 to 10 µm diameter) size range. Each of the particle size categories was modeled as a separate PM species in CALPUFF. The filterable PM_{10} emission rate is reported by the facility at 10.48 g/s (83.2 lb/hr). Based on AP-42 Table 1.1-5, the total condensable PM_{10} is approximately 0.01 lb/mmBtu based on approximately 0.4% sulfur coal or 7.07 g/sec (56.1 lb/hr) assuming an heat input of 5609 mmBtu/hr. This estimate is consistent with the stack test data (August, 2006) at Otter Tail Power's Hoot Lake Plant, Unit 2, (which burns PRB coal) where the ratio of the filterable/total PM_{10} was 0.66, resulting in a 2/3 filterable and 1/3 condensable split to the total PM_{10}.[1]

Elemental Carbon (EC) emissions were assumed to be 3.7% of the fine filterable fraction based on U.S. EPA (2002) and were assigned to the smallest particle size category. The primary H_2SO_4 emissions are 0.454 g/s (3.604 lb/hr) based on annual emission inventories and Toxic Release Inventory reports. The remaining condensable emissions were assigned to organic carbon and distributed equally into the two smallest particle size categories.

Table 2-3 provides a summary of the PM_{10} speciation and size distribution.

Note that since all Class I areas are more than 50 km away from the facility, as recommended by the Federal Land Managers (FLMs) (US Fish and Wildlife, National Park Service and U.S. Forest Service), no downwash computations was performed.

[1] AP-42 Table 1.1-8 was not used to estimate the particulate matter size distribution for Big Stone I because the emission factors were derived for cyclones burning bituminous coal, not sub-bituminous coal which is burned at Big Stone I.

Table 2-1: Point Source Parameters and Emission Rates

Source	LCC[1] East (km)	LCC[1] North (km)	Stack Ht (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp. (K)	SO_2 Emission Rate (g/s)	H_2SO_4 Emission Rate (g/s)	NO_x Emission Rate (g/s)	Filterable PM_{10} Emission Rate (g/s)	Condensable PM_{10} Emission Rate (g/s)
Main Stack	38.141	587.875	151.79	328.90	7.37	20.14	423.00	608.9	0.454	611.7	10.48	7.07

[1] Lambert Conformal Projection with an origin of 40.0N, 97.0W and standard parallels at 33N and 45N. Datum is NWS-84.

Table 2-2: PM_{10} Size Distribution1

Particle Size[2] (µm)	Cumulative Mass (PM) (%)	Cumulative Mass (PM_{10}) (%)
15	97	-
10	92	100
6	77	83.7
2.5	53	57.6
1.25	31	33.7
1.00	25	27.2

1 From AP-42, Table 1.1-6, Cumulative particle size distribution and size-specific emission factors for dry bottom boilers burning pulverized bituminous and subbituminous coal.

2 Expressed as aerodynamic equivalent diameter.

Table 2-3: PM_{10} Speciation and Size Distribution

input Data:							H_2SO_4	**PM_{10}**	$PM_{2.5}$			
							g/s	**g/s**	g/s			
PM_{10} and H_2SO_4 Emissions (g/s)							0.454	**17.550**	13.106			
	filterable								**condensable**			
condensable %	**59.7%**								**40.3%**			
				g/s						g/s		
	10.480								7.070			
									non H_2SO_4 condensable			
										g/s		
									6.616			
	AP-42, Table 1.1-6											
	coarse	coarse	soil	soil	soil	soil	EC	H_2SO_4	OC	OC	IC (soil)	IC (soil)
	PM800	PM425	PM187	PM112	PM081	PM056	PM056		PM081	PM056	PM081	PM056
	6.00 - 10.00	2.50-6.00	1.25-2.50	1.00-1.25	0.625-1.00	0.50-0.625	0.50-0.625		0.625-1.00	0.50-0.625	0.625-1.00	0.50-0.625
	16.3%	26.1%	23.9%	6.5%	12.0%	15.2%	57.6%		50.0%	50.0%	50.0%	50.0%
EC % of filterable			**96.3%**				**3.7%**		**100%**		**0%**	
inorganic % of	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s		
condensable	1.708	2.735	2.412	0.656	1.211	1.534	0.223	0.454	3.308	3.308		
	inputs to POSTUTIL:											
Extinction coefficient	0.6	0.6	1	1	1	1	10	3*f(RH)	4	4		
	coarse	**coarse**	**soil**	**soil**	**soil**	**soil**	**EC**	**H_2SO_4**	**OC**	**OC**		
	PM800	**PM425**	**PM187**	**PM112**	**PM081**	**PM056**	**PM056**		**PM081**	**PM056**		
	g/s	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**		
	1.708	**2.735**	**2.412**	**0.656**	**1.211**	**1.534**	**0.223**	**0.454**	**3.308**	**3.308**		

3. GEOPHYSICAL AND METEOROLOGICAL DATA

The South Dakota Department of Environment and Natural Resources requested that the eight Class I areas shown in Figure 3-1 be considered in the BART analysis. Rainbow Lake Wilderness is one of two Class I areas where the visibility analysis is not required so it has been removed from the present analysis (see http://www.dnr.state.wi.us/org/aw/air/modeling/psd.htm). The MM5 dataset for this analysis were extended to include the Isle Royale National Park as well as all of the Boundary Waters Class I area.

3.1 Terrain

The topography of the domain area consists of terrain increasing toward the southwest from approximately 300 meters at the facility to 900 meters at Badlands NP and 1200 meters at Wind Cave NP, resulting in 900 meters (~3,000 feet) of terrain relief. The terrain relief also increases towards the northeast. The terrain gets mountainous on the west side of the facility near Badlands and Wind Cave National Parks.

Gridded terrain elevations for the refined modeling domain were derived from 3 arc-second digital elevation models (DEMs) produced by the United States Geological Survey (USGS). Data are provided in files covering 1 degree by 1 degree blocks of latitude and longitude. The 1-degree DEMs are produced by the Defense Mapping Agency using cartographic and photographic sources. USGS 1:250,000 scale topographic maps are the primary source of 1-degree DEMs.

One degree DEM data consists of an array of 1201 by 1201 elevations referenced on the geographic (latitude/longitude) coordinate system of the World Geodetic System 1972 Datum. Elevations are in meters relative to mean sea level, and the spacing of the elevations along each profile is 3 arc-seconds, which corresponds to a spacing of approximately 90 meters. For the North part of the east domain and north west domain covering the south side of Manitoba and Ontario, Canada, SRTM-3 data with also an approximate resolution of 90 meters were used.

The MM5 simulations conducted at 12-km grid spacing covering the modeling domain were used as initial guess field. CALMET was run at the 4-km resolution.

The USGS elevation records located within each grid cell in the computational domain are averaged to produce a mean elevation at each grid point. The CALPUFF computational domain is the same as the CALMET domain. The CALMET and CALPUFF domains extend at least 50 km beyond the Class I areas in order to provide an adequate buffer zone at the boundaries, and to allow the effects of flow curvature and possible small-scale recirculation to be evaluated.

3.2 Land Use

The Composite Theme Grid (CTG) land use data from the USGS, at a resolution of approximately 90m were processed to produce gridded fields of dominant land use categories for each grid cell. For the northern part of the domain covering Canada (south part of Manitoba and Ontario), 900 meters Global USGS land use data were also incorporated using a mesh density for sampling of 2.

Land use data are first processed to produce fractional land use categories. The 37 USGS land use categories are then mapped into 14 CALMET land use categories. Surface properties such as albedo, Bowen ratio, roughness length, and leaf area index are computed proportionally to the fractional land use. The USGS land use categories are described in Table 3-1. Table 3-2 displays the 14 CALMET land use categories and their associated geophysical parameters. Figure 3-2 shows the dominant land use categories used in the modeling.

3.3 Meteorological Data Base

The CALMET model has the ability to assimilate meteorological information from surface stations, precipitation stations, buoy data and upper air stations. Specifically, CALMET uses surface observations of wind speed, wind direction, temperature, cloud cover, ceiling height, surface pressure, relative humidity, and precipitation type (e.g., snow, rain, etc.). These variables are routinely measured at the National Weather Service (NWS) surface stations and were directly included on an hourly basis into CALMET. Upper air observations however are only available twice-daily at a few stations throughout the domain. The locations of the upper air stations in and around the region of interest, and used in the modeling, are displayed in Figure 3-3.

The surface, buoy and precipitation stations that were included in the modeling are displayed in Figure 3-4. For 2002, there are 272 surface stations, 2 buoys and 265 precipitation stations available with similar numbers in 2006 and 2007. Observed cloud cover and ceiling height from the surface meteorological stations were used in the analysis.

The three-dimensional gridded data from the prognostic numerical model MM5 with nested grids of 36-km, 12-km grid spacing were generated by TRC for 2006 and 2007. Information about the MM5 model configuration and an evaluation of model performance are provided in Appendix B.

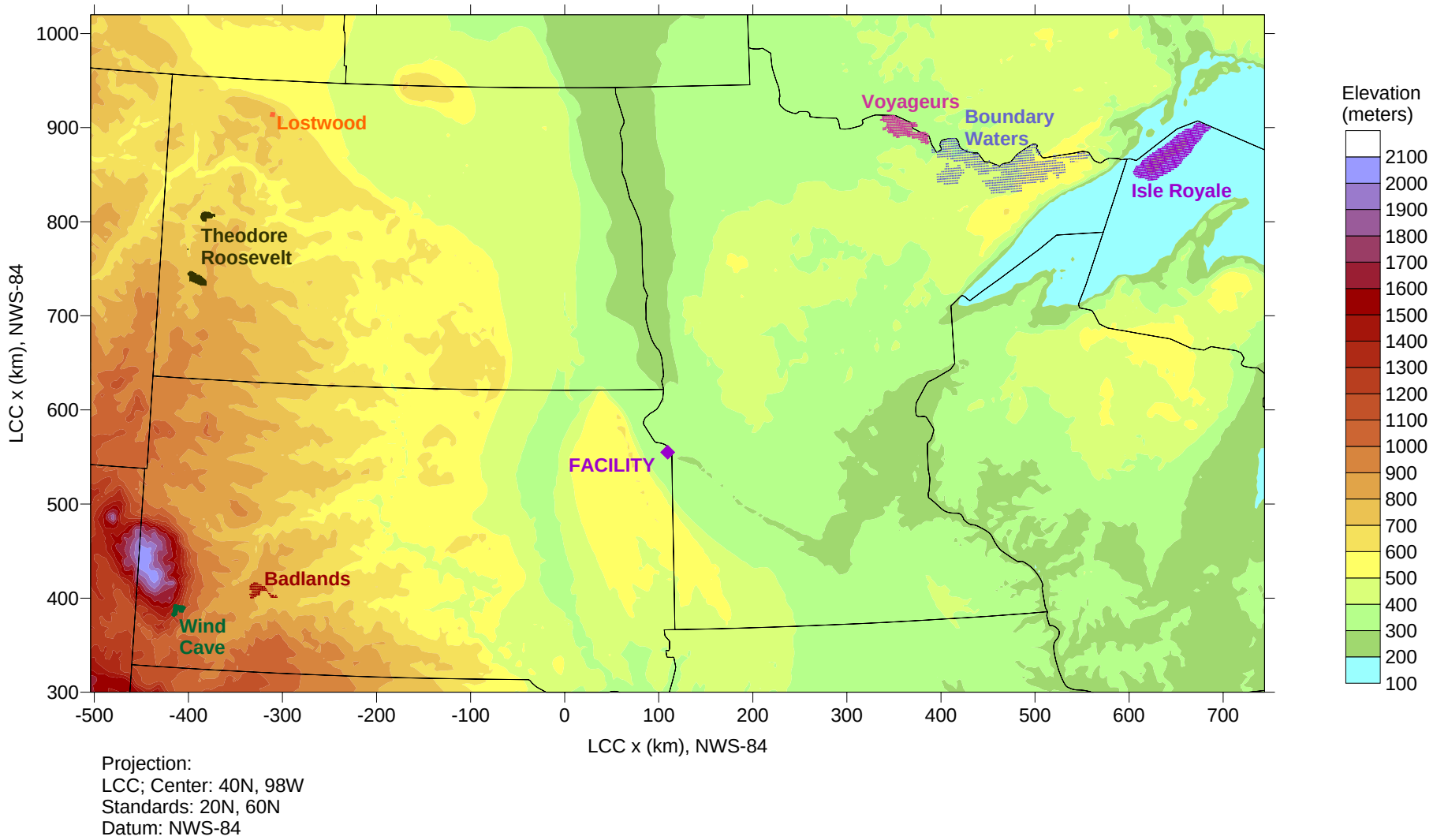

Figure 3-1. Terrain elevations for the CALMET and CALPUFF modeling domain at 4 km resolution. The locations of the Big Stone facility and Class I areas are also shown.

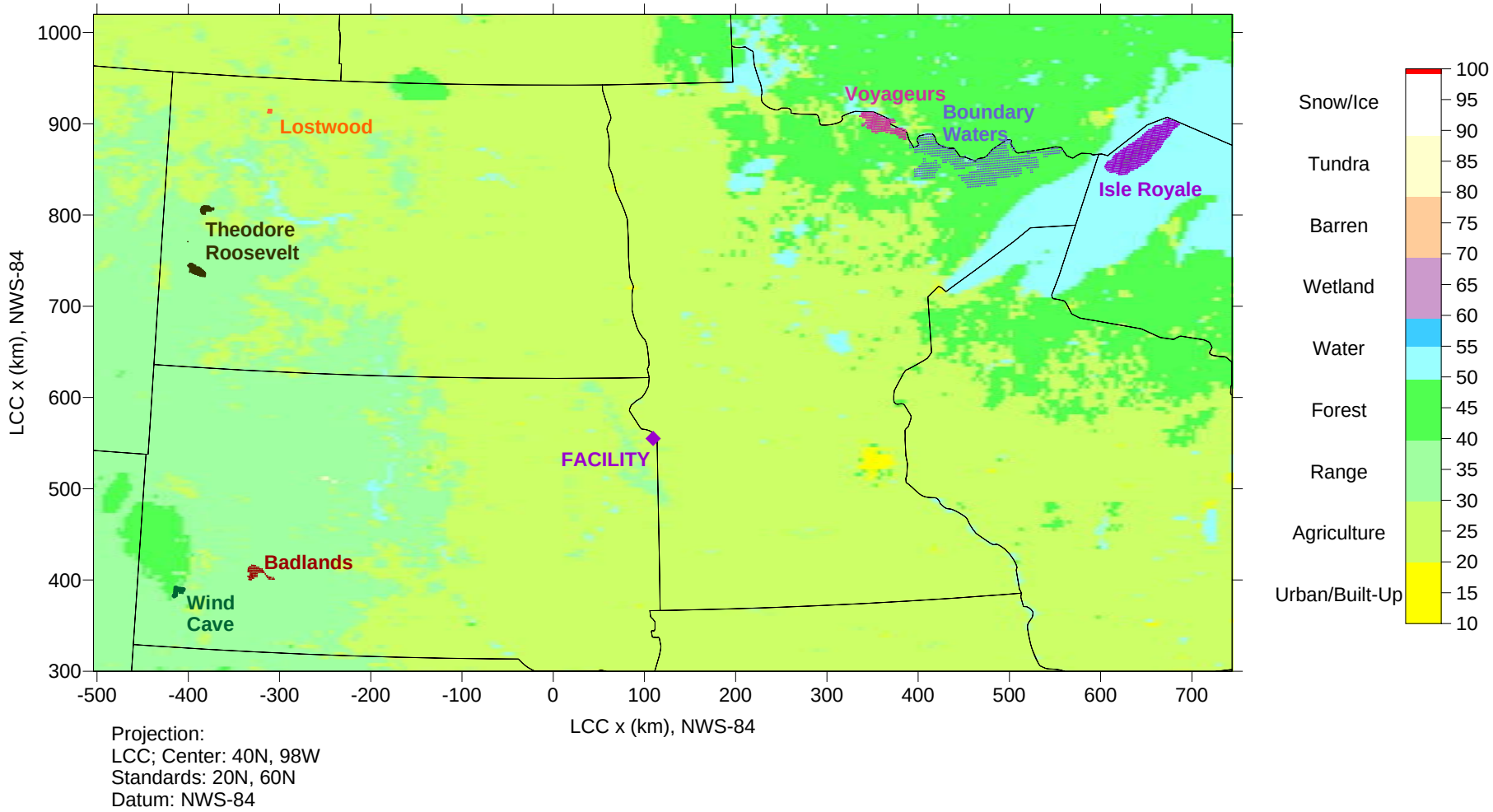

Figure 3-2. Dominant land use categories at 4 km resolution on the CALMET and CALPUFF modeling domains. The locations of the Big Stone facility and Class I areas are also shown.

Table 3-1: U.S. Geological Survey Land Use and Land Cover Classification System

	Level I		Level II
10	Urban or Built-up Land	11	Residential
		12	Commercial and Services
		13	Industrial
		14	Transportation, Communications and Utilities
		15	Industrial and Commercial Complexes
		16	Mixed Urban or Built-up Land
		17	Other Urban or Built-up Land
20	Agricultural Land	21	Cropland and Pasture
		22	Orchards, Groves, Vineyards, Nurseries, and Ornamental Horticultural Areas
		23	Confined Feeding Operations
		24	Other Agricultural Land
30	Rangeland	31	Herbaceous Rangeland
		32	Shrub and Brush Rangeland
		33	Mixed Rangeland
40	Forest Land	41	Deciduous Forest Land
		42	Evergreen Forest Land
		43	Mixed Forest Land
50	Water	51	Streams and Canals
		52	Lakes
		53	Reservoirs
		54	Bays and Estuaries
		55	Oceans and Seas
60	Wetland	61	Forested Wetland
		62	Non-Forested Wetland
70	Barren Land	71	Dry Salt Flats
		72	Beaches
		73	Sandy Areas Other than Beaches
		74	Bare Exposed Rock
		75	Strip Mines, Quarries, and Gravel Pits
		76	Transitional Areas
		77	Mixed Barren Land
80	Tundra	81	Shrub and Brush Tundra
		82	Herbaceous Tundra
		83	Bare Ground
		84	Wet Tundra
		85	Mixed Tundra
90	Perennial Snow or Ice	91	Perennial Snowfields
		92	Glaciers

Table 3-2. Default CALMET Land Use Categories and Associated Geophysical Parameters based on the U.S. Geological Survey Land Use Classification System (14-Category System)

Land Use Type	Description	Surface Roughness (m)	Albedo	Bowen Ratio	Soil Heat Flux Parameter	Anthropogenic Heat Flux (W/m^2)	Leaf Area Index
10	Urban or Built-up Land	1.0	0.18	1.5	.25	0.0	0.2
20	Agricultural Land - Unirrigated	0.25	0.15	1.0	.15	0.0	3.0
-20*	Agricultural Land - Irrigated	0.25	0.15	0.5	.15	0.0	3.0
30	Rangeland	0.05	0.25	1.0	.15	0.0	0.5
40	Forest Land	1.0	0.10	1.0	.15	0.0	7.0
50	Water	0.001	0.10	0.0	1.0	0.0	0.0
54	Small Water Body	0.001	0.10	0.0	1.0	0.0	0.0
55	Large Water Body	0.001	0.10	0.0	1.0	0.0	0.0
60	Wetland	1.0	0.10	0.5	.25	0.0	2.0
61	Forested Wetland	1.0	0.1	0.5	0.25	0.0	2.0
62	Nonforested Wetland	0.2	0.1	0.1	0.25	0.0	1.0
70	Barren Land	0.05	0.30	1.0	.15	0.0	0.05
80	Tundra	.20	0.30	0.5	.15	0.0	0.0
90	Perennial Snow or Ice	.05	0.70	0.5	.15	0.0	0.0

* Negative values indicate "irrigated" land use

Table 3-3. Meteorological Data Sources and Parameters Available

Type of Dataset	Frequency	Source	Parameters available
Surface Observations	Hourly	NWS	Wind speed, wind direction, temperature, ceiling height, cloud cover, relative humidity, surface pressure, precipitation type
Upper Air	Twice-daily	NWS/NCDC	Soundings of wind speed, wind direction, temperature, and pressure
Precipitation Observations	Hourly	NWS	Precipitation rate
Buoy	Hourly	NWS/NCDC	Air-sea surface temperature difference, air temperature, relative humidity, overwater mixing height, temperature lapse rate below the mixing height overwater, temperature lapse rate above the mixing height overwater, wind speed, wind direction, dominant wave period, significant wave height
Modeled Profiles MM5 for 2002, 2006 and 2007	Hourly	EPA – 2002 TRC - 2006, 2007	Hourly, gridded fields of winds, temperature, pressure, and humidity and liquid water content on 12-km grid.

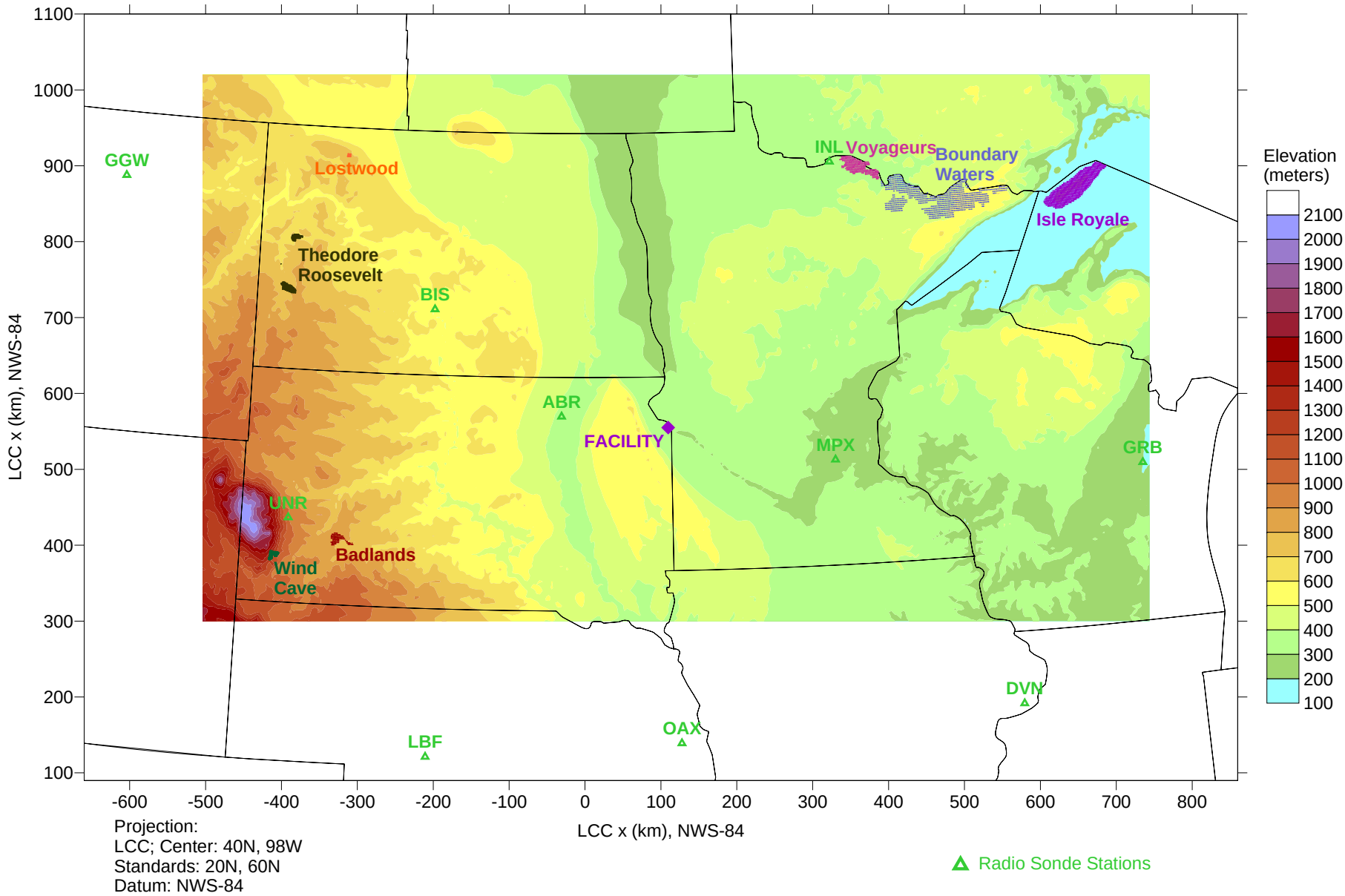

Figure 3-3. Plot of upper air stations available in the modeling domain.

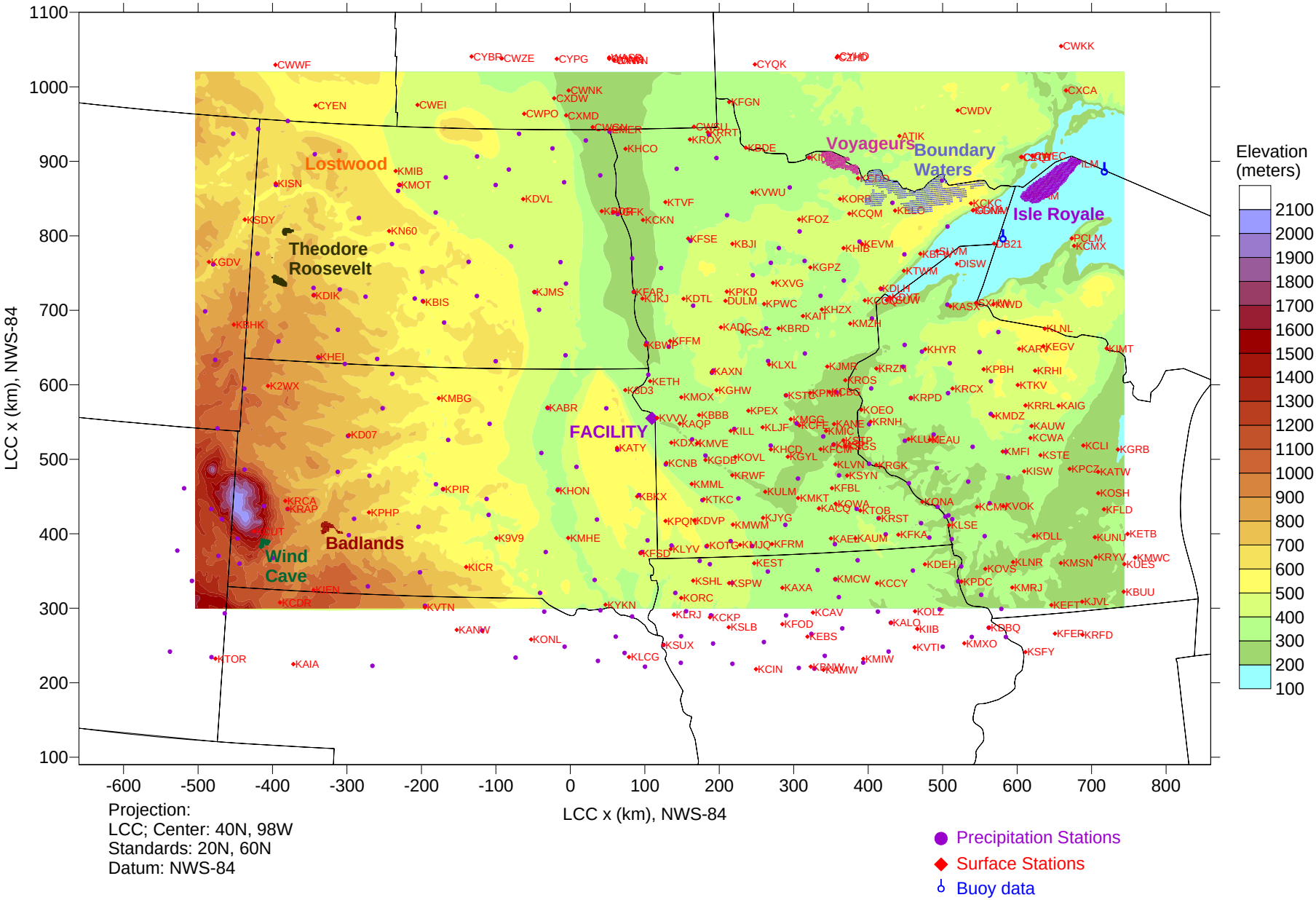

Figure 3-4. Plot of surface and precipitation stations available in the modeling domain.

3.4 Air Quality Monitoring Data

CALPUFF used hourly ozone concentration measurements in the chemical transformation rates (SO_2 to SO_4, NO_x to HNO_3/NO_3). The ambient ozone measurements are used in determining SO_2 loss rates due to chemical transformation to sulfate and in determining NO_x loss rates to nitrate. Ambient ozone hourly concentrations from EPA AIRS and CASTNet networks for 2002, 2006 and 2007 were processed into OZONE.DAT files and used as ozone background in CALPUFF. An 80 parts per billion (ppb) concentration was used as backup when hourly ozone concentrations are missing, which given the number of ozone stations was unlikely to be used.

A constant background ammonia concentration of 1 parts per billion (ppb) as recommended by the FLMs and EPA was used in the CALPUFF runs. No additional repartitioning was done on the nitrate concentrations in the base simulations (MNITRATE=0). This may produce some double-counting of ammonia in the calculation of nitrate, but any differences are likely to be small.

Additional postprocessing was conducted using POSTUTIL for an alternative case based on the full ammonia limiting method (MNITRATE=3) using background monthly average sulfate, total nitrate and total ammonia data from the 2002 CMAQ model. This option accounts for both overlapping puffs from the modeled source as well as spatial and monthly variability of ammonia and background sulfate and nitrate from sources not included in the CALPUFF simulations. The results from these simulations are also presented in Section 5.

4. AIR QUALITY MODELING OPTIONS

4.1 Modeling Domain

CALMET and CALPUFF use terrain-following coordinates. In order to cover a large enough area for the refined analysis covering all seven Class I areas within a single domain, and including a buffer of at least 50 km around each Class I area, the domain dimensions of 1250 km x 720 km were used. For a 4-km grid spacing, this amounts to 313 x 181 grid cells. In the vertical, a stretched grid was used with finer resolution in the lower layers and somewhat coarser resolution aloft thus allowing adequate representation of the mixed layer. The ten vertical levels were centered at: 10, 30, 60, 120, 240, 480, 920, 1600, 2500 and 3500 meters.

CALMET and CALPUFF were run for three years, 2002, 2006 and 2007. A network of discrete receptors derived from the list of receptors developed by the National Park Service (NPS) are located within the boundaries of the seven Class I areas modeled: Boundary Waters Canoe Area Wilderness, Voyageurs National Park, Badlands National Park, Wind Cave National Park, Lostwood National Wildlife Refuge, Theodore Roosevelt National Park and Isle Royale National Park.

4.2 Meteorological Modeling Options

4-km Simulation. EPA-approved Version 5.8 Level 070623 of CALMET was run using the recommended switch settings from U.S. EPA (2009). This includes using the regulatory set of options, including Maul-Carson convective mixing height over land only (IMIXH= - 1), OCD delta-T method for overwater fluxes (ICOARE=0), and no convective heat flux threshold overland (THRESHL= 0 W/m^3). These values of IMIXH, ICOARE and THRESHL, differ from the settings in the CALMET input files provided for sources located in South Dakota state on the WRAP Regional Modeling Center web page http://pah.cert.ucr.edu/aqm/308/bart.shtml, but follow regulatory guidance set by EPA. In addition, NOOBS was set to 0 in this application rather than 1 as in the WRAP CALMET inputs.

Initial Guess Field

MM5 data were used to define the initial guess field for the CALMET simulations (IPROG=14). For all three years hourly MM5 data with a grid spacing of 12 km were used in the modeling. The CALMET horizontal grid spacing was set to 4 km.

CALMET runs were conducted using the traditional model options including diagnostic adjustments for terrain effects, with the typical 2:1 ratio of RMAX1/R1 and RMAX2/R2. In these simulations RMAX1=100 km, RMAX2=200 km, R1=50 km and R2=100 km were used. This is consistent with the U.S. EPA (2009) recommendations. NOOBS=0 was used in the 4-km simulations. Precipitation rates were determined based on precipitation station measurements. Cloud amount and ceiling height were derived from the surface station measurements. Overwater air-sea temperature difference were derived from the buoy data (ITWPROG=0). Three-dimensional temperature fields were determined from surface and upper air observations (ITPROG=0).

Step 1 Field: Terrain Effects

In developing the Step 1 wind field, CALMET adjusts the initial guess field to terrain effects, including slope flows and blocking effects. Slope flows are a function of the local slope and altitude of the nearest crest. The crest is defined as the highest peak within a radius TERRAD around each grid point. A value of TERRAD of 15 km was used in the CALMET simulations as it is recommended by the U.S. EPA (2009) and in agreement with an analysis of the scale of the terrain. The Step 1 field produces a flow field consistent with the fine-scale CALMET terrain resolution (4 km).

Step 2 Field: Objective Analysis

In Step 2, observations are incorporated into the Step 1 wind field to produce a final wind field. Each observation site influences the final wind field within a radius of influence (parameters RMAX1 at the surface, RMAX2 aloft and RMAX3 over water). Observations and Step 1 wind fields are weighted by means of parameters R1 at the surface and R2 aloft: at a distance R1 from an observation site, the Step 1 wind field and the surface observations are weighted equally. As noted above, RMAX1/R1 and RMAX2/R2 are set with 2:1 ratio. Vertical extrapolation for the surface meteorological stations was activated (IEXTRP=-4), which is in agreement with the U.S. EPA (2009) recommendations. This setting insures that the surface observations, vertically extrapolated within the boundary layer, are blended with the MM5-based Step 1 field aloft.

4.2 Dispersion Modeling Options

CALPUFF simulations was conducted generally following the WRAP Protocol 2006 guidance, but with the EPA-approved Version 5.8 Level 070623 rather than Version 6 of the model. List of options used in the modeling includes:

- Gaussian near-field vertical distribution
- Partial plume path adjustment method for terrain
- Transitional plume rise modeled
- Partial plume penetration of elevated inversion option activated
- Stack tip downwash
- MESOPUFF II scheme for the chemical transformation
- Pasquill-Gifford (PG) dispersion coefficients (rural areas) and McElroy-Pooler coefficients (urban areas) used to compute dispersion coefficients. The probability density function (PDF) for convective conditions not used because this is available only with the turbulence-based dispersion option.
- Transition of σ_y to time-dependent (Heffter) growth rates set to 550 meters
- The switch for using Heffter equation for sigma z not activated
- PG sigma-y, z adjustment for roughness not selected
- Puff splitting (MSPLIT=1) activated
- Wet deposition, dry deposition applied
- The minimum turbulence velocities sigma-v for each stability class set to 0.5 m/s over land and 0.37 m/s over water.

The CALPUFF computational grid is the same as the meteorological grid. The modeling domain includes a buffer zone of 50 km around the source area and beyond the borders of the Class I areas. This minimizes edge effects and allows pollutants involved in flow reversals to be brought back into the Class I areas. Note that the CALMET modeling domain from previous studies was extended to include the Isle Royale National Park.

Two important computational parameters in CALPUFF are XMXLEN (maximum length of an emitted puff, in grid units) and XSAMLEN (maximum travel distance of a puff, in grid units, during one time step). Both of these variables were set to 1.0 in the CALPUFF simulations in order to allow the strong wind channeling effects to be accounted for in the puff trajectory calculations. The first parameter ensures that the length of an emitted puff does not become so large so that it cannot respond to changes in the wind field on the scale of the meteorological grid. The model automatically increases the frequency of puff releases to ensure the length of a single puff is not larger than the grid size. The second parameter decreases the internal time step to ensure the travel distance during one time step does not exceed the grid size.

The partial plume path adjustment option was used in CALPUFF for this analysis (MCTADJ=3). The CALMET wind field incorporates the effect of the terrain on the plume trajectories. The plume path coefficient was used to characterize the local effect on ground-level concentrations. The default plume path coefficients (PPC) was used for this analysis as listed below:

Stability Class	A	B	C	D	E	F
PPC	0.5	0.5	0.5	0.5	0.35	0.35

Deposition and chemical transformation effects were modeled using the default dry deposition model, the scavenging coefficient wet removal module, and the default chemical transformation mechanism.

A total of five chemically active species were modeled with CALPUFF for this analysis: SO_2, SO_4, NO_x, HNO_3 and NO_3., The chemical mechanism computes transformation rates of SO_2 to SO_4 and NO_x to NO_3/HNO_3. Hourly measured ozone concentrations were provided in an external file for use with the chemical transformation module. These ozone concentrations, along with radiation intensity, are used as surrogates for the OH concentration during the day when the gas phase free radical chemistry is active.

Six additional PM_{10} species were modeled corresponding to the midpoint of each particle size bin shown in Table 2-2. The fine, coarse, elemental carbon and organic carbon species were constructed in postprocessing steps using the POSTUTIL program from these six PM species according to the appropriate size weights for size bin as discussed in Section 2.

4.3 Visibility Calculations

Calculations of the impact of the simulated plume particulate matter component concentrations on light extinction were carried out with the CALPOST postprocessor following the new proposed FLAG (2008) guidance. The original IMPROVE/EPA equation (1) described below was recommended to determine the change in light extinction due to changes in component concentrations. Using the notations of CALPOST:

$$B_{ext} = 3f(RH)[(NH_4)2SO_4] + 3f(RH)[NH_4NO_3] + 4[OC] + 1[Soil] + 0.6[Coarse\ Mass] + 10[EC] + b_{ray} \quad (1)$$

The concentrations, in square brackets, are in μg/m^3 and b_{ext} is in units of Mm^{-1}.

But a revised new IMPROVE algorithm to compute the extinction (1/Mm) has been developed by the IMPROVE steering committee for estimating light extinction from particulate matter as described in equation (2) below. This algorithm provides a better correspondence between the measured visibility and that calculated from particulate matter component concentrations (Tombach, 2006):

$$\begin{aligned} b_{ext} = {} & 2.2 f_S(RH) \bullet [small\ sulfate] + 4.8 f_L(RH) \bullet [large\ sulfate] \\ & + 2.4 f_S(RH) \bullet [small\ nitrate] + 5.1 f_L(RH) \bullet [large\ nitrate] \\ & + 2.8 \bullet [small\ organics] + 6.1 \bullet [large\ organics] \\ & + 10 \bullet [elemental\ carbon] \\ & + 1 \bullet [fine\ soil] \\ & + 1.7 f_{SS}(RH) \bullet [sea\ salt] \\ & + 0.6 \bullet [coarse\ matter] \\ & + Rayleigh\ scattering\ (site-specific) \\ & + 0.17 \bullet [NO_2] \end{aligned} \quad (2)$$

All of the brackets [] denote concentrations in μg/m^3.

In CALPOST, the new IMPROVE algorithm as proposed by FLAG (2008) is implemented as CALPOST Method 8. The implementation of this method in CALPOST is described in more details in Appendix A. The proposed FLAG (2008) methodology is included in CALPOST V6.221 Level 080724, which has been reviewed and approved by the FLMs. This version of CALPOST is publicly available on the TRC's CALPUFF website (http://www.src.com/calpuff/calpuff1.htm) and was used for this analysis.

The Rayleigh scattering term (b_{ray}) is site-specific and computed as a function of the elevation as shown in Table 4-1, following FLAG (2008) guidance. Note that organic carbon (OC), which consists of condensable particulates and elemental carbon (EC) for soot particulates were modeled along with fine and coarse particulate matter as described in Section 2.

To represent background natural conditions, monthly background concentrations must be entered into the CALPOST input control file for all aerosols defining the background. The WRAP Protocol (2006) recommendations for natural conditions background are to use all three types of EPA default Natural Conditions: Best 20% Days, Annual Average and Worst 20% Days. In "Guidance for Estimating Visibility Conditions Under the Regional Haze Rule" (EPA, 2003), these three default values are defined only by their extinction coefficient in Mm^{-1}. For CALPOST Method 8, explicit background concentrations are required to allow the computation of the small and large sulfate particulates, nitrate particulates and organic carbon. So, in this analysis, the annual averaged background conditions were used to define the natural background for each of the seven Class I areas, following FLAG (2008). The concentrations used as background for each of the seven Class I areas are summarized in Table 4-2.

These concentrations were used to compute the natural background light extinction following the revised IMPROVE formulae described above, for each of the Class I areas.

Tables 4-3, 4-4, and 4-5, provide the monthly f(RH) values for each of the seven Class I areas, that are used to compute extinction coefficients for hygroscopic species, respectively for small ammonium sulfate and ammonium nitrate particles, large ammonium sulfate and ammonium nitrate particles, and sea salt particles.

The 8th highest (98th percentile) predicted light extinction change for each year modeled was compared to the threshold value of 0.5 deciview.

Table 4-1. Rayleigh Scattering Term (Mm^{-1}) for each Class I area as a Function of Elevation

Class I Area	Highest Elevation in feet (meters)	Rayleigh Scattering Term (Mm^{-1})
Boundary Waters Canoe Area Wilderness	1998.0 (609)	11
Voyageurs NP	1335.3 (407)	12
Badlands NP	3031.5 (924)	11
Wind Cave NP	4796.6 (1462)	10
Lostwood NWR	2427.8 (740)	11
Theodore Roosevelt NP	2900.3 (884)	11
Isle Royale NP	1325.5 (404)	11

Source: FLAG (2008)

Table 4-2. Annual Averaged Conditions Levels of Aerosol Components ($\mu g/m^3$) to Define Natural Background (FLAG 2008) – Method 8 values per Class I Area

Class I Area	SO_4	NO_3	OC	EC	Soil	Coarse Mass
Boundary Waters Canoe Area Wilderness	0.23	0.10	1.71	0.02	0.31	2.53
Voyageurs NP	0.23	0.10	1.75	0.02	0.26	2.73
Badlands NP	0.12	0.10	0.60	0.02	0.50	3.00
Wind Cave NP	0.12	0.10	0.60	0.02	0.49	2.98
Lostwood NWR	0.12	0.10	0.60	0.02	0.50	3.00
Theodore Roosevelt NP	0.12	0.10	0.60	0.02	0.50	3.00
Isle Royale NP	0.23	0.10	1.55	0.02	0.24	2.89

Source: FLAG (2008)

Table 4-3. Monthly Site-Specific RH adjustment factors f(RH) values for hygroscopic species – Small ammonium sulfate and ammonium nitrate particles - Method 8 (FLAG, 2008)

Class I area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Boundary Waters CAW	3.23	2.81	2.93	2.63	2.89	3.22	3.44	3.71	3.83	3.08	3.49	3.49
Voyageurs NP	3.16	2.77	2.82	2.59	2.65	3.28	3.25	3.48	3.66	3.02	3.37	3.32
Badlands NP	2.94	2.96	3.01	2.87	3.10	2.91	2.64	2.59	2.56	2.58	3.11	2.98
Wind Cave NP	2.81	2.81	2.86	2.82	3.06	2.81	2.50	2.46	2.44	2.52	2.97	2.83
Lostwood NWR	3.21	3.15	3.36	2.60	2.54	2.86	2.89	2.60	2.53	2.72	3.60	3.52
Theodore Roosevelt NP	3.17	3.11	3.22	2.71	2.74	2.85	2.73	2.49	2.48	2.66	3.42	3.37
Isle Royale NP	3.26	2.74	2.87	2.58	2.46	3.00	3.59	3.68	3.92	2.88	3.72	3.67

Source: FLAG (2008)

Table 4-4. Monthly Site-Specific RH adjustment factors f(RH) values for hygroscopic species – Large ammonium sulfate and ammonium nitrate particles – Method 8 (FLAG, 2008)

Class I area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Boundary Waters CAW	2.50	2.25	2.28	2.09	2.20	2.43	2.57	2.71	2.78	2.38	2.64	2.64
Voyageurs NP	2.46	2.22	2.22	2.07	2.09	2.46	2.46	2.59	2.70	2.35	2.58	2.55
Badlands NP	2.31	2.31	2.31	2.21	2.34	2.25	2.08	2.05	2.02	2.05	2.38	2.33
Wind Cave NP	2.23	2.22	2.22	2.18	2.32	2.18	2.00	1.97	1.95	2.00	2.30	2.24
Lostwood NWR	2.51	2.45	2.54	2.06	2.03	2.21	2.23	2.05	2.02	2.13	2.69	2.67
Theodore Roosevelt NP	2.47	2.42	2.45	2.12	2.14	2.21	2.14	1.99	1.99	2.10	2.58	2.57
Isle Royale NP	2.53	2.21	2.26	2.07	1.99	2.32	2.65	2.69	2.82	2.28	2.76	2.74

Source: FLAG (2008)

Table 4-5. Monthly Site-Specific RH adjustment factors f(RH) values for hygroscopic species – Sea salt particles - Method 8 (FLAG, 2008)

Class I area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Boundary Waters CAW	3.73	3.35	3.29	2.91	3.00	3.44	3.68	3.88	3.98	3.45	3.89	3.91
Voyageurs NP	3.69	3.31	3.20	2.90	2.89	3.46	3.55	3.71	3.87	3.42	3.83	3.80
Badlands NP	3.37	3.33	3.27	3.05	3.25	3.15	2.89	2.81	2.74	2.82	3.41	3.38
Wind Cave NP	3.25	3.20	3.13	3.01	3.22	3.06	2.75	2.68	2.63	2.75	3.28	3.24
Lostwood NWR	3.77	3.66	3.67	2.86	2.79	3.07	3.11	2.82	2.80	2.99	3.93	3.95
Theodore Roosevelt NP	3.67	3.56	3.51	2.93	2.97	3.09	2.96	2.72	2.72	2.93	3.75	3.78
Isle Royale NP	3.78	3.34	3.28	2.93	2.78	3.31	3.83	3.87	4.06	3.40	4.05	4.04

Source: FLAG (2008)

5. RESULTS

The results for the BART analysis for the Big Stone I facility are presented in this section. The analysis consists of evaluating the visibility impact (percent change in light extinction due to the sources measured in deciview) at all the Class I areas modeled. The results for the base case are presented in three tables, each table gathering the impact at seven Class I areas for each of the years modeled: Table 5-1 for 2002, Table 5-2 for 2006 and Table 5-3 for 2007. The change in light extinction due to the source is compared to the annual average natural background light extinction. The interpretation of the results is done by comparing the 98th percentile of Delta deciview for each year to the 0.5 delta deciview threshold. Analysis is performed by using CALPOST Method 8.

Ammonia Limiting Method (ALM) with CMAQ 2002 monthly averages as background was performed as well. These results are presented in Tables 5-4 through 5-6.

Table 5-1. Visibility impacts for 2002. Constant (1 ppb) ammonia.

Park	Max Delta Deciview	4th Highest (99%)	8th Highest (98%)	Nb. Exceed. > 5%	Nb. Exceed. > 10%
Boundary Waters	1.315	0.837	**0.574**	14	1
Voyageurs	2.162	0.690	**0.623**	9	3
Wind Cave	0.873	0.475	0.305	3	0
Theodore Roosevelt	1.390	0.555	0.215	4	1
Lostwood National	0.564	0.388	0.232	2	0
Badlands	0.762	0.671	0.452	7	0
Isle Royale	1.182	0.789	**0.629**	10	2

Table 5-2. Visibility impacts for 2006. Constant (1 ppb) ammonia.

Park	Max Delta Deciview	4th Highest (99%)	8th Highest (98%)	Nb. Exceed. > 5%	Nb. Exceed. > 10%
Boundary Waters	2.572	1.183	**0.790**	16	5
Voyageurs	1.578	0.862	**0.574**	11	2
Wind Cave	0.454	0.302	0.120	0	0
Theodore Roosevelt	2.232	0.772	0.459	6	3
Lostwood National	1.110	0.662	0.385	5	1
Badlands	1.002	0.519	0.481	7	1
Isle Royale	1.806	0.635	**0.506**	8	2

Table 5-3. Visibility impacts for 2007. Constant (1 ppb) ammonia.

Park	Max Delta Deciview	4th Highest (99%)	8th Highest (98%)	Nb. Exceed. > 5%	Nb. Exceed. > 10%
Boundary Waters	3.574	1.351	**1.079**	25	9
Voyageurs	2.062	1.376	**0.724**	19	5
Wind Cave	1.671	0.591	0.325	4	2
Theodore Roosevelt	0.744	0.491	0.322	3	0
Lostwood National	0.959	0.722	0.409	6	0
Badlands	2.202	0.698	0.471	6	2
Isle Royale	1.224	0.745	**0.665**	13	2

Table 5-4. Visibility impacts with ALM considered for 2002.

Park	Max Delta Deciview	4th Highest (99%)	8th Highest (98%)	Nb. Exceed. > 5%	Nb. Exceed. > 10%
Boundary Waters	0.740	0.491	0.389	3	0
Voyageurs	1.256	0.546	0.380	4	1
Wind Cave	0.725	0.435	0.275	3	0
Theodore Roosevelt	1.355	0.472	0.181	2	1
Lostwood National	0.510	0.298	0.198	1	0
Badlands	0.714	0.617	0.422	7	0
Isle Royale	0.661	0.560	0.350	4	0

Table 5-5. Visibility impacts with ALM considered for 2006.

Park	Max Delta Deciview	4th Highest (99%)	8th Highest (98%)	Nb. Exceed. > 5%	Nb. Exceed. > 10%
Boundary Waters	1.439	0.830	**0.550**	10	3
Voyageurs	1.150	0.540	0.391	5	1
Wind Cave	0.319	0.191	0.111	0	0
Theodore Roosevelt	1.280	0.606	0.367	5	1
Lostwood National	0.673	0.521	0.377	4	0
Badlands	0.917	0.477	0.269	3	0
Isle Royale	0.805	0.467	0.352	1	0

Table 5-6. Visibility impacts with ALM considered for 2007.

Park	Max Delta Deciview	4th Highest (99%)	8th Highest (98%)	Nb. Exceed. > 5%	Nb. Exceed. > 10%
Boundary Waters	1.530	0.786	**0.654**	13	2
Voyageurs	1.357	0.714	**0.553**	9	1
Wind Cave	0.713	0.427	0.276	3	0
Theodore Roosevelt	0.724	0.388	0.278	2	0
Lostwood National	0.934	0.563	0.353	4	0
Badlands	1.042	0.571	0.353	5	1
Isle Royale	0.793	0.551	0.486	7	0

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APPENDIX A

CALPOST VISIBILITY METHOD 8

The revised visibility algorithm developed for the IMPROVE Steering Committee (IMPROVE 2005) as recommended by FLAG (2008) has been implemented in CALPOST. It differs from the previous IMPROVE algorithm as used in Method 2 and Method 6 in six areas:

- Extinction efficiencies of sulfates, nitrates, and organics vary with concentration, as there are distinct efficiencies for "small" and "large" particles and the ratio of small-to-large particle fraction decreases as the concentration increases. Furthermore, the extinction efficiency for sulfates no longer equals that for nitrates.
- A separate hygroscopic humidity enhancement factor curve is prescribed for "small" and "large" particles, $f_S(RH)$ and $f_L(RH)$. These curves apply to sulfates and nitrates.
- Light extinction due to scattering by sea salt (with its own hygroscopic humidity enhancement factor $f_{SS}(RH)$) is included.
- Light absorption by NO_2 gas is included in the extinction.
- Background particulate organic matter concentration is taken to be 1.8 times measured organic carbon concentrations.
- Rayleigh scattering extinction varies with site elevation and mean temperature.

Items 5 and 6 remain direct inputs to CALPOST, and required no structural changes to the postprocessor. The user must confirm that appropriate values are provided.

Item 4, the introduction of light extinction due to NO_2 gas absorption, has been added to CALPOST as a discrete component independent of the visibility method chosen. New control file inputs associated with NO_2 in the recommended FLAG (2008) mode are:

```
Source of NO2 when ASPEC=NO2 (above) or LVNO2=T (Group 2) may be
from CALPUFF NO2 concentrations OR from a fraction of CALPUFF NOx
concentrations.  Specify the fraction of NOx that is treated as NO2
either as a constant or as a table of fractions that depend on the
magnitude of the NOx concentration:
                       (NO2CALC) -- Default: 1   ! NO2CALC =   1  !
   0 =  Use NO2 directly (NO2 must be in file)
   1 =  Specify a single NO2/NOx ratio (RNO2NOX)
   2 =  Specify a table NO2/NOx ratios (TNO2NOX)
        (NOTE: Scaling Factors must NOT be used with NO2CALC=2)

Single NO2/NOx ratio (0.0 to 1.0) for treating some
or all NOx as NO2, where [NO2] = [NOX] * RNO2NOX
(used only if NO2CALC = 1)
                       (RNO2NOX) -- Default: 1.0 ! RNO2NOX = 1.0 !
```

Items 1 through 3 are implemented as visibility Method 8 in CALPOST, along with the specific choice of the new f(RH) curves. Selection of the revised IMPROVE algorithm requires the following new control file selections:

```
Particle growth curve f(RH) for hygroscopic species
                            (MFRH) -- Default: 2   ! MFRH   = 4  !
     1 =  IWAQM (1998) f(RH) curve (originally used with MVISBK=1)
     2 =  FLAG (2000) f(RH) tabulation
     3 =  EPA (2003) f(RH) tabulation
     4 =  IMPROVE (2006) f(RH) tabulations for sea salt, and for
          small and large SULFATE and NITRATE particles;
          Used with Visibility Method 8 (MVISBK = 8)

Method used for background light extinction
                          (MVISBK) -- Default: 2   ! MVISBK =  8  !
     1 =  Supply single light extinction and hygroscopic fraction
     2 =  Compute extinction from speciated PM measurements (A)
     3 =  Compute extinction from speciated PM measurements (B)
     4 =  Read hourly transmissometer background extinction measurements
     5 =  Read hourly nephelometer background extinction measurements
     6 =  Compute extinction from speciated PM measurements
     7 =  Use observed weather or prognostic weather information for
          background extinction during weather events; otherwise, Method 2
     8 =  Compute extinction from speciated PM measurements using the
          IMPROVE (2006) variable extinction efficiency formulation
          (MFRH must be set to 4)
          - Split between small and large particle concentrations of
            SULFATES, NITRATES, and ORGANICS is a function of concentration
            and different extinction efficiencies are used for each
          - Source-induced change in visibility includes the increase in
            extinction of the background aerosol due to the change in the
            extinction efficiency that now depends on total concentration.
          - Fsmall(RH) and Flarge(RH) adjustments for small and large
            particles are applied to observed and modeled sulfate and
            nitrate concentrations
          - Fsalt(RH) adjustment for sea salt is applied to background
            sea salt concentrations
          - F(RH) factors are capped at F(RHMAX)
          - RH for Fsmall(RH), Flarge(RH), and Fsalt(RH) may be obtained
            from hourly data as in Method 2 or from the FLAG monthly RH
            adjustment factor used for Method 6 where EPA F(RH) tabulation
            is used to infer RH, or monthly Fsmall, Flarge, and Fsalt RH
            adjustment factors can be directly entered. Furthermore, a
            monthly RH factor may be applied to either hourly
            concentrations or daily concentrations to obtain the 24-hour
            extinction.

            These choices are made using the M8_MODE selection.
```

```
    Additional inputs used for MVISBK = 8:
    --------------------------------------
Extinction coefficients for hygroscopic species (modeled and
background) may be computed using hourly RH values and hourly
modeled concentrations, or using monthly RH values inferred from
the RHFAC adjustment factors and either hourly or daily modeled
concentrations, or using monthly RHFSML, RHFLRG, and RHFSEA adjustment
factors and either hourly or daily modeled concentrations.

     (M8_MODE) -- Default: 5     ! M8_MODE=  5   !
                  FLAG (2008)

          1 = Use hourly RH values from VISB.DAT file with hourly
              modeled and monthly background concentrations.
          2 = Use monthly RH from monthly RHFAC and EPA (2003) f(RH)
              tabulation with hourly modeled and monthly background
              concentrations.
                            (VISB.DAT file is NOT needed).
          3 = Use monthly RH from monthly RHFAC with EPA (2003) f(RH)
              tabulation with daily modeled and monthly background
              concentrations.
                            (VISB.DAT file is NOT needed).
          4 = Use monthly RHFSML, RHFLRG, and RHFSEA with hourly modeled and
              monthly background concentrations.
                            (VISB.DAT file is NOT needed).
          5 = Use monthly RHFSML, RHFLRG, and RHFSEA with daily modeled
              and monthly background concentrations.
                            (VISB.DAT file is NOT needed).
```

The last of these selections, M8_MODE, provides options for how concentrations are averaged, and how the relative humidity enhancement factors for hygroscopic species are determined. M8_MODE has a default value of 5, which is consistent with the new FLAG (2008) guidance

APPENDIX B

MM5 MODEL CONFIGURATION

MM5 Domain Configuration (36-km, 12-km Resolution)

The Fifth Generation Penn State University/NCAR Mesoscale Model (MM5) (Dudhia et al, 2000) has been run for 2006 and 2007 for North America for two domains: a coarse Domain 1 (36-km resolution), and a nested Domain 2 (12-km resolution). The Lambert Conical Conformal (LCC) mapping projection is used in modeling. The center of the coordinate system is located at the center of Domain 1 at 40°N and 98°W. Two standard latitudes of LCC are set to 20°N and 60°N. The coarse domain (Domain 1) covers an area of 7488 km in the west-east (X) direction by 6768 km in the south-north (Y) direction with grid spacing of 36 km (Table B-1). Figure B-1 shows Modeling Domains 1 and 2.

There are forty-one sigma levels in the vertical direction from the surface up to 100 hPa (Table B-2). The first sigma level is about 11 m above the ground, very close to the anemometer height at operational weather stations. The vertical spatial resolution varies from the surface to the model top. About twenty levels are below 1500 m above the ground for better resolving the atmospheric boundary layer in the model.

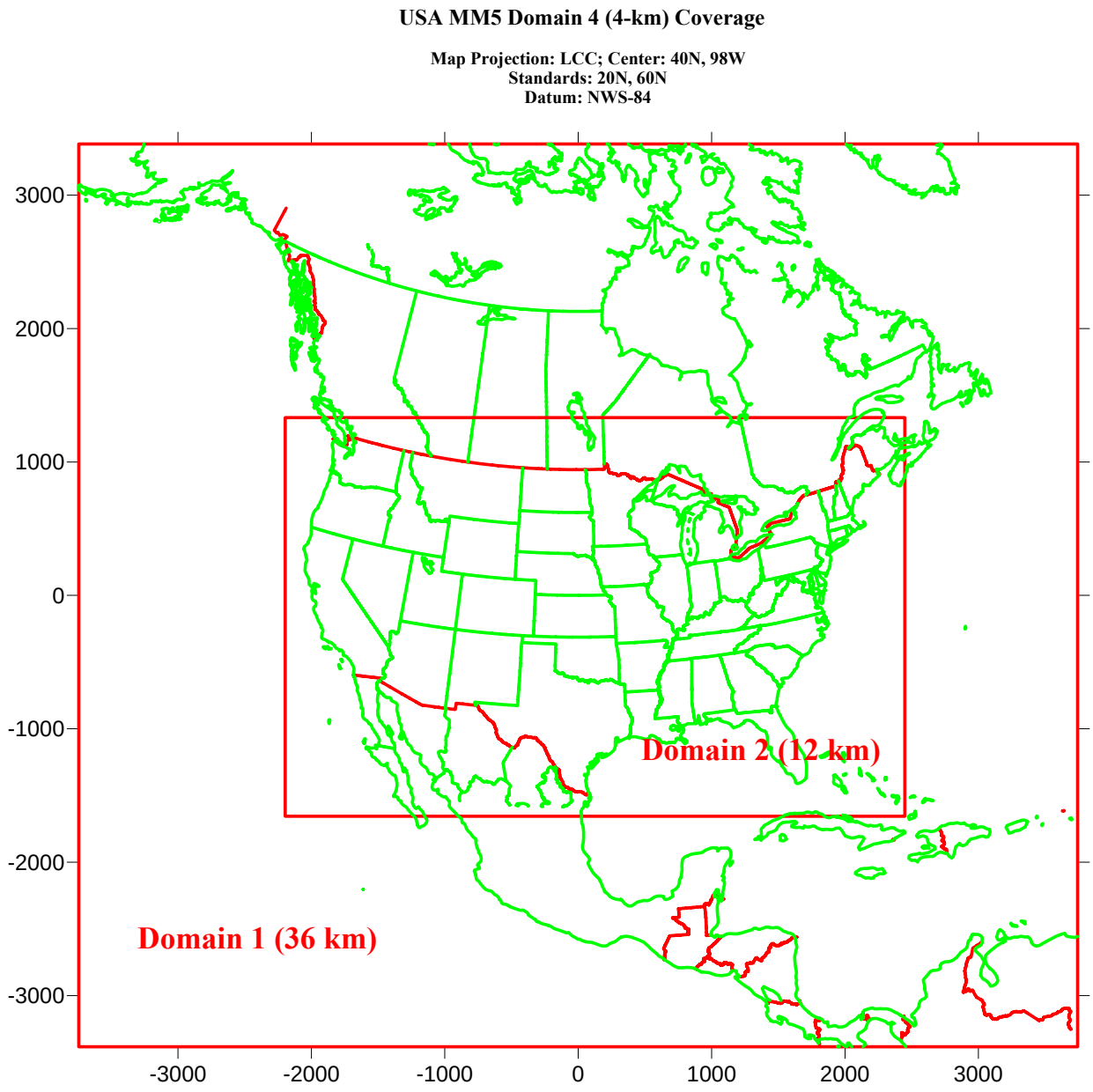
Model Parameterizations and Schemes

The MM5 model was run for 2006 and 2007 in the non-hydrostatic mode using the upper radiative boundary condition. MM5 physical schemes and parameterizations are listed in Table B-1. The Reisner graupel scheme was used for the explicit moisture parameterization. It predicts all five water contents in the atmosphere. This scheme includes additional equation to predict graupel. It is a more computationally expensive scheme compared with simple ice scheme. The cumulus scheme used in MM5 is the Kain-Fritsch 2 scheme (Kain, 2004). This scheme includes shallow convection. For planetary boundary layer (PBL) scheme, the Mellor-Yamada scheme used in the ETA model (Janjic, 1990, 1994) was used in this MM5 modeling. This scheme was implemented in the NCEP MRF model. It is efficient and suitable for high-resolution PBL. The Rapid Radiative Transfer Model was used for the radiation scheme in both Domains (Mlawer et al., 1997). This scheme is a highly accurate and efficient method developed by AER Inc. Multiple-layer soil temperatures were computed using the NOAH land surface model (National Centers for Environmental Prediction, Oregon State University, Air Force, and Hydrologic Research Laboratory). Additional geographical data, such as soil types, vegetation fraction, and annual deep soil temperatures are needed for the land surface model; and these data were obtained from NCAR.

One way nesting is used in the MM5 simulation, meaning that the mother domain is not affected by its child-domain. Such nesting allows adding new domains later without re-running all the other domains. Analysis Four Dimensional Data Assimilation (FDDA) was applied to both Domain 1 and Domain 2.

Table B-1 Domain Configuration and Parameterizations for 2006 and 2007 MM5 Simulations. The Lambert Conical Conformal (LCC) map projection is used in the MM5 modeling.

Settings	Domain 1	Domain 2
Grid number	209 x 189	388 x 250
Grid size (km)	36	12
Nesting	NA	One-way
Sigma levels	41	41
Moisture	Reisner 2	Reisner 2
Cumulus	Kain-Fritsch 2	Kain-Fritsch 2
Boundary layer	ETA	ETA
Radiation	RRTM	RRTM
Soil model	NOAH LSM	NOAH LSM
FDDA	3D and Surface Analysis	3D and Surface Analysis
Run Length	2.5 days	2.5 days
Spin-up time	12 hours	12 hours
Terrain and land-use data	USGS 10-minute (~19 km)	USGS 5-minute (~9 km)



MM5 Domains:
D1: X: -3744 - 3744 km, Y: -3384 - 3384 km; dxy= 36 km; 209 x 189 i1= 1,j1= 1
D2: X: -2196 - 2448 km, Y: -1656 - 1332 km; dxy= 12 km; 388 x 250 i1= 44,j1= 49

D3: X: -612 - 864 km, Y: -48 - 1080 km; dxy= 4 km; 370 x 283 i1=133,j1=135

Figure B-1. Map showing the MM5 Domain 1 (36-km) and Domain 2 (12-km).

Table B-2. Sigma Levels used in the North American MM5 Simulations for 2006 and 2007.

Level	Sigma	Half Sigma	Ref. Pressure (mb)	Height (m)
surface	1.0000	-	1010.0	0.0
1	0.9970	0.9985	1008.6	10.9
2	0.9936	0.9953	1005.7	34.1
3	0.9898	0.9917	1002.4	60.3
4	0.9856	0.9877	998.8	89.6
5	0.9808	0.9832	994.7	122.5
6	0.9754	0.9781	990.1	160.0
7	0.9694	0.9724	984.9	202.1
8	0.9626	0.9660	979.1	249.6
9	0.9549	0.9588	972.5	303.7
10	0.9463	0.9506	965.0	364.8
11	0.9367	0.9415	956.8	433.5
12	0.9258	0.9313	947.4	511.5
13	0.9136	0.9197	936.9	600.1
14	0.8999	0.9068	925.1	700.4
15	0.8845	0.8922	911.9	814.4
16	0.8672	0.8759	897.0	944.1
17	0.8477	0.8575	880.3	1092.1
18	0.8258	0.8368	861.4	1261.5
19	0.8012	0.8135	840.3	1455.3
20	0.7736	0.7874	816.5	1677.7
21	0.7425	0.7581	789.8	1934.1
22	0.7076	0.7251	759.8	2230.9
23	0.6683	0.6880	726.0	2576.1
24	0.6242	0.6463	688.1	2980.0
25	0.5746	0.5994	645.5	3455.7
26	0.5188	0.5467	597.5	4021.9
27	0.4688	0.4938	549.4	4628.0
28	0.4284	0.4486	508.2	5180.4
29	0.3879	0.4082	471.4	5705.6
30	0.3474	0.3677	434.6	6265.0
31	0.3065	0.3270	397.5	6866.0
32	0.2620	0.2843	358.7	7545.5
33	0.2175	0.2398	318.2	8317.4
34	0.1675	0.1925	275.2	9224.7
35	0.1175	0.1425	229.7	10311.2
36	0.0783	0.0979	189.1	11426.7
37	0.0588	0.0686	162.4	12261.6
38	0.0392	0.0490	144.6	12875.1
39	0.0196	0.0294	126.8	13547.3
40	0.0000	0.0098	108.9	14290.2

Initial Data and Simulation

MM5 is initialized using the 1° x 1° Final Analysis (FNL) data from NCEP at NCAR. It is an improvement of the original 2.5-degree by 2.5-degree dataset. The FNL data were archived at NCAR with temporal resolution of six hours at the surface and 26 standard pressure levels under 10 hPa: 1000, 975, 950, 925, 900, 850, 800, 750, 700, 650, 600, 550, 500, 450, 400, 350, 300, 250, 200, 150, 100, 70, 50, 30, 20, and 10 hPa. The dataset includes two-dimensional variables of snow cover, sea surface temperature (SST), sea level pressure, and three-dimensional variables of temperature, geopotential height, U and V components, and relative humidity.

The SST spatial resolution of 1° x 1° in FNL data is too coarse in the coastal area. To improve SST in MM5, a better SST dataset, the daily 4-km MODIS SSTs, is ingested into the simulation. The MODIS (MODerate Resolution Imaging Spectroradiometer) SSTs are derived from the sensors onboard the NASA Terra and Aqua platforms. The MODIS SSTs include from both the sensors of mid-infrared (IR) and thermal IR channels. The product used in the simulation is the MODIS Global Level 3 Mapped mid-IR SSTs.

MM5 is run for 2.5-day periods with 12 hours for spin-up time. The initial FNL data are model output and already in the dynamically-consistent state. The spin-up time of 12 hours is enough to allow MM5 reach dynamical balance in its domains. The 2.5-day simulation length can reduce the divergence between forecasts and analyses. MM5 output covers the period from 2005123112 to 2007010111, so that any conversion between local and UTC times can be properly processed. There are 183 2.5-day simulations in total for the annual period.

Evaluation of model performance

The MM5 model output dataset was evaluated using observations from hourly and synoptic surface data available from the US National Climatic Data Center (NCDC) in Asheville, North Carolina. The locations of the stations used in the evaluation are shown in Figure 3-4. The statistical index used for the evaluation is the Index of Agreement (IOA) is defined as:

$$IOA = 1 - \left[\frac{IJ.RMSE^2}{\sum_{j=1}^{J} \sum_{i=1}^{I} \left| P_j^i - M_o \right| + \left| O_j^i - M_o \right|} \right] \tag{1}$$

where RMSE is the Root Mean Square Error, and calculated using the equation

$$RMSE = \left[\frac{i}{IJ} \sum_{j=1}^{J} \sum_{i=1}^{I} (P_j^i - O_j^i)^2 \right]^{1/2} \tag{2}$$

P_j^i and O_j^i are the prediction and the observation at Station *j* and time *i*. M_o is the Mean Observations and equal to

$$M_o = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I} O_j^i \tag{3}$$

The other two quantities used in the evaluation are Mean Bias Error (B) and Gross Error (E). Mean Bias Error is calculated using

$$B = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left(P_j^i - O_j^i\right) \tag{4}$$

Gross Error equals

$$E = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left|P_j^i - O_j^i\right| \tag{5}$$

In their studies, Emery et al. (2001) and Tesche et al. (2001) provided benchmarks for MM5 model evaluation or for other three-dimensional mesoscale model evaluation based on MM5/RAMS model performance evaluation literature. The benchmarks are for wind speed, wind direction, temperature and specific humidity. These benchmarks are "not to assign a passing or failing grade to a particular meteorological modeling application, but rather to put its results into a useful contact" (Tesche et al., 2002). It is not expected that all simulations will fall within the benchmarks, but rather the benchmarks are useful in comparing the results from various simulations in a quantitative manner. The benchmarks were designed to be used with large groups of stations in a given region or stations of a particular classification rather than with individual stations.

Table B-3 contains a summary of the statistical measures above comparing using hourly surface meteorological observations with the MM5 modeling results prepared by TRC for 2006 and 2007. Also included is a comparison of the results with the EPA-sponsored 2002 MM5 dataset which has been subject to previous model evaluations. The comparisons were done using the surface meteorological stations within the CALPUFF modeling domain, which consisted of 172, 210 and 210 stations for 2002, 2006 and 2007, respectively. The performance is similar for each of the datasets. The statistical measures are all better than the benchmark values, with the exception in the 2002 dataset of the mean gross error for temperature, which is slight above the benchmark, and the Index of Agreement (IOA), which is slightly lower than the benchmark.

Table B-3. Performance Statistics by Year – MM5 Simulations – 12-km Grid Resolution

	Wind Speed			Wind Direction		Temperature			Specific Humidity		
	Mean IOA	**Mean Bias**	**Mean RMSE**	**Mean Bias**	**Mean Gross Error**	**Mean IOA**	**Mean Bias**	**Mean Gross Error**	**Mean IOA**	**Mean Bias**	**Mean Gross Error**
2002	0.77	0.18	1.88	2.70	21.15	0.79	-0.05	2.75	0.84	-0.06	0.73
2006	0.83	0.04	1.54	1.76	16.68	0.96	-0.19	1.19	0.81	0.43	0.83
2007	0.83	0.14	1.59	2.31	17.05	0.96	-0.12	1.23	0.81	0.47	0.86
Benchmark	**$x \geq 0.60$**	**$\lvert x \rvert \leq 0.50$**	**$x \leq 2.00$**	**$\lvert x \rvert \leq 10.0$**	**$x \leq 30.0$**	**$x \geq 0.80$**	**$\lvert x \rvert \leq 0.50$**	**$x \leq 2.00$**	**$x \geq 0.60$**	**$\lvert x \rvert \leq 1.00$**	**$x \leq 2.00$**

References for Appendix B

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APPENDIX C

CALMET CONTROL FILE WITH MODEL SETTINGS

```
4 km resolution CALMET simulation
BART Analysis
Otter Tail Power Big Stone I 2006
---------------- Run title (3 lines) ----------------------------------------

                    CALMET MODEL CONTROL FILE
                    -------------------------

-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names


Subgroup (a)
------------
Default Name  Type          File Name
------------  ----          ---------
GEO.DAT       input    ! GEODAT=geo-4km-hires.dat !
SURF.DAT      input    ! SRFDAT=bs_surf2006ext.dat       !
CLOUD.DAT     input    * CLDDAT=            *
PRECIP.DAT    input    ! PRCDAT=bs_precip-2006ext.dat    !
WT.DAT        input    * WTDAT=             *

CALMET.LST    output   ! METLST=met2006_4km_a2r2_011.lst !
CALMET.DAT    output   ! METDAT=met2006_4km_a2r2_011.dat !
PACOUT.DAT    output   * PACDAT=            *

All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
         T = lower case      ! LCFILES = T !
         F = UPPER CASE

NUMBER OF UPPER AIR & OVERWATER STATIONS:

    Number of upper air stations (NUSTA)  No default     ! NUSTA =  10  !
    Number of overwater met stations
                                 (NOWSTA) No default     ! NOWSTA =  2  !

NUMBER OF PROGNOSTIC and IGF-CALMET FILEs:

    Number of MM4/MM5/3D.DAT files
                                 (NM3D) No default       ! NM3D = 1  !

    Number of IGF-CALMET.DAT files
                                 (NIGF)   No default     ! NIGF =  0  !

                       !END!
-------------------------------------------------------------------------------
Subgroup (b)
---------------------------------
Upper air files (one per station)
---------------------------------
Default Name  Type       File Name
------------  ----       ---------
UP1.DAT       input     1  ! UPDAT= up-abr-2006n.dat!    !END!
UP2.DAT       input     2  ! UPDAT= up-bis-2006n.dat!    !END!
UP3.DAT       input     3  ! UPDAT= up-dvn-2006n.dat!    !END!
UP4.DAT       input     4  ! UPDAT= up-ggw-2006n.dat!    !END!
UP5.DAT       input     5  ! UPDAT= up-grb-2006n.dat!    !END!
UP6.DAT       input     6  ! UPDAT= up-inl-2006n.dat!    !END!
UP7.DAT       input     7  ! UPDAT= up-lbf-2006n.dat!    !END!
UP8.DAT       input     8  ! UPDAT= up-mrx-2006n.dat!    !END!
UP9.DAT       input     9  ! UPDAT= up-oax-2006n.dat!    !END!
UP0.DAT       input    10  ! UPDAT= up-unr-2006n.dat!    !END!

-------------------------------------------------------------------------------
Subgroup (c)
----------------------------------------
Overwater station files (one per station)
----------------------------------------
Default Name  Type       File Name
------------  ----       ---------
SEA1.DAT      input     1  ! SEADAT= 45001-2006.dat!    !END!
SEA2.DAT      input     2  ! SEADAT= 45006-2006.dat!    !END!
```

```
-------------------------------------------------------------------------------
Subgroup (d)
-----------------------------------------------
MM4/MM5/3D.DAT files (consecutive or overlapping)
-----------------------------------------------
Default Name  Type       File Name
------------  ----       ---------

MM5001 ! M3DDAT=../mm5_2006/mm5-200601.m3d! !END!
-------------------------------------------------------------------------------
Subgroup (e)
-----------------------------------------------
IGF-CALMET.DAT files (consecutive or overlapping)
-----------------------------------------------
Default Name  Type       File Name
------------  ----       ---------
IGFn.DAT       input     1  * IGFDAT=CALMET0.DAT *    *END*
-------------------------------------------------------------------------------
Subgroup (f)
----------------
Other file names
----------------

Default Name  Type       File Name
------------  ----       ---------
DIAG.DAT      input      * DIADAT=                  *
PROG.DAT      input      * PRGDAT=                  *

TEST.PRT      output     * TSTPRT=                  *
TEST.OUT      output     * TSTOUT=                  *
TEST.KIN      output     * TSTKIN=                  *
TEST.FRD      output     * TSTFRD=                  *
TEST.SLP      output     * TSTSLP=                  *
DCST.GRD      output     * DCSTGD=                  *

-------------------------------------------------------------------------------
NOTES: (1) File/path names can be up to 70 characters in length
       (2) Subgroups (a) and (f) must have ONE 'END' (surrounded by
           delimiters) at the end of the group
       (3) Subgroups (b) through (e) are included ONLY if the corresponding
           number of files (NUSTA, NOWSTA, NM3D, NIGF) is not 0, and each must have
           an 'END' (surround by delimiters) at the end of EACH LINE

                        !END!


-------------------------------------------------------------------------------

INPUT GROUP: 1 -- General run control parameters
--------------


     Starting date:   Year (IBYR) -- No default       ! IBYR=  2006  !
                     Month (IBMO) -- No default       ! IBMO=  1  !
                       Day (IBDY) -- No default       ! IBDY=  1  !
                      Hour (IBHR) -- No default       ! IBHR=  1  !

     Note: IBHR is the time at the END of the first hour of the simulation
           (IBHR=1, the first hour of a day, runs from 00:00 to 01:00)

     Base time zone        (IBTZ) -- No default       ! IBTZ=  7  !
        PST = 08, MST = 07
        CST = 06, EST = 05

     Length of run (hours) (IRLG) -- No default       ! IRLG=  120  !

     Run type            (IRTYPE) -- Default: 1       ! IRTYPE=  1  !

        0 = Computes wind fields only
        1 = Computes wind fields and micrometeorological variables
            (u*, w*, L, zi, etc.)
        (IRTYPE must be 1 to run CALPUFF or CALGRID)

     Compute special data fields required
```

```
     by CALGRID (i.e., 3-D fields of W wind
     components and temperature)
     in additional to regular            Default: T    ! LCALGRD = T !
     fields ? (LCALGRD)
     (LCALGRD must be T to run CALGRID)

      Flag to stop run after
      SETUP phase (ITEST)             Default: 2       ! ITEST=  2   !
      (Used to allow checking
      of the model inputs, files, etc.)
      ITEST = 1 - STOPS program after SETUP phase
      ITEST = 2 - Continues with execution of
                  COMPUTATIONAL phase after SETUP


     Test options specified to see if
     they conform to regulatory
     values? (MREG)                   No Default       ! MREG =  1   !

        0 = NO checks are made
        1 = Technical options must conform to USEPA guidance
                  IMIXH    -1       Maul-Carson convective mixing height
                                    over land; OCD mixing height overwater
                  ICOARE   0        OCD deltaT method for overwater fluxes
                  THRESHL  0.0      Threshold buoyancy flux over land needed
                                    to sustain convective mixing height growth

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 2 -- Map Projection and Grid control parameters
--------------

     Projection for all (X,Y):
     -------------------------

     Map projection
     (PMAP)                     Default: UTM    ! PMAP = LCC  !

         UTM :  Universal Transverse Mercator
         TTM :  Tangential Transverse Mercator
         LCC :  Lambert Conformal Conic
          PS :  Polar Stereographic
          EM :  Equatorial Mercator
        LAZA :  Lambert Azimuthal Equal Area

     False Easting and Northing (km) at the projection origin
     (Used only if PMAP= TTM, LCC, or LAZA)
     (FEAST)                    Default=0.0     ! FEAST  = 0.000  !
     (FNORTH)                   Default=0.0     ! FNORTH = 0.000  !

     UTM zone (1 to 60)
     (Used only if PMAP=UTM)
     (IUTMZN)                   No Default      ! IUTMZN =  0   !

     Hemisphere for UTM projection?
     (Used only if PMAP=UTM)
     (UTMHEM)                   Default: N      ! UTMHEM = N  !
         N   :  Northern hemisphere projection
         S   :  Southern hemisphere projection

     Latitude and Longitude (decimal degrees) of projection origin
     (Used only if PMAP= TTM, LCC, PS, EM, or LAZA)
     (RLAT0)                    No Default      ! RLAT0 = 40N  !
     (RLON0)                    No Default      ! RLON0 = 98W  !

         TTM :  RLON0 identifies central (true N/S) meridian of projection
                RLAT0 selected for convenience
         LCC :  RLON0 identifies central (true N/S) meridian of projection
                RLAT0 selected for convenience
         PS  :  RLON0 identifies central (grid N/S) meridian of projection
                RLAT0 selected for convenience
         EM  :  RLON0 identifies central meridian of projection
```

```
            RLAT0 is REPLACED by 0.0N (Equator)
    LAZA:   RLON0 identifies longitude of tangent-point of mapping plane
            RLAT0 identifies latitude of tangent-point of mapping plane

Matching parallel(s) of latitude (decimal degrees) for projection
(Used only if PMAP= LCC or PS)
(XLAT1)                    No Default      ! XLAT1 = 20N  !
(XLAT2)                    No Default      ! XLAT2 = 60N  !

    LCC :   Projection cone slices through Earth's surface at XLAT1 and XLAT2
    PS  :   Projection plane slices through Earth at XLAT1
            (XLAT2 is not used)

----------
Note:  Latitudes and longitudes should be positive, and include a
       letter N,S,E, or W indicating north or south latitude, and
       east or west longitude.  For example,
       35.9  N Latitude  =  35.9N
       118.7 E Longitude = 118.7E


Datum-region
------------

The Datum-Region for the coordinates is identified by a character
string.  Many mapping products currently available use the model of the
Earth known as the World Geodetic System 1984 (WGS-84).  Other local
models may be in use, and their selection in CALMET will make its output
consistent with local mapping products.  The list of Datum-Regions with
official transformation parameters is provided by the National Imagery and
Mapping Agency (NIMA).

NIMA Datum - Regions(Examples)
-------------------------------------------------------------------------------
WGS-84    WGS-84 Reference Ellipsoid and Geoid, Global coverage (WGS84)
NAS-C     NORTH AMERICAN 1927 Clarke 1866 Spheroid, MEAN FOR CONUS (NAD27)
NAR-C     NORTH AMERICAN 1983 GRS 80 Spheroid, MEAN FOR CONUS (NAD83)
NWS-84    NWS 6370KM Radius, Sphere
ESR-S     ESRI REFERENCE 6371KM Radius, Sphere

Datum-region for output coordinates
(DATUM)                    Default: WGS-84    ! DATUM = NWS-84 !


Horizontal grid definition:
---------------------------

Rectangular grid defined for projection PMAP,
with X the Easting and Y the Northing coordinate

       No. X grid cells (NX)      No default     ! NX = 313 !
       No. Y grid cells (NY)      No default     ! NY = 181 !

Grid spacing (DGRIDKM)            No default     ! DGRIDKM = 4. !
                                  Units: km

Reference grid coordinate of
SOUTHWEST corner of grid cell (1,1)

   X coordinate (XORIGKM)         No default     ! XORIGKM = -506. !
   Y coordinate (YORIGKM)         No default     ! YORIGKM =  298. !
                                  Units: km


Vertical grid definition:
-------------------------

   No. of vertical layers (NZ)    No default     ! NZ =  10  !

   Cell face heights in arbitrary
   vertical grid (ZFACE(NZ+1))    No defaults
                                  Units: m
! ZFACE = 0.,20.,40.,80.,160.,320.,640.,1200.,2000.,3000.,4000.  !
```

```
!END!
-------------------------------------------------------------------------------

INPUT GROUP: 3 -- Output Options
--------------


    DISK OUTPUT OPTION

       Save met. fields in an unformatted
       output file ?              (LSAVE)  Default: T     ! LSAVE = T !
       (F = Do not save, T = Save)

       Type of unformatted output file:
       (IFORMO)                            Default: 1    ! IFORMO =  1  !

            1 = CALPUFF/CALGRID type file (CALMET.DAT)
            2 = MESOPUFF-II type file     (PACOUT.DAT)


    LINE PRINTER OUTPUT OPTIONS:

       Print met. fields ?  (LPRINT)       Default: F     ! LPRINT = F !
       (F = Do not print, T = Print)
       (NOTE: parameters below control which
              met. variables are printed)

       Print interval
       (IPRINF) in hours                   Default: 1     ! IPRINF =  1  !
       (Meteorological fields are printed
        every  1  hours)


       Specify which layers of U, V wind component
       to print (IUVOUT(NZ)) -- NOTE: NZ values must be entered
       (0=Do not print, 1=Print)
       (used only if LPRINT=T)        Defaults: NZ*0        ! IUVOUT =  10*0  !
       -----------------------


       Specify which levels of the W wind component to print
       (NOTE: W defined at TOP cell face --  10  values)
       (IWOUT(NZ)) -- NOTE: NZ values must be entered
       (0=Do not print, 1=Print)
       (used only if LPRINT=T & LCALGRD=T)
       -----------------------------------
                                            Defaults: NZ*0         ! IWOUT =  10*0  !


       Specify which levels of the 3-D temperature field to print
       (ITOUT(NZ)) -- NOTE: NZ values must be entered
       (0=Do not print, 1=Print)
       (used only if LPRINT=T & LCALGRD=T)
       -----------------------------------
                                            Defaults: NZ*0         ! ITOUT =  10*0  !

       Specify which meteorological fields
       to print
       (used only if LPRINT=T)             Defaults: 0 (all variables)
       -----------------------


         Variable            Print ?
                         (0 = do not print,
                          1 = print)
         --------        ------------------

      !  STABILITY  =           0           ! - PGT stability class
      !  USTAR      =           0           ! - Friction velocity
      !  MONIN      =           0           ! - Monin-Obukhov length
      !  MIXHT      =           0           ! - Mixing height
      !  WSTAR      =           0           ! - Convective velocity scale
      !  PRECIP     =           0           ! - Precipitation rate
      !  SENSHEAT   =           0           ! - Sensible heat flux
```

```
      !  CONVZI     =           0           ! - Convective mixing ht.


       Testing and debug print options for micrometeorological module

          Print input meteorological data and
          internal variables (LDB)         Default: F       ! LDB = F !
          (F = Do not print, T = print)
          (NOTE: this option produces large amounts of output)

          First time step for which debug data
          are printed (NN1)                Default: 1       ! NN1 =  1  !

          Last time step for which debug data
          are printed (NN2)                Default: 1       ! NN2 =  1  !

          Print distance to land
          internal variables (LDBCST)      Default: F       ! LDBCST = F !
          (F = Do not print, T = print)
          (Output in .GRD file DCST.GRD, defined in input group 0)

       Testing and debug print options for wind field module
       (all of the following print options control output to
        wind field module's output files: TEST.PRT, TEST.OUT,
        TEST.KIN, TEST.FRD, and TEST.SLP)

          Control variable for writing the test/debug
          wind fields to disk files (IOUTD)
          (0=Do not write, 1=write)        Default: 0       ! IOUTD =  0  !

          Number of levels, starting at the surface,
          to print (NZPRN2)                Default: 1       ! NZPRN2 =  0  !

          Print the INTERPOLATED wind components ?
          (IPR0) (0=no, 1=yes)             Default: 0       !  IPR0 =  0  !

          Print the TERRAIN ADJUSTED surface wind
          components ?
          (IPR1) (0=no, 1=yes)             Default: 0       !  IPR1 =  0  !

          Print the SMOOTHED wind components and
          the INITIAL DIVERGENCE fields ?
          (IPR2) (0=no, 1=yes)             Default: 0       !  IPR2 =  0  !

          Print the FINAL wind speed and direction
          fields ?
          (IPR3) (0=no, 1=yes)             Default: 0       !  IPR3 =  0  !

          Print the FINAL DIVERGENCE fields ?
          (IPR4) (0=no, 1=yes)             Default: 0       !  IPR4 =  0  !

          Print the winds after KINEMATIC effects
          are added ?
          (IPR5) (0=no, 1=yes)             Default: 0       !  IPR5 =  0  !

          Print the winds after the FROUDE NUMBER
          adjustment is made ?
          (IPR6) (0=no, 1=yes)             Default: 0       !  IPR6 =  0  !

          Print the winds after SLOPE FLOWS
          are added ?
          (IPR7) (0=no, 1=yes)             Default: 0       !  IPR7 =  0  !

          Print the FINAL wind field components ?
          (IPR8) (0=no, 1=yes)             Default: 0       !  IPR8 =  0  !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 4 -- Meteorological data options
--------------
```

```
    NO OBSERVATION MODE             (NOOBS)  Default: 0     ! NOOBS =  0   !
          0 = Use surface, overwater, and upper air stations
          1 = Use surface and overwater stations (no upper air observations)
              Use MM4/MM5/3D for upper air data
          2 = No surface, overwater, or upper air observations
              Use MM4/MM5/3D for surface, overwater, and upper air data

    NUMBER OF SURFACE & PRECIP. METEOROLOGICAL STATIONS

       Number of surface stations   (NSSTA)  No default     ! NSSTA = 250 !

       Number of precipitation stations
       (NPSTA=-1: flag for use of MM5/3D precip data)
                                    (NPSTA)  No default     ! NPSTA = 267 !

    CLOUD DATA OPTIONS
       Gridded cloud fields:
                                   (ICLOUD)  Default: 0     ! ICLOUD =  0  !
       ICLOUD = 0 - Gridded clouds not used
       ICLOUD = 1 - Gridded CLOUD.DAT generated as OUTPUT
       ICLOUD = 2 - Gridded CLOUD.DAT read as INPUT
       ICLOUD = 3 - Gridded cloud cover computed from prognostic fields

    FILE FORMATS

       Surface meteorological data file format
                                   (IFORMS)  Default: 2     ! IFORMS =  2  !
       (1 = unformatted (e.g., SMERGE output))
       (2 = formatted   (free-formatted user input))

       Precipitation data file format
                                   (IFORMP)  Default: 2     ! IFORMP =  2  !
       (1 = unformatted (e.g., PMERGE output))
       (2 = formatted   (free-formatted user input))

       Cloud data file format
                                   (IFORMC)  Default: 2     ! IFORMC =  2  !
       (1 = unformatted - CALMET unformatted output)
       (2 = formatted   - free-formatted CALMET output or user input)

!END!
-------------------------------------------------------------------------------

INPUT GROUP: 5 -- Wind Field Options and Parameters
--------------


    WIND FIELD MODEL OPTIONS
       Model selection variable (IWFCOD)     Default: 1      ! IWFCOD =  1  !
          0 = Objective analysis only
          1 = Diagnostic wind module

       Compute Froude number adjustment
       effects ? (IFRADJ)                    Default: 1      ! IFRADJ =  1  !
       (0 = NO, 1 = YES)

       Compute kinematic effects ? (IKINE)   Default: 0      ! IKINE  =  0  !
       (0 = NO, 1 = YES)

       Use O'Brien procedure for adjustment
       of the vertical velocity ? (IOBR)     Default: 0      ! IOBR =  0  !
       (0 = NO, 1 = YES)

       Compute slope flow effects ? (ISLOPE) Default: 1      ! ISLOPE  =  1  !
       (0 = NO, 1 = YES)

       Extrapolate surface wind observations
       to upper layers ? (IEXTRP)            Default: -4     ! IEXTRP = -4  !
       (1 = no extrapolation is done,
        2 = power law extrapolation used,
        3 = user input multiplicative factors
            for layers 2 - NZ used (see FEXTRP array)
        4 = similarity theory used
        -1, -2, -3, -4 = same as above except layer 1 data
```

```
        at upper air stations are ignored

   Extrapolate surface winds even
   if calm? (ICALM)                      Default: 0      ! ICALM  =  0  !
   (0 = NO, 1 = YES)

   Layer-dependent biases modifying the weights of
   surface and upper air stations (BIAS(NZ))
     -1<=BIAS<=1
   Negative BIAS reduces the weight of upper air stations
     (e.g. BIAS=-0.1 reduces the weight of upper air stations
   by 10%; BIAS= -1, reduces their weight by 100 %)
   Positive BIAS reduces the weight of surface stations
     (e.g. BIAS= 0.2 reduces the weight of surface stations
   by 20%; BIAS=1 reduces their weight by 100%)
   Zero BIAS leaves weights unchanged (1/R**2 interpolation)
   Default: NZ*0
                          ! BIAS =  10*0  !

   Minimum distance from nearest upper air station
   to surface station for which extrapolation
   of surface winds at surface station will be allowed
   (RMIN2: Set to -1 for IEXTRP = 4 or other situations
    where all surface stations should be extrapolated)
                                         Default: 4.     ! RMIN2 = -1.0 !

   Use gridded prognostic wind field model
   output fields as input to the diagnostic
   wind field model (IPROG)              Default: 0      ! IPROG = 14  !
   (0 = No, [IWFCOD = 0 or 1]
    1 = Yes, use CSUMM prog. winds as Step 1 field, [IWFCOD = 0]
    2 = Yes, use CSUMM prog. winds as initial guess field [IWFCOD = 1]
    3 = Yes, use winds from MM4.DAT file as Step 1 field [IWFCOD = 0]
    4 = Yes, use winds from MM4.DAT file as initial guess field [IWFCOD = 1]
    5 = Yes, use winds from MM4.DAT file as observations [IWFCOD = 1]
    13 = Yes, use winds from MM5/3D.DAT file as Step 1 field [IWFCOD = 0]
    14 = Yes, use winds from MM5/3D.DAT file as initial guess field [IWFCOD = 1]
    15 = Yes, use winds from MM5/3D.DAT file as observations [IWFCOD = 1]

   Timestep (hours) of the prognostic
   model input data   (ISTEPPG)          Default: 1      ! ISTEPPG =  1   !

   Use coarse CALMET fields as initial guess fields (IGFMET)
   (overwrites IGF based on prognostic wind fields if any)
                                         Default: 0      ! IGFMET =  0  !

RADIUS OF INFLUENCE PARAMETERS

   Use varying radius of influence       Default: F      ! LVARY =  F!
   (if no stations are found within RMAX1,RMAX2,
    or RMAX3, then the closest station will be used)

   Maximum radius of influence over land
   in the surface layer (RMAX1)          No default      ! RMAX1 = 100. !
                                         Units: km
   Maximum radius of influence over land
   aloft (RMAX2)                         No default      ! RMAX2 = 200. !
                                         Units: km
   Maximum radius of influence over water
   (RMAX3)                               No default      ! RMAX3 = 200. !
                                         Units: km


OTHER WIND FIELD INPUT PARAMETERS

   Minimum radius of influence used in
   the wind field interpolation (RMIN)   Default: 0.1    ! RMIN = 0.1 !
                                         Units: km
   Radius of influence of terrain
   features (TERRAD)                     No default      ! TERRAD = 15. !

                                         Units: km
   Relative weighting of the first
   guess field and observations in the
```

```
   SURFACE layer (R1)                    No default      ! R1 = 50. !
   (R1 is the distance from an           Units: km
   observational station at which the
   observation and first guess field are
   equally weighted)

   Relative weighting of the first
   guess field and observations in the
   layers ALOFT (R2)                     No default      ! R2 = 100. !
   (R2 is applied in the upper layers    Units: km
   in the same manner as R1 is used in
   the surface layer).

   Relative weighting parameter of the
   prognostic wind field data (RPROG)    No default      ! RPROG = 0. !
   (Used only if IPROG = 1)              Units: km
   ------------------------

   Maximum acceptable divergence in the
   divergence minimization procedure
   (DIVLIM)                              Default: 5.E-6  ! DIVLIM= 5.0E-06 !

   Maximum number of iterations in the
   divergence min. procedure (NITER)     Default: 50     ! NITER =  50  !

   Number of passes in the smoothing
   procedure (NSMTH(NZ))
   NOTE: NZ values must be entered
        Default: 2,(mxnz-1)*4 ! NSMTH =  2 ,  9*4  !

   Maximum number of stations used in
   each layer for the interpolation of
   data to a grid point (NINTR2(NZ))
   NOTE: NZ values must be entered       Default: 99.    ! NINTR2 = 10*99 !

   Critical Froude number (CRITFN)       Default: 1.0    ! CRITFN = 1. !

   Empirical factor controlling the
   influence of kinematic effects
   (ALPHA)                               Default: 0.1    ! ALPHA = 0.1 !

   Multiplicative scaling factor for
   extrapolation of surface observations
   to upper layers (FEXTR2(NZ))          Default: NZ*0.0 ! FEXTR2 = 10*0. !
   (Used only if IEXTRP = 3 or -3)


BARRIER INFORMATION

   Number of barriers to interpolation
   of the wind fields (NBAR)             Default: 0      ! NBAR =  0  !

   Level (1 to NZ) up to which barriers
   apply (KBAR)                          Default: NZ     ! KBAR =  10  !

   THE FOLLOWING 4 VARIABLES ARE INCLUDED
   ONLY IF NBAR > 0
   NOTE: NBAR values must be entered     No defaults
         for each variable               Units: km

      X coordinate of BEGINNING
      of each barrier (XBBAR(NBAR))      ! XBBAR = 0. !
      Y coordinate of BEGINNING
      of each barrier (YBBAR(NBAR))      ! YBBAR = 0. !

      X coordinate of ENDING
      of each barrier (XEBAR(NBAR))      ! XEBAR = 0. !
      Y coordinate of ENDING
      of each barrier (YEBAR(NBAR))      ! YEBAR = 0. !


DIAGNOSTIC MODULE DATA INPUT OPTIONS

   Surface temperature (IDIOPT1)         Default: 0      ! IDIOPT1 =  0  !
```

```
   0 = Compute internally from
       hourly surface observations
   1 = Read preprocessed values from
       a data file (DIAG.DAT)

   Surface met. station to use for
   the surface temperature (ISURFT)   No default     ! ISURFT =  211  !
   (Must be a value from 1 to NSSTA)
   (Used only if IDIOPT1 = 0)
   --------------------------

Domain-averaged temperature lapse
rate (IDIOPT2)                        Default: 0     ! IDIOPT2 =  0  !
   0 = Compute internally from
       twice-daily upper air observations
   1 = Read hourly preprocessed values
       from a data file (DIAG.DAT)

   Upper air station to use for
   the domain-scale lapse rate (IUPT) No default     ! IUPT   =  1  !
   (Must be a value from 1 to NUSTA)
   (Used only if IDIOPT2 = 0)
   --------------------------

   Depth through which the domain-scale
   lapse rate is computed (ZUPT)      Default: 200.  ! ZUPT = 200. !
   (Used only if IDIOPT2 = 0)         Units: meters
   --------------------------

Domain-averaged wind components
(IDIOPT3)                             Default: 0     ! IDIOPT3 =  0  !
   0 = Compute internally from
       twice-daily upper air observations
   1 = Read hourly preprocessed values
       a data file (DIAG.DAT)

   Upper air station to use for
   the domain-scale winds (IUPWND)    Default: -1    ! IUPWND = -1  !
   (Must be a value from -1 to NUSTA)
   (Used only if IDIOPT3 = 0)
   --------------------------

   Bottom and top of layer through
   which the domain-scale winds
   are computed
   (ZUPWND(1), ZUPWND(2))        Defaults: 1., 1000. ! ZUPWND= 1., 1000. !
   (Used only if IDIOPT3 = 0)    Units: meters
   --------------------------

Observed surface wind components
for wind field module (IDIOPT4)  Default: 0     ! IDIOPT4 =  0  !
   0 = Read WS, WD from a surface
       data file (SURF.DAT)
   1 = Read hourly preprocessed U, V from
       a data file (DIAG.DAT)

Observed upper air wind components
for wind field module (IDIOPT5)  Default: 0     ! IDIOPT5 =  0  !
   0 = Read WS, WD from an upper
       air data file (UP1.DAT, UP2.DAT, etc.)
   1 = Read hourly preprocessed U, V from
       a data file (DIAG.DAT)

LAKE BREEZE INFORMATION

   Use Lake Breeze Module  (LLBREZE)
                                     Default: F      ! LLBREZE = F !

    Number of lake breeze regions (NBOX)            ! NBOX =  0  !

 X Grid line 1 defining the region of interest
                                                   ! XG1 = 0. !
 X Grid line 2 defining the region of interest
                                                   ! XG2 = 0. !
```

```
        Y Grid line 1 defining the region of interest
                                                        ! YG1 = 0. !
        Y Grid line 2 defining the region of interest
                                                        ! YG2 = 0. !

         X Point defining the coastline (Straight line)
                   (XBCST)  (KM)   Default: none    ! XBCST = 0. !

         Y Point defining the coastline (Straight line)
                   (YBCST)  (KM)   Default: none    ! YBCST = 0. !

         X Point defining the coastline (Straight line)
                   (XECST)  (KM)   Default: none    ! XECST = 0. !

         Y Point defining the coastline (Straight line)
                   (YECST)  (KM)   Default: none    ! YECST = 0. !


       Number of stations in the region     Default: none ! NLB =  0 !
       (Surface stations + upper air stations)

       Station ID's  in the region   (METBXID(NLB))
       (Surface stations first, then upper air stations)
         ! METBXID =  0 !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 6 -- Mixing Height, Temperature and Precipitation Parameters
--------------

    EMPIRICAL MIXING HEIGHT CONSTANTS

       Neutral, mechanical equation
       (CONSTB)                             Default: 1.41   ! CONSTB = 1.41 !
       Convective mixing ht. equation
       (CONSTE)                             Default: 0.15   ! CONSTE = 0.15 !
       Stable mixing ht. equation
       (CONSTN)                             Default: 2400.  ! CONSTN = 2400.!
       Overwater mixing ht. equation
       (CONSTW)                             Default: 0.16   ! CONSTW = 0.16 !
       Absolute value of Coriolis
       parameter (FCORIOL)                  Default: 1.E-4  ! FCORIOL = 1.0E-04!
                                            Units: (1/s)

    SPATIAL AVERAGING OF MIXING HEIGHTS

       Conduct spatial averaging
       (IAVEZI)  (0=no, 1=yes)              Default: 1      ! IAVEZI =  1  !

       Max. search radius in averaging
       process (MNMDAV)                     Default: 1      ! MNMDAV =  1  !
                                            Units: Grid
                                                   cells
       Half-angle of upwind looking cone
       for averaging (HAFANG)               Default: 30.    ! HAFANG = 30. !
                                            Units: deg.
       Layer of winds used in upwind
       averaging (ILEVZI)                   Default: 1      ! ILEVZI =  1  !
       (must be between 1 and NZ)


    CONVECTIVE MIXING HEIGHT OPTIONS:
       Method to compute the convective
       mixing height(IMIHXH)                Default: 1      ! IMIXH =  -1  !
           1: Maul-Carson for land and water cells
          -1: Maul-Carson for land cells only -
              OCD mixing height overwater
           2: Batchvarova and Gryning for land and water cells
          -2: Batchvarova and Gryning for land cells only
              OCD mixing height overwater
```

```
   Threshold buoyancy flux required to
   sustain convective mixing height growth
   overland (THRESHL)                    Default: 0.0    ! THRESHL = 0.0 !
   (expressed as a heat flux             units: W/m3
    per meter of boundary layer)


   Threshold buoyancy flux required to
   sustain convective mixing height growth
   overwater (THRESHW)                   Default: 0.05   ! THRESHW = 0.05 !
   (expressed as a heat flux             units: W/m3
    per meter of boundary layer)


   Option for overwater lapse rates used
   in convective mixing height growth
   (ITWPROG)                             Default: 0      ! ITWPROG =  0  !
   0 : use SEA.DAT lapse rates and deltaT (or assume neutral
       conditions if missing)
   1 : use prognostic lapse rates (only if IPROG>2)
       and SEA.DAT deltaT (or neutral if missing)
   2 : use prognostic lapse rates and prognostic delta T
       (only if iprog>12 and 3D.DAT version# 2.0 or higher)

   Land Use category ocean in 3D.DAT datasets
   (ILUOC3D)                             Default: 16     ! ILUOC3D =  16  !
   Note: if 3D.DAT from MM5 version 3.0, iluoc3d = 16
         if MM4.DAT,           typically iluoc3d = 7


OTHER MIXING HEIGHT VARIABLES

   Minimum potential temperature lapse
   rate in the stable layer above the
   current convective mixing ht.         Default: 0.001  ! DPTMIN = 0.001 !
   (DPTMIN)                              Units: deg. K/m
   Depth of layer above current conv.
   mixing height through which lapse     Default: 200.   ! DZZI = 200. !
   rate is computed (DZZI)               Units: meters

   Minimum overland mixing height        Default:  50.   ! ZIMIN = 50. !
   (ZIMIN)                               Units: meters
   Maximum overland mixing height        Default: 3000.  ! ZIMAX = 3000. !
   (ZIMAX)                               Units: meters
   Minimum overwater mixing height       Default:   50.  ! ZIMINW = 50. !
   (ZIMINW) -- (Not used if observed     Units: meters
   overwater mixing hts. are used)
   Maximum overwater mixing height       Default: 3000.  ! ZIMAXW = 3000. !
   (ZIMAXW) -- (Not used if observed     Units: meters
   overwater mixing hts. are used)


OVERWATER SURFACE FLUXES METHOD and PARAMETERS
      (ICOARE)                           Default: 10      ! ICOARE =  0   !
       0: original deltaT method (OCD)
      10: COARE with no wave parameterization (jwave=0, Charnock)
      11: COARE with wave option jwave=1 (Oost et al.)
          and default wave properties
     -11: COARE with wave option jwave=1 (Oost et al.)
          and observed wave properties (must be in SEA.DAT files)
      12: COARE with wave option 2 (Taylor and Yelland)
           and default wave properties
     -12: COARE with wave option 2 (Taylor and Yelland)
          and observed wave properties (must be in SEA.DAT files)

      Note:  When ICOARE=0, similarity wind profile stability PSI functions
             based on Van Ulden and Holtslag (1985) are substituted for
             later formulations used with the COARE module, and temperatures
             used for surface layer parameters are obtained from either the
             nearest surface station temperature or prognostic model 2D
             temperatures (if ITPROG=2).

      Coastal/Shallow water length scale (DSHELF)
      (for modified z0 in shallow water)
```

```
         ( COARE fluxes only)
                                        Default : 0.        ! DSHELF = 0. !
                                        units: km

          COARE warm layer computation (IWARM)              ! IWARM =  0   !
          1: on - 0: off (must be off if SST measured with
          IR radiometer)                Default: 0

          COARE cool skin layer computation (ICOOL)         ! ICOOL =  0   !
          1: on - 0: off (must be off if SST measured with
          IR radiometer)                Default: 0


    TEMPERATURE PARAMETERS

       3D temperature from observations or
       from prognostic data? (ITPROG)       Default:0        ! ITPROG =  0   !

          0 = Use Surface and upper air stations
              (only if NOOBS = 0)
          1 = Use Surface stations (no upper air observations)
              Use MM5/3D for upper air data
              (only if NOOBS = 0,1)
          2 = No surface or upper air observations
              Use MM5/3D for surface and upper air data
              (only if NOOBS = 0,1,2)

       Interpolation type
       (1 = 1/R ; 2 = 1/R**2)               Default:1         ! IRAD =  1  !

       Radius of influence for temperature
       interpolation (TRADKM)               Default: 500.     ! TRADKM = 500. !
                                            Units: km

       Maximum Number of stations to include
       in temperature interpolation (NUMTS) Default: 5        ! NUMTS = 5  !

       Conduct spatial averaging of temp-
       eratures (IAVET)  (0=no, 1=yes)      Default: 1        ! IAVET =  1  !
       (will use mixing ht MNMDAV,HAFANG
        so make sure they are correct)

       Default temperature gradient         Default: -.0098   ! TGDEFB = -0.0098 !
       below the mixing height over         Units: K/m
       water (TGDEFB)

       Default temperature gradient         Default: -.0045   ! TGDEFA = -0.0045 !
       above the mixing height over         Units: K/m
       water (TGDEFA)

       Beginning (JWAT1) and ending (JWAT2)
       land use categories for temperature                    ! JWAT1 =  55  !
       interpolation over water -- Make                       ! JWAT2 =  55  !
       bigger than largest land use to disable

   PRECIP INTERPOLATION PARAMETERS

       Method of interpolation (NFLAGP)     Default: 2       ! NFLAGP =  2  !
        (1=1/R,2=1/R**2,3=EXP/R**2)
       Radius of Influence  (SIGMAP)        Default: 100.0   ! SIGMAP = 100. !
        (0.0 => use half dist. btwn         Units: km
         nearest stns w & w/out
         precip when NFLAGP = 3)
       Minimum Precip. Rate Cutoff (CUTP)   Default: 0.01    ! CUTP = 0.01 !
        (values < CUTP = 0.0 mm/hr)         Units: mm/hr
!END!
-------------------------------------------------------------------------------
INPUT GROUP: 7 -- Surface meteorological station parameters
--------------

     SURFACE STATION VARIABLES
     (One record per station --  250  records in all)

             1     2
```

```
          Name   ID            X coord.   Y coord.   Time   Anem.
                                 (km)       (km)      zone   Ht.(m)
        ---------------------------------------------------------
! SS1   ='CYBR',  711400,  -132.737961       1040.684570   7    10 !
! SS002 ='CWNK',  711470,    -2.262997        995.140137   7    10 !
! SS003 ='CWPO',  711480,   -62.049206        963.792969   7    10 !
! SS004 ='CWZE',  711700,   -91.927345       1038.115110   7    10 !
! SS005 ='CWDV',  714350,   520.234131        968.333252   7    10 !
! SS006 ='CWGN',  714410,    29.940273        945.930359   7    10 !
! SS007 ='CWEI',  714470,  -205.322525        975.742554   7    10 !
! SS008 ='CWSU',  714490,   165.977509        946.451843   7    10 !
! SS009 ='CWWF',  714520,  -396.077026       1029.438350   7    10 !
! SS010 ='EMER',  715600,    53.065262        942.609009   7    10 !
! SS011 ='CXMD',  715640,    -5.724126        961.681702   7    10 !
! SS012 ='WINN',  715790,    59.056881       1035.899780   7    10 !
! SS013 ='CZHD',  715820,   357.821838       1039.401120   7    10 !
! SS014 ='ATIK',  717470,   441.910736        933.946167   7    10 !
! SS015 ='CXDW',  718400,   -21.778795        984.620911   7    10 !
! SS016 ='CYHD',  718425,   358.876953       1041.158940   7    10 !
! SS017 ='CXWN',  718430,    59.056881       1035.899780   7    10 !
! SS018 ='WASP',  718490,    52.213905       1039.430420   7    10 !
! SS019 ='CYQK',  718500,   247.840500       1030.198360   7    10 !
! SS020 ='CYPG',  718510,   -18.181787       1037.431640   7    10 !
! SS021 ='CYWG',  718520,    52.229706       1037.633420   7    10 !
! SS022 ='CYEN',  718620,  -342.161255        975.010742   7    10 !
! SS023 ='KHZX',  720258,   337.785278        701.057190   7    10 !
! SS024 ='KFKA',  720283,   440.500244        398.718048   7    10 !
! SS025 ='KIIB',  720293,   465.955536        272.288361   7    10 !
! SS026 ='KVTI',  720326,   462.249084        247.538208   7    10 !
! SS027 ='KLUM',  720327,   454.199249        527.013367   7    10 !
! SS028 ='KCKP',  720344,   187.478500        287.882965   7    10 !
! SS029 ='KPEX',  720367,   239.019058        565.214783   7    10 !
! SS030 ='KDVP',  720368,   166.747665        418.091461   7    10 !
! SS031 ='KSYN',  722003,   371.754822        478.146027   7    10 !
! SS032 ='KBWP',  722004,   100.999161        653.452332   7    10 !
! SS033 ='KLYV',  722006,   134.958801        379.514679   7    10 !
! SS034 ='KACQ',  722032,   333.878906        433.998291   7    10 !
! SS035 ='KGDB',  722033,   181.560699        499.042145   7    10 !
! SS036 ='KCFE',  722114,   307.498352        545.390259   7    10 !
! SS037 ='KJKJ',  722129,    96.844124        715.808105   7    10 !
! SS038 ='KMGG',  722144,   296.022736        553.863770   7    10 !
! SS039 ='KOVL',  722168,   221.420837        503.003906   7    10 !
! SS040 ='KRNH',  722179,   403.259186        550.473206   7    10 !
! SS041 ='KRZN',  722183,   411.001251        621.797424   7    10 !
! SS042 ='KSFY',  722204,   611.118896        241.281296   7    10 !
! SS043 ='KLCG',  722241,    78.773186        234.543762   7    10 !
! SS044 ='KCNB',  722252,   128.874329        495.268707   7    10 !
! SS045 ='KTKC',  722342,   179.218750        446.241730   7    10 !
! SS046 ='KRCX',  723758,   513.212524        594.974731   7    10 !
! SS047 ='KAXA',  725457,   284.761230        327.492554   7    10 !
! SS048 ='KCAV',  725458,   325.802399        294.237671   7    10 !
! SS049 ='KMIW',  725461,   393.433167        232.077042   7    10 !
! SS050 ='KCCY',  725463,   411.742310        333.622681   7    10 !
! SS051 ='KCIN',  725468,   249.315628        218.213760   7    10 !
! SS052 ='KDBQ',  725470,   562.008728        273.891357   7    10 !
! SS053 ='KAMW',  725472,   339.960693        217.356750   7    10 !
! SS054 ='KMXO',  725475,   529.074829        252.985184   7    10 !
! SS055 ='KDEH',  725476,   476.241272        359.092377   7    10 !
! SS056 ='KEBS',  725478,   318.428436        261.887787   7    10 !
! SS057 ='KALO',  725480,   430.451233        280.485382   7    10 !
! SS058 ='KLRJ',  725484,   139.213089        291.510315   7    10 !
! SS059 ='KMCW',  725485,   355.652557        339.276703   7    10 !
! SS060 ='KBNW',  725486,   322.820679        221.638809   7    10 !
! SS061 ='KOLZ',  725488,   462.849091        295.942047   7    10 !
! SS062 ='KORC',  725489,   148.912033        313.869507   7    10 !
! SS063 ='KFOD',  725490,   284.697876        278.665985   7    10 !
! SS064 ='KSHL',  725495,   164.999420        337.029449   7    10 !
! SS065 ='KSLB',  725496,   212.618134        274.528046   7    10 !
! SS066 ='KANW',  725556,  -152.562332        271.011780   7    10 !
! SS067 ='KONL',  725566,   -52.690170        258.100037   7    10 !
! SS068 ='KSUX',  725570,   125.017456        250.804749   7    10 !
! SS069 ='KAIA',  725635,  -371.946045        225.001831   7    10 !
! SS070 ='KCDR',  725636,  -390.018555        307.721893   7    10 !
! SS071 ='KVTN',  725670,  -195.296432        301.377747   7    10 !
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! SS072 ='KTOR',  725763,  -476.574402        232.416214   7    10 !
! SS073 ='KLNR',  726416,   594.580078        362.063934   7    10 !
! SS074 ='KMDZ',  726417,   567.921021        557.987793   7    10 !
! SS075 ='KOEO',  726418,   390.745178        566.480835   7    10 !
! SS076 ='KASX',  726419,   510.271820        705.353516   7    10 !
! SS077 ='KSUW',  726427,   424.747314        713.702942   7    10 !
! SS078 ='KLSE',  726430,   508.635651        411.707031   7    10 !
! SS079 ='KEAU',  726435,   482.727417        526.252747   7    10 !
! SS080 ='KVOK',  726436,   581.265625        437.046356   7    10 !
! SS081 ='KCMY',  726437,   546.142822        436.117981   7    10 !
! SS082 ='KOVS',  726438,   557.368958        352.953308   7    10 !
! SS083 ='KRST',  726440,   414.564484        420.806641   7    10 !
! SS084 ='KPDC',  726444,   525.151245        335.964905   7    10 !
! SS085 ='KAQP',  726466,   146.927185        547.887634   7    10 !
! SS086 ='KRPD',  726467,   457.289001        582.535217   7    10 !
! SS087 ='KPBH',  726468,   555.096680        620.769592   7    10 !
! SS088 ='KEST',  726499,   246.954147        360.483246   7    10 !
! SS089 ='KSPW',  726500,   213.177475        333.802368   7    10 !
! SS090 ='KMRJ',  726507,   593.426697        327.873383   7    10 !
! SS091 ='KHYR',  726508,   476.630768        647.714050   7    10 !
! SS092 ='KFSD',  726510,    94.328735        374.210144   7    10 !
! SS093 ='KCUT',  726514,  -424.749512        403.337982   7    10 !
! SS094 ='KBKX',  726515,    89.727325        450.046783   7    10 !
! SS095 ='KPHP',  726516,  -270.501099        428.665131   7    10 !
! SS096 ='KIEN',  726517,  -344.901764        324.377960   7    10 !
! SS097 ='KICR',  726518,  -139.856018        355.472290   7    10 !
! SS098 ='K8D3',  726519,    73.856110        592.815918   7    10 !
! SS099 ='KYKN',  726525,    47.198750        304.747040   7    10 !
! SS100 ='K9V9',  726530,   -99.478973        394.145111   7    10 !
! SS101 ='KD07',  726539,  -297.153381        532.540222   7    10 !
! SS102 ='KHON',  726540,   -17.115011        458.027527   7    10 !
! SS103 ='KORB',  726544,   362.149048        849.423584   7    10 !
! SS104 ='KMHE',  726545,    -2.867938        394.439606   7    10 !
! SS105 ='KATY',  726546,    62.674583        515.427490   7    10 !
! SS106 ='KGHW',  726547,   196.441757        592.791626   7    10 !
! SS107 ='KRRT',  726548,   184.543518        938.973633   7    10 !
! SS108 ='KCQM',  726549,   374.770538        829.738953   7    10 !
! SS109 ='KSTC',  726550,   289.477570        585.952942   7    10 !
! SS110 ='KMVE',  726553,   170.196106        521.343323   7    10 !
! SS111 ='KJYG',  726554,   258.831940        421.393066   7    10 !
! SS112 ='KBRD',  726555,   279.693115        675.731506   7    10 !
! SS113 ='KRWF',  726556,   217.481979        478.586823   7    10 !
! SS114 ='KAXN',  726557,   190.130997        617.650024   7    10 !
! SS115 ='KCOQ',  726558,   395.496307        713.259888   7    10 !
! SS116 ='KMML',  726559,   162.968735        466.842621   7    10 !
! SS117 ='KFFM',  726560,   133.957138        658.783936   7    10 !
! SS118 ='KADC',  726561,   202.232361        677.177307   7    10 !
! SS119 ='KLVN',  726562,   355.831726        493.177429   7    10 !
! SS120 ='KFBL',  726563,   351.367981        461.196899   7    10 !
! SS121 ='KRGK',  726564,   410.713379        492.334595   7    10 !
! SS122 ='KMOX',  726565,   149.050827        583.337769   7    10 !
! SS123 ='KPQN',  726566,   127.867722        417.218353   7    10 !
! SS124 ='KULM',  726567,   261.794373        456.355988   7    10 !
! SS125 ='KOWA',  726568,   356.252655        440.308838   7    10 !
! SS126 ='KHCD',  726569,   269.311188        513.197021   7    10 !
! SS127 ='KMFI',  726574,   580.651794        510.377930   7    10 !
! SS128 ='KMIC',  726575,   343.520233        538.094177   7    10 !
! SS129 ='KILL',  726576,   215.343185        538.084961   7    10 !
! SS130 ='KANE',  726577,   354.121063        547.264282   7    10 !
! SS131 ='KLXL',  726578,   267.035187        627.336975   7    10 !
! SS132 ='KFCM',  726579,   335.989746        513.490601   7    10 !
! SS133 ='KMSP',  726580,   353.555969        519.771912   7    10 !
! SS134 ='KLJF',  726583,   258.245758        542.910095   7    10 !
! SS135 ='KSTP',  726584,   366.675781        525.429749   7    10 !
! SS136 ='KMKT',  726585,   305.851746        448.014862   7    10 !
! SS137 ='KFRM',  726586,   270.888275        386.311646   7    10 !
! SS138 ='KOTG',  726587,   183.869949        384.251251   7    10 !
! SS139 ='KONA',  726588,   472.697937        442.873871   7    10 !
! SS140 ='KAEL',  726589,   350.012085        393.702515   7    10 !
! SS141 ='KMJQ',  726593,   228.025085        385.108063   7    10 !
! SS142 ='KTOB',  726596,   389.349762        431.199585   7    10 !
! SS143 ='KSGS',  726603,   369.330719        517.929749   7    10 !
! SS144 ='KRAP',  726620,  -379.573975        433.557648   7    10 !
! SS145 ='KRCA',  726625,  -382.719269        444.108978   7    10 !
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! SS146 ='K2WX',  726627,  -406.119324        598.495300   7    10 !
! SS147 ='KGDV',  726676,  -485.291168        764.848572   7    10 !
! SS148 ='KROS',  726679,   369.271759        606.119019   7    10 !
! SS149 ='KPNM',  726682,   321.927612        589.078491   7    10 !
! SS150 ='KMBG',  726685,  -176.595627        581.943726   7    10 !
! SS151 ='KPIR',  726686,  -170.840286        460.034729   7    10 !
! SS152 ='KBHK',  726777,  -451.931519        680.796631   7    10 !
! SS153 ='KTWM',  727444,   447.882660        753.196777   7    10 !
! SS154 ='KIWD',  727445,   568.052795        708.005310   7    10 !
! SS155 ='KMZH',  727449,   375.724762        682.198181   7    10 !
! SS156 ='KDLH',  727450,   416.484497        729.449829   7    10 !
! SS157 ='KCKN',  727452,    97.614517        821.203613   7    10 !
! SS158 ='KPKD',  727453,   210.237167        725.100281   7    10 !
! SS159 ='KCKC',  727454,   538.050964        843.562256   7    10 !
! SS160 ='KHIB',  727455,   366.902435        783.460327   7    10 !
! SS161 ='KDYT',  727456,   428.819427        717.451233   7    10 !
! SS162 ='KDTL',  727457,   152.005173        715.434570   7    10 !
! SS163 ='KGPZ',  727458,   322.304291        757.524109   7    10 !
! SS164 ='KELO',  727459,   436.137146        833.787537   7    10 !
! SS165 ='KDXX',  727466,   135.592072        522.303162   7    10 !
! SS166 ='KFGN',  727467,   213.240936        979.714966   7    10 !
! SS167 ='KFOZ',  727468,   307.224548        821.887573   7    10 !
! SS168 ='KGNA',  727469,   540.576965        834.178345   7    10 !
! SS169 ='KINL',  727470,   320.312805        905.074768   7    10 !
! SS170 ='KCDD',  727473,   386.335419        877.262329   7    10 !
! SS171 ='KEVM',  727474,   391.790405        788.879883   7    10 !
! SS172 ='KJMR',  727475,   345.046997        624.486511   7    10 !
! SS173 ='KBDE',  727476,   235.597336        918.279846   7    10 !
! SS174 ='KROX',  727477,   160.620377        929.324951   7    10 !
! SS175 ='KHCO',  727478,    74.069351        916.788330   7    10 !
! SS176 ='KVWU',  727486,   244.470413        858.134155   7    10 !
! SS177 ='KXVG',  727497,   272.035095        736.835632   7    10 !
! SS178 ='KCBG',  727503,   348.076263        590.344666   7    10 !
! SS179 ='KAIT',  727504,   312.392944        692.284912   7    10 !
! SS180 ='KFSE',  727505,   158.197388        796.274719   7    10 !
! SS181 ='KMWM',  727506,   218.269440        412.281738   7    10 !
! SS182 ='KBBB',  727507,   172.873306        559.424866   7    10 !
! SS183 ='KPWC',  727508,   260.166504        708.491943   7    10 !
! SS184 ='KSAZ',  727514,   231.012894        671.240906   7    10 !
! SS185 ='KVVV',  727515,   116.557121        555.432495   7    10 !
! SS186 ='KGYL',  727517,   292.026825        503.395447   7    10 !
! SS187 ='KFAR',  727530,    85.235794        724.666626   7    10 !
! SS188 ='KETH',  727533,   107.109177        604.916931   7    10 !
! SS189 ='KJMS',  727535,   -48.600674        724.799500   7    10 !
! SS190 ='KBJI',  727550,   217.668808        789.249329   7    10 !
! SS191 ='KTVF',  727555,   127.754288        845.218018   7    10 !
! SS192 ='KBFW',  727556,   470.053284        775.894714   7    10 !
! SS193 ='KAUM',  727566,   382.861328        393.856171   7    10 !
! SS194 ='KDVL',  727573,   -63.301125        849.265076   7    10 !
! SS195 ='KRDR',  727575,    42.193775        833.090881   7    10 !
! SS196 ='KGFK',  727576,    58.054287        831.958191   7    10 !
! SS197 ='KHEI',  727584,  -338.650360        637.574768   7    10 !
! SS198 ='KBIS',  727640,  -197.468048        711.348206   7    10 !
! SS199 ='KDIK',  727645,  -344.816040        720.144897   7    10 !
! SS200 ='KISN',  727670,  -395.559692        870.364624   7    10 !
! SS201 ='KMIB',  727675,  -234.574783        887.034424   7    10 !
! SS202 ='KMOT',  727676,  -229.883179        868.627991   7    10 !
! SS203 ='KN60',  727677,  -243.419296        806.407776   7    10 !
! SS204 ='KSDY',  727687,  -437.134430        821.736145   7    10 !
! SS205 ='DB21',  992130,   569.102051        789.578186   7    10 !
! SS206 ='DISW',  994190,   518.981140        762.303711   7    10 !
! SS207 ='GDMM',  997259,   541.324097        834.560608   7    10 !
! SS208 ='DULM',  997269,   208.355286        712.645996   7    10 !
! SS209 ='SLVM',  997737,   492.508667        779.533997   7    10 !
! SS210 ='SXHW',  997738,   545.045349        710.175049   7    10 !
! SS211 ='KABR',   14929,   -30.927084        569.527222   7    10 !
! SS212 ='CXCA',  712910,   665.708           995.123      7    10 !
! SS213 ='CWKK',  714680,   659.087          1054.620      7    10 !
! SS214 ='CZTB',  716670,   605.270           905.768      7    10 !
! SS215 ='CYQT',  717490,   606.384           905.880      7    10 !
! SS216 ='CWEC',  717510,   620.303           907.286      7    10 !
! SS217 ='KPCZ',  720343,   670.534           487.112      7    10 !
! SS218 ='KBUU',  722059,   743.135           322.231      7    10 !
! SS219 ='KFEP',  722082,   650.792           265.980      7    10 !
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! SS220 ='KTKV',  722332,   600.874           599.685      7    10 !
! SS221 ='KLNL',  723123,   637.072           675.329      7    10 !
! SS222 ='KRFD',  725430,   687.861           264.429      7    10 !
! SS223 ='KARV',  726404,   602.749           648.160      7    10 !
! SS224 ='KMWC',  726405,   758.425           368.114      7    10 !
! SS225 ='KUES',  726409,   744.074           359.229      7    10 !
! SS226 ='KMSN',  726410,   658.688           360.685      7    10 !
! SS227 ='KETB',  726413,   748.375           399.775      7    10 !
! SS228 ='KEFT',  726414,   645.849           304.217      7    10 !
! SS229 ='KJVL',  726415,   687.411           308.790      7    10 !
! SS230 ='KSTE',  726426,   631.316           505.457      7    10 !
! SS231 ='KRRL',  726449,   611.236           572.272      7    10 !
! SS232 ='KGRB',  726450,   735.334           513.081      7    10 !
! SS233 ='KISW',  726452,   609.461           483.824      7    10 !
! SS234 ='KOSH',  726456,   708.916           454.486      7    10 !
! SS235 ='KATW',  726457,   708.810           483.186      7    10 !
! SS236 ='KAUW',  726463,   619.378           544.664      7    10 !
! SS237 ='KRYV',  726464,   705.542           368.458      7    10 !
! SS238 ='KCWA',  726465,   617.935           528.652      7    10 !
! SS239 ='KCLI',  726502,   688.915           518.593      7    10 !
! SS240 ='KDLL',  726503,   622.616           397.178      7    10 !
! SS241 ='KEGV',  726504,   635.279           651.763      7    10 !
! SS242 ='KFLD',  726506,   716.660           432.829      7    10 !
! SS243 ='KUNU',  726509,   704.428           395.344      7    10 !
! SS244 ='KAIG',  726626,   655.759           571.941      7    10 !
! SS245 ='KRHI',  727415,   624.144           618.968      7    10 !
! SS246 ='KIMT',  727437,   720.330           648.861      7    10 !
! SS247 ='KCMX',  727440,   676.490           786.555      7    10 !
! SS248 ='PILM',  994090,   674.212           897.149      7    10 !
! SS249 ='ROAM',  994130,   611.612           853.525      7    10 !
! SS250 ='PCLM',  997732,   673.459           796.578      7    10 !
-------------------
      1
        Four character string for station name
        (MUST START IN COLUMN 9)

      2
        Six digit integer for station ID
!END!
--------------------------------------------------------------------------------
INPUT GROUP: 8 -- Upper air meteorological station parameters
--------------

     UPPER AIR STATION VARIABLES
     (One record per station --  10  records in all)

             1     2
         Name    ID      X coord.   Y coord.  Time zone
                            (km)       (km)
        ---------------------------------------------
! US1  ='ABR'   14929    -30.853664   569.526855   7  !
! US2  ='BIS'   24011   -197.624863   710.933411   7  !
! US3  ='DVN'   94982    579.394958   191.740204   7  !
! US4  ='GGW'   94008   -603.732971   887.948792   7  !
! US5  ='GRB'   14898    734.982605   509.566772   7  !
! US6  ='INL'   14918    321.891815   905.579956   7  !
! US7  ='LBF'   24023   -210.715042   121.217461   7  !
! US8  ='MPX'   94983    330.071899   512.976318   7  !
! US9  ='OAX'   94980    127.800606   139.010620   7  !
! US0 = 'UNR'   94043   -391.126526   436.751404   7  !

-------------------
      1
        Four character string for station name
        (MUST START IN COLUMN 9)

      2
        Five digit integer for station ID

!END!
--------------------------------------------------------------------------------
INPUT GROUP: 9 -- Precipitation station parameters
--------------
```

```
     PRECIPITATION STATION VARIABLES
     (One record per station --  267  records in all)
     (NOT INCLUDED IF NPSTA = 0)

            1          2
         Name   Station    X coord.  Y coord.
                  Code       (km)      (km)
         ------------------------------------
! PS1   ='BVDI', 110583,    704.8387    272.3856   !
! PS002 ='FEEI', 113262,    647.5109    271.0132   !
! PS003 ='LNKI', 114879,    631.2090    247.9581   !
! PS004 ='MHYI', 115493,    751.1465    283.1947   !
! PS005 ='KRFD', 117382,    687.8933    264.1178   !
! PS006 ='AMSI', 130200,    327.6863    218.9460   !
! PS007 ='BLVI', 130608,    584.8422    261.4843   !
! PS008 ='BYRI', 130853,    217.6606    225.4780   !
! PS009 ='CASI', 131257,    539.0943    261.5334   !
! PS010 ='CCTI', 131363,    500.1082    248.3606   !
! PS011 ='CKPI', 131442,    188.7850    290.5321   !
! PS012 ='KDBQ', 132367,    562.0087    273.8914   !
! PS013 ='FSCI', 132977,    332.1617    351.2404   !
! PS014 ='HORI', 133944,    148.3817    226.7336   !
! PS015 ='HBTI', 133980,    289.6530    290.3780   !
! PS016 ='IDGI', 134038,    191.6283    252.6864   !
! PS017 ='IWAI', 134142,    365.1421    272.9465   !
! PS018 ='MSHI', 135198,    393.2604    227.0463   !
! PS019 ='KMCW', 135235,    355.9792    338.8755   !
! PS020 ='MGGI', 135315,    520.6938    336.1376   !
! PS021 ='MOVI', 135823,    148.6746    262.4633   !
! PS022 ='OCHI', 136190,    187.3795    359.1556   !
! PS023 ='OGDI', 136209,    306.8351    219.8488   !
! PS024 ='REMI', 136975,    155.4437    295.9428   !
! PS025 ='RINI', 137058,    265.1759    349.3717   !
! PS026 ='RWCI', 137167,    259.9339    254.6663   !
! PS027 ='SANI', 137326,    385.8669    364.4076   !
! PS028 ='SHFI', 137572,    360.6382    314.8558   !
! PS029 ='SHRI', 137602,    413.0282    295.5028   !
! PS030 ='SIBI', 137664,    173.7475    363.5918   !
! PS031 ='SIXI', 137700,    140.9742    320.5928   !
! PS032 ='KSUX', 137708,    125.0175    250.8047   !
! PS033 ='K3SE', 137844,    217.3630    334.0425   !
! PS034 ='SPLI', 137855,    460.0540    350.6164   !
! PS035 ='STYI', 137985,    341.7265    236.1608   !
! PS036 ='SPTI', 138009,    495.9100    298.6285   !
! PS037 ='TREI', 138315,    427.3502    241.8837   !
! PS038 ='KALO', 138706,    430.4512    280.4854   !
! PS039 ='WEBI', 138806,    323.6514    265.5879   !
! PS040 ='ALBM', 200089,    684.2539    732.0740   !
! PS041 ='BRUM', 201088,    635.1568    715.0804   !
! PS042 ='IRNM', 204090,    722.8865    645.7775   !
! PS043 ='KENM', 204328,    657.2375    712.0861   !
! PS044 ='ONGM', 206215,    622.5252    747.8704   !
! PS045 ='STMM', 207812,    680.3516    669.5223   !
! PS046 ='WAKM', 208559,    581.8848    704.2177   !
! PS047 ='ALBM', 210075,    355.3395    386.1382   !
! PS048 ='KAXN', 210112,    190.1019    616.1816   !
! PS049 ='AXNM', 210116,    192.0553    619.1755   !
! PS050 ='AMBM', 210157,    288.7599    411.9700   !
! PS051 ='BGFM', 210746,    294.6127    864.8739   !
! PS052 ='BKKM', 210973,    102.1184    655.9871   !
! PS053 ='BUFM', 211107,    303.8945    548.1531   !
! PS054 ='CMBM', 211227,    357.2755    590.0135   !
! PS055 ='RLWM', 211250,    196.2616    904.4382   !
! PS056 ='CANM', 211263,    128.1724    493.1620   !
! PS057 ='DDGM', 212166,    384.4749    433.4247   !
! PS058 ='KDLH', 212248,    417.3215    728.7693   !
! PS059 ='ELYM', 212543,    432.4948    844.2844   !
! PS060 ='ELVM', 212645,    388.3740    792.2442   !
! PS061 ='FLDM', 212842,    367.2563    739.9268   !
! PS062 ='FSSM', 212916,    161.3947    793.3084   !
! PS063 ='FRZM', 212964,    164.9626    706.2097   !
! PS064 ='GOLM', 213202,    339.6924    530.6596   !
! PS065 ='GDPM', 213296,    584.3096    861.8482   !
! PS066 ='GTEM', 213311,    181.4707    504.9010   !
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! PS067 ='GLLM', 213411,    263.0453    675.7494   !
! PS068 ='GNFM', 213417,    498.9962    874.2490   !
! PS069 ='HLSM', 213463,     82.9847    769.6907   !
! PS070 ='HLYM', 213863,    404.9866    689.0575   !
! PS071 ='HSNM', 213962,    269.0934    518.4244   !
! PS072 ='KINL', 214026,    320.6607    905.0931   !
! PS073 ='LCRM', 214418,    503.6740    423.0656   !
! PS074 ='LKFM', 214453,    215.1507    390.1127   !
! PS075 ='FEDM', 214652,    269.2213    763.7258   !
! PS076 ='LESM', 214721,    305.6771    474.0750   !
! PS077 ='LTFM', 214793,    265.6005    631.9966   !
! PS078 ='LUVM', 214937,    135.9208    384.2386   !
! PS079 ='MRSM', 215175,    307.8797    805.9199   !
! PS080 ='KMSP', 215435,    353.5560    519.7719   !
! PS081 ='NRFM', 215987,    360.9039    478.3724   !
! PS082 ='ONMM', 216166,    314.9640    642.0206   !
! PS083 ='ORWM', 216228,    132.1633    650.9859   !
! PS084 ='PKGM', 216612,    314.5689    766.2769   !
! PS085 ='RIAM', 216795,    210.4573    827.7108   !
! PS086 ='RDWM', 216822,    401.1355    493.9360   !
! PS087 ='KRST', 217004,    414.0315    420.8777   !
! PS088 ='RUDM', 217184,    471.0624    414.2486   !
! PS089 ='KSTC', 217294,    289.5603    585.7471   !
! PS090 ='SDYM', 217460,    336.0036    719.4551   !
! PS091 ='SHRM', 217602,    243.9724    383.5873   !
! PS092 ='SPFM', 217907,    225.7181    447.4742   !
! PS093 ='SPRM', 217917,    482.1662    394.8293   !
! PS094 ='SPGM', 217941,    423.4222    399.2727   !
! PS095 ='TLRM', 218235,    142.8105    889.9860   !
! PS096 ='TOFM', 218280,    506.4730    812.3920   !
! PS097 ='TCYM', 218323,    177.4506    445.1472   !
! PS098 ='TWNM', 218411,    121.8223    756.6730   !
! PS099 ='WALM', 218613,    448.5977    775.0430   !
! PS100 ='WAKM', 218621,    244.9690    747.1674   !
! PS101 ='WRRM', 218679,    186.0316    935.6436   !
! PS102 ='WTSM', 218729,    163.5419    526.7195   !
! PS103 ='WHRM', 218947,    104.7027    613.4695   !
! PS104 ='WLLM', 219004,    220.1296    540.7602   !
! PS105 ='WNBM', 219059,    280.0303    783.5529   !
! PS106 ='KOTG', 219170,    182.9918    383.1815   !
! PS107 ='ALZM', 240165,   -473.8755    541.4405   !
! PS108 ='EKLM', 242689,   -476.9735    633.4473   !
! PS109 ='GNDM', 243581,   -479.6689    761.5683   !
! PS110 ='ISMM', 244442,   -490.4647    698.6182   !
! PS111 ='PTWM', 246589,   -452.8222    937.0795   !
! PS112 ='WSBM', 248777,   -419.1858    943.3163   !
! PS113 ='AMEN', 250180,    -73.5246    233.7535   !
! PS114 ='BSTN', 250580,   -118.4281    270.1134   !
! PS115 ='CLEN', 251776,     60.8985    261.9291   !
! PS116 ='CFTN', 252049,     40.3591    297.2858   !
! PS117 ='HRRN', 253620,   -464.1168    293.2032   !
! PS118 ='LYNN', 255040,    -35.0843    295.4801   !
! PS119 ='PNDN', 256630,    100.2274    221.5656   !
! PS120 ='PIRN', 256720,     37.0557    229.3818   !
! PS121 ='ROYN', 257351,     -7.7141    248.3947   !
! PS122 ='KVTN', 258760,   -195.1619    303.3590   !
! PS123 ='WAYN', 259050,     72.8387    240.0117   !
! PS124 ='WHIN', 259262,   -265.8226    222.7091   !
! PS125 ='ADMN', 320022,     -8.3296    871.8898   !
! PS126 ='AMBN', 320189,   -379.4584    954.1055   !
! PS127 ='ALYN', 320382,   -100.2561    631.6342   !
! PS128 ='BLDN', 320450,     -5.9390    735.8462   !
! PS129 ='BFRN', 320492,   -180.9230    831.2956   !
! PS130 ='KBIS', 320819,   -198.0849    712.3129   !
! PS131 ='BOWN', 320995,   -392.1297    658.3008   !
! PS132 ='CAON', 321288,    -82.5768    888.9763   !
! PS133 ='CRNN', 321362,    -79.5731    785.9337   !
! PS134 ='CVLN', 321435,     20.7365    927.9660   !
! PS135 ='DAWN', 322018,   -125.4999    719.1512   !
! PS136 ='KDIK', 322183,   -344.4455    720.3346   !
! PS137 ='DCKN', 322188,   -344.9175    730.0309   !
! PS138 ='KFAR', 322859,     85.2358    724.6666   !
! PS139 ='GLNN', 323496,   -275.0014    718.2638   !
! PS140 ='GRAN', 323594,     40.1860    881.1769   !
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! PS141 ='KGFK', 323616,     57.4969    831.3218   !
! PS142 ='GRFN', 323621,     63.5791    829.1727   !
! PS143 ='HFDN', 323926,    -13.2475    764.6330   !
! PS144 ='HZTN', 324083,   -169.5298    683.5571   !
! PS145 ='HETN', 324180,   -338.1250    636.4974   !
! PS146 ='KJMS', 324413,    -47.9586    724.3745   !
! PS147 ='LNGN', 324958,    -23.9686    917.3320   !
! PS148 ='LDSN', 325078,   -100.3021    868.1802   !
! PS149 ='MESN', 325479,   -208.9686    715.8164   !
! PS150 ='MCGN', 325720,   -343.1684    909.5942   !
! PS151 ='KMOT', 325988,   -229.3390    868.1865   !
! PS152 ='MNON', 325993,   -231.3919    860.2588   !
! PS153 ='MONN', 326105,    -42.0241    700.6135   !
! PS154 ='MTTN', 326155,   -312.1531    673.7914   !
! PS155 ='OAKN', 326620,     -6.4662    639.6499   !
! PS156 ='PBAN', 326947,     52.6743    939.8636   !
! PS157 ='RAUN', 327405,   -284.0016    823.9304   !
! PS158 ='RDTN', 327530,   -309.6853    727.9753   !
! PS159 ='RIVN', 327585,   -239.5621    788.9016   !
! PS160 ='RTEN', 327655,   -125.2927    906.5640   !
! PS161 ='SRLN', 327844,    -68.9054    936.9689   !
! PS162 ='TWNN', 328792,   -167.2207    878.3873   !
! PS163 ='TRON', 328812,   -420.1660    775.9999   !
! PS164 ='TUTN', 328853,   -136.6915    765.0718   !
! PS165 ='WTGN', 329219,   -259.4384    634.7834   !
! PS166 ='KISN', 329425,   -395.3525    868.1364   !
! PS167 ='WTON', 329455,   -199.0533    751.7303   !
! PS168 ='KABR', 390020,    -30.3432    568.7914   !
! PS169 ='BROS', 391076,     92.1705    451.9631   !
! PS170 ='CACS', 391294,   -437.8077    594.8177   !
! PS171 ='CPRS', 391452,      8.2556    489.8082   !
! PS172 ='CWDS', 391972,   -290.4360    420.1009   !
! PS173 ='EMTS', 392557,   -444.1663    359.8992   !
! PS174 ='EGMS', 392565,   -447.2860    393.6244   !
! PS175 ='FAIS', 392852,   -298.5418    531.3470   !
! PS176 ='GTYS', 393302,   -164.0811    525.8958   !
! PS177 ='HOWS', 394037,     35.7884    419.1016   !
! PS178 ='KHON', 394127,    -16.6633    459.3860   !
! PS179 ='INTS', 394184,   -297.4555    398.1286   !
! PS180 ='ISAS', 394268,   -252.1393    568.5466   !
! PS181 ='LNRS', 394651,   -271.9312    329.3606   !
! PS182 ='LKSS', 394766,   -109.6760    425.3580   !
! PS183 ='LEMS', 394864,   -302.8922    628.0018   !
! PS184 ='MCIS', 395381,   -239.2239    614.5892   !
! PS185 ='MNOS', 395481,     32.6538    337.9855   !
! PS186 ='MVLS', 395544,   -269.8144    477.8271   !
! PS187 ='MSSS', 395620,   -201.9105    348.2929   !
! PS188 ='MURS', 395891,   -203.9713    409.3122   !
! PS189 ='PIES', 396170,   -180.5313    466.4690   !
! PS190 ='ONKS', 396282,   -108.4420    547.5420   !
! PS191 ='ORLS', 396304,   -399.6830    367.4265   !
! PS192 ='RAPS', 396427,   -411.5727    437.1682   !
! PS193 ='PKSS', 396574,    -40.6760    320.5826   !
! PS194 ='KPIR', 396597,   -170.8458    459.8257   !
! PS195 ='PNVS', 396636,   -312.4171    483.0867   !
! PS196 ='KRAP', 396937,   -379.5922    433.2443   !
! PS197 ='K3DE', 397052,    -38.9352    508.4391   !
! PS198 ='EROS', 397662,    103.6776    391.1785   !
! PS199 ='FSDS', 397666,     96.1284    375.3860   !
! PS200 ='KFSD', 397667,     94.3272    374.3146   !
! PS201 ='SPES', 397882,   -437.6306    486.2325   !
! PS202 ='STPS', 397992,   -112.4635    446.7385   !
! PS203 ='STKS', 398007,    -33.0744    375.5005   !
! PS204 ='VRMS', 398622,     82.8919    289.0081   !
! PS205 ='KATY', 398932,     63.0713    512.7103   !
! PS206 ='WNRS', 398980,     48.2724    568.4824   !
! PS207 ='WNDS', 399347,   -414.0301    384.8526   !
! PS208 ='AFTW', 470045,    685.2767    311.5101   !
! PS209 ='ALMW', 470124,    454.5445    467.7898   !
! PS210 ='ARLW', 470308,    658.3940    377.4543   !
! PS211 ='AEFW', 470349,    506.3299    707.5601   !
! PS212 ='BBCW', 470456,    588.1370    475.5576   !
! PS213 ='BLKW', 470855,    534.3033    469.9684   !
! PS214 ='BVLW', 470890,    622.5366    323.1918   !
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! PS215 ='CHMW', 471416,    649.4243    351.2666   !
! PS216 ='CHIW', 471568,    738.9901    462.9800   !
! PS217 ='CHFW', 471578,    487.9245    533.2549   !
! PS218 ='CLIW', 471667,    700.7871    302.8314   !
! PS219 ='CNTW', 471676,    687.5571    519.3958   !
! PS220 ='CRIW', 471897,    720.0029    600.3361   !
! PS221 ='CBCW', 471913,    578.7880    299.1148   !
! PS222 ='EPLW', 472447,    611.8039    522.4976   !
! PS223 ='FRSW', 472973,    613.6624    443.8912   !
! PS224 ='GENW', 473038,    512.1511    392.7966   !
! PS225 ='KGRB', 473269,    734.4010    509.3955   !
! PS226 ='HARW', 473453,    727.3196    387.8478   !
! PS227 ='HYRW', 473511,    472.1889    644.6486   !
! PS228 ='THRW', 473636,    660.4031    627.8968   !
! PS229 ='HORW', 473756,    709.3147    397.4457   !
! PS230 ='KLSE', 474370,    507.8517    424.7510   !
! PS231 ='KARX', 474373,    512.9490    419.4862   !
! PS232 ='LADW', 474396,    507.2212    588.8231   !
! PS233 ='LAFW', 474404,    556.4146    396.8088   !
! PS234 ='LANW', 474546,    551.7680    318.1030   !
! PS235 ='LUCW', 474894,    404.0576    595.1112   !
! PS236 ='LYNW', 474937,    524.9281    356.1731   !
! PS237 ='KMSN', 474961,    658.6881    360.6846   !
! PS238 ='MFDW', 475120,    584.9993    510.2444   !
! PS239 ='MEDW', 475255,    564.6284    560.8494   !
! PS240 ='MENW', 475335,    449.3014    524.7825   !
! PS241 ='MERW', 475352,    574.7755    670.8159   !
! PS242 ='RRLW', 475364,    614.4525    569.6350   !
! PS243 ='MNGW', 475524,    448.9307    653.5699   !
! PS244 ='NRIW', 475948,    401.2504    547.0966   !
! PS245 ='PKFW', 476398,    549.4885    643.9443   !
! PS246 ='PHEW', 476518,    647.8389    667.1542   !
! PS247 ='PORW', 476718,    647.9724    400.2571   !
! PS248 ='PRNW', 476854,    564.8926    604.7028   !
! PS249 ='LTKW', 476939,    615.9632    639.5358   !
! PS250 ='RILW', 477132,    457.3847    582.2273   !
! PS251 ='RRVW', 477140,    604.4020    607.5921   !
! PS252 ='SPOW', 478027,    446.7621    624.3160   !
! PS253 ='STMW', 478259,    492.2289    488.2560   !
! PS254 ='KMKX', 478316,    720.9299    348.8920   !
! PS255 ='TOMW', 478515,    563.0179    441.0115   !
! PS256 ='TREW', 478589,    493.0102    436.1974   !
! PS257 ='WLKW', 479176,    682.3917    577.6713   !
! PS258 ='WLDW', 479218,    540.3058    516.7501   !
! PS259 ='WTRW', 479304,    509.5294    628.9366   !
! PS260 ='DLCW', 482725,   -527.8164    377.3655   !
! PS261 ='LCKW', 485371,   -508.2396    336.7448   !
! PS262 ='MCTW', 486395,   -518.7186    461.0498   !
! PS263 ='MCKW', 486603,   -472.6974    370.2560   !
! PS264 ='NCLW', 486660,   -467.9591    419.5807   !
! PS265 ='OSGW', 486935,   -482.4476    433.2086   !
! PS266 ='TORW', 488995,   -481.9526    234.3690   !
! PS267 ='WLDW', 489615,   -537.7224    241.8340   !

--------------------
      1
        Four character string for station name
        (MUST START IN COLUMN 9)

      2
        Six digit station code composed of state
        code (first 2 digits) and station ID (last
        4 digits)

!END!
```

Appendix C

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

DRAFT

Otter Tail Power Company
Big Stone Generating Station
Unit 1

Best Available Retrofit Technology Analysis

November 2, 2009

Project 53777

Otter Tail Power Company
Big Stone Plant
Unit I
Best Available Retrofit Technology Analysis

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EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency (EPA) finalized the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations in 2005 (40 CFR 51, Subpart P; 40 CFR 51, App. Y). 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 a BART-eligible source. 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 non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology" (40 CFR 51.301). This document presents the BART analysis for each of three major pollutants (nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM)) for Otter Tail Power Company's (OTPC's) Big Stone Plant (BSP) Unit I located near Big Stone City, South Dakota. Otter Tail Power Company is operating agent for the Big Stone Plant co-owners: NorthWestern Energy, Montana-Dakota Utilities, Co., a division of MDU Resources Group, and Otter Tail Power Company.

BSP is a steam electric generating plant with one generating unit burning Powder River Basin coal and a net electrical output of 475 MW. Particulate control for Unit I is provided by a conventional pulse-jet fabric filter installed in 2007. Nitrogen oxides (NO_x) emissions from the unit are controlled with an over-fire air system (OFA). The unit does not have controls for sulfur dioxide emissions other than firing low-sulfur Powder River Basin coal. Unit I began operation in 1975 and is presumed to be subject to the requirements for BART analysis under the Regional Haze Rule absent a formal determination to the contrary from the DENR.

The BART analysis steps 1 through 5 for NO_X, SO_2 and PM emissions from BSP are described in this report. Potentially applicable control technologies are first identified. A brief description of the processes and their capabilities are then reviewed for availability and feasibility. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to control capability. The impacts analysis then reviews the estimated capital and O&M costs for each alternative, the energy impacts and non-air quality impacts. The impact based on the remaining useful life of the source is reviewed as part of the cost analysis. In the final step of the analysis, feasible and available technologies are assessed for their potential visibility impairment impact reduction capability via visibility modeling results. The results of the impact analyses are tabulated and potential BART control options are listed.

The final result of this analysis is a recommendation of the Best Available Retrofit Technology (BART) based upon the detailed analysis conducted in this report. For NO_X, five control alternatives were identified and evaluated using the 5 steps. Over-fire air (OFA), separated over-fire air (SOFA), Selective Non-Catalytic Reduction (SNCR) with SOFA and Selective Catalytic Reduction (SCR) with SOFA were the technologies that remained after completing steps 1 though 4 of the analysis. To reduce visibility impacts due to NO_X emissions below a discernable level of 0.5 dV, SOFA is recommended as BART for BSP Unit I. Application of SOFA for NO_X control translates into a BART emission rate of 2,804 pounds per hour.

For SO_2, three control alternatives were identified and evaluated using the 5 steps. Wet FGD and semi-dry FGD at two levels of control were selected for visibility impacts evaluation after completing steps 1 though 4 of the analysis. To reduce visibility impacts due to SO_2 emissions below a discernable level of 0.5 dV, semi-dry FGD is recommended as BART for BSP Unit I. Application of semi-dry FGD for SO_2 control translates into a BART emission rate of 505 pounds per hour.

For the PM evaluation, three post combustion control technologies were selected for evaluation in addition to the existing pulse-jet fabric filter. BSP Unit I currently uses a pulse-jet fabric filter (installed in 2007) that is the best technology available for particulate control, the impact review was abbreviated and maintaining the existing pulse-jet fabric filter is recommended as BART for BSP Unit I. The corresponding BART emission rate for the existing fabric filter is 84.1 pounds per hour

Modeling to determine visibility impairment was performed using the recommended BSP Unit I BART emission rates for NO_X, SO_2, and PM. The 98th percentile results are provided in Table ES-1.

TABLE ES-1 – Visibility Impairment Impacts from Combined Emissions

Control Technique	NO_X Emission Rate (lb/hr)	SO_2 Emission Rate (lb/hr)	PM Emission Rate (lb/hr)	Visibility Impairment Impact (dV)
BART	2,804	505	84.1	0.493

The modeling showed that the proposed BART emissions rates for NO_X, SO_2 and PM caused no Class I area to exceed 0.5 dV for predicted visibility impairment impact (98th percentile) with Boundary Waters Canoe Area Wilderness (Boundary Waters) showing the highest predicted visibility impairment impact at 0.493 dV for the 2007 modeled year.

1.0 INTRODUCTION

The EPA finalized the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations in 2005 (40 CFR 51, Subpart P; 40 CFR 51, App.Y). 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 a BART-eligible source. 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 non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology" (40 CFR 51.301). This document presents the BART analysis for each of three major pollutants (nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM)) for Otter Tail Power Company's (OTPC's) Big Stone Plant (BSP) Unit I located near Big Stone City, South Dakota. Otter Tail Power Company is operating agent for the Big Stone Plant co-owners: NorthWestern Energy, Montana-Dakota Utilities, Co., a division of MDU Resources Group, and Otter Tail Power Company.

A BART eligible source is one that meets three criteria identified by EPA: (1) source is BART eligible if operations fall within one of 26 specifically listed source categories, (2) the source entered into service between August 7, 1962 and August 7, 1977, and (3) the source has the potential to emit 250 tons per year or more of any air (40 CFR 51.301)). The South Dakota Department of Environment & Natural Resources (DENR) reviewed the sources within South Dakota and independently determined which sources are BART eligible. The DENR classified the electric generating unit (EGU) at Big Stone Plant as BART eligible. Once a source is determined to be eligible, baseline modeling is performed to determine if the source "contributes" to visibility impairment by exceeding EPA's recommended 0.5 deciView (dV) threshold. Baseline modeling results show that Unit I at BSP exceeds the 0.5 dV impact threshold and is subject to a BART analysis.

The EPA has established guidelines for states to follow when determining BART. These guidelines are discretionary for sources other than 750 MW power plants (40 CFR 51.308(e); 40 CFR 51, App, Y, I.H). Per EPA's guidelines, the general steps for determining BART for each pollutant are (40 CFR 51, Appy. Y, IV.D.):

STEP 1 - Identify all available retrofit control technologies (within the BART Guidelines).
STEP 2 - Eliminate technically infeasible options.

STEP 3 - Evaluate control effectiveness of remaining control technologies.

STEP 4 - Evaluate the following impacts for each feasible control technology and document results:

- The cost of compliance.
- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

STEP 5 – Evaluate the visibility impacts.

OTPC retained Burns & McDonnell to assist in the completion of the Best Available Retrofit Technology analysis for Big Stone Plant (BSP) Unit I.[i] This report includes steps 1 through 5 of the BART Determination for emissions from Unit I at BSP. Section 1 of the report summarizes the plant conditions, provides the parameters used in the analysis and discusses the approach to the BART Determination. The BART analysis for each pollutant (NO_X, SO_2 and PM) is provided in Sections 2 through 5. Within the section for each pollutant, the results of each step of the BART analysis are summarized for the unit. Summaries are provided at the end of the report that communicate the results of each step in the analyses, that combine results obtained for each pollutant and that develop permit limit recommendations based upon a 30 day rolling average.

1.1 BACKGROUND

Otter Tail Power Company operates the Big Stone Plant near Big Stone City, South Dakota. BSP is a steam electric generating plant with one Babcock & Wilcox (B&W) cyclone-fired steam generating unit burning Powder River Basin coal and a net electrical output of 475 MW. Particulate control for Unit I was originally provided by an electrostatic precipitator. In 2001, a new developmental technology, the Advanced Hybrid™ system, was installed. The Advanced Hybrid™ technology used both an electrostatic precipitator and a fabric filter (baghouse) for exhaust gas particulate removal. However, the demonstration technology encountered operational problems during its testing phase, which resulted in decreased fabric filter life, decreased particulate removal efficiencies, and limited plant operations. Consequently, the Advanced Hybrid™ system was deemed unacceptable for particulate emissions control and was removed and replaced with a conventional pulse-jet fabric filter in 2007. The Advanced Hybrid™ system is not currently used in any coal-fired power plant. Nitrogen oxides (NO_x) emissions

[i] Burns & McDonnell plans, designs and constructs electric generating facilities and has been providing environmental services to the power industry since the 1970s. As a result of its long history providing these services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies, BART analysis and control technology analysis.

from the unit are controlled with an over-fire air system (OFA). The unit does not have controls for sulfur dioxide emissions other than firing low-sulfur Powder River Basin coal. Unit I began operation in 1975 and is presumed to be subject to the requirements for BART analysis under the Regional Haze Rule absent a formal determination to the contrary from the DENR.

1.2 BART ANALYSIS PARAMETERS

Table 1.2-1 contains the design and operating parameters for BSP Unit I used in the analysis. Typical coal parameters used in the BART analysis are provided in Table 1.2-2. The economic factors for this study are presented in Table 1.2-3.

TABLE 1.2-1 – Unit Design and Operating Parameters

Unit Characteristics	Unit I Parameters
Boiler Type	Cyclone
Boiler Manufacturer	B&W
Boiler Heat Input Capacity (descriptive), mmBtu/hr	5,609
Unit Generator Output Capacity, MW (net)	475
NO_X Emissions	
lb/mmBtu	0.86
lb/hr[1]	4,854.8
SO_2 Emissions	
lb/mmBtu	0.86
lb/hr[1]	4,832.2
PM Emissions	
lb/mmBtu	0.015
lb/hr[2]	84.1

[1]Highest 24-hour actual average emission rates during 2001-2003 as recommended by the BART Guideline. The SO_2 emission rate does not correspond to fuel sulfur content.
[2]Highest achievable 24-hour average emission rate based on the existing control technology emission rate and the unit heat input

TABLE 1.2-2 – Coal Parameters

Ultimate Coal Analysis (% by mass):	PRB Typical
Moisture	29.75
Carbon	49.30
Hydrogen	3.32
Nitrogen	0.66
Chlorine	0.01
Sulfur	0.33
Ash	4.63
Oxygen	12.00
Total	100.00
Higher Heating Value, Btu/lb	8,547
Ash Mineral Analysis (% by mass):	
Silica	35.51
Alumina	17.11
Titania	1.26
Calcium Oxide	26.67
Magnesium Oxide	5.30
Sodium Oxide	1.68
Iron Oxide	6.07
Sulfur Trioxide	1.56
Potassium Oxide	2.87
Phosphorus Pentoxide	0.97
Strontium Oxide	not reported
Barium Oxide	not reported
Manganese Oxide	not reported
Total	99.00

TABLE 1.2-3 – Economic Factors

Total Possible Operating Hours per Year	8,760
Amortization Life, Years	30
Discount Rate	9%
Construction Cost Escalation	3%
O&M Escalation	2%
Auxiliary Electric Power Cost, $/MW-hr	$25
Fly Ash Disposal Cost ($/ton)	$2
Bottom Ash Disposal ($/ton)	$3.50
Gypsum Waste Disposal ($/ton)	$1
Operating Labor Rate, $/hr	$48
Lime Cost ($/ton delivered)	$145
Limestone Cost ($/ton delivered)	$24
Urea Cost, ($/ton delivered)	$380
Ammonia Cost ($/ton delivered)	$325

1.3 APPROACH

The purpose of the Regional Haze Rule is to address visibility impairment in mandatory Class I areas that results from the emission of SO_2, NO_X, PM, Volatile Organic Compounds (VOCs) and ammonia from certain major sources. The visibility impact of VOCs and ammonia are considered negligible and are not addressed further in this report. Before the actual BART analysis can begin, a basis must be defined for establishing emission rates to be used for BSP Unit I. For NO_X and SO_2, the highest 24-hour actual average emission rates for 2001-2003 were used for the basis as recommended by the BART guideline. For PM, the achievable emission rate for the fabric filter installed in 2007 was used as the basis of the study. A sulfuric acid mist (SAM) emission rate of 3.604 pounds per hour as approved in the Modeling Protocol was used for the baseline evaluation and for all control scenarios.

In Part IV of the Guidelines for BART Determination, and discussed in Section 1.0 of this report, the EPA provides five basic steps for a case-by-case BART analysis although states have the discretion to adopt approaches that differ from the guidelines for sources other than 750 MW power plants. The format of this report follows these basic steps. The approach used to complete each step is summarized below.

1.3.1 IDENTIFICATION OF RETROFIT CONTROL TECHNOLOGIES

The initial step in the BART determination is the identification of retrofit control technologies. In order to identify the applicable control technologies, several reference works are consulted. A preliminary list of control technologies and their estimated capabilities is developed.

1.3.2 FEASIBILITY ANALYSIS

The second step of the BART process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible. The BART guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the "availability" and "applicability" of each control technology.

A control technology is considered available, "if the source owner may obtain it through commercial channels, or it is otherwise available in the common sense meaning of the term" or "if it has reached the stage of licensing and commercial availability." On the contrary, a control technology is not considered available "in the pilot scale testing stages of development." (70 FR 39165) When considering a source's applicability, technical judgment must be exercised to determine "if it can reasonably be installed and operated on the source type." The EPA also does not "expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type." (70 FR 39165) "A technology that is available and applicable is technically feasible." (70 FR 39165)

1.3.3 EVALUATE TECHNICALLY FEASIBLE CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the BART analysis, the control efficiency is reviewed and presented with the description of each technology. The evaluation of the technically feasible BART alternatives concludes with the alternatives ranked in descending order of control effectiveness.

1.3.4 IMPACT ANALYSIS

Step four in the BART analysis procedure is the impact analysis. The BART Guidelines lists four factors to be considered in the impact analysis:

- The costs of compliance;
- Energy impacts;

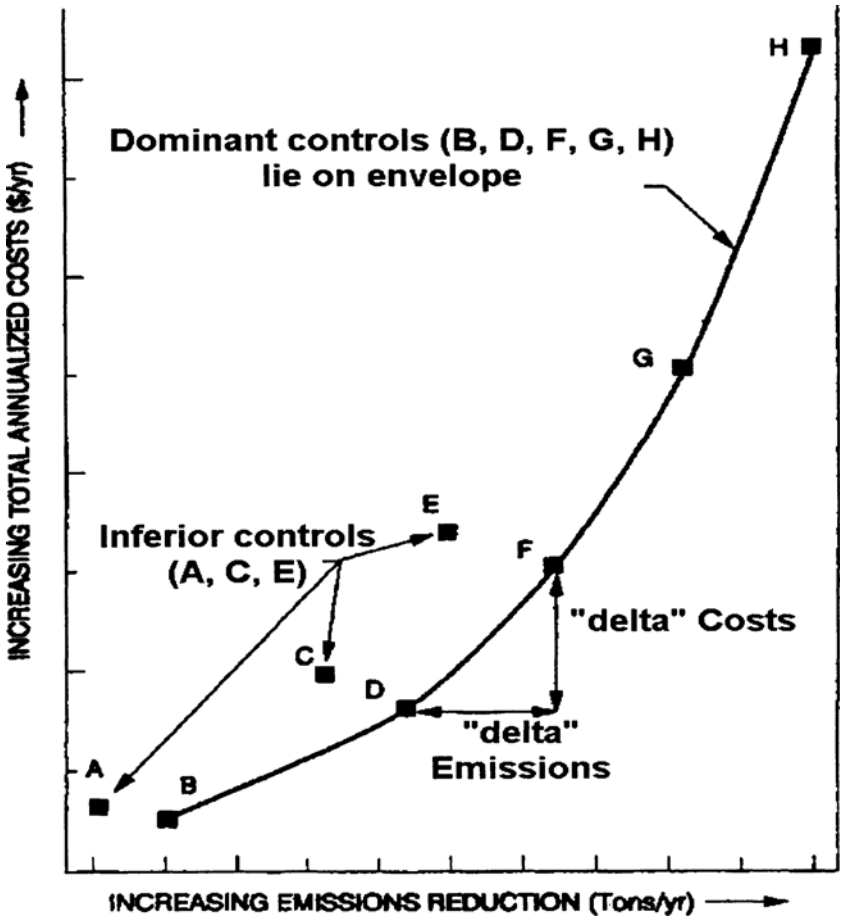
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

The first three of the four factors considered in the impact analysis are discussed in the associated pollutant section. The remaining useful life of the source is included as part of the cost of compliance. Due to the complexity involved with estimating costs, additional discussion is provided below.

1.3.5 METHODOLOGY FOR ESTIMATED COSTS

The economic evaluations of each control alternative are presented together for each pollutant in the respective sections of the report. Capital and O&M cost estimates for each control alternative are presented. The Levelized Total Annual Cost (LTAC) and Unit Control Costs for the control alternatives are calculated and presented. The Levelized Total Annual Cost (LTAC) represents the levelized annual cost of procurement, construction and operation over a 30 year design life in current (2009) dollars. As a minimum, the design life for any alternative was taken to be that recommended by "The EPA Air Pollution Control Cost Manual", Sixth Edition, January 2002, EPA/452/B-02-001.

The LTAC is used to calculate the average annual and incremental cost effectiveness of each alternative. The differences between alternatives are also presented graphically in the form of a plot of the LTAC versus the annual emissions reduction (tpy) for each alternative. This form of plot graphically depicts the cost effectiveness (in $/ton of pollutant reduction) of each alternative relative to all of the others. The average cost effectiveness is defined as the LTAC divided by the annual emissions reduction (ton/yr). The area on the plot indicated by the various data points represents the cost effectiveness envelope for the alternatives under consideration. A smooth line is drawn on this plot connecting the rightmost points (those with the lowest cost for a given level of emissions reduction). This line is referred to as the Dominant Control Curve (DCC). The DCC defines the right hand boundary of the envelope encompassing all of the alternatives considered. The DCC is used as a screening tool between considered alternatives. Those alternatives whose plotted position is above and/or to the left of the DCC are not as cost effective as those forming the line and thus can be eliminated from further analysis. An example DCC chart was provided in the BART Guidelines.



To more accurately compare alternatives having different costs and control efficiencies; the incremental cost effectiveness is also determined for those alternatives on the DCC. The incremental cost effectiveness is defined as the LTAC of a given control option minus the LTAC of an alternative, divided by the difference between the annual emissions reduction (tpy) of the given control option and the alternative being evaluated. The combination of these two economic analyses can be used as an argument for the elimination of control technologies with significantly greater marginal control costs than the given case. The equation used for the incremental cost effectiveness is shown below.

$$ICF = \frac{(LTAC_1 - LTAC_2)}{(AE_1 - AE_2)}$$

Where,

ICF = Incremental cost effectiveness ($/incremental ton removed)
$LTAC_1$ = Levelized Total Annual Cost of control alternative No. 1 ($/yr)
$LTAC_2$ = Levelized Total Annual Cost of control alternative No. 2 ($/yr)
AE_1 = Control option No. 1 Annual Emissions Reduction (ton/yr)
AE_2 = Control option No. 2 Annual Emissions Reduction (ton/yr)
(The higher cost, more effective control option is subscript 1 in this equation.)

The economic analyses presented in this report include not only the estimated capital and O&M costs for each alternative, but also the LTAC for economic comparison of the various alternatives. In addition, the average cost effectiveness is presented for each alternative. Finally, a comparison between alternatives, in the form of the incremental cost effectiveness, is presented in both numerical and graphical form. Thus a comprehensive comparison of the economic impacts of each alternative, as well as the differences in economic impact between alternatives is clearly presented.

1.3.6 METHODOLOGY FOR VISIBILITY IMPACTS DETERMINATION

In the BART Determination Guidelines, and discussed in Section 1.0 of this report, the EPA provides five basic steps for a case-by-case BART analysis. The fifth step involves evaluating visibility impacts utilizing dispersion modeling. Visibility impairment impacts for modeled baseline (pre-control) and post-control emission levels and visibility improvements are to be assessed in deciViews (dV). The BART guidelines describe the thresholds for visibility impairment as:

> "A single source that is responsible for a 1.0 dV change or more should be considered to "cause" visibility impairment; a source that causes less than a 1.0 dV change may still contribute to visibility impairment..... any threshold that you (the States) use for determining whether a source "contributes" to visibility impairment should not be higher than 0.5 dV." (70 FR 39161)

This study follows the EPA's Regional Haze Rule threshold recommendations and thus, 0.5 dV is the de minimis threshold level of visibility impairment impact for an otherwise BART-eligible source. In other words, a BART-eligible source for which modeling predicts a visibility impairment impact of greater than 0.5 dV is deemed to contribute to a visibility impairment impact and thus is subject to a case-by-case BART analysis. A BART-eligible source for which the modeling predicts less than a 0.5 dV impact

would be deemed to not have a visibility impairment impact, and thus could be exempted from a case-by-case BART analysis on that basis. Most noticeably, the EPA fails to address the question of whether or not a difference in visibility impairment impact improvement of less than 0.5 dV between two BART alternatives would constitute equivalency under the visibility analysis, or if any difference in the model results, no matter how slight, should be interpreted as ranking one solution over the other.

The approach taken in the BART analysis for BSP incorporates the visibility analysis results as part of the decision making process. If two alternatives have an identical potential for visibility improvement, the remaining criteria identified for consideration as part of the impact analysis are then used to differentiate between the two alternatives. Where similar visibility improvement potentials are identified for two or more alternatives, the incremental cost to achieve the slightly greater visibility improvement is determined and evaluated against incremental costs for the next most stringent alternative. This approach identifies the more effective BART alternative in terms of regional haze considerations, not in terms of the most stringent control alternative, as would happen if a strictly top-down approach had been implemented.

1.3.7 ADDITIONAL APPROACH METHODS

In addition to the steps discussed above, the presumptive limits and their application to power plants smaller than 750 MW in size warrant mention due to their effects on the contents of the report. For power plants greater than 750 MW in size, the EPA requires state agencies to apply the presumptive limits for BART as a floor for NO_X or SO_2 control. However, for power plants smaller than 750 MW in size, the presumptive limits are described as being "generally cost-effective" but not set as a minimum performance requirement (see, e.g., 40 CFR 51, App. Y, IV.E.4). Thus, EGUs at power plants smaller than 750 MW in size, like BSP, are not required to meet the presumptive BART limits. This BART analysis for BSP will evaluate potential control options that can attain presumptive limits on typical EGUs. However, based upon the feasibility analysis, the recommended control options may not achieve the EPA's presumptive BART limits for specific pollutants.

1.4 THE ROLE OF MODELING AND CALPUFF IN A BART ANALYSIS

The BART guidelines list visibility impact at a Class I area as one of the factors in a BART determination. For Class I areas more than 50 km from a source, the EPA has identified CALPUFF as a guideline model for long-range transport that is suitable for predicting potential changes in visibility.

CALPUFF is a non-steady-state meteorological and air quality dispersion modeling system used to assess long-range transport of pollutants. Seven Class I areas have been identified for inclusion in the visibility analysis for BSP. These are the Theodore Roosevelt National Park (NP), the Lostwood National Wildlife Refuge (WR), Voyagers NP, Isle Royal NP, Boundary Waters Canoe Area Wilderness, Badlands NP, and Wind Cave NP, the closest of which is more than 400 km (248 miles) from BSP.

1.4.1 CALPUFF MODELING METHODOLOGY

The specific version of CALPUFF, coordinate grid points, wind field options, terrain, dispersion options, receptor coordinates and plume characteristics and other model parameters approved by the DENR were used for modeling. Meteorological data for the years 2002, 2006 and 2007 were used for the modeling. In order to predict the change in light extinction at the Class I areas, SO_2, NO_X, and PM were modeled with CALPUFF using pre-control (baseline) and post-control emission scenarios. A variety of post-control scenarios were modeled to determine the reduction in visibility impact for each control technology.

The BART guideline states that a visibility improvement is based upon the modeled change in visibility impacts, measured in deciViews, for the pre-control and post-control emission scenarios. The comparison should be made for the 98th percentile days (40 CFR 51, App. Y, IV.D.5). In other words, visibility impacts should be compared on an annual basis using the eighth highest day for comparison (365 * (1-.98) ≈ 7 days of acceptable exceedance). Therefore, the visibility impairment impact reduction presented for each control scenario in this section is based on the 98th percentile value or eighth highest day.

1.4.2 MODELING SCENARIOS

Since a BART analysis is based on the degree of visibility impairment reduction achieved by the application of control technologies, the CALPUFF analysis examined multiple emission scenarios based upon the feasible control technologies identified for each pollutant. These scenarios represent the emissions of SO_2, NO_X, and PM under the following conditions:

- Baseline NO_X, SO_2 and PM emissions
- PM emissions based upon existing controlled baseline conditions, and NO_X and SO_2 emissions based upon application of several control technologies

The modeled emission rates in each scenario are presented in Table 1.4-1.

TABLE 1.4-1 – Big Stone Plant Modeling Scenarios

Scenario		Unit I		
		NO_X (lb/h)	SO_2 (lb/h)	PM (lb/h)[1]
0	Baseline	4,854.8	4,832.2	84.1
1	Over-fire Air (OFA) Presumptive Dry FGD	3,645.9	841.4	84.1
2	OFA Presumptive Wet FGD	3,645.9	841.4	84.1
3	OFA Dry FGD at 90% Control	3,645.9	504.8	84.1
4	OFA Wet FGD at 95% Control	3,645.9	241.2	84.1
5	Separated OFA (SOFA) Presumptive Dry FGD	2,804.5	841.4	84.1
5A	SOFA Dry FGD at 90% Control	2,804.5	504.8	84.1
5B	SOFA Wet FGD at 95% Control	2,804.5	241.2	84.1
6	SNCR with SOFA Presumptive Dry FGD	1,963.2	841.4	84.1
7	RRI+SNCR with SOFA Presumptive Dry FGD	1,121.8	841.4	84.1
8	SCR with SOFA Presumptive Dry FGD	560.9	841.4	84.1

1 – The PM technology for all modeling scenarios is the existing pulse-jet fabric filter.

These scenarios represent the range of emissions evaluated for consideration in making a BART determination. The baseline scenario is based on the historical, highest 24-hour actual average SO_2 and NO_X emission rates for BSP between 2001 and 2003. The emission rate for PM is the achievable controlled emission rate for the existing fabric filter. Due to the number of variations involved for each pollutant, the scenarios are discussed in the section related to the controlled pollutant.

2.0 NO_X BART EVALUATION

The BART analysis steps 1 through 5 for NO_X emissions from BSP are described in this section. Potentially applicable NO_x control technologies are first identified. A brief description of the processes and their capabilities are then reviewed for availability and feasibility. A detailed technical description of each control technology is provided in Appendix A1. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal NO_x control capability. The impacts analysis then reviews the estimated capital and O&M costs for each alternative, including Balance Of Plant (BOP) requirements. Following the cost determination, the energy impacts and non-air quality impacts are reviewed for each technology. The impact based on the remaining useful life of the source is reviewed as part of the cost analysis. In the final step of the analysis, feasible and available technologies are assessed for their potential visibility impairment impact reduction capability via visibility modeling results. The results of the impact analyses are tabulated and potential BART control options are listed.

2.0.1 BART GUIDELINE NO_X LIMITS FOR CYCLONE-FIRED BOILERS

EPA's presumptive limit for emissions of nitrogen oxides from cyclone-fired boilers, which does not apply to BSP, was established in the final BART Guidelines[1]:

> "The use of SCRs at cyclone units burning bituminous coal, sub-bituminous coal, and lignite should enable the units to cost-effectively meet NO_X rates of 0.10 lbs/mmBtu. As a result, [the EPA] are establishing a presumptive NO_x limit of 0.10 lbs/mmBtu based on the use of SCR for coal-fired cyclone units greater than 200 MW located at 750 MW power plants. " [70 FR 39172]

40 CFR 51, App. Y, IV.E.5. While Unit I at BSP is greater than 200 MW output, it is not located at a 750 MW power plant. Thus, Unit I is not subject to presumptive limits.

2.1 IDENTIFICATION OF RETROFIT NO_X CONTROL TECHNOLOGIES

The first step in the BART evaluation for NO_x emissions is to identify potentially applicable retrofit control alternatives. A comprehensive literature search was performed, with sources including technical papers and presentations made by parties involved with design, construction, and testing of NO_X control techniques at conferences sponsored by nationally-recognized technical organizations, plus hardware supplier experience lists.

There are two basic categories of NO_X emission control alternatives:

- Combustion controls; and
- Post-Combustion controls.

A summary of the potentially available alternatives identified for NO_X emissions control on coal-fired cyclone units is shown in Table 2.1-1.

TABLE 2.1-1 – Potentially Available NO_X Control Alternatives Identified for BART Analysis

Combustion Controls
Low-NO_X Burners (LNBs)
Over-fire Air (OFA)
Separated Over-fire Air (SOFA)
Post-Combustion Controls
Selective Non-Catalytic Reduction (SNCR)
Rich Reagent Injection (RRI)
Selective Catalytic Reduction (SCR)

2.2 TECHNICAL DESCRIPTIONS AND FEASIBILITY ANALYSIS OF NO_X CONTROL TECHNOLOGIES

The second step of the BART process is to evaluate the control processes that have been identified and eliminate any that are technically infeasible for application at the source. The following paragraphs summarize the evaluation of the processes for technical feasibility for BSP Unit I NO_X controls. A detailed description of the various NO_X control technology retrofits and their technical feasibility is included in Appendix A1, with the associated references for technical literature.

2.2.1 FEASIBILITY OF COMBUSTION NO_X CONTROLS

The following combustion controls are potentially feasible technologies that are applied to a cyclone-fired boiler.

- An over-fire air (OFA) system has already been implemented on the Unit I boiler with the ability to significantly lower NO_X emissions. Implementation of more stringent operational procedures to

maintain significantly lower NO_X emissions with the existing OFA system was considered a feasible application at BSP for Unit I.

- Separated over-fire air (SOFA) systems have been retrofit to many cyclone boilers for combustion NO_X control.[2,3,4,5,6] SOFA offers the highest performing version of this technology for cyclone boilers, and may include relocating vent ports and/or flue gas recirculation ports. SOFA is a feasible technology for BSP Unit I and is included in the control effectiveness analysis for additional NO_X. The NO_X control improvements through use of SOFA on Unit I will be limited by potential adverse impacts on cyclone operation associated with air-staged (sub-stoichiometric air/fuel) cyclone operation, which are described in Appendix A1.

Low-NOX burners (LNBs), while commonly applied to pulverized coal-fired boilers, are not applicable to cyclone fired units since initial combustion occurs in the barrel-shaped cyclone and not in the furnace chamber as is the case for the pulverized coal-fired boiler. Therefore, they will not be considered further.

2.2.2 FEASIBILITY OF POST-COMBUSTION NO_X CONTROLS

Post-combustion controls involve technologies that are applied to the flue gas after the combustion process. Typically these processes involve the use of a reagent to chemically react with NO_X. These are summarized as follows; for more details, refer to the technical feasibility evaluation included in Appendix A1:

- SNCR has been applied on several cyclone-fired boilers since 1995 and its installation on the Unit I cyclone boiler is considered feasible.[7,8,9] Because BSP Unit I already has OFA for NO_X control, SNCR will be evaluated in conjunction with the existing OFA or SOFA.
- Rich Reagent Injection (RRI) injects aqueous urea into the high-temperature lower furnace zone and requires an "air-starved" atmosphere to avoid creating instead of reducing NO_X. RRI has been developed and demonstrated with application intended only on cyclone boilers.[9,10,11,12] RRI has been installed and is commercially available.
    - RRI is susceptible to impairment due to fouling by ash slag deposits and heat-related damage of injection nozzles, which are located near the cyclones in the lower furnace.
    - RRI is considered feasible for application on cyclone boilers operating under substoichiometric conditions with advanced forms of SOFA and in combination with SNCR for NO_X control at BSP Unit I.
- Selective Catalytic Reduction (SCR) technology has been installed on 22 cyclone-fired boilers in the U.S., burning bituminous or sub-bituminous coals, and its installation on BSP Unit I for

additional NO_X control is considered technically feasible.[34] As with SNCR, SCR will be evaluated in conjunction with the existing OFA or SOFA.

2.2.3 RESULTS OF FEASIBILITY ANALYSIS

The results of the evaluation of the identified BART alternatives following the feasibility analysis are summarized in Table 2.2-1.

TABLE 2.2-1 – NO_X BART Feasibility Analysis Results

Control Technology	In service on Existing Utility Boilers	Commercially Available	Technically Applicable To Big Stone Plant
Over-fire Air (OFA)	Yes	Yes	Yes
Separated OFA (SOFA)	Yes	Yes	Yes
Selective Non-catalytic Reduction (SNCR) with OFA or SOFA	Yes	Yes	Yes
Rich Reagent Injection (RRI) + SNCR with SOFA	Yes	Yes	Yes
Selective Catalytic Reduction (SCR) with OFA or SOFA	Yes	Yes	Yes

2.3 CONTROL EFFECTIVENESS EVALUATION OF NO_X CONTROL TECHNOLOGIES

Control options that offer zero or very small additional control performance at a significant cost impact were not included in impact analysis. Alternatives that are equally effective in predicted emission reduction percentage but are more expensive to install and operate, or have more substantial operational limitations compared to other feasible alternatives, were also eliminated from further analysis. Table 2.3-1 lists the feasible control technologies and indicates the technologies evaluated in the analysis.

TABLE 2.3-1 – Evaluated NO_X Control Technologies

Control Technology	Approximate Control Efficiency	Evaluated
Over-fire Air (OFA)	25	Yes
Separated OFA (SOFA)	42	Yes
Selective Non-catalytic Reduction (SNCR) with OFA	60	No[1]
SNCR with SOFA	60	Yes
Rich Reagent Injection (RRI)+SNCR with SOFA	77	Yes
Selective Catalytic Reduction (SCR) with OFA	88	No[2]
SCR with SOFA	88	Yes

1 – Due to an estimated $1,810,000 increase in levelized annual costs for the same level of control as SNCR with SOFA, this technology would be above the dominant controls curve and are not evaluated further as described in Section 1.3.5.
2 – Due to an estimated $140,000 increase in levelized annual costs for the same level of control as SCR with SOFA, this technology would be above the dominant controls curve and are not evaluated further as described in Section 1.3.5

Available NO_X emission control options considered feasible for BSP Unit I boiler are listed in Table 2.3-2 in descending order of control effectiveness. Ranking of the alternatives in Table 2.3-2 assumes that the baseline level of NO_X emissions for the BSP Unit I boiler is associated with the emission rate of 0.86 lb/mmBtu.

The emission reduction (control effectiveness) percentages developed for the feasible alternatives shown in Table 2.3-2 are estimates based upon engineering judgments with considerations of:

- the general combustion properties of Powder River Basin (PRB) coal;
- published and available emission reduction performance achieved at other similar utility power plants (wet-bottom cyclone-fired boilers); and
- inclusion of performance margins to allow for variations in fuel, weather, equipment condition, and other factors that prevent the ultimate peak short-term performance from being reliably sustained over the course of long-term operation.

The potential operational limitations mentioned in the detailed feasibility discussions included in Appendix A1 for deeply air-staged cyclones associated with separated over-fire air and Rich Reagent Injection alternatives are expected to limit the amount of NO_X control potential possible compared to other boiler types where this technique or technology was applied.

TABLE 2.3-2 – Estimated Control Options NO_X Emission Rates Evaluated

NO_X Control Technique	Emission Rate (lb/mmBtu)	Control Percentage	Hourly Emission (lb/hr)
SCR w/ SOFA	0.10	88	560.9
Rich Reagent Injection (RRI)+SNCR w/ SOFA	0.20	77	1,121.8
SNCR w/ SOFA	0.35	60	1,963.2
Separated Over-fire Air (SOFA)	0.50	42	2,804.5
Over-fire Air (OFA)	0.65	25	3,645.9
Baseline	0.86	--	4,854.8

2.4 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

The fourth step of a BART analysis is to evaluate the following impacts of feasible emission controls:

- The cost of compliance.
- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

The purpose of the impacts evaluation is to determine if there are any energy, economic, non-air quality environmental reasons, or aspects of the remaining useful life of the source, which would eliminate the remaining control technologies from consideration for BSP Unit I.

2.4.1 COST IMPACTS OF NO_X CONTROLS

An evaluation was performed to determine the compliance costs of installing various feasible NO_X control alternatives on BSP Unit I boiler. This evaluation included estimates for:

- Capital costs;
- Fixed and variable operating and maintenance (O&M) costs; and
- Levelized total annual costs to engineer, procure, construct, install, startup, test, and place into commercial operation a particular control technology.

The results of this evaluation are summarized in Tables 2.4-1 through 2.4-6.

2.4.1.1 CAPITAL COST ESTIMATES FOR NO_X CONTROLS

The capital costs to implement the various NO_X control technologies were largely estimated from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. Anticipated costs unique to BSP that are necessary for installation of the control technology were also identified. In the cases involving SNCR or RRI, vendor budgetary cost information was obtained and used in place of, or to adjust, the published unit output cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

A review of the unit capital cost factor and associated capital costs for the feasible NO_X emission reduction technology evaluated for BSP are presented in Table 2.4-1.

TABLE 2.4-1 – Unit Capital Cost Factors of Feasible NO_X Control Options

NO_X Control Technique	Unit Capital Cost[1] ($/kW)	Capital Cost ($1000)
SCR with SOFA	172[2]	81,800
RRI + SNCR with SOFA	34[3]	16,200
SNCR with SOFA	25	11,900
Separated Over-fire Air (SOFA)	10	4,800
Over-fire Air (OFA)	Existing	Existing

1 – Unit capital cost factors ($/kW) of these individual technologies were combined by simple addition. Actual installed costs may differ due to positive or negative synergistic effects.
2 – Estimate taken from CUECost adjusted to reflect Burns & McDonnell project experience included in Appendix A2.
3 – RRI estimate is taken from the DOE report, "Field Testing of Advanced Layered Technology Approach (ALTA™) for NOx Control in Sioux Unit 1".

2.4.1.2 OPERATING AND MAINTENANCE COST ESTIMATES FOR NO_X CONTROLS

The operation and maintenance costs to implement the NO_X control technology evaluated for BSP Unit I were largely estimated from cost factors established in the EPA's Air Pollution Control Cost Manual

(OAQPS), and from engineering judgment applied to that control technology. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's O&M costs are estimates of:

- Auxiliary electrical power consumption for operating the additional control equipment;
- Reagent consumption, and reagent unit cost for SCR, SNCR and RRI alternatives;
- Catalyst replacement for SCR; and
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler equipment.

A review of the estimated operation and maintenance costs for the feasible NO_X emission reduction technology evaluated for BSP are presented in Table 2.4-2.

TABLE 2.4-2 – Estimated O&M Costs for NO_X Control Options

NO_X Control Alternative	First Year O&M Cost ($1,000)
SCR with SOFA	4,110
RRI+SNCR and SOFA	7,260
SNCR with SOFA	2,120
Separated Over-fire Air (SOFA)	152
Over-fire Air (OFA)	106

In order to compare a particular NO_X emission reduction alternative during the cost of compliance impact analysis portion of the BART selection process, the basic methodology defined in the BART Guidelines was followed. The Levelized Total Annual Cost (LTAC) of these NO_X control alternatives was calculated based on the same economic conditions and a 30 year project life (see Section 1.3.5 of this BART evaluation for methodology details). Estimated capital costs were split evenly over a two year construction period for all alternatives and a present value was calculated. Table 2.4-3 shows the estimated present value capital cost and annualized cost values for the various feasible NO_X emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top.

TABLE 2.4-3 – Capital and Annualized Costs Estimated for NO_X Control Alternatives

NO_X Control Alternative	Capital Cost[1] ($1000)	Present Value Capital Cost ($1,000)	First Year O&M Cost ($1,000)	Levelized Cost[2] ($1,000)
SCR with SOFA	81,800	76,800	4,110	13,210
RRI+SNCR and SOFA	16,200	15,200	7,260	11,390
SNCR with SOFA	11,900	11,200	2,120	3,990
Separated Over-fire Air (SOFA)	4,800	4,500	152	650
Over-fire Air (OFA)	0	0	106	140

1 – Installed capital cost is estimated for determination of total capital cost for a control technology, assuming maximum unit output capacity is based on 475,000 kW.
2 – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. The Annualized O&M cost factor = 1.361 and the Capital Recovery Factor = 0.0991

The average cost effectiveness was then determined as the LTAC divided by baseline annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. Table 2.4-4 shows the average cost effectiveness comparison for the NO_X control technologies. The feasible control alternatives were also compared by calculating the change in LTAC per incremental ton of pollutant removed for the next most stringent alternative (incremental cost effectiveness). This identified which alternatives produced the highest increment of expected pollutant reduction for the estimated lowest average LTAC increment compared with the pre-control baseline emission rate. The expected annual number of tons of pollutant removed versus estimated LTAC for each remaining control alternative was then plotted.

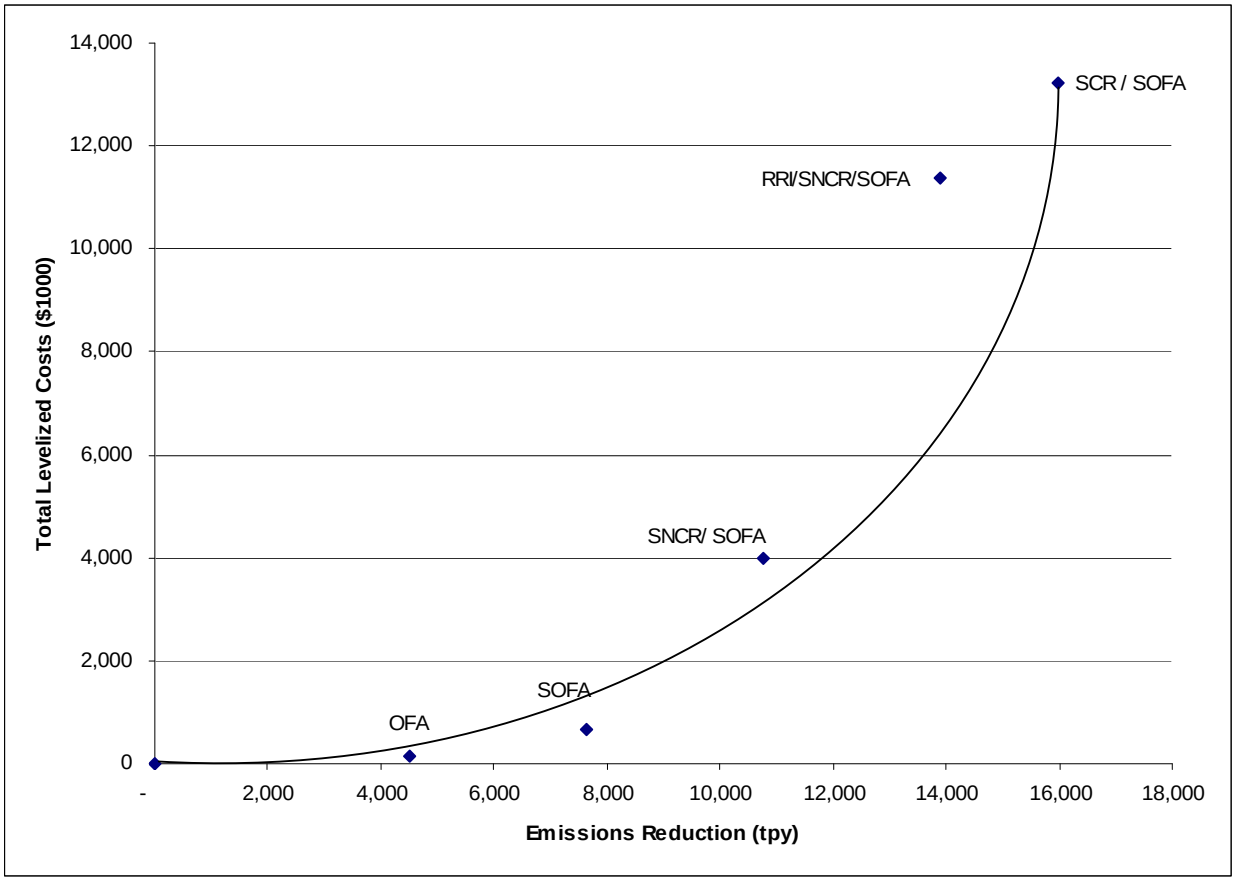
TABLE 2.4-4 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives

NO_X Control Alternative	Annual NO_X Emissions[1] (Tons/yr)	Annual NO_X Emissions Reduction[1] (Tons/yr)	Levelized Total Annual Cost ($1,000)	Average Cost Effectiveness ($/ton)
SCR with SOFA	2,090	16,000	13,210	825
RRI+SNCR and SOFA	4,180	13,910	11,390	818
SNCR with SOFA	7,310	10,780	3,990	197
Separated Over-fire Air (SOFA)	10,440	7,640	650	85
Over-fire Air (OFA)	13,570	4,510	140	31
Baseline	18,080	-	-	-

1 – Annual NO_X emissions and control level based upon 8,760 hours of operation and 85% capacity factor.

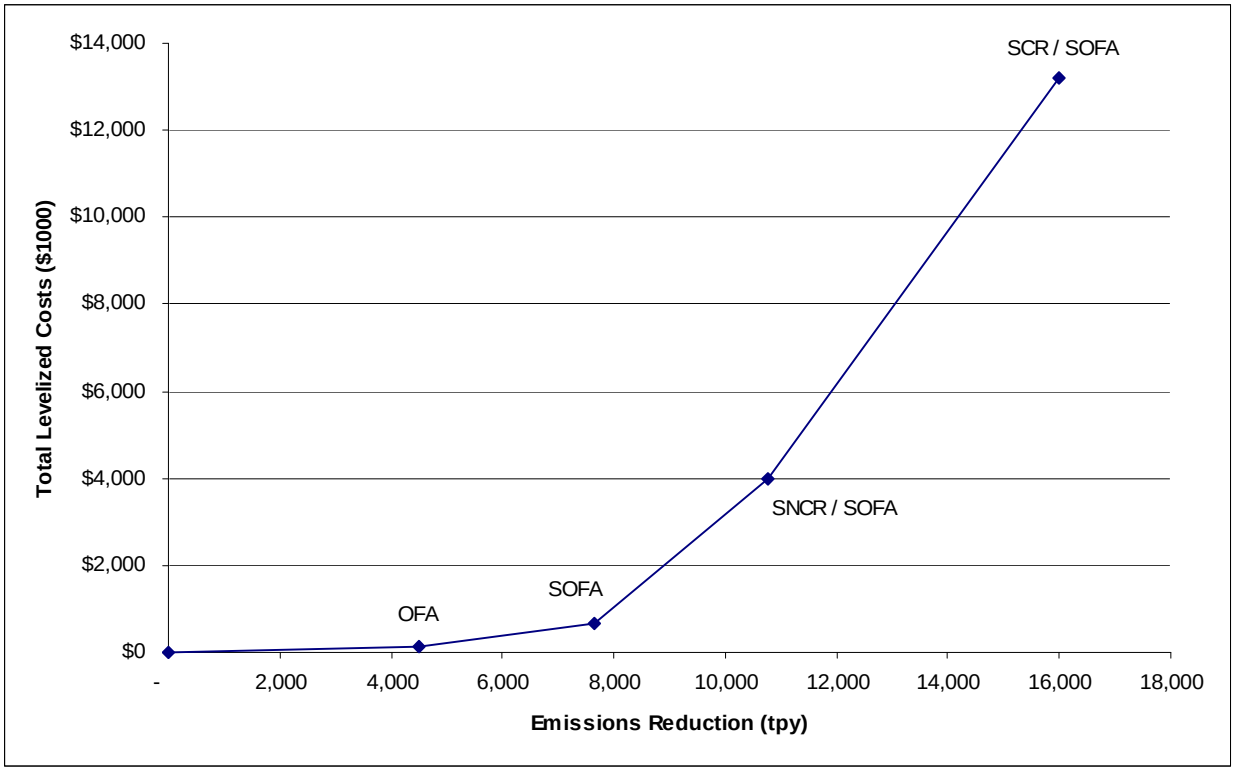
The comparison of the cost-effectiveness of the control options evaluated for BSP is shown in Figure 2.4-1. The estimated annual amount of NO_X removal (emission reduction) in tons per year is plotted on the abscissa (horizontal axis) and the estimated LTAC in thousands of U.S. dollars per year on the ordinate (vertical axis).

Figure 2.4-1 – NO_X Control Cost Effectiveness



The purpose of Figure 2.4-1 is to show the range of control and cost for the evaluated NO_X reduction alternatives and identify the least-cost controls so that the Dominant Controls Curve (DCC) can be created. The DCC is the best fit line through the points forming the lower rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual NO_X removal tonnage for the various remaining BART alternatives. Points distinctly to the left of and above this curve are inferior control alternatives per the BART Guidelines on a cost effectiveness basis. Following a "bottom-up" graphical comparison approach, each of the NO_X control technologies represented by a data point to the left of and above the least cost envelope should be excluded from further analysis on a cost efficiency basis. Of the highest-performing versions of the technically feasible NO_X control alternatives evaluated for cost-effectiveness, the data point for RRI/SNCR/SOFA is seen to be more costly for fewer tons of NO_X removed than for SCR with SOFA. This appears to be an inferior control, and thus should not be included on the least cost and DCC boundary. Figure 2.4.2 provides the DCC.

Figure 2.4-2 – NO_X Control Cost Effectiveness and Dominant Control Cost Curve



The next step in the cost effectiveness analysis for the BART NO_X control alternatives is to review the incremental cost effectiveness between remaining least-cost alternatives. Table 2.4-5 contains a repetition of the LTAC and NO_X control information with RRI+SNCR/SOFA removed, and shows the incremental cost effectiveness between each successive set of least-cost NO_X control alternatives. The incremental NO_X control tons per year, divided by the incremental levelized annual cost, yields an incremental control cost effectiveness ($/ton).

TABLE 2.4-5 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives

NO_X Control Technique	Levelized Total Annual Cost ($1,000)	Annual Emission Reduction[1] (Tons/yr)	Incremental Levelized Total Annual Cost[2] ($1,000)	Incremental Annual Emission Reduction[1,2] (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)[3]
SCR with SOFA	13,210	16,000	9,220	5,220	1,766
SNCR with SOFA	3,990	10,780	3,340	3,140	1,063
SOFA	650	7,640	510	3,130	163
OFA	140	4,510	140	4,510	31

1 – Annual NO_X emissions and control level based upon 8,760 hours of operation and 85% capacity factor.
2 – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
3 – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

In the final BART Guidelines, the EPA does not propose hard definitions for reasonable or unreasonable average or incremental cost effectiveness values. As can be seen from a review of Table 2.4-4, the average levelized control cost effectiveness of control alternatives ranges from $31/ton to $825/ton.

The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. The incremental cost analysis indicates that from a cost effectiveness viewpoint, the most costly alternative is SCR with SOFA. This control option is considered technically feasible for BSP, but incurs a significant annual (levelized) incremental cost compared to the other feasible NO_X control techniques.

2.4.2 ENERGY IMPACTS OF NO_X CONTROL ALTERNATIVES

The feasible NO_X control alternatives were reviewed for significant or unusual energy penalties or benefits associated with their use. There are several basic kinds of energy impacts for NO_X emissions controls:

- Potential increase or decrease in power plant energy consumption resulting from a change in thermal (heat) energy to net electrical output conversion efficiency of the unit, usually expressed as an hourly unit heat rate (Btu/kW-hr). This may or may not change the net electrical output

(MW) capacity of the EGU depending on if there are physical or imposed limits on the total heat input to the boiler or electrical power output.

- Potential increase or decrease in net electrical output of the unit resulting from changes in physical operational limitations imposed on the ability to sustain a fuel heat input rate (mmBtu/hr), which results in a potentially lower or higher unit net electrical output (MW) capacity. This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in net electrical output of the unit resulting from changes in auxiliary electrical power demand and usage (kW, kW-hrs). This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in reliability and availability to generate electrical power. This results in a change to the number of hours of annual operation, not necessarily a change in net electrical output (MW) capacity of the EGU.

There should not be a major impact on energy consumption by the operation of the variations of an over-fire air (OFA) system, such as separated over-fire air (SOFA). An OFA system does not significantly change the total amount of air introduced into the boiler, only the location where it is introduced. Combustion air damper actuators' electrical power demand would be an insignificant (+ 1 kW) change in net electrical power consumption. For cyclone boilers, providing effective volumes and velocities of separated over-fire air at the injection ports should not require higher forced draft fan power consumption resulting from higher fan discharge pressure. Higher vent ductwork pressure drop impacts of the OFA system on the forced draft fans' auxiliary electrical power consumption are expected to be negligible (less than 1% of the annual auxiliary power consumed by these fans) so that unit net electrical output (MW) capacity is essentially the same as the current nameplate rating.

Boiler furnace exit gas temperature and superheater steam / reheater steam outlet temperatures may be slightly elevated during air-staged cyclone operation with OFA. This impact on the boiler's operation is typically small, and within the design capabilities of the boiler from a heat transfer and mechanical stress standpoint. This small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kW-hr) was not quantified, as the historical variation in coal heat content that influences plant unit heat rate is expected to have more significant impacts.

OFA is not expected to significantly reduce unit reliability and availability to generate electrical power, once the amount of secondary combustion air that can be withdrawn from the cyclones is established for consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions.

There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during OFA operation. Such conditions can promote corrosion from sulfur compounds in the furnace gases being created above the cyclones and below the OFA injection ports. Due to the relatively small amounts of sulfur content in the PRB coal and the modest amount of air-staging of the existing cyclones during OFA operation, the expected change in corrosion rate of the boiler tubes should be minor. This degradation is expected to occur over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes to avoid forced outages to repair tube leaks or failed sections. The potential change in the frequency of furnace wall tube failures and changeouts is difficult to estimate, and has not been quantified.

For SNCR-related NO_X control alternatives, the injection of a diluted urea solution requires some additional auxiliary power for heating and pumping the liquid, and using compressed air for atomization and cooling the reagent injection nozzles/lances, on the order of 150 to 400 kW. The injection of water (used for urea dilution) into the boiler flue gas also has a small negative impact on the plant heat rate (higher Btu/kw-hr), which is approximately equal to the heat released from the reaction of the reagent with NO_X or oxygen. The impact of additional flue gas created by operation of an SNCR-related system on induced draft fan power consumption should be insignificant.

For the SCR NO_X control alternative, the system requires the same 150 to 400 kW of auxiliary power for heating and pumping the reagent (ammonia) as SNCR, and using compressed air for atomization and cooling the reagent injection nozzles/lances, on the order of 150 to 400 kW. If a urea based reagent feed system is used, an additional 400 kW of auxiliary power is required to convert the urea to ammonia. However, the major consumer of auxiliary power for a SCR is additional induced draft fan power needed to overcome the additional 6 to 9 inches of water column pressure drop created by the addition of catalyst and ductwork. In most cases, the addition of an SCR would require replacement of the induced draft fans and depending upon the fan and motor efficiency additional 400 to 1000 kW of auxiliary power.

2.4.3 NON AIR QUALITY AND OTHER ENVIRONMENTAL IMPACTS OF NO_X CONTROL ALTERNATIVES

Operation using OFA or SOFA systems for NO_X emissions control will increase the amount of unburned carbon in the flyash produced by the boiler and collected for disposal by small increments. The potential

changes in the annual amounts of flyash disposal rates are expected to be inconsequential, and have not been quantified.

Operation of an SCR or SNCR system will normally create a small amount of unreacted ammonia or urea to be emitted into the flue gas. The amount of ammonia slip produced depends on the amount of reagent utilization and location of the injection points. Higher NO_X reduction performance involves greater amounts of reagent usage and ammonia slip. This is typically controlled to less than 10 ppmvd, especially since the possible formation of sulfates such as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium bisulfate [NH_4HSO_4] will be more problematic at higher slip levels. Sulfur trioxide (SO_3) can also be formed during combustion in the boiler or conversion in the SCR to combine with ammonia during passage through the flue gas ductwork to form the sulfates.

Some of the unreacted ammonia and other compounds discussed above will be collected with the flyash in the pulse-jet fabric filter. If a scrubber is installed, some of the ammonia and other compounds will be captured. These collected materials may impact the disposal of fly ash or scrubber blow down.

Storage of ammonia reagent on-site creates the potential for accidents, leaks, and subsequent releases to air, ground, and surface water immediately surrounding the facility. Regulation of storage and containment of such reagents s will be under the requirements of various federal Acts.

2.4.4 VISIBILITY IMPAIRMENT IMPACTS OF NO_X CONTROLS

The final impact analysis conducted was to assess the visibility impairment impact reduction for the NO_X control technologies. The analysis used a baseline NO_X emission rate which assumed the highest 24-hour actual emission rate for 2001-2003 as recommended by the BART guideline and listed in the Modeling Protocol. Four CALPUFF model runs for BSP were conducted with the constant SO_2 emission rate of 0.15 lb/mmBtu, constant PM emission rate of 0.015 lb/mmBtu, and various levels of NO_X control. Table 2.4-6 shows the modeled emission rates.

The difference between the modeled impacts at the 98th percentile level from various controlled emission rates represents the visibility impairment impact reduction in deciViews (dV). Table 2.4-6 shows the results of the visibility impact modeling attributable to NO_x reductions while maintaining PM and SO_2 emissions constant. A table containing the 98th percentile results for all modeled years and Class I areas is included in Appendix A3. Combined impacts from all pollutants are addressed later in the report.

TABLE 2.4-6 – Visibility Impairment Impacts from Emission Controls

NO_X Control Technique	Emission Rate (lb/mmBtu)	Visibility Impairment Impact (dV)	Visibility Impairment Reduction (Δ dV)[1]	Technology Incremental Reduction (Δ dV)
SCR with SOFA	0.10	0.170	0.487	0.218
SNCR with SOFA	0.35	0.388	0.269	0.136
Separated Over-fire Air (SOFA)	0.50	0.524	0.133	0.133
Over-fire Air (OFA)	0.65	0.657	-	-
Baseline	0.86	1.079	-	-

1 – Impairment reduction is from OFA levels.

The results of the baseline visibility impairment modeling for BSP showed that NO_X emissions caused a Class I area to exceed 0.5 dV for predicted visibility impairment impact (98th percentile). Modeled visibility impairment impacts decreased with the addition of NO_X controls.

The 0.5 dV value is the lowest visibility impairment impact that is considered discernible by the human eye and the EPA set this threshold as the point where a given source is considered a "contributing source" (40 CFR 51, App. Y, III.A.1.). Thus, an impairment impact of less than 0.5 dV is considered visibly indiscernible. The difference in impacts between OFA (lowest control level) and SCR (highest control level) is less than 0.5 dV, which is visibly indiscernible. To assess the cost effectiveness of the various controls with respect to visibility improvement, the incremental cost to achieve the visibility improvement is determined and evaluated against incremental costs for the next most stringent alternative. Table 2.4-7 shows the costs to achieve the incremental reduction in visibility impairment.

TABLE 2.4-7 – Cost for Incremental Visibility Improvement

NO_X Control Technique	Incremental Levelized Total Annual Cost[1] ($)	Impairment Reduction (Δ dV)	Incremental Reduction (Δ dV)	Cost for Incremental Improvement ($/dV)
SCR with SOFA	9,220,000	0.487	0.218	42,290,000
SNCR with SOFA	3,340,000	0.269	0.136	24,560,000
Separated Over-fire Air (SOFA)	510,000	0.133	0.133	3,830,000
Over-fire Air (OFA)	140,000	-	-	-

1 – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

2.4.5 SUMMARY OF IMPACTS OF NO_X CONTROLS – BSP UNIT I

Table 2.4-8 summarizes the various quantifiable impacts discussed in Sections 2.4.1 through 2.4.4 for the NO_X alternatives evaluated for BSP Unit I.

TABLE 2.4-8 – Impacts Summary for BSP Unit I NO_X Controls

NO_X Control Technique	Emission Rate (lb/mmBtu)	Levelized Total Annual Cost ($1,000)	Incremental Levelized Total Annual Cost[1] ($1,000)	Visibility Impairment Impact (dV)	Visibility Impairment Reduction (dV)	Technology Incremental Reduction (Δ dV)
SCR with SOFA	0.10	13,210	9,220	0.170	0.487	0.218
SNCR with SOFA	0.35	3,990	3,140	0.388	0.269	0.136
Separated Over-fire Air (SOFA)	0.50	650	510	0.524	0.133	0.133
Over-fire Air (OFA)	0.65	140	140	0.657	-	-
Baseline	0.86	-	-	1.079	-	-

1 – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

NO_X SECTION REFERENCES:

1. "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations"; Environmental Protection Agency; Federal Register, Volume 70, No. 128; July 6, 2005.

2. "The State of the Art in Cyclone Boiler NO_X Reduction", by O'Connor, Dave, Himes, Rick, and Facchiano, Tony (Electric Power Research Institute), presented at the EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, Atlanta, GA, August 16-20, 1999.

3. "B&W's Advances on Cyclones NO_X Control Via Fuel and Air Staging Technologies", by Farzan, H., Maringo, G., Johnson, D. W., and Wong, D.K. (Babcock & Wilcox, Co.), Beard, C.T. (Eastman Kodak Company), and Brewster, S.E. (Tennessee Valley Authority), presented at the EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, Atlanta, GA, August 16-20, 1999. Available at B&W's internet website: http://www.babcock.com/pgg/tt/pdf/BR-1683.pdf

4. B&W experience list September 18, 2002.

5. "Reburning Projects in the Department of Energy's Clean Coal Technology Demonstration Program", by Mann, Al and Ruppel, Tom (Parsons Corporation), and Sarkus, Tom (National Energy Technical Laboratory), presented at the 2004 DOE-NETL Conference on Reburning for NO_X Control, Morgantown, WV, May 18, 2004. A reburn-related document (an updated version of a poster from the May 18 Conference) is titled "Scorecard on Reburning 6/1/2004" by Al Mann and Tom Ruppel, Parsons Corporation, available on-line at: http://www.netl.doe.gov/publications/proceedings/04/NOx/posters/Reburning%20Scorecard.pdf

6. GE Energy (formerly GE-EER) experience list September 29, 2005.

7. "Demonstration of Rich Reagent Injection for NO_X Control in AmerenUE's Sioux Unit 1" by Cremer, Marc A. and Adams, Bradley R. (Reaction Engineering International), Boll, David E. (AmerenUE), and O'Connor, David C. (Electric Power Research Institute), presented at the US DOE Conference on SCR/SNCR for NO_X Control, Pittsburgh, PA, May 15-16, 2002.

8. "Evaluation of Cost Effective Non-SCR Options for NO_X Control in PRB Fired Cyclone Boilers" by Cremer, Marc A., Wang, David H. and Adams, Bradley R. (Reaction Engineering International); Boll, David E. and Stuckmeyer, Kenneth B. (AmerenUE), presented at the Western Fuels Symposium, 19th International Conference on Lignite, Brown, and Subbituminous Coals (formerly Low-Rank Fuels), October 12-14, 2004, Billings, MT.

9. "NO_X Emissions Below 0.15 lb/Mbtu Achieved in a Cyclone-Fired Boiler Using In-Furnace Control", by Cremer, M., Adams, B., and Chiodo, A., (Reaction Engineering International); Giesmann, C., Stuckmeyer, K., and Boyle, J. (AmerenUE), presented at the Powergen International 2005 conference, December 6-8, 2005, Las Vegas, Nevada.

10. RJM experience list September 3, 2004.

11. "Design and Demonstration of Rich Reagent Injections (RRI) Performance For NO_X Reduction at Connectiv's B.L. England Station" by Cremer, Marc A. and Adams, Bradley R. (Reaction Engineering International); O'Connor, David C. (Electric Power Research Institute); Bhamidipati, Venkata (Conectiv B.L. England Station), and Broderick, R. Gifford (RJM Corporation), presented at the 2001 US EPA/DOE/EPRI MEGA Symposium on SCR and SNCRs, Chicago, IL, August 20-23, 2001. (available from REI's internet website http://www.reaction-eng.com/donwloads/rri_mega.pdf)

12. "Improved Rich Reagent Injection (RRI) Performance For NO_X Control In Coal Fired Utility Boilers" by Cremer, Marc A. and Wang, Huafeng D. (Reaction Engineering International), Boll, David E. (AmerenUE), Schindler, Edmund (RJM Corporation), and Vasquez, Edmundo RMT, Inc. (Alliant Energy Corp.), presented at 2003 U.S. DOE Conference on SCR and SNCR for NO_X Control, Pittsburgh, PA, October 29-30, 2003.

3.0 SO_2 BART EVALUATION

In this section, steps 1 through 5 of the BART determination for BSP are described for SO_2. Potentially applicable SO_2 control technologies are first identified. A brief description of the processes and their capabilities are then reviewed for availability and feasibility. A detailed technical description of each control technology is provided in Appendix B1. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal SO_2 control capability. The impacts analysis then reviews the estimated capital and O&M costs for each alternative, including Balance Of Plant (BOP) requirements. Following the cost determination, the energy impacts and non-air quality impacts are reviewed for each technology. The impact based on the remaining useful life of the source is reviewed as part of the cost analysis. In the final step of the analysis, feasible and available technologies are assessed for their potential visibility impairment impact reduction capability via visibility modeling results. The results of the impact analyses are tabulated and potential BART control options are listed.

3.0.1 BART GUIDELINE SO_2 LIMITS FOR CYCLONE-FIRED BOILERS

EPA's recommended limit for emissions of sulfur dioxides from cyclone-fired boilers was established in the final BART Guidelines:

> "You [meaning States] must require 750 MW power plants to meet specific control levels for SO_2 of either 95 percent control or 0.15 lbs/mmBtu, for each EGU greater than 200 MW that is currently uncontrolled unless you determine that an alternative control level is justified based on a careful consideration of the statutory factors."

40 CFR 51, App. Y, IV.E.4. While Unit I at BSP is greater than 200 MW output, it is not located at a 750 MW power plant. Thus, Unit I is not subject to presumptive limits.

3.1 IDENTIFICATION OF RETROFIT SO_2 CONTROL TECHNOLOGIES

The initial step in the BART determination is the identification of retrofit SO_2 control technologies. In order to identify the applicable SO_2 control technologies, several reference works were consulted, including "Controlling SO_2 Emissions: A Review of Technologies (EPA-600/R-00-093, October 2000) and the RACT/BACT/LAER Clearinghouse (RLBC). From these and other literature sources, a preliminary list of control technologies and their estimated capabilities was developed.

Removal of SO_2 from flue gas can either be accomplished prior to combustion, or post combustion. The primary method for pre-combustion controls is fuel switching. Post combustion methods include wet Flue Gas Desulfurization (FGD) typically using limestone reagent and semi-dry FGD technologies using lime reagent. Following are descriptions and technical analyses of the identified technologies for application to BSP Unit I. Table 3.1-1 contains the results of this effort.

TABLE 3.1-1 – SO_2 Control Technologies Identified for BART Analysis

Control Technology
Fuel Switching
Semi-Dry Flue Gas Desulfurization
Wet Flue Gas Desulfurization

3.2 TECHNICAL DESCRIPTION AND FEASIBLITY ANALYSIS

The second step in the BART analysis procedure is a technical feasibility analysis of the options identified in Step 1. The two concepts to consider are the "availability" and "applicability" of each control technology. The technical and feasibility analysis is presented below for each identified option.

3.2.1 PRE-COMBUSTION FUEL TREATMENTS - FUEL SWITCHING

Fuel switching can be a viable method of fuel sulfur content reduction in certain situations. The PRB coal listed in Table 1.2-2 is one of the lower sulfur coals available in the U.S. and switching to a different lower sulfur coal (if available) would achieve little to no additional reduction in SO_2 emissions. Therefore, for the purpose of this BART analysis, fuel switching is not considered a viable option for SO_2 control for BSP Unit I.

3.2.2 POST- COMBUSTION FLUE GAS DESULFURIZATION

Two different post combustion processes for reducing SO_2 emissions were evaluated as BART alternatives in this analysis. These include two well established Flue Gas Desulfurization (FGD) processes, wet and semi-dry. Commercially-available wet and semi-dry FGD processes achieve SO_2 removal by absorption of the SO_2 into an aqueous slurry which contains a neutralizing agent, normally either lime or ground limestone. Chemical reaction(s) between the SO_2 and the neutralizing agent convert the SO_2 to a stable compound that can be readily sold or disposed of in a permitted facility.

3.2.2.1 WET FLUE GAS DESULFURIZATION

Wet FGD technology utilizing lime or limestone as the reagent and employing forced oxidation to produce gypsum (calcium sulfate dihydrate, $CaSO_4\,2H_2O$) as the byproduct is commonly applied to coal-fired boilers. Absorbed SO_2 is converted to calcium sulfite and then oxidized to calcium sulfate dihydrate (gypsum) which is filtered from the scrubber solution and either disposed of in a permitted disposal facility, or possibly sold for wallboard production.

Based on commercial availability and applicability, wet FGD systems were found to be an acceptable BART alternative for SO_2 emission control.

3.2.2.2 SEMI-DRY FLUE GAS DESULFURIZATION

The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a fabric filter for downstream particulate collection. This report addresses the spray dryer FGD process. Two other variations, the Novel Integrated Desulfurization (NID ™) and Circulating Dry Scrubber are similar technologies that achieve similar levels of control effectiveness. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling. Due to similar nature of the different semi-dry technologies and the similar levels of control efficiency achieved by all the technologies, semi-dry technologies are grouped together for the analysis. Technical characteristics associated with the semi-dry technologies are described in Appendix B1.

Based upon availability and applicability, semi-dry FGD is considered a viable alternative for SO_2 emission control.

3.2.3 RESULTS OF FEASIBILITY ANALYSIS

The results of the evaluation of the identified BART alternatives following the feasibility analysis are summarized in Table 3.2-1.

TABLE 3.2-1 – SO_2 BART Feasibility Analysis Results

Control Technology	In service on Existing Utility Boilers	Commercially Available	Technically Applicable To Big Stone Plant
Fuel Switching	Yes	Yes	No
Wet FGD	Yes	Yes	Yes
Semi-dry FGD	Yes	Yes	Yes

3.3 EVALUATE TECHNICALLY FEASIBILE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives.

Historically, wet FGD systems have operated with SO_2 control efficiency anywhere from 70% to in excess of 95%. For the purposes of this study, wet FGD performance was evaluated at presumptive BART limit of 0.15 lb/mmBtu and also at the 95% SO_2 control as representative of the performance of this technology on PRB coal. Further technical characteristics associated with wet FGD are described in Appendix B1.

No variation of semi-dry FGD systems has clearly demonstrated the ability to achieve SO_2 removal levels similar to wet FGD systems in the U.S. Table B-1, in Appendix B, lists many of the recent lime spray dryer system installations in the U.S. The information in Table B-1 was obtained from the RACT/BACT/LAER Clearing House. Burns & McDonnell completed a study of the emission reduction performance of existing, electric utility, semi-dry FGD systems.[3] Information utilized for the evaluation was derived from EIA coal quality data and EPA SO_2 stack emissions and heat input data. The evaluation determined that the highest SO_2 removal efficiency maintained by semi-dry FGD on a continuous basis was just above 90%. No unit was able to maintain an efficiency of 95%. Semi-dry FGD is considered a viable alternative to achieve the presumptive SO_2 BART level, but the upper bound on SO_2 removal efficiency was set at 90% based on a review of the historic performance of this technology.

Table 3.3.1 presents the remaining BART alternatives following the feasibility analysis ranked in descending order according to their effectiveness in SO_2 control.

TABLE 3.3-1 – SO_2 Control Technologies Identified for BART Analysis

SO_2 Control Technique	Emission Rate (lb/mmBtu)	Control Percentage	Hourly Emission (lb/hr)
Wet Limestone FGD	0.043	95	241.2
Semi-dry Lime FGD	0.09	90	504.8
Presumptive Wet Limestone FGD	0.15	83	841.4
Presumptive Semi-dry Lime FGD	0.15	83	841.4
Baseline	0.86	--	4,832.2

3.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS

Step four in the BART analysis procedure is the impact analysis. The BART Guidelines lists four factors to be considered in the impact analysis.

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four impacts required by the BART Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the BART determination for BSP. In addition, the visibility impairment impact of each alternative was evaluated as part of the impact analysis.

3.4.1 COST ESTIMATES

Cost estimates for the wet and semi-dry (including SDA and fabric filter) SO_2 control technologies were completed utilizing the Coal Utility Environmental Cost (CUECost) computer model (Version 1.0) available from the EPA. The CUECost model is a spreadsheet-based computer model that was specifically developed to estimate the cost of air pollution control technologies for utility power plants within +/- 30 percent accuracy. The EPA released the version of the model used for this study in

February 2000. The model is available for download from the EPA website at http://www.epa.gov/ttncatc1/products.html.

The user must specify the design parameters for the air pollution control technologies in CUECost. Unit costs for consumables, labor, and other variables can be modified by the user to fit the specific situation under evaluation. Because these models are in spreadsheet form, the calculation procedures and assumptions can be readily determined and adjusted by the experienced user as necessary to fit the unique requirements of the evaluation being conducted. The program itself is also somewhat user adjustable to compensate for local conditions. The CUECost default case is a generic facility located in Pennsylvania. Burns & McDonnell has adjusted the CUECost spreadsheets as described in the following sections to account for known facility and local conditions.

Operating information utilized as input into the model for the purpose of cost estimating is listed in Tables 1.2-1 and 1.2-2. Economic information utilized as input into the model is given in Table 1.2-3. The model was run with 2008 designated as the cost basis year because equipment cost estimating in the model is based on the Chemical Engineering Cost Index and the composite 2008 index is the latest version available. Following completion of the estimating on a 2008 cost basis year, all costs were escalated to a 2009 basis year utilizing the inflation rates designated in Table 1.2-3.

3.4.1.1 WET FGD CAPITAL COST ESTIMATE

The capital cost estimate for the wet FGD system includes the SO_2 control system and major support facilities. This capital cost estimate for wet FGD applies to either evaluated emission rate as the accuracy of the estimate cannot account for the cost differential due to minor equipment differences. The SO_2 control system cost is representative of a typical furnish and erect contract by a wet FGD system supplier. The "typical" furnish and erect contract would not include costs for foundations. The wet FGD system cost estimated by CUECost is broken down into the major subsystems of reagent preparation, SO_2 absorption tower, dewatering systems, flue gas handling systems (booster fans and ductwork) and support systems. The estimated capital cost associated with a wet FGD system is $171,800,000 or a unit capital cost of $362/kW.

3.4.1.2 SEMI-DRY FGD CAPITAL COST ESTIMATE

Estimated direct costs for the semi-dry FGD system include the absorbers and major support facilities. It was assumed that the existing fabric filter can be used to collect the reaction products from the semi-dry FGD absorber. The SO_2 control system cost is representative of a typical furnish and erect contract by a

lime semi-dry FGD system supplier. This capital cost estimate for semi-dry FGD applies to either evaluated emission rate as the accuracy of the estimate cannot account for the cost differential due to minor equipment differences. The "typical" furnish and erect contract would not include costs for foundations. The system costs estimated by CUECost are broken down into the major subsystems of reagent preparation, absorber, waste handling systems, flue gas handling systems (booster fans and ductwork) and support systems. The estimated capital cost associated with a semi-dry FGD system is $141,300,000 or a unit capital cost of $297/kW.

3.4.1.3 O&M COST ESTIMATE

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). These costs were developed as part of the CUECost model and include operating labor, administrative and support labor and maintenance. Table 3.4-1 summarizes the O&M cost estimates for the wet and semi-dry FGD systems.

TABLE 3.4-1 – First Year O&M Cost Estimate for BSP FGD Systems

SO_2 Control System	Fixed Costs ($1000/yr)	Variable Costs ($1000/yr)	Total O&M ($1000/yr)
Wet FGD	$7,000	$2,600	$9,600
Presumptive Wet FGD	$7,000	$2,490	$9,490
Semi-dry FGD	$4,500	$3,160	$7,660
Presumptive Semi-dry FGD	$4,490	$2,990	$7,480

3.4.1.4 LEVELIZED TOTAL ANNUAL COST

In order to compare a particular SO_2 emission reduction alternative during the cost of compliance impact analysis portion of the BART selection process, the basic methodology defined in the BART Guidelines was followed [70 FR 39167-39168]. The Levelized Total Annual Cost (LTAC) for these SO_2 control alternatives was calculated based on the same economic conditions and a 30 year project life (see Section 1.3.5 of this BART evaluation for methodology details). Estimated capital costs were split evenly over a two year construction period for all alternatives and a present value was calculated. Table 3.4-2 shows the estimated present value capital cost and the annualized cost for the two feasible SO_2 emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top.

TABLE 3.4-2 – Capital and Annualized Costs Estimated for SO_2 Control Alternatives

SO_2 Control Alternative	Capital Cost[1] ($1000)	Present Value Capital Cost ($1,000)	First Year O&M Cost ($1,000)	Levelized Cost[2] ($1,000)
Wet FGD	171,800	161,400	9,600	29,050
Presumptive Wet FGD	171,800	161,400	9,490	28,900
Semi-dry FGD	141,300	132,700	7,660	23,570
Presumptive Semi-dry FGD	141,300	132,700	7,480	23,330

1 – Installed capital cost is estimated for determination of total capital cost for a control technology, assuming maximum unit output capacity is based on 475,000 kW.
2 – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. The Annualized O&M cost factor = 1.361 and the Capital Recovery Factor = 0.0991

The average cost effectiveness was then determined as the LTAC divided by the annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. Table 3.4-3 shows the average cost effectiveness comparison for the SO_2 control technologies. The feasible control alternatives were also compared by calculating the change in LTAC per incremental ton of pollutant removed for the next most stringent alternative (incremental cost effectiveness). This identified which alternatives produced the highest increment of expected pollutant reduction for the estimated lowest average LTAC increment compared with the pre-control baseline emission rate. The expected annual number of tons of pollutant removed versus estimated LTAC for each remaining control alternative was then plotted.

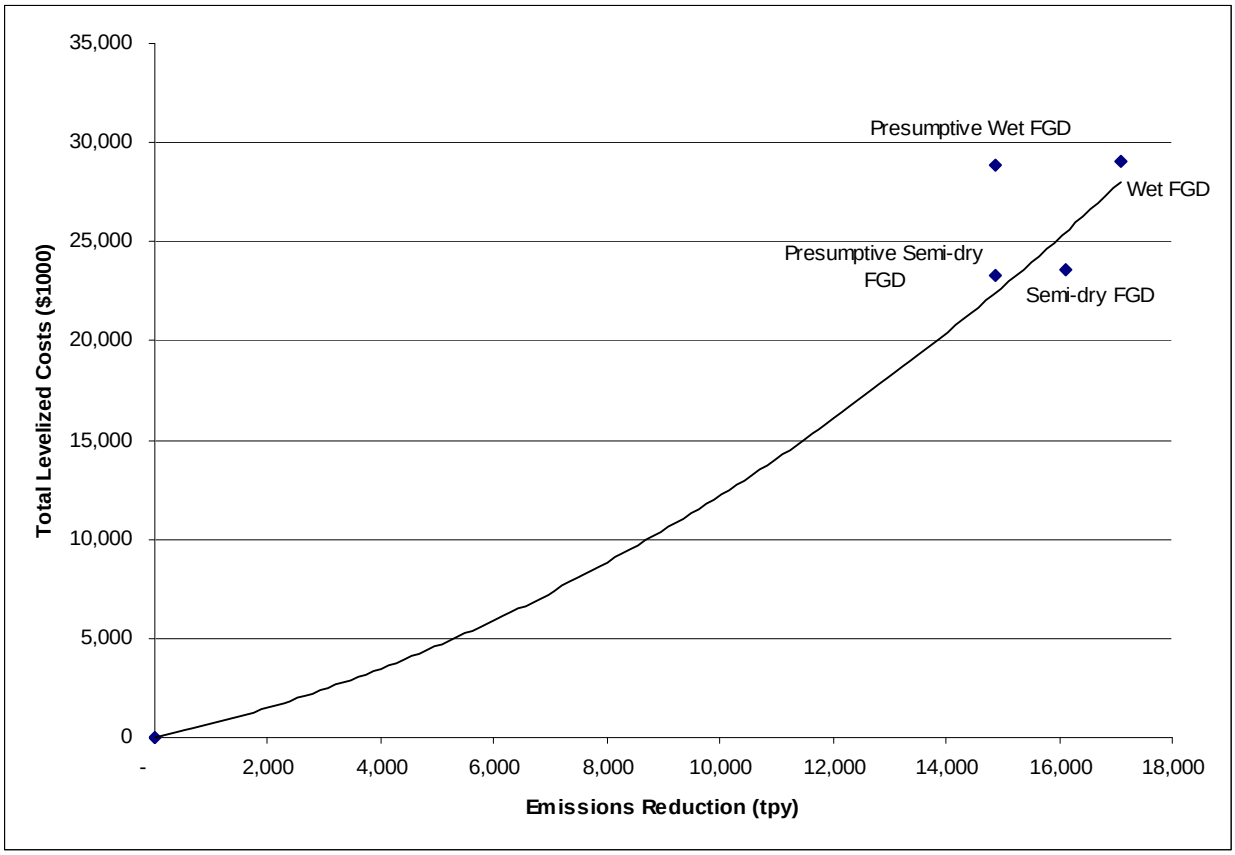
TABLE 3.4-3 – Estimated Annual Emissions and LTAC for SO_2 Control Alternatives

SO_2 Control Alternative	Annual SO_2 Emissions[1] (Tons/yr)	Annual SO_2 Emissions Reduction[1] (Tons/yr)	Levelized Total Annual Cost ($1,000)	Average Cost Effectiveness ($/ton)
Wet FGD	900	17,100	29,050	1,699
Semi-dry FGD	1,880	16,120	23,570	1,462
Presumptive Wet FGD	3,130	14,870	28,900	1,944
Presumptive Semi-dry FGD	3,130	14,870	23,330	1,569
Baseline	18,000	-	-	-

1 – Annual SO_2 emissions and control level based upon 8,760 hours of operation and 85% capacity factor.

The comparison of the cost-effectiveness of the control options evaluated for BSP is shown in Figure 3.4-1. The estimated annual amount of SO_2 removal (emission reduction) in tons per year is plotted on the abscissa (horizontal axis) and the estimated levelized total annual cost in thousands of U.S. dollars per year on the ordinate (vertical axis).

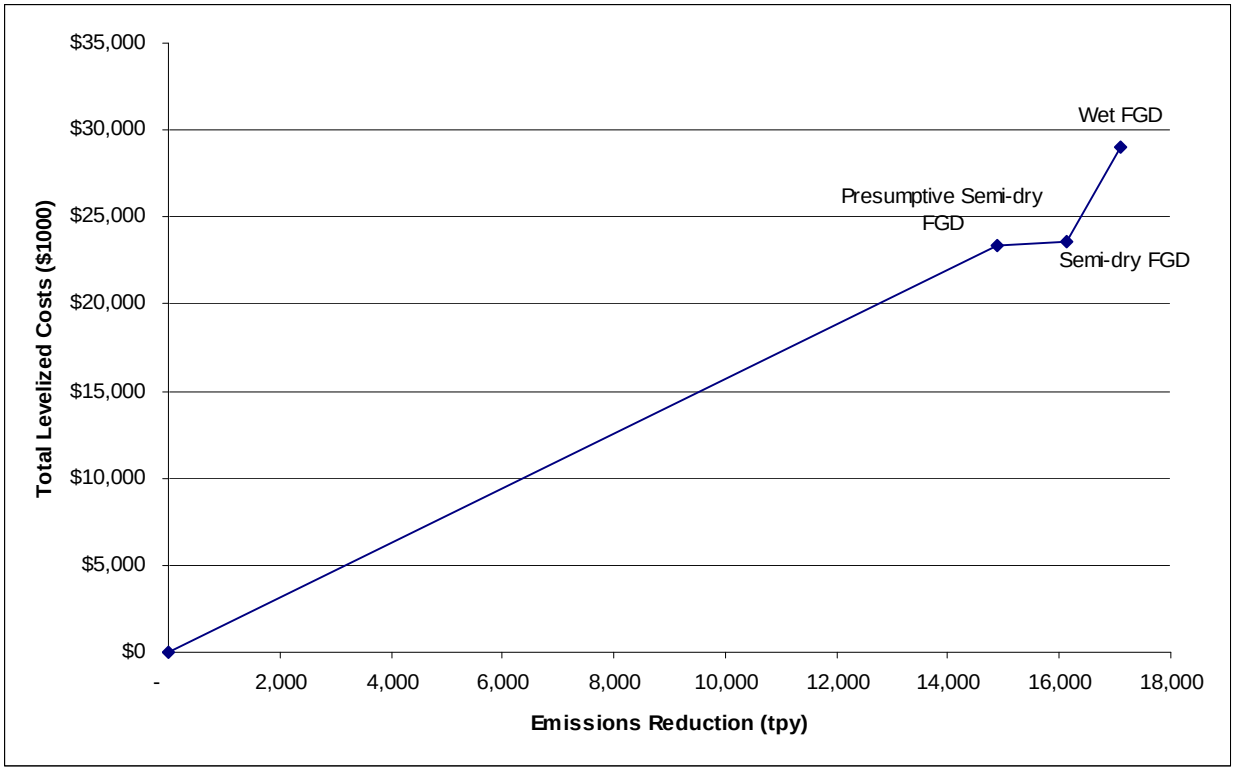
Figure 3.4-1 – SO_2 Control Cost Effectiveness



The purpose of Figure 3.4-1 is to show the range of control and cost for the evaluated SO_2 reduction alternatives and identify the least-cost controls so that the Dominant Controls Curve (DCC) can be created. The DCC is the best fit line through the points forming the lower rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual SO_2 removal tonnage for the various remaining BART alternatives. Points distinctly to the left of and above this curve are inferior control alternatives per the BART Guidelines on a cost effectiveness basis. Following a "bottom-up" graphical comparison approach, each of the SO_2 control technologies represented by a data point to the left of and above the least cost envelope should be excluded from further analysis on a cost efficiency basis. Of the highest-performing versions of the technically feasible SO_2 control alternatives evaluated for cost-effectiveness, the data point for presumptive wet FGD is seen to be more costly for the same tons of SO_2 removed than for presumptive

semi-dry FGD, semi-dry FGD or wet FGD. The presumptive wet FGD appears to be an inferior control, and thus should not be included on the least cost and DCC boundary. Figure 3.4.2 provides the DCC for the SO_2 Controls

Figure 3.4-2 – SO_2 Control Cost Effectiveness and Dominant Cost Control Curve



The next step in the cost effectiveness analysis for the BART SO_2 control alternatives is to review the incremental cost effectiveness between remaining least-cost alternatives. Table 3.4-4 contains a repetition of the levelized total annual cost and SO_2 control information with presumptive wet FGD removed, and shows the incremental cost effectiveness between each successive set of least-cost SO_2 control alternatives. The incremental SO_2 control tons per year, divided by the incremental levelized annual cost, yields an incremental average unit cost ($/ton).

TABLE 3.4-4 – Estimated Incremental Annual Emissions and LTAC for SO_2 Control Alternatives

SO_2 Control Technique	Levelized Total Annual Cost ($1,000)	Annual Emission Reduction[1] (Tons/yr)	Incremental Levelized Total Annual Cost[2] ($1,000)	Incremental Annual Emission Reduction[1,2] (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)[3]
Wet FGD	29,050	17,100	5,480	980	5,592
Semi-dry FGD	23,570	16,120	240	1,250	192
Presumptive Semi-dry FGD	23,330	14,870	23,330	14,870	1,569

1 – Annual SO_2 emissions and control level based upon 8,760 hours of operation and 85% capacity factor.
2 – Increment based upon comparison between consecutive alternatives from lowest to highest.
3 – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

As can be seen from a review of Table 3.4-4, the incremental levelized control cost effectiveness of control alternatives ranges from $192/ton to $5,592/ton. In the final BART Guidelines, the EPA state that:

> "For example, you may be faced with a choice between two available control devices at a source, control A and control B, where control B achieves slightly greater emission reductions. The average cost (total annual cost/total annual emission reductions) for each may be deemed to be reasonable. However, the incremental cost (total annual cost A – B/total annual emission reductions A – B) of the additional control B may be very great. In such an instance, it may be inappropriate to choose control B, based on its high incremental costs, even though its average cost may be considered reasonable." (40 CFR 51, App. Y, IV.D.e.5.)

The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. The incremental cost analysis indicates that from a cost effectiveness viewpoint, the most costly alternative is wet FGD. The wet FGD control option is considered technically feasible for BSP, but incurs a significant annual (levelized) incremental cost compared to the other feasible SO_2 control techniques and is an inappropriate control option based upon high incremental costs.

3.4.2 ENERGY IMPACTS

The energy impacts of each alternative, in terms of both estimated kW of energy usage and the percent of total generation, are given in Table 3.4-5. The primary energy impact of the wet FGD alternative consists of the additional electrical load resulting from pumps, blowers, booster fans, ball mills for limestone grinding and vacuum pumps for byproduct slurry dewatering. The largest energy users for the semi-dry alternatives are pumps, atomizers and booster fans. Building HVAC and interior and exterior lighting loads are also included, but the major energy consumption is due to the primary systems described above.

TABLE 3.4-5 Energy Requirements of SO_2 BART Alternatives

BART Alternative	Energy Demand (kW)	Percent of Nominal Generation
Wet FGD	9,500	2.0%
Semi-dry FGD	3,325	0.7%

3.4.3 NON-AIR QUALITY ENVIRONMENTAL IMPACTS

Non-air quality environmental impacts of the installation and operation of the various BART alternatives include solid and aqueous waste streams, and salable products that could result from the implementation of various BART alternatives. Captured mercury would be present in the solid waste stream from any post combustion alternative as a trace contaminant in the solid waste. Under current regulation, the presence of trace amounts of mercury would not affect its disposal.

A wet FGD system for BSP Unit I is estimated to produce approximately 6 tons per hour of solid waste. The waste stream would be composed of gypsum solids and inerts at approximately 15% moisture. Over the course of a year, the total solid waste quantity is estimated to be approximately 44,700 tons of gypsum solids which would need to be landfilled.

The annual quantity of aqueous waste that would be produced by a wet FGD system is difficult to quantify because the blowdown rate from a wet FGD system is primarily a function of the dissolved chloride levels in the absorber reaction tank. Most of the chloride reaching the scrubber is in the form of hydrochloric acid which is readily absorbed and neutralized. Based upon the use of relatively low chloride coal, one can assume the chlorides to be removed via the blowdown stream as $CaCl_2$ and would leave the plant in the entrained moisture in the solid waste. No blowdown specifically for chloride disposal or special treatment of the waste would be required under these conditions.

3.4.4 VISIBILITY IMPACTS

The final impact analysis conducted was to assess the visibility impairment impact reduction for the SO_2 control technologies. The analysis used a baseline SO_2 emission rate which assumed the highest 24-hour actual emission rate for 2001-2003 as recommended by the BART guideline and listed in the Modeling Protocol. Three CALPUFF model runs for BSP were conducted with the constant NO_X emission rate of 0.65 lb/mmBtu, constant PM emission rate of 0.015 lb/mmBtu, and various levels of SO_2 control applied. Table 3.4-6 shows the modeled emission rates.

The modeling for this analysis was performed using CALPUFF. The difference between the modeled impacts at the 98th percentile level from various controlled emission rates represents the visibility impairment impact reduction in deciViews (dV). Table 3.4-6 shows the results of the visibility impact modeling attributable to SO_2 reductions while maintaining NO_X and PM emissions constant. The modeling results with combined impacts from all pollutants are addressed later in the report.

TABLE 3.4-6 – Visibility Impairment Impacts from Emission Controls

SO_2 Control Technique	Emission Rate (lb/mmBtu)	Visibility Impairment Impact (dV)	Visibility Impairment Reduction[1] (Δ dV)	Technology Incremental Reduction (Δ dV)
Wet FGD	0.043	0.611	0.046	0.009
Semi-dry FGD	0.09	0.620	0.037	0.037
Presumptive Semi-dry FGD	0.15	0.657	-	-
Baseline	0.86	1.079	-	-

1 – Impairment reduction is from presumptive semi-dry FGD levels.

The results of the baseline visibility impairment modeling for BSP showed that SO_2 emissions caused a Class I area to exceed 0.5 dV for predicted visibility impairment impact (98th percentile). Modeled visibility impairment impacts decreased with the addition of all SO_2 controls.

As previously discussed, the 0.5 dV value is the lowest visibility impairment impact that is considered discernible by the human eye and the EPA set this threshold as the point where a given source is considered a "contributing source". Thus, an impairment impact or a difference in impairment impacts of

less than 0.5 dV is considered visibly indiscernible. Because the difference in impacts between semi-dry FGD and wet FGD are 0.009 dV apart, the visibility improvement resulting from these controls is considered indiscernible. Where visibility improvement between alternatives is indiscernible, the incremental cost to achieve the indiscernible visibility improvement is determined and evaluated against incremental costs for the next most stringent alternative. Table 3.4-7 shows the costs to achieve the incremental reduction in visibility impairment.

TABLE 3.4-7 – Cost for Incremental Visibility Improvement

SO_2 Control Technique	Incremental Levelized Total Annual Cost[1] ($)	Impairment Reduction (Δ dV)	Incremental Reduction (Δ dV)	Cost for Incremental Improvement ($/dV)
Wet FGD	5,480,000	0.046	0.009	608,900,000
Semi-dry FGD	240,000	0.037	0.037	6,500,000
Presumptive Semi-dry FGD	23,330,000	-	-	-

1 – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

3.4.5 IMPACT SUMMARY

Table 3.4-8 summarizes the various quantifiable impacts discussed in Sections 3.4.1 through 3.4.4 for the SO_2 alternatives evaluated for BSP Unit I.

TABLE 3.4-8 – Impacts Summary for BSP Unit I SO_2 Controls

SO_2 Control Technique	Emission Rate (lb/mmBtu)	Levelized Total Annual Cost ($1,000)	Incremental Levelized Total Annual Cost[1] ($1,000)	Visibility Impairment Impact (dV)	Visibility Impairment Reduction (dV)	Technology Incremental Reduction (Δ dV)
Wet FGD	0.043	29,050	5,480	0.611	0.046	0.009
Semi-dry FGD	0.09	23,570	240	0.620	0.037	0.037
Presumptive Semi-dry FGD	0.15	23,330	23,330	0.657	-	-
Baseline	0.86	-	-	1.079	-	-

1 – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

4.0 PARTICULATE MATTER BART EVALUATION

In this section, steps 1 through 5 of the BART determination for BSP Unit I are described for PM. All PM control technologies are first identified. A technical description of the processes and their capabilities are then reviewed to determine availability and feasibility. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal PM control capability. The impacts analysis then reviews the estimated cost, energy, and non-air quality impacts for each technology. The impact of the remaining useful life of the source is reviewed as part of the cost analysis. In the final step of the analysis, the remaining technologies are assessed for their potential visibility impairment impact reduction capability via visibility modeling results. The results of the complete analyses are tabulated and possible BART control options are listed.

The BART guidelines published in the Federal Register on July 6, 2005 (70 FR 39104) do not specify presumptive BART levels for particulate matter (PM) emissions. The guidelines suggest the use of PM_{10} as the indicator for all $PM_{2.5}$, because all $PM_{2.5}$ is encompassed within the PM_{10} emissions fraction. (40 CFR 51, App. Y, II.A.3.) The BART guidelines specify the distinction between coarse (PM_{10} minus $PM_{2.5}$) or fine ($PM_{2.5}$) PM in determining visibility impacts, which was made during the CALPUFF visibility modeling.

The BART Guidelines indicate that one of the evaluated emission limits must be at least as stringent as the New Source Performance Standard (NSPS) requirement for the source (40 CFR 51, App. Y, IV.D.1). The BSP pulse-jet fabric filter meets the current NSPS emission rate 0.015 lb/mmBtu as required of new sources under 40 CFR § 60.42Da(c). All of the evaluated control technologies used a PM emission rate of 0.015 lb/mmBtu.

4.1 IDENTIFICATION OF AVAILABLE RETROFIT PM CONTROL TECHNOLOGIES

The initial step of the BART determination is the identification of available retrofit PM control technologies. In order to produce a list of control technologies and their estimated capabilities, sources such as the RACT/BACT/LAER Clearinghouse (RBLC) were used. The results of the investigation determined that the removal of PM from flue gas is accomplished using post combustion technology. The two most common post combustion technologies used to control PM emissions include fabric filters (FF)

and electrostatic precipitators (ESPs). The existing BSP configuration contains a pulse-jet fabric filter that was installed in 2007. Table 4.1-1 contains the results of the available PM control technologies.

TABLE 4.1-1 PM Control Technologies Identified for BART Analysis

Control Technology
Existing Fabric Filter
New Fabric Filter
COHPAC Baghouse
Electrostatic Precipitator

4.2 TECHNICAL DESCRIPTION AND FEASIBLITY ANALYSIS

The second step in the BART analysis procedure is a technical feasibility analysis of the options identified in Step 1. This analysis is presented below for each identified option.

4.2.1 FABRIC FILTER (FF)

A fabric filter or baghouse removes particulate by passing flue gas through filter bags. A pulse-jet fabric filter (PJFF), a common type of fabric filter, consists of isolatable compartments and a tube sheet which separates the particulate laden flue gas from the clean flue gas. The flue gas passes through the PJFF by flowing from the outside of the bag to the inside up the center of the bag through the hole in the tube sheet and out the PJFF. Fly ash particles are collected on the outside of the bags and the cleaned gas stream passes through the bag to the outlet of the fabric filter. Each filter bag alternates between relatively long periods of filtering and short periods of cleaning. During the cleaning period, fly ash that has accumulated on the bags is removed by pulses of air and falls into a hopper for disposal.

The existing fabric filter on BSP Unit I can achieve a filterable PM emission rate of 0.015 lb/mmBtu. Therefore, continuing the use of the existing fabric filter is a technically feasible option. Replacement of the existing fabric filter with a new fabric filter is feasible, but would provide little to no increase in removal efficiency or reduction in emission rate.

4.2.2 COHPAC

A COmpact Hybrid PArticulate Collector (COHPAC) is a high air-to-cloth ratio pulse jet fabric filter located downstream of an existing ESP. The COHPAC acts as a polishing device for control of particulate emissions. The difference between a COHPAC and the fabric filter described above is that a COHPAC is installed after an ESP. Because Big Stone Plant does not have an ESP and already uses a fabric filter for particulate control, the use of a COHPAC is not considered further.

4.2.3 ELECTROSTATIC PRECIPITATOR (ESP)

ESPs are commonly used as the primary filterable PM control device on coal fired units. The ESP discharge electrodes generate a high voltage electrical field that gives the particulate matter an electric charge (positive or negative). The charged particles will then be collected on a collection plate. Technical characteristics associated with ESPs are described in Appendix C1.

It is anticipated that a new ESP installed at BSP could achieve a PM emission rate of approximately 0.015 lb/mmBtu. Therefore, the use of a new electrostatic precipitator is a technically feasible option. Replacement of the existing fabric filter with a new ESP is feasible, but would provide little to no increase in removal efficiency or reduction in emission rate.

The results of the feasibility analysis for the available BART alternatives are summarized in Table 4.2-1.

TABLE 4.2-1 – PM BART Feasibility Analysis Results

Control Technology	In Service on Existing Utility Boilers	Commercially Available	Technically Applicable To Big Stone Plant
Existing Fabric Filter	Yes	Yes	Yes
New Fabric Filter	Yes	Yes	Yes
COHPAC Baghouse	No[1]	Yes	No
New ESP	Yes	Yes	Yes

1 – While COHPAC has been installed on existing EGUs, it has not been installed in conjunction with an existing fabric filter.

4.3 RANK OF TECHNICALLY FEASIBLE PM CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis procedure is to rank the technically feasible alternatives. However, because BSP Unit I currently uses a pulse-jet fabric filter that is the best technology available for particulate control and can achieve similar emission rates to new versions of the same technology or a new ESP replacing the existing fabric filter with new particulate control is inappropriate. Thus, the existing fabric filter is the highest ranked and only option evaluated further.

4.4 EVALUATION OF IMPACTS FOR FEASIBLE PM CONTROLS – UNIT I

Step four in the BART analysis procedure is the impact analysis. The BART Guidelines list four factors to be considered in the impact analysis:

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Because Big Stone Plant Unit I currently uses a pulse-jet fabric filter that is the best technology available for particulate control and can achieve similar emission rates to new versions of the same technology replacing the existing fabric filter with new particulate control is inappropriate. Reviewing the four impacts listed above would provide no additional information regarding the type of technology to be selected to best achieve visual emissions improvement. However, as described in Section 1.3.6, the visibility impairment impacts due to particulate matter were included as part of the analysis.

4.4.1 VISIBILITY IMPACTS

A visibility analysis specifically for PM was not conducted due to the selection of the existing fabric filter and the conclusion that the alternatives would result in the same emission rate. Per the BART Guidelines, because BSP has "elected to apply the most stringent controls available…you need not conduct, or require the source to conduct, an air quality modeling analysis for the purpose of determining its visibility impacts." (40 CFR 51. App. Y, IV.D.5.)

5.0 BART RECOMMENDATIONS

The presented emission rates in this section are the BART recommendation. However, because the accuracy of the cost estimate is ± 30% and in some cases is greater than the variance of the estimated costs between control alternatives, the technology selected by Big Stone Plant to meet the BART recommendation may change. This section summarizes the analysis performed for each pollutant.

5.1 NO_X BART

Five types of NO_X control processes were identified for evaluation. Over-fire air (OFA), separated over-fire air (SOFA), Selective Non-Catalytic Reduction (SNCR), Rich Reagent Injection (RRI), Selective Catalytic Reduction (SCR) and combinations these technologies were evaluated for control effectiveness. Of these alternatives, stand alone SNCR and SCR were eliminated from further impacts analysis as BSP already has an OFA system in operation. A cost analysis of the remaining technologies eliminated RRI/SNCR/SOFA due to the operating costs.

Predicted visibility impairment impacts decreased significantly with the NO_X control technologies. The largest incremental impact reduction came from the application of SCR. However, the difference in impacts between OFA (lowest control level) and SCR (highest control level) is less than 0.5 dV, which is visibly indiscernible. The modeling also shows that SOFA must be applied to reduce visibility impacts due to the NO_X contribution below a discernable level of 0.5 dV. An analysis of the incremental cost-effectiveness of consecutively more stringent controls was performed for BSP Unit I. Installing and operating any control technology beyond SOFA would cost more than 24 million dollars per dV of visibility impairment improvement and would only improve predicted visibility impacts by an amount that is not discernable to the human eye.

Based on the analysis, SOFA is recommended as BART for BSP Unit I. Application of SOFA for NO_X control translates into a BART emission rate of 2,804 pounds per hour (0.50 pounds per million Btu of fuel heat input at 5,609 mmBtu/hr). The emission rate of 2,804 pounds per hour is recommended as the permit limit based upon a 30 day rolling average.

5.2 SO_2 BART

Three types of SO_2 control processes were identified for evaluation. While evaluating each process for BSP SO_2 control, fuel switching was eliminated due to the current use of low sulfur PRB coal. Wet FGD and semi-dry FGD at two levels of control were selected for further evaluation. A cost analysis of the remaining technologies eliminated wet FGD at the presumptive emissions rate due to the higher cost for achieving the same emission rate as semi-dry FGD.

The difference in impacts between semi-dry FGD and wet FGD are 0.009 dV apart, which is visibly indiscernible. The modeling also shows that semi-dry FGD at 90% control must be applied to reduce

visibility impacts due to the SO_2 contribution below a discernable level of 0.5 dV. An analysis of the incremental cost-effectiveness of consecutively more stringent controls was performed for BSP Unit I. Installing and operating wet FGD over semi-dry FGD would cost 608 million dollars per dV of visibility impairment improvement and would only improve predicted visibility impacts by an amount that is not discernable to the human eye.

Based on the analysis, semi-dry FGD is recommended as BART for BSP Unit I. Application of semi-dry FGD for SO_2 control translates into a BART emission rate of 505 pounds per hour (0.09 pounds per million Btu of fuel heat input at 5,609 mmBtu/hr heat input). The emission rate of 505 pounds per hour is recommended as the permit limit based upon a 30 day rolling average.

5.3 PM BART

For the PM evaluation, three post combustion control technologies were selected for evaluation in addition to the existing pulse-jet fabric filter. While evaluating each technology for BSP Unit 1 PM control, a COHPAC baghouse was eliminated from the evaluation. A new fabric filter and ESP were eliminated in the analysis because the existing fabric filter provides a similar level of control effectiveness without the additional capital costs.

Because BSP Unit I currently uses a pulse-jet fabric filter that is the best technology available for particulate control and is the only technology remaining in the analysis, the impact review can be abbreviated.

Reviewing the cost of compliance, the energy and non-air quality environmental impacts, other pollution control equipment in use at the source, and the remaining useful life of the source would provide no additional information to change technologies from the existing fabric filter. The modeling was conducted with a constant PM emission rate of 84.1 pounds per hour.

Based upon selection of the best available PM control technology, maintaining the existing pulse-jet fabric filter is recommended as BART for BSP Unit I. The corresponding BART emission rate for the existing fabric filter is 84.1 pounds per hour (0.015 pounds per million Btu of fuel heat input at 5,609 mmBtu/hr heat input). The emission rate of 84.1 pounds per hour is recommended as the permit limit based upon a 30 day rolling average.

5.4 COMBINED BART

As indicated previously, this report presents the analysis of control technologies for NO_X, SO_2, and PM for BSP Unit I. The BART control technology recommendations for the individual pollutants are based upon the steps outlined in the EPA guideline. Modeling to determine visibility impairment was performed using the recommended BSP Unit I BART emission rates for NO_X, SO_2, and PM. The 98th percentile results are provided in Table 5.4-1.

TABLE 5.4-1 – Visibility Impairment Impacts from Combined Emissions

Control Technique	NO_X Emission Rate (lb/hr)	SO_2 Emission Rate (lb/hr)	PM Emission Rate (lb/hr)	Visibility Impairment Impact (dV)
BART	2,804	505	84.1	0.493

The results of the visibility impairment modeling for BSP showed that the proposed BART emissions rates for NO_X, SO_2 and PM caused no Class I area to exceed 0.5 dV for predicted visibility impairment impact (98th percentile) with Boundary Waters Canoe Area Wilderness (Boundary Waters) showing the highest predicted visibility impairment impact at 0.493 dV for the 2007 modeled year. Modeled visibility impairment impacts decreased significantly with the addition of the BART controls.

APPENDIX A

Technical Feasibility Assessment Details for NO_X Controls (A1)

CUECost Input Summary (A2)

Summary of Modeling Results (A3)

A1 Technical Feasibility Assessment of NO_X Control Alternatives

Uncontrolled NO_X emissions from a coal-fired electric generating unit are highly dependent on type of firing method, amount of solid fuel fired per unit time and furnace volume, and the fuel's basic combustion properties and elemental composition. The methods for reduction of such emissions:

- either prevent pollution, i.e., use inherently lower-emitting processes/practices which produce fewer NO_X emissions during the power generation process; or
- involve improvements to, or provide new add-on controls that, reduce emissions after they are produced before they are emitted from the facility; or
- are combinations of inherently lower-emitting processes and add-on controls.

There are two basic categories of NO_X emission control alternatives:

- Combustion controls; and
- Post-Combustion controls.

A significant number of the identified control options have been commercially-available, installed, and operating in many full-scale, permanent installations in the United States for five years or more. Similar to the dependency of the uncontrolled emissions being based on the unit type, the applicability of the control technologies are also dependent upon the type of coal-fired unit.

Combustion controls, such as over-fire air (OFA) or separated over-fire (SOFA) air are applicable to cyclone fired units. Low-NO_X burners (LNBs), while commonly applied to pulverized coal-fired boilers, are not applicable to cyclone fired units since initial combustion occurs in the barrel-shaped cyclone and not in the furnace chamber as is the case for the pulverized coal-fired boiler.

Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) are post-combustion technologies that have been applied on bituminous or sub-bituminous coal-fired boilers. Others, mostly comprised of a combination of available control technologies, are often referred to as "hybrid" or "layered" control technologies. Variations of SNCR, such as more recently developed "Rich Reagent Injection" (RRI) technology, have only been demonstrated on a limited number of cyclone-fired boilers. In most of the "layered" control combination and emerging control cases, the NO_X control technology has been demonstrated to be capable of controlling the targeted pollutant(s) on either:

- a full-scale basis, but only with temporary equipment; or

- a full-scale basis, with permanent equipment but in a limited number of installations.

A1.1 Combustion Controls

Nitrogen oxides (NO_X) are produced when nitrogen in the fuel and combustion air are exposed to high temperatures. Nitrogen oxide (NO) is the most predominant form of NO_X emissions, along with nitrogen dioxide (NO_2). The formation of these compounds in utility powerplant boilers is sensitive to the method of firing and combustion controls utilized. The techniques employed for mixing the combustion air and fuel, which creates flames and high temperature combustion products, results from the rapid oxidization of carbon, hydrogen, and other exothermic reactions. Cyclone-fired boilers, by design, create intense heat release rates to melt and fluidize the coal ash introduced into the barrel-shaped furnaces. This produces very high uncontrolled NO_X emissions.

Combustion controls employ methods that reduce the amount of NO_X emissions created in the combustion zone of the boiler prior to exhausting the flue gases from the furnace (upstream of the convective heat transfer zones). This results in fewer emissions that may require subsequent reduction from applicable post-combustion techniques.

A1.1.1 Low-NOx Burners (LNB)

LNBs are not applicable to cyclone-fired boilers[1]. This is due to the physical constraints imposed by the cyclone furnaces' (barrels) length and diameter, and the incompatibility with the amount of heat released and flame dispersion patterns, and insufficient amount of fine coal particles required to sustain stable combustion associated with air-staged firing of coal using low-NO_X burners with pulverized fuel. This alternative was eliminated from consideration for potential additional NO_X emissions reductions from Big Stone's boiler.

A1.1.2 Over-fire Air (OFA) or Separated Over-fire Air (SOFA)

Over-fire Air (OFA) and Separated overf-ire air (SOFA) systems are commonly-applied, combustion-related NO_X emission reduction technology. Separated Overfire Air (SOFA) is an air-staging NO_X reduction technique that is usually based on withholding 15 to 20 percent of the total combustion air conventionally supplied to the firing zone. It is believed that Big Stone's boiler would be a suitable candidate for the installation of SOFA and for additional NO_X control, if this is necessary.

For typical cyclone coal-fired boilers, the operation of SOFA involves diverting approximately 20 percent of the secondary combustion air from the burner barrels, forcing the cyclones to operate fuel-rich. The diverted combustion air is then injected in the upper furnace, where combustion is completed.

SOFA can achieve significant NO_X reduction, typically 30 to 70 percent on typical cyclone coal-fired boilers with this typical amount of air staging. A summary of several of the first OFA retrofits to cyclone-fired boilers is described in published technical papers[1,2]. At least thirty nine existing cyclone-fired boilers, firing eastern bituminous, midwestern bituminous, and western subbituminous ("Powder River Basin") coals in units ranging in size from 50 to 1150 MW, have been retrofitted with commercial SOFA since 1998[3]. Additional cyclone-fired boilers have installed separated overfire air systems in conjunction with commercial fuel reburn retrofit projects[4]. Other NO_X emission reduction demonstration projects, primarily sponsored by U.S. Department of Energy National Energy Technology Laboratory's Clean Coal Technology Program[5], and other fuel reburn retrofit projects[6] have also installed separated overfire air on cyclone boilers.

A basic form of separated overfire air (SOFA) can be applied and installed on Big Stone. There are potential impacts and limitations unique to cyclone boilers firing PRB that should be recognized as part of this emission reduction technology application.

A key aspect of successfully applying and operating separated overfire air on a cyclone-fired boiler is the ability to maintain adequate molten coal ash (slag) formation and flow within the barrels and slag taps. As secondary combustion air is diverted, less heat is released during air-staged combustion from the intentional formation of carbon monoxide, and temperatures within the cyclones decreases. The degree to which the cyclones can be operated with less than theoretical (stoichiometric) combustion air directly contributes to less NO_X formation and further in-furnace emission reduction but also risks solidification of the molten coal ash. There are several challenges anticipated for implementing SOFA, primarily involving the ability to route large SOFA ductwork for diverting secondary air from the windboxes. These are believed to be solvable. Using a basic SOFA system, assuming a sustainable level of NO_X emissions control with the operation of modestly air-staged cyclone furnaces with suitable combustion controls, is considered feasible for Big Stone.

A1.2 Post-Combustion Controls

Post-combustion controls deal with techniques that thermally or chemically-treat the flue gases to reduce NO_X emissions after they have exited the boiler's lower furnace. In the case of Big Stone Unit I, this primarily involves forms of selective catalytic reduction (SCR) and selective non-catalytic reduction (SCR) technologies.

A1.2.1 Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR) technologies are all post-combustion types of boiler NO_X emission controls. These technologies promote NO_X reduction with chemical reactions that are insensitive to the specific fuel types whose combustion products are being treated. While the large majority of boiler applications to date have been on pulverized coal-fired units burning eastern bituminous fuels, SNCR has been used to reduce NO_X emissions on utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal. SNCR has also been used with fuel oil and natural gas-fired units. SNCR (and hydrocarbon-enhanced SNCR) technologies can each be applied to fossil fuel-fired boilers with or without the use of a SOFA system. The ability to apply SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has been installed, with or without overfire air in full operation. Operation at these plants has demonstrated that SNCR can decrease NO_X emissions as much as 15-40% at full load, most typically between 25-35%.[7, 8, 9]

In the conventional SNCR process, urea or ammonia is injected into the boiler in a region where the combustion gas temperature is in the 1700 to 2100 degrees F range. Under these temperature conditions, the urea reagent [$CO(NH_2)_2$] or ammonia [NH_3] reacts with the nitrogen oxides [NO_X], forming elemental nitrogen [N_2] and water, reducing NO_X emissions.

SNCR can be applied and installed on the Big Stone boiler in combination with basic or separated form of over-fire air (OFA).

A1.2.2 Rich Reagent Injection (RRI)

Rich Reagent Injection (RRI) is a NO_X control technology that has been developed and demonstrated specifically for use on cyclone boilers. Rich Reagent Injection is an SNCR process that involves the injection of urea into the lower furnace between the cyclones and the SOFA ports. RRI targets a high

temperature, fuel-rich zone within the boiler-furnace environment immediately adjacent to the cyclone burners, and requires temperatures in the range of 2400 to 3100 degrees F. The combustion gases must be essentially devoid of free oxygen, in order to avoid oxidizing the nitrogen contained in the injected reagent, which would create NO_X emissions instead of reducing them.

The RRI process for NO_X reduction must be used in conjunction with air-starved (substoichiometric staged-air) cyclone combustion resulting from the installation and operation of an OFA system. The cyclones' air/fuel stoichiometry must be carefully controlled to maintain fuel-rich conditions for the RRI process to be effective. This introduces oxygen in the same vicinity as the reagent injection ports, and will disrupt the beneficial action of the fuel-rich zone and amine reagent to significantly reduce NO_X emissions. Without SOFA, RRI will not contribute positively to NO_X emissions control on Big Stone Unit I boiler. This places a large emphasis on the expected performance of SOFA in order for RRI to be successful in producing significant additional NOx emissions reduction on PRB-fired cyclone boilers.

The three zones of a Rich Reagent Injection SNCR application on a boiler with separated overfire air are shown as a sectional side elevation view of the furnace[11] in Figure A.1-4.

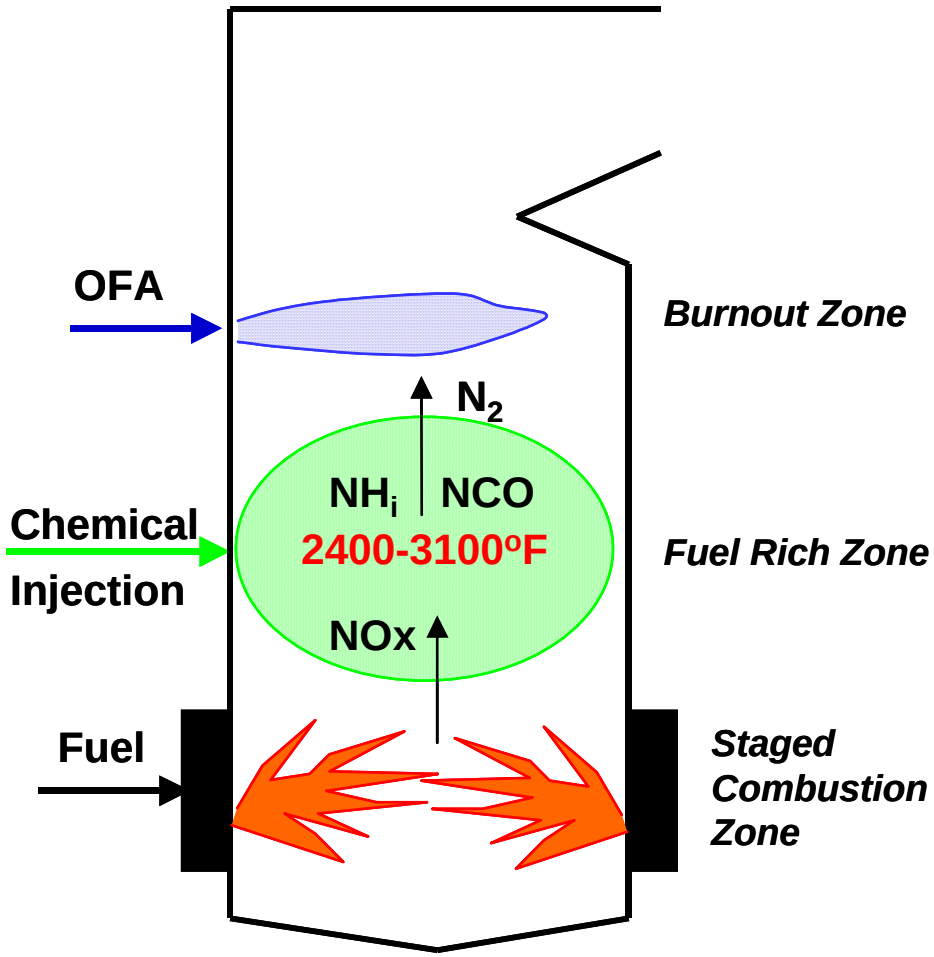


Figure A.1-4 Rich Reagent Injection Application on Boiler With Overfire Air[10]

The Rich Reagent Injection (RRI) process has been successfully demonstrated on at least two cyclone-fired boilers, with the most recent installation at Ameren's Sioux Unit I, a 500 MW boiler firing a blend of PRB and midwestern bituminous coals.

The NO_X emission reduction reagent injection for RRI processes must be precisely located and carefully controlled to be effective. Operation outside of the required operating ranges can even result in increased NO_X emissions. Extensive computational fluid dynamic (CFD) simulations are needed to determine the optimum injection points. Boiler operating conditions will change with unit load and varying fuel characteristics. The RRI process control systems must be able to adjust for these changing conditions.

RRI has the potential to provide a moderate degree of NO_X reduction on coal-fired cyclone boilers. Rich Reagent Injection can be applied and installed on Big Stone boiler only with separated over-fire air (SOFA).

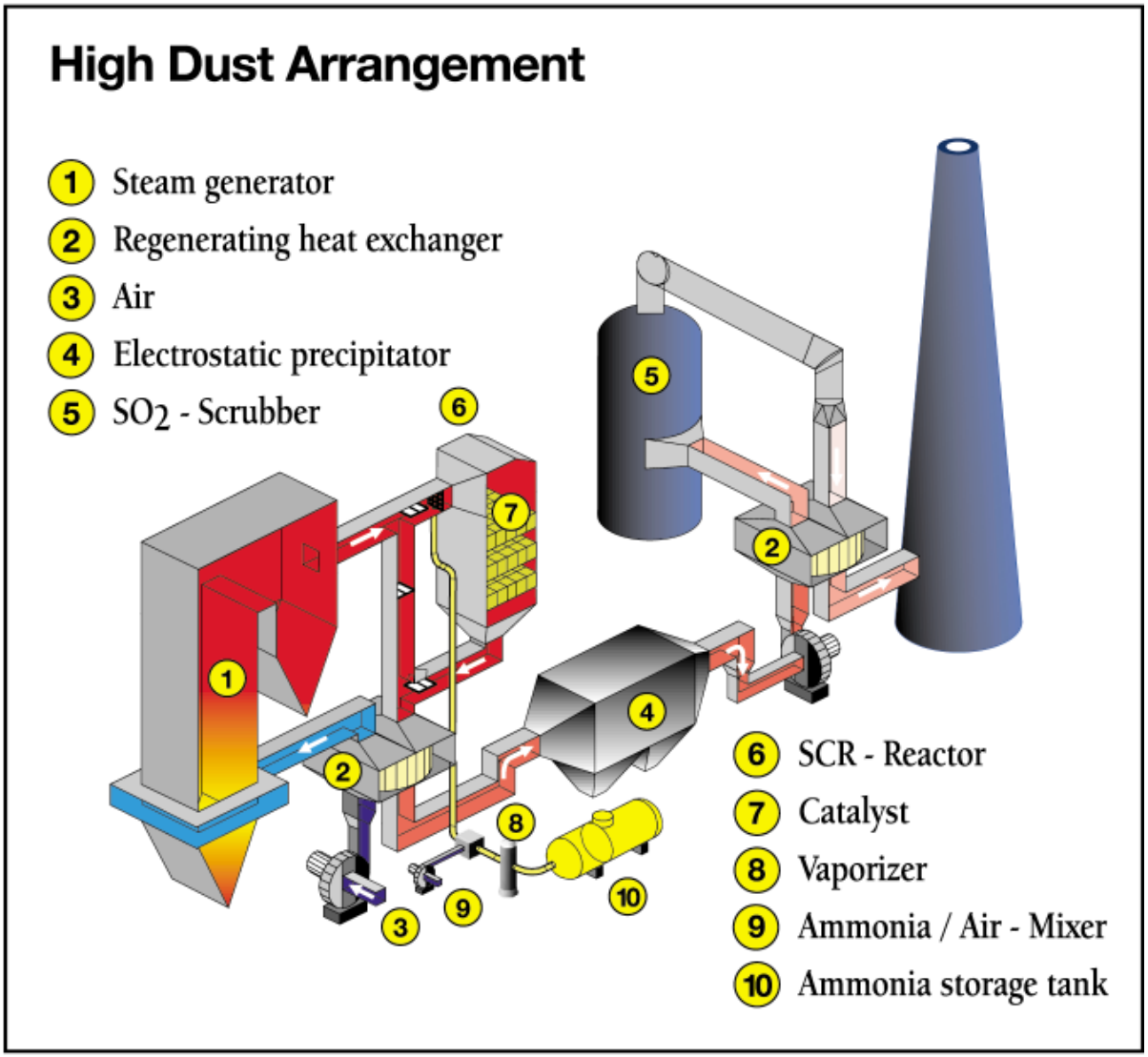
A1.2.3 Selective Catalytic Reduction (SCR)

The lowest NOx emission levels from coal-fired utility boilers are typically achieved by installing and operating selective catalytic reduction (SCR) technology. In the SCR process, the gas stream is passed through a catalyst bed in the presence of ammonia to reduce NO_X to molecular nitrogen and water. The process is termed "selective" because the ammonia preferentially reacts with the NO_X rather than with the oxygen in the flue gas. A catalyst is used to enhance NO_X reduction and ammonia utilization at appropriate flue gas temperatures. SCR is usually applied to flue gas in the 600°F to 750°F temperature range. There are variations in the SCR process for coal-fired boilers that mostly involve locations in the flue gas path where the catalyst is placed in order to promote the desired NO_X emission reduction effect. These are described below.

For coal-fired boilers, a conventional SCR reactor utilizes readily-available catalyst materials and reagent in the form of ammonia. A conventional SCR reactor is commonly installed in a high-dust, hot-side arrangement, located between the economizer outlet and air heater inlet, where the flue gas temperature is within the desired operating range for the SCR catalyst.

A schematic graphic diagram for a conventional high-dust, hot-side SCR system on a boiler with a flue gas desulfurization system and stack gas reheat is provided in Figure A.1-5.

Figure A.1-5 Conventional SCR Arrangement with FGD Scrubber Outlet Reheat



(figure copied from Wheelabrator Air Pollution Control literature)

SCR technology has been installed on several pulverized coal and cyclone boilers firing bituminous and subbituminous coal in the United States. The installation of SCR systems has been completed on approximately 22 cyclone units. Several SCR installations have been retrofit on existing cyclone-fire boilers burning western subbituminous coal (or PRB blended with midwestern bituminous coal). For cyclone coal-fired utility boilers retrofitted with SCR technology, all were originally designed to burn bituminous coal.

Two byproducts from the high-dust, hot-side SCR process are ammonia slip and SO_3:

- Ammonia Slip: Slip is ammonia that is unreacted in the NO_x emission reduction process. Maximum ammonia slip for a gas fired unit is usually 10 ppmvd whereas, on a coal fired unit, ammonia slip below 2 ppm is desired. For certain applications, this concentration can be problematic, therefore requiring more catalyst to reduce slip. Most new SCR applications have ammonia slip guaranteed at a 2 ppmvd maximum for an initial operating period, and are expected to continue to operate at these low ammonia slips levels beyond the end of the initial period.
- SO_3: Due to the composition of typical SCR catalysts, a small percentage of inherent SO_2 will be oxidized to SO_3. This oxidation can be controlled by catalyst selection and can be less than 1%. SO_2 to SO_3 oxidation must be carefully controlled to avoid creating SO_3 levels sufficiently high to raise the possibility of air heater fouling. A unit firing high-sulfur coal with SCR technology is especially vulnerable to SO_2 oxidation and ammonia slip-related fouling problems. The deposition and fouling is due to formation of solid ammonium sulfate ($(NH_4)_2SO_4$) and liquid ammonium bisulfate (NH_4HSO_4). The most important design variable is optimizing the catalyst selection and amount of catalyst that will reduce NO_X emissions, control ammonia slip, and minimize SO_2 oxidation.

As posted on Electric Power Research Institute Inc.'s (EPRI's) website regarding the impact of coal type on SCR catalyst life and performance, a recent EPRI study[11] produced field data analyzed from an "In-Situ Mini SCR Reactor" system installed in a typical "high-dust" location at seven different test sites, including four firing PRB coal, one firing Texas lignite, one firing high-sulfur eastern bituminous coal, and one firing a PRB/eastern bituminous coal blend. The PRB/bituminous coal blend test was performed at AmerenUE's Sioux Station, on one of the two 500 MW cyclone-fired boilers. This study found that the cyclone unit firing the PRB/bituminous coal blend exhibited the fastest rate of catalyst activity degradation. Also, the higher deactivation rates seen at this site were due to economizer exit flue gas temperatures being significantly higher than at the other sites. A comparison of the Texas lignite and one

of the PRB-fired sites of two different catalysts' deactivation was more a function of trace elements in the flue gas and flyash than the specific catalyst type or formulation.

Based upon this technical assessment that looked at the various design and operational issues associated with the installation of hot-side, high-dust SCR technology, SCR is considered a feasible option for Unit I at Big Stone.

References for Appendix A1:

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2. "B&W's Advances on Cyclones NOx Control Via Fuel and Air Staging Technologies", by Farzan, H., Maringo, G., Johnson, D. W., and Wong, D.K. (Babcock & Wilcox, Co.), Beard, C.T. (Eastman Kodak Company), and Brewster, S.E. (Tennessee Valley Authority), presented at the EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, Atlanta, GA, August 16-20, 1999. Available at B&W's internet website: http://www.babcock.com/pgg/tt/pdf/BR-1683.pdf

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4. B&W experience list September 18, 2002.

5. "Reburning Projects in the Department of Energy's Clean Coal Technology Demonstration Program", by Mann, Al and Ruppel, Tom (Parsons Corporation), and Sarkus, Tom (National Energy Technical Laboratory), presented at the 2004 DOE-NETL Conference on Reburning for NOx Control, Morgantown, WV, May 18, 2004. A reburn-related document (an updated version of a poster from the May 18 Conference) is titled "Scorecard on Reburning 6/1/2004" by Al Mann and Tom Ruppel, Parsons Corporation, available on-line at: http://www.netl.doe.gov/publications/proceedings/04/NOx/posters/Reburning%20Scorecard.pdf

6. GE Energy (formerly GE-EER) experience list September 29, 2005.

7. Fuel Tech experience list dated 1/28/2005.

8. SNCR "White Paper", Institute of Clean Air Companies, Inc. (ICAC), SNCR Committee, May 2000, Fuel Tech website http://www.fueltechnv.com/pdf/TPP-534.pdf.

9. RJM experience list September 3, 2004.

10. "Improved Rich Reagent Injection (RRI) Performance For NOx Control In Coal Fired Utility Boilers" by Cremer, Marc A. and Wang, Huafeng D. (Reaction Engineering International), Boll, David E. (AmerenUE), Schindler, Edmund (RJM Corporation), and Vasquez, Edmundo RMT, Inc. (Alliant Energy Corp.), presented at 2003 U.S. DOE Conference on SCR and SNCR for NOx Control, Pittsburgh, PA, October 29-30, 2003.

11. "Ash Impacts on SCR Catalyst Performance", Energy & Environmental Research Center (EERC) of the University of North Dakota", Benson, Steven A., Ph.D., October 2005.

A2 CUECost Input Summary

APC Technology Choices

Description	Units	Case 1	Case 2	Case 3
FGD Process	Integer	1	1	1
(1 = LSFO, 2 = LSD)				
Particulate Control	Integer	1	1	1
(1 = Fabric Filter, 2 = ESP)				
NOx Control	Integer	1	1	1
(1 = SCR, 2 = SNCR, 3 = LNBs, 4 = NGR)				

INPUTS

Description	Units	Case 1	Case 2	Case 3
General Plant Technical Inputs				
Location - State	Abbrev.	SD	SD	SD
MW Equivalent of Flue Gas to Control System	MW	475	475	475
Net Plant Heat Rate	Btu/kWhr	11,809	11,809	11,809
Plant Capacity Factor	%	85%	85%	85%
Total Air Downstream of Economizer	%	120%	120%	120%
Air Heater Leakage	%	10%	10%	10%
Air Heater Outlet Gas Temperature	°F	320	320	320
Inlet Air Temperature	°F	70	70	70
Ambient Absolute Pressure	In. of Hg	28.75	28.75	28.75
Pressure After Air Heater	In. of H2O	-15	-15	-15
Moisture in Air	lb/lb dry air	0.013	0.013	0.013
Ash Split:				
Fly Ash	%	80%	80%	80%
Bottom Ash	%	20%	20%	20%
Seismic Zone	Integer	0	0	0
Retrofit Factor	Integer	1.5	1.5	1.5
(1.0 = new, 1.3 = medium, 1.6 = difficult)				
Select Coal	Integer	1	1	1
Is Selected Coal a Powder River Basin Coal?	Yes / No	Yes	Yes	Yes
Economic Inputs				
Cost Basis -Year Dollars	Year	2008	2008	2007
Sevice Life (levelization period)	Years	30	30	30
Inflation Rate	%	3%	3%	3%
After Tax Discount Rate (current $'s)	%	9%	9%	9%
AFDC Rate (current $'s)	%	11%	11%	11%
First-year Carrying Charge (current $'s)	%	10%	10%	10%
Levelized Carrying Charge (current $'s)	%	10%	10%	10%
First-year Carrying Charge (constant $'s)	%	10%	10%	10%
Levelized Carrying Charge (constant $'s)	%	10%	10%	10%
Sales Tax	%	6%	6%	0%
Escalation Rates:				
Consumables (O&M)	%	3%	3%	3%

Capital Costs:				
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes	Yes
If "Yes" input cost basis CE Plant Index	Integer	575.4	575.4	575.4
If "No" input escalation rate.	%	3%	3%	3%
Construction Labor Rate (Not Used N Calc)	$/hr	$35	$35	$35
Prime Contractor's Markup	%	3%	3%	3%
Operating Labor Rate	$/hr	$48	$48	$48
Power Cost	Mills/kWh	25	25	25
Steam Cost	$/1000 lbs	3.5	3.5	3.5
Limestone Forced Oxidation (LSFO) Inputs				
Any By-Pass around the scrubber		2	2	2
(1 = yes, 2 = no)				
Percent of By-Passed Gas	%	0.0%	0.0%	0.0%
SO2 Removal Required	%	95.0%	83.0%	95.0%
L/G Ratio	gal / 1000 acf	125	125	110
Design Scrubber with Dibasic Acid Addition?	Integer	2	2	2
(1 = yes, 2 = no)				
Adiabatic Saturation Temperature	°F	132	132	135
Reagent Feed Ratio	Factor	1.05	1.05	1.03
(Mole CaCO3 / Mole SO2 removed)				
Scrubber Slurry Solids Concentration	Wt. %	15%	15%	15%
Stacking, Landfill, Wallboard	Integer	2	2	3
(1 = stacking, 2 = lanfill, 3 = wallboard)				
Number of Absorbers	Integer	1	1	1
(Max. Capacity = 700 MW per absorber)				
Absorber Material	Integer	1	1	1
(1 = alloy, 2 = RLCS)				
Absorber Pressure Drop	in. H2O	6	6	6
Reheat Required ?	Integer	2	2	2
(1 = yes, 2 = no)				
Amount of Reheat	°F	0	0	0
Reagent Bulk Storage	Days	60	60	30
Reagent Cost (delivered)	$/ton	$24	$24	$12
Landfill Disposal Cost	$/ton	$4	$4	$30
Stacking Disposal Cost	$/ton	$2	$2	$6
Credit for Gypsum Byproduct	$/ton	$0	$0	$0
Maintenance Factors by Area (% of Installed Cost)				
Reagent Feed	%	3%	3%	3%
SO2 Removal	%	3%	3%	3%
Flue Gas Handling	%	3%	3%	3%
Waste / Byproduct	%	3%	3%	3%
Support Equipment	%	3%	3%	3%
Contingency by Area (% of Installed Cost)				
Reagent Feed	%	20%	20%	20%
SO2 Removal	%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%
Support Equipment	%	20%	20%	20%
General Facilities by Area (% of Installed Cost)				
Reagent Feed	%	10%	10%	10%
SO2 Removal	%	10%	10%	10%

Flue Gas Handling	%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%
Support Equipment	%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)				
Reagent Feed	%	10%	10%	10%
SO2 Removal	%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%
Support Equipment	%	10%	10%	10%
Lime Spray Dryer (LSD) Inputs				
SO2 Removal Required	%	90%	83%	90%
Adiabatic Saturation Temperature	°F	132	132	135
Flue Gas Approach to Saturation	°F	20	20	25
Spray Dryer Outlet Temperature	°F	152	152	160
Reagent Feed Ratio	Factor	0.92	0.85	0.92
(Mole CaO / Mole Inlet SO2)				
Recycle Rate	Factor	30	30	30
(lb recycle / lb lime feed)				
Recycle Slurry Solids Concentration	Wt. %	35%	35%	35%
Number of Absorbers	Integer	2	2	1
(Max. Capacity = 300 MW per spray dryer)				
Absorber Material	Integer	1	1	2
(1 = alloy, 2 = RLCS)				
Spray Dryer Pressure Drop	in. H2O	5	5	5
Reagent Bulk Storage	Days	60	60	30
Reagent Cost (delivered)	$/ton	$145	$145	$60
Dry Waste Disposal Cost	$/ton	$4	$4	$30
Maintenance Factors by Area (% of Installed Cost)				
Reagent Feed	%	2%	2%	2%
SO2 Removal	%	2%	2%	2%
Flue Gas Handling	%	2%	2%	2%
Waste / Byproduct	%	2%	2%	2%
Support Equipment	%	2%	2%	2%
Contingency by Area (% of Installed Cost)				
Reagent Feed	%	20%	20%	20%
SO2 Removal	%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%
Support Equipment	%	20%	20%	20%
General Facilities by Area (% of Installed Cost)				
Reagent Feed	%	10%	10%	10%
SO2 Removal	%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%
Support Equipment	%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)				
Reagent Feed	%	10%	10%	10%
SO2 Removal	%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%
Support Equipment	%	10%	10%	10%

Particulate Control Inputs				
Outlet Particulate Emission Limit	lbs/MMBtu	0.015	0.015	0.015
Fabric Filter:				
Pressure Drop	in. H2O	9	9	9
Type (1 = Reverse Gas, 2 = Pulse Jet)	Integer	1	2	1
Gas-to-Cloth Ratio	ACFM/ft^2	2.3	3.5	2.3
Bag Material (RGFF fiberglass only)	Integer	1	3	1
(1 = Fiberglass, 2 = Nomex, 3 = Ryton)				
Bag Diameter	inches	12	6	12
Bag Length	feet	30	26	30
Bag Reach		3	3	3
Compartments out of Service	%	10%	10%	10%
Bag Life	Years	5	3	5
Maintenance (% of installed cost)	%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%
ESP:				
Strength of the electric field in the ESP = *E*	kV/cm	10.0	10.0	10.0
Plate Spacing	in.	12	12	16
Plate Height	ft.	36	36	36
Pressure Drop	in. H2O	3	3	2
Maintenance (% of installed cost)	%	5%	5%	5%
Contingency (% of installed cost)	%	20%	20%	20%
General Facilities (% of installed cost)	%	10%	10%	10%
Engineering Fees (% of installed cost)	%	10%	10%	10%
NOx Control Inputs				
Selective Catalytic Reduction (SCR) Inputs				
NH3/NOX Stoichiometric Ratio	NH3/NOX	0.8	0.8	0.800641299
NOX Reduction Efficiency	Fraction	0.80	0.84	0.70
Inlet NOx	lbs/MMBtu	0.5	0.65	0.15
Space Velocity (Calculated if zero)	1/hr	0	0	0
Overall Catalyst Life	years	2	2	3
Ammonia Cost	$/ton	325	325	325
Catalyst Cost	$/ft3	150	150	150
Solid Waste Disposal Cost	$/ton	11.48	11.48	11.48
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%
General Facilities (% of installed cost)	%	5%	5%	5%
Engineering Fees (% of installed cost)	%	10%	10%	10%
Number of Reactors	integer	2	2	2
Number of Air Preheaters	integer	2	2	2
Selective NonCatalytic Reduction (SNCR) Inputs				
Reagent	1:Urea 2:Ammonia	1	1	1
Number of Injector Levels	integer	3	3	3
Number of Injectors	integer	18	18	18
Number of Lance Levels	integer	0	0	0

Number of Lances	integer	0	0	0
Steam or Air Injection for Ammonia	integer	1	1	1
NOX Reduction Efficiency	Fraction	0.30	0.60	0.46
Inlet NOx	lbs/MMBtu	0.5	0.5	0.65
NH3/NOX Stoichiometric Ratio	NH3/NOX	2	4	2
Urea/NOX Stoichiometric Ratio	Urea/NOX	2	4	2
Urea Cost	$/ton	380	380	380
Ammonia Cost	$/ton	325	325	325
Water Cost	$/1,000 gal	0.407	0.407	0.407
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%
General Facilities (% of installed cost)	%	5%	5%	5%
Engineering Fees (% of installed cost)	%	10%	10%	10%
Low NOX Burner Technology Inputs				
NOX Reduction Efficiency	fraction	0.35	0.35	0.35
Boiler Type	T:T-fired, W:Wall	T	T	T
Retrofit Difficulty	L:Low, A:Average, H:High	A	A	A
Maintenance Labor (% of installed cost)	%	0.8%	0.8%	0.8%
Maintenance Materials (% of installed cost)	%	1.2%	1.2%	1.2%
Natural Gas Reburning Inputs				
NOX Reduction Efficiency	fraction	0.61	0.61	0.61
Gas Reburn Fraction	fraction	0.15	0.15	0.15
Waste Disposal Cost	$/ton	11.48	11.48	11.48
Natural Gas Cost	$/MMBtu	2.31	2.31	2.31
Maintenance (% of installed cost)	%	1.5%	1.5%	1.5%
Contingency (% of installed cost)	%	20%	20%	20%
General Facilities (% of installed cost)	%	2%	2%	2%
Engineering Fees (% of installed cost)	%	10%	10%	10%
Sulfuric Acid Mist Control Inputs				

A3 Summary of Modeling Results

Modeling Report for a BART Assessment of the Big Stone I Coal-Fired Power Plant, Big Stone City, South Dakota Part 2 – BART Controls

October 2009

Prepared For:

Big Stone I
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1. INTRODUCTION

TRC Environmental Corporation has conducted a site-specific BART (Best Available Retrofit Technology) modeling assessment of the Big Stone I coal-fired power plant facility located near Milbank and Big Stone City in South Dakota to determine if this facility is subject to BART controls on emissions. Part I of the October 2009 report presented a modeling assessment of baseline emissions from the Big Stone I power plant facility to determine whether the facility is subject to BART controls. This report (Part 2) represents the results of 10 emission control scenarios.

On July 6, 2005 the U.S. Environmental Protection Agency (U.S. EPA) published in the Federal Register the "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations" (40 CFR Part 51). The regional haze rule requires States to submit implementation plans (SIPs) to address regional haze visibility impairment in 156 Federally-protected parks and wilderness areas, commonly referred to as "Class 1 Areas". The final rule addresses BART-eligible sources, which are defined as sources that have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were put in place between August 7, 1962 and August 7, 1977 and whose operations fall within one or more of 26 specifically listed source categories, of which Coal-Fired Power Plants are one.

The modeling described in this report is consistent with modeling described in baseline report. All CALMET/CALPUFF switches used in this BART analysis are identical with the switches used and described in previous report. In this report, ten BART control scenarios were analyzed and results of these modeling presented.

The purpose of the modeling is to assess the visibility impacts of sulfur dioxide (SO_2), particulate matter (PM) and nitrogen oxides (NO_x) emissions from the Big Stone I boiler and compare the impacts to the 0.5 change in deciview threshold at all the federally mandatory Class I areas. Since there is no Class I area within the 300 km radius usually applied, the South Dakota Department of Environment and Natural Resources requested that the Class I areas between 300 km and up to 625 km away from the Big Stone I facility sources be modeled. A total of eight Class I areas are located between these distances: two wilderness areas: Boundary Waters Canoe Area Wilderness and Rainbow Lake Wilderness, one National Wildlife Refuge (NWR): Lostwood and five National Parks: Voyageurs NP, Theodore Roosevelt NP, Badlands NP, Wind Cave NP and Isle Royale NP. However, Rainbow Lake Wilderness is one of two Class I areas where the visibility analysis is not required (http://www.dnr.state.wi.us/org/aw/air/modeling/ psd.htm), so it is not included in the modeling analysis. The MM5 datasets distributed by WRAP did not extend far enough in the East to include the Isle Royale NP or cover all of the Boundary Waters Class I area. The re-extracted MM5 data for 2002 and new MM5 domains for 2006 and 2007 include these areas.

The CALMET and CALPUFF non-steady-state models (Scire et al., 2000a,b) are recommended by the U.S. EPA (*Federal Register*, 6 July 2005) to perform source-specific subject-to-BART

screening. The CALPUFF system was therefore used for this modeling analysis. The U.S. EPA has promulgated the CALPUFF modeling system as a *Guideline Model* for Class I impact assessments and other long range transport applications or near field applications involving complex flows (U.S. EPA, 2000), and the model is recommended by both the Federal Land Managers (FLM) Air Quality Workgroup (FLAG, 2000) and the Interagency Workgroup on Air Quality Modeling (IWAQM, 1998). The CALPUFF modeling system is also recommended in new proposed guidance by the FLMs (FLAG, 2008). On August 31, 2009 EPA issued new recommendations on CALMET switch settings. The current modeling is based on the August 2009 recommendations.

The Big Stone I BART modeling analysis was performed with the EPA-approved Version 5.8 of the CALMET and CALPUFF models. Version 6.221 of CALPOST was used because it contains the FLM-approved implementation of Method 8 (FLAG, 2008), but in other respects is identical to the EPA-approved Version 5.6394.

CALMET is a diagnostic meteorological model that produces three-dimensional wind fields based on parameterized treatments of terrain effects such as slope flows and terrain blocking effects. Normally, meteorological observations are blended with gridded data from the NCAR-PSU Mesoscale Model, Version 5 (MM5). For this evaluation, MM5 data were generated by TRC with a 12-km grid spacing for two years (2006 and 2007) to define the initial guess wind fields. For 2002, 12-km MM5 data were re-extracted from the EPA MM5 dataset to cover entire region including the Isle Royale NP to the east.

CALPUFF is a non-steady-state puff dispersion model. It accounts for spatial changes in the CALMET-produced meteorological fields, variability in surface conditions (elevation, surface roughness, vegetation type, etc.), chemical transformation, wet removal due to rain and snow, dry deposition, and terrain influences on plume interaction with the surface. CALPUFF contains a module to compute visibility effects, based on a humidity-dependent relationship between particulate matter concentrations and light extinction, as well as wet and dry acid deposition fluxes. The meteorological and dispersion modeling simulations were conducted for three years (2002, 2006 and 2007). SO_2, SO_4, PM, and NO_x, emissions and their secondary products resulting from chemical conversions from the Big Stone I facility were modeled and their impacts on visibility evaluated at receptors in the Class I areas. Visibility impacts were estimated with the new FLM-recommended visibility algorithm and monthly average relative humidity adjustment factors (Method 8 in Version 6.221).

This report outlines the techniques and data sources used in the BART analyses. In Section 2, a general description of the source configurations for the baseline case and 10 control scenarios are provided. Section 3 refers to the baseline report where descriptions of the site characteristics and data bases (meteorological, geophysical, and aerometric) were provided, as well as an overview of the CALMET and CALPUFF models settings and parameters that were used in the analysis. The results of the control scenario evaluations are summarized in Section 4.

2. SOURCE DESCRIPTION

The 450-megawatt Big Stone I facility is a coal-fired power plant situated close to Big Stone City and Milbank in Grant County, South Dakota, at the border of Minnesota State. A BART applicability analysis was completed for the facility to determine those sources subject to the BART controls. The BART-eligible source is the Big Stone I cyclone-fired boiler with one stack 152 meters (498 feet) high.

The proposed emissions for the BART analysis were described in a Modeling Protocol dated June 2009. These emissions were reviewed and approved by SD DENR. In addition, 10 different control scenarios were modeled. Table 2-1 shows the source parameters and emission rates for the source considered in this report both for the baseline case and ten control scenarios. The highest 24-hour average actual emission rates of SO_2, NOx and PM under normal conditions over the 2001-2003 period were used for the baseline case in this analysis.

As shown in Table 2-2, the filterable PM_{10} are divided into a particle size distribution based on AP-42, Table 1.1-6 for baghouse controlled emissions because the facility currently uses a fabric filter for PM control. Approximately 57.6% of the filterable mass is in the fine (PM2.5) size category, and 42.4% in the coarse (2.5 to 10 µm diameter) size range. Each of the particle size categories was modeled as a separate PM species in CALPUFF. The filterable PM_{10} emission rate is reported by the facility at 10.48 g/s (83.2 lb/hr). Based on AP-42 Table 1.1-5, the total condensable PM_{10} is approximately 0.01 lb/mmBtu based on approximately 0.4% sulfur coal or 7.07 g/sec (56.1 lb/hr) assuming an heat input of 5609 mmBtu/hr. This estimate is consistent with the stack test data (August, 2006) at Otter Tail Power's Hoot Lake Plant, Unit 2, (which burns PRB coal) where the ratio of the filterable/total PM_{10} ratio was 0.66, resulting in a 2/3 filterable and 1/3 condensable split to the total PM_{10}.[1]

Elemental Carbon (EC) emissions were assumed to be 3.7% of the fine filterable fraction based on U.S. EPA (2002) and were assigned to the smallest particle size category. The primary H_2SO_4 emissions are 0.454 g/s (3.604 lb/hr) based on annual emission inventories and Toxic Release Inventory reports. The remaining condensable emissions were assigned to organic carbon and distributed equally into the two smallest particle size categories.

Table 2-3 provides a summary of the PM_{10} speciation and size distribution.

Note that since all Class I areas are more than 50 km away from the facility, as recommended by the Federal Land Managers (FLMs) (US Fish and Wildlife, National Park Service and U.S. Forest Service), no downwash computations was performed.

[1] AP-42 Table 1.1-8 was not used to estimate the particulate matter size distribution for Big Stone I because the emission factors were derived for cyclones burning bituminous coal, not sub-bituminous coal which is burned at Big Stone I.

Table 2-1: Point Source Parameters and Emission Rates

Main Stack	LCC[1] East (km)	LCC[1] North (km)	Stack Ht (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp. (K) [2]	SO_2 Emission Rate (g/s)	H_2SO_4 Emission Rate (g/s)	NO_x Emission Rate (g/s)	Filterable PM_{10} [2] Emission Rate (g/s)	Condensable PM_{10} Emission Rate (g/s)
Baseline Case	38.141	587.875	151.79	328.90	7.37	20.14	423.1	608.9	0.454	611.7	10.48	7.07
Control 1 Over-fire Air (OFA) Presumptive Dry FGD	"	"	"	"	"	19.57	352.6	106.0	"	459.4	"	"
Control 2 OFA Presumptive Wet FGD	"	"	"	"	"	18.23	330.4	106.0	"	459.4	"	"
Control 3 OFA Dry FGD at 90% Control	"	"	"	"	"	19.57	352.6	63.6	"	459.4	"	"
Control 4 OFA Wet FGD at 95% Control	"	"	"	"	"	18.23	330.4	30.4	"	459.4	"	"
Control 5 Separated OFA (SOFA) Presumptive Dry FGD	"	"	"	"	"	19.57	352.6	106.0	"	353.4	"	"
Control 5a SOFA Dry FGD at 90% Control	"	"	"	"	"	19.57	352.6	63.6	"	353.4	"	"
Control 5b SOFA Wet FGD at 95% Control	"	"	"	"	"	18.23	330.4	30.4	"	353.4	"	"
Control 6 SNCR with SOFA, Presumptive Dry FGD	"	"	"	"	"	19.57	352.6	106.0	"	247.4	"	"
Control 7 RRI+SNCR with SOFA Presumptive Dry FGD	"	"	"	"	"	19.57	352.6	106.0	"	141.3	"	"
Control 8 SCR with SOFA Presumptive Dry FGD	"	"	"	"	"	19.57	352.6	106.0	"	70.7	"	"

[1] Lambert Conformal Projection with an origin of 40.0N, 97.0W and standard parallels at 33N and 45N. Datum is NWS-84.

[2] The PM technology for all modeling scenarios is the existing pulse-jet fabric filter.

Table 2-2: PM_{10} Size Distribution1

Particle Size[2] (µm)	Cumulative Mass (PM) (%)	Cumulative Mass (PM_{10}) (%)
15	97	-
10	92	100
6	77	83.7
2.5	53	57.6
1.25	31	33.7
1.00	25	27.2

1 From AP-42, Table 1.1-6, Cumulative particle size distribution and size-specific emission factors for dry bottom boilers burning pulverized bituminous and subbituminous coal.

2 Expressed as aerodynamic equivalent diameter.

Table 2-3: PM_{10} Speciation and Size Distribution

input Data:							H_2SO_4	**PM_{10}**	$PM_{2.5}$			
							g/s	**g/s**	g/s			
PM_{10} and H_2SO_4 Emissions (g/s)							0.454	**17.550**	13.106			
	filterable								**condensable**			
condensable %	**59.7%**								**40.3%**			
				g/s						g/s		
	10.480								7.070			
									non H_2SO_4 condensable			
										g/s		
									6.616			
	AP-42, Table 1.1-6											
	coarse	coarse	soil	soil	soil	soil	EC	H_2SO_4	OC	OC	IC (soil)	IC (soil)
	PM800	PM425	PM187	PM112	PM081	PM056	PM056		PM081	PM056	PM081	PM056
	6.00 - 10.00	2.50-6.00	1.25-2.50	1.00-1.25	0.625-1.00	0.50-0.625	0.50-0.625		0.625-1.00	0.50-0.625	0.625-1.00	0.50-0.625
	16.3%	26.1%	23.9%	6.5%	12.0%	15.2%	57.6%		50.0%	50.0%	50.0%	50.0%
EC % of filterable			**96.3%**				**3.7%**		**100%**		**0%**	
inorganic % of	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s		
condensable	1.708	2.735	2.412	0.656	1.211	1.534	0.223	0.454	3.308	3.308		
	inputs to POSTUTIL:											
Extinction coefficient	0.6	0.6	1	1	1	1	10	3*f(RH)	4	4		
	coarse	**coarse**	**soil**	**soil**	**soil**	**soil**	**EC**	**H_2SO_4**	**OC**	**OC**		
	PM800	**PM425**	**PM187**	**PM112**	**PM081**	**PM056**	**PM056**		**PM081**	**PM056**		
	g/s	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**	**g/s**		
	1.708	**2.735**	**2.412**	**0.656**	**1.211**	**1.534**	**0.223**	**0.454**	**3.308**	**3.308**		

3. GEOPHYSICAL AND METEOROLOGICAL DATA, AIR QUALITY MODELING OPTIONS

The South Dakota Department of Environment and Natural Resources requested that the eight Class I areas shown in Figure 3-1 be considered in the BART analysis. Rainbow Lake Wilderness is one of two Class I areas where the visibility analysis is not required so it has been removed from the present analysis (see http://www.dnr.state.wi.us/org/aw/air/modeling/psd.htm). The MM5 dataset for this analysis were extended to include the Isle Royale National Park as well as all of the Boundary Waters Class I area.

Processing of the topography and land use for the domain shown in Figure 3-1 was described in detail in Section 3 of the October 2009 Big Stone Report (Report). In the same Report, all meteorological data and ozone data used in the modeling have been discussed. Locations of the stations were presented in Figures 3-3 and 3-4 of the Report.

CALMET was run with 4-km grid resolution using 12-km MM5 data for initial guess fields. CALMET and CALPUFF use terrain-following coordinates. In order to cover a large enough area for the refined analysis covering all seven Class I areas within a single domain, and including a buffer of at least 50 km around each Class I area, the domain dimensions of 1250 km x 720 km were used. For a 4-km grid spacing, this amounts to 313 x 181 grid cells. In the vertical, a stretched grid was used with finer resolution in the lower layers and somewhat coarser resolution aloft thus allowing adequate representation of the mixed layer. The ten vertical levels were centered at: 10, 30, 60, 120, 240, 480, 920, 1600, 2500 and 3500 meters.

CALMET and CALPUFF were run for three years, 2002, 2006 and 2007. A network of discrete receptors derived from the list of receptors developed by the National Park Service (NPS) are located within the boundaries of the seven Class I areas modeled: Boundary Water Canoe Area Wilderness, Voyageur National Park, Badlands National Park, Wind Cave National Park, Lostwood National Wildlife Refuge, Theodore Roosevelt National Park and Isle Royale National Park.

Meteorological modeling options including initial guess fields and step 1 and 2 wind fields, dispersion modeling options and visibility calculations were all described in Section 4 of the October 2009 report.

Calculations of the impact of the simulated plume particulate matter component concentrations on light extinction were carried out with the CALPOST postprocessor following the new proposed FLAG (2008) guidance. A revised new IMPROVE algorithm to compute the extinction (1/Mm) has been developed by the IMPROVE steering committee for estimating light extinction from particulate matter. That algorithm provides a better correspondence between the measured visibility and that calculated from particulate matter component concentrations (Tombach, 2006):

To represent background natural conditions, monthly background concentrations must be entered into the CALPOST input control file for all aerosols defining the background. The WRAP Protocol (2006) recommendations for natural conditions background are to use all three types of EPA default Natural Conditions: Best 20% Days, Annual Average and Worst 20% Days. In “Guidance for Estimating Visibility Conditions Under the Regional Haze Rule” (EPA, 2003), these three default values are defined only by their extinction coefficient in Mm^{-1}. For CALPOST Method 8, explicit background

concentrations are required to allow the computation of the small and large sulfate particulates, nitrate particulates and organic carbon. So, in this analysis, the annual averaged background conditions were used to define the natural background for each of the seven Class I areas, following FLAG (2008). The concentrations used as background for each of the seven Class I areas are summarized in Table 4-2 of the October 2009 report. These concentrations were used to compute the natural background light extinction following the revised IMPROVE formulae described above, for each of the Class I areas.

Tables 4-3, 4-4, and 4-5 in October 2009 report, provide the monthly f(RH) values for each of the seven Class I areas, that are used to compute extinction coefficients for hygroscopic species, respectively for small ammonium sulfate and ammonium nitrate particles, large ammonium sulfate and ammonium nitrate particles, and sea salt particles.

The 8th highest (98th percentile) predicted light extinction change for each year modeled was compared to the threshold value of 0.5 deciview.

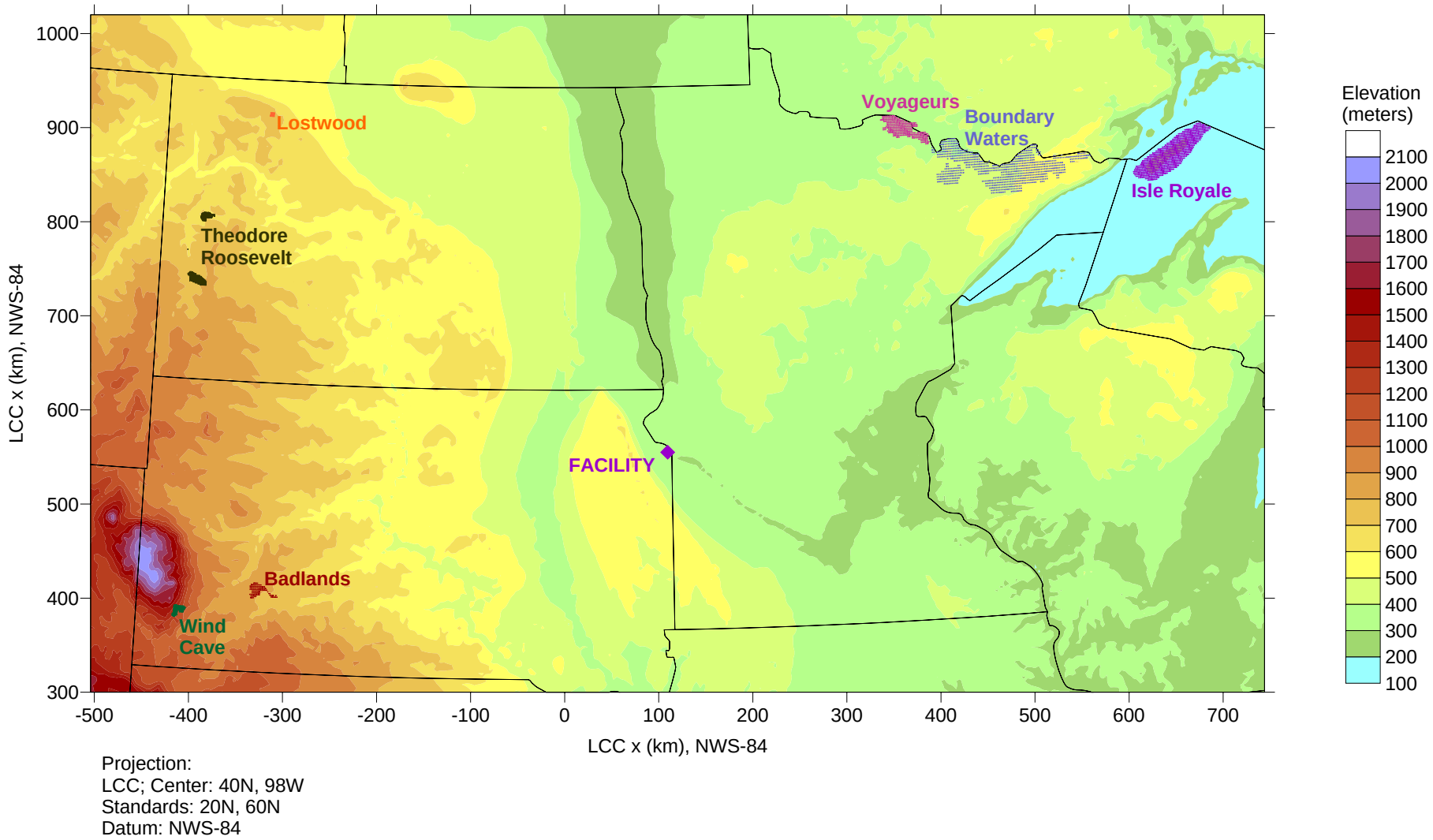

Figure 3-1. Terrain elevations for the CALMET and CALPUFF modeling domain at 4 km resolution. The locations of the Big Stone facility and Class I areas are also shown.

4. RESULTS

The results for the BART analysis for the Big Stone I facility are presented in this section. The analysis consists of evaluating the visibility impact (percent change in light extinction due to the sources measured in deciview) at all the Class I areas modeled. The results are presented in three tables for the baseline case and ten control scenarios, each table gathering the impact at seven Class I areas for each of the years modeled: Table 4-1 for 2002, Table 4-2 for 2006 and Table 4-3 for 2007. The change in light extinction due to the source is compared to the annual average natural background light extinction. The interpretation of the results is done by comparing the 98th percentile of delta deciview for each year to the 0.5 delta deciview threshold. Analysis is performed by using CALPOST Method 8.

Table 4-1. Visibility Impacts for 2002

	Park	Max Delta Deciview	4th Highest (99%)	8th Highest (98%)	Nb. Exceed. > 5%	Nb. Exceed. > 10%
Baseline	Boundary Waters	1.315	0.837	**0.574**	14	1
	Voyageurs	2.162	0.690	**0.623**	9	3
	Wind Cave	0.873	0.475	0.305	3	0
	Theodore Roosevelt	1.390	0.555	0.215	4	1
	Lostwood	0.564	0.388	0.232	2	0
	Badlands	0.762	0.671	0.452	7	0
	Isle Royale	1.182	0.789	**0.629**	10	2
Control 1	Boundary Waters	0.685	0.563	0.330	5	0
	Voyageurs	1.252	0.541	0.329	4	1
	Wind Cave	0.485	0.258	0.101	0	0
	Theodore Roosevelt	0.530	0.298	0.092	1	0
	Lostwood	0.329	0.171	0.111	0	0
	Badlands	0.462	0.342	0.223	0	0
	Isle Royale	0.780	0.471	0.377	2	0
Control 2	Boundary Waters	0.716	0.639	0.360	5	0
	Voyageurs	1.191	0.586	0.349	5	1
	Wind Cave	0.417	0.262	0.095	0	0
	Theodore Roosevelt	0.476	0.278	0.099	0	0
	Lostwood	0.320	0.155	0.118	0	0
	Badlands	0.549	0.315	0.234	1	0
	Isle Royale	0.809	0.497	0.367	3	0
Control 3	Boundary Waters	0.647	0.542	0.319	5	0
	Voyageurs	1.210	0.534	0.307	4	1
	Wind Cave	0.473	0.244	0.093	0	0
	Theodore Roosevelt	0.453	0.287	0.087	0	0
	Lostwood	0.317	0.150	0.109	0	0
	Badlands	0.441	0.326	0.219	0	0
	Isle Royale	0.758	0.448	0.363	2	0
Control 4	Boundary Waters	0.687	0.593	0.350	5	0
	Voyageurs	1.121	0.574	0.312	4	1
	Wind Cave	0.379	0.237	0.080	0	0
	Theodore Roosevelt	0.421	0.260	0.084	0	0
	Lostwood	0.298	0.138	0.103	0	0
	Badlands	0.505	0.281	0.225	1	0
	Isle Royale	0.762	0.456	0.351	2	0

Table 4-1. Visibility Impacts for 2002 (continued).

	Park	Max Delta Deciview	4th Highest (99%)	8th Highest (98%)	Nb. Exceed. > 5%	Nb. Exceed. > 10%
Control 5	Boundary Waters	0.551	0.449	0.264	2	0
	Voyageurs	0.997	0.426	0.263	3	0
	Wind Cave	0.385	0.206	0.083	0	0
	Theodore Roosevelt	0.458	0.237	0.076	0	0
	Lostwood	0.263	0.144	0.089	0	0
	Badlands	0.370	0.272	0.169	0	0
	Isle Royale	0.618	0.375	0.298	2	0
Control 5a	Boundary Waters	0.513	0.428	0.250	2	0
	Voyageurs	0.955	0.419	0.249	3	0
	Wind Cave	0.372	0.191	0.074	0	0
	Theodore Roosevelt	0.380	0.227	0.069	0	0
	Lostwood	0.251	0.124	0.085	0	0
	Badlands	0.349	0.256	0.165	0	0
	Isle Royale	0.595	0.355	0.285	2	0
Control 5b	Boundary Waters	0.537	0.465	0.274	2	0
	Voyageurs	0.876	0.449	0.244	2	0
	Wind Cave	0.296	0.184	0.063	0	0
	Theodore Roosevelt	0.325	0.204	0.066	0	0
	Lostwood	0.234	0.109	0.081	0	0
	Badlands	0.396	0.219	0.174	0	0
	Isle Royale	0.594	0.357	0.274	2	0
Control 6	Boundary Waters	0.418	0.335	0.200	0	0
	Voyageurs	0.740	0.309	0.196	2	0
	Wind Cave	0.283	0.154	0.072	0	0
	Theodore Roosevelt	0.384	0.176	0.063	0	0
	Lostwood	0.196	0.118	0.075	0	0
	Badlands	0.278	0.203	0.120	0	0
	Isle Royale	0.464	0.275	0.221	0	0
Control 7	Boundary Waters	0.285	0.221	0.137	0	0
	Voyageurs	0.481	0.192	0.130	0	0
	Wind Cave	0.180	0.104	0.070	0	0
	Theodore Roosevelt	0.309	0.115	0.050	0	0
	Lostwood	0.129	0.085	0.051	0	0
	Badlands	0.187	0.135	0.090	0	0
	Isle Royale	0.310	0.174	0.142	0	0
Control 8	Boundary Waters	0.198	0.143	0.097	0	0
	Voyageurs	0.309	0.125	0.086	0	0
	Wind Cave	0.119	0.072	0.053	0	0
	Theodore Roosevelt	0.262	0.074	0.036	0	0
	Lostwood	0.085	0.053	0.037	0	0
	Badlands	0.127	0.102	0.079	0	0
	Isle Royale	0.207	0.113	0.092	0	0

Table 4-2. Visibility Impacts for 2006.

	Park	Max Delta Deciview	4th Highest (99%)	8th Highest (98%)	Nb. Exceed. > 5%	Nb. Exceed. > 10%
Baseline	Boundary Waters	2.572	1.183	**0.790**	16	5
	Voyageurs	1.578	0.862	**0.574**	11	2
	Wind Cave	0.454	0.302	0.120	0	0
	Theodore Roosevelt	2.232	0.772	0.459	6	3
	Lostwood	1.110	0.662	0.385	5	1
	Badlands	1.002	0.519	0.481	7	1
	Isle Royale	1.806	0.635	**0.506**	8	2
Control 1	Boundary Waters	1.375	0.799	**0.548**	9	3
	Voyageurs	1.262	0.554	0.399	5	1
	Wind Cave	0.273	0.162	0.024	0	0
	Theodore Roosevelt	1.234	0.469	0.247	3	1
	Lostwood	0.619	0.355	0.168	2	0
	Badlands	0.504	0.319	0.176	1	0
	Isle Royale	1.010	0.467	0.296	2	1
Control 2	Boundary Waters	1.405	0.830	**0.546**	11	3
	Voyageurs	1.549	0.594	0.494	7	2
	Wind Cave	0.266	0.162	0.027	0	0
	Theodore Roosevelt	1.116	0.454	0.244	3	1
	Lostwood	0.588	0.366	0.171	3	0
	Badlands	0.482	0.326	0.199	0	0
	Isle Royale	1.014	0.462	0.273	3	1
Control 3	Boundary Waters	1.319	0.780	**0.534**	8	3
	Voyageurs	1.218	0.540	0.391	5	1
	Wind Cave	0.260	0.150	0.023	0	0
	Theodore Roosevelt	1.196	0.455	0.234	3	1
	Lostwood	0.594	0.339	0.153	2	0
	Badlands	0.482	0.308	0.172	0	0
	Isle Royale	0.983	0.454	0.287	2	0
Control 4	Boundary Waters	1.313	0.793	**0.521**	10	3
	Voyageurs	1.469	0.571	0.464	6	1
	Wind Cave	0.244	0.139	0.025	0	0
	Theodore Roosevelt	1.052	0.431	0.230	3	1
	Lostwood	0.554	0.335	0.144	2	0
	Badlands	0.443	0.306	0.191	0	0
	Isle Royale	0.966	0.440	0.250	3	0

Table 4-2. Visibility Impacts for 2006 (continued).

	Park	Max Delta Deciview	4th Highest (99%)	8th Highest (98%)	Nb. Exceed. > 5%	Nb. Exceed. > 10%
Control 5	Boundary Waters	1.109	0.635	0.433	6	2
	Voyageurs	1.013	0.440	0.314	2	1
	Wind Cave	0.216	0.132	0.019	0	0
	Theodore Roosevelt	0.987	0.372	0.199	2	0
	Lostwood	0.494	0.281	0.136	0	0
	Badlands	0.401	0.252	0.137	0	0
	Isle Royale	0.804	0.366	0.235	2	0
Control 5a	Boundary Waters	1.051	0.615	0.419	6	2
	Voyageurs	0.967	0.426	0.306	2	0
	Wind Cave	0.204	0.120	0.018	0	0
	Theodore Roosevelt	0.948	0.358	0.186	2	0
	Lostwood	0.468	0.265	0.124	0	0
	Badlands	0.378	0.242	0.133	0	0
	Isle Royale	0.777	0.355	0.226	2	0
Control 5b	Boundary Waters	1.036	0.622	0.407	6	2
	Voyageurs	1.160	0.449	0.365	3	1
	Wind Cave	0.189	0.109	0.019	0	0
	Theodore Roosevelt	0.827	0.336	0.180	2	0
	Lostwood	0.430	0.259	0.114	0	0
	Badlands	0.344	0.237	0.147	0	0
	Isle Royale	0.758	0.342	0.195	1	0
Control 6	Boundary Waters	0.837	0.468	0.318	3	0
	Voyageurs	0.759	0.325	0.228	2	0
	Wind Cave	0.161	0.103	0.016	0	0
	Theodore Roosevelt	0.736	0.274	0.150	1	0
	Lostwood	0.369	0.209	0.103	0	0
	Badlands	0.297	0.186	0.098	0	0
	Isle Royale	0.595	0.268	0.174	1	0
Control 7	Boundary Waters	0.560	0.299	0.202	1	0
	Voyageurs	0.502	0.204	0.157	1	0
	Wind Cave	0.107	0.071	0.014	0	0
	Theodore Roosevelt	0.479	0.176	0.101	0	0
	Lostwood	0.244	0.138	0.082	0	0
	Badlands	0.227	0.120	0.066	0	0
	Isle Royale	0.382	0.169	0.115	0	0
Control 8	Boundary Waters	0.373	0.186	0.136	0	0
	Voyageurs	0.328	0.128	0.107	0	0
	Wind Cave	0.071	0.047	0.012	0	0
	Theodore Roosevelt	0.306	0.111	0.070	0	0
	Lostwood	0.162	0.092	0.064	0	0
	Badlands	0.188	0.079	0.060	0	0
	Isle Royale	0.239	0.104	0.077	0	0

Table 4-3. Visibility Impacts for 2007.

	Park	Max Delta Deciview	4th Highest (99%)	8th Highest (98%)	Nb. Exceed. > 5%	Nb. Exceed. > 10%
Baseline	Boundary Waters	3.574	1.351	**1.079**	25	9
	Voyageurs	2.062	1.376	**0.724**	19	5
	Wind Cave	1.671	0.591	0.325	4	2
	Theodore Roosevelt	0.744	0.491	0.322	3	0
	Lostwood	0.959	0.722	0.409	6	0
	Badlands	2.202	0.698	0.471	6	2
	Isle Royale	1.224	0.745	**0.665**	13	2
Control 1	Boundary Waters	2.018	0.874	**0.657**	9	2
	Voyageurs	1.260	0.750	0.460	7	2
	Wind Cave	0.950	0.334	0.130	3	0
	Theodore Roosevelt	0.393	0.211	0.190	0	0
	Lostwood	0.547	0.415	0.245	1	0
	Badlands	1.292	0.395	0.241	3	1
	Isle Royale	0.665	0.436	0.339	2	0
Control 2	Boundary Waters	1.959	0.890	**0.667**	11	2
	Voyageurs	1.232	0.768	**0.521**	8	2
	Wind Cave	1.030	0.355	0.130	2	1
	Theodore Roosevelt	0.395	0.228	0.161	0	0
	Lostwood	0.558	0.426	0.253	2	0
	Badlands	1.369	0.440	0.254	2	1
	Isle Royale	0.720	0.439	0.323	2	0
Control 3	Boundary Waters	1.944	0.848	**0.620**	9	1
	Voyageurs	1.225	0.717	0.450	7	1
	Wind Cave	0.902	0.317	0.120	2	0
	Theodore Roosevelt	0.380	0.204	0.173	0	0
	Lostwood	0.520	0.394	0.226	1	0
	Badlands	1.234	0.378	0.230	2	1
	Isle Royale	0.641	0.418	0.323	2	0
Control 4	Boundary Waters	1.844	0.840	**0.611**	10	1
	Voyageurs	1.171	0.705	0.502	8	1
	Wind Cave	0.938	0.323	0.117	2	0
	Theodore Roosevelt	0.373	0.197	0.138	0	0
	Lostwood	0.509	0.381	0.234	1	0
	Badlands	1.261	0.405	0.234	2	1
	Isle Royale	0.677	0.406	0.290	2	0

Table 4-3. Visibility Impacts for 2007 (continued).

	Park	Max Delta Deciview	4th Highest (99%)	8th Highest (98%)	Nb. Exceed. > 5%	Nb. Exceed. > 10%
Control 5	Boundary Waters	1.630	0.699	**0.524**	8	1
	Voyageurs	0.997	0.602	0.364	4	0
	Wind Cave	0.763	0.268	0.106	1	0
	Theodore Roosevelt	0.311	0.175	0.156	0	0
	Lostwood	0.439	0.328	0.211	0	0
	Badlands	1.039	0.315	0.191	2	1
	Isle Royale	0.525	0.349	0.272	2	0
Control 5a	Boundary Waters	1.554	0.671	0.493	6	1
	Voyageurs	0.961	0.569	0.354	4	0
	Wind Cave	0.715	0.251	0.096	1	0
	Theodore Roosevelt	0.299	0.160	0.141	0	0
	Lostwood	0.412	0.314	0.178	0	0
	Badlands	0.979	0.298	0.180	2	0
	Isle Royale	0.503	0.331	0.256	1	0
Control 5b	Boundary Waters	1.459	0.667	0.478	6	1
	Voyageurs	0.915	0.554	0.393	6	0
	Wind Cave	0.735	0.253	0.091	1	0
	Theodore Roosevelt	0.291	0.155	0.108	0	0
	Lostwood	0.399	0.301	0.182	0	0
	Badlands	0.991	0.316	0.182	2	0
	Isle Royale	0.527	0.319	0.227	1	0
Control 6	Boundary Waters	1.233	0.520	0.388	4	1
	Voyageurs	0.737	0.454	0.267	3	0
	Wind Cave	0.575	0.202	0.085	1	0
	Theodore Roosevelt	0.230	0.143	0.121	0	0
	Lostwood	0.331	0.241	0.157	0	0
	Badlands	0.781	0.236	0.143	1	0
	Isle Royale	0.388	0.259	0.199	0	0
Control 7	Boundary Waters	0.825	0.339	0.256	2	0
	Voyageurs	0.501	0.304	0.176	1	0
	Wind Cave	0.389	0.137	0.071	0	0
	Theodore Roosevelt	0.149	0.112	0.080	0	0
	Lostwood	0.223	0.155	0.101	0	0
	Badlands	0.524	0.157	0.099	1	0
	Isle Royale	0.268	0.172	0.134	0	0
Control 8	Boundary Waters	0.549	0.217	0.170	1	0
	Voyageurs	0.383	0.205	0.123	0	0
	Wind Cave	0.265	0.093	0.055	0	0
	Theodore Roosevelt	0.102	0.090	0.064	0	0
	Lostwood	0.152	0.122	0.063	0	0
	Badlands	0.352	0.105	0.070	0	0
	Isle Royale	0.189	0.124	0.098	0	0

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APPENDIX B

Technical Description of SO_2 Controls (B1)

B1 Technical Description of SO_2 Controls

B1.1 Fuel Switching

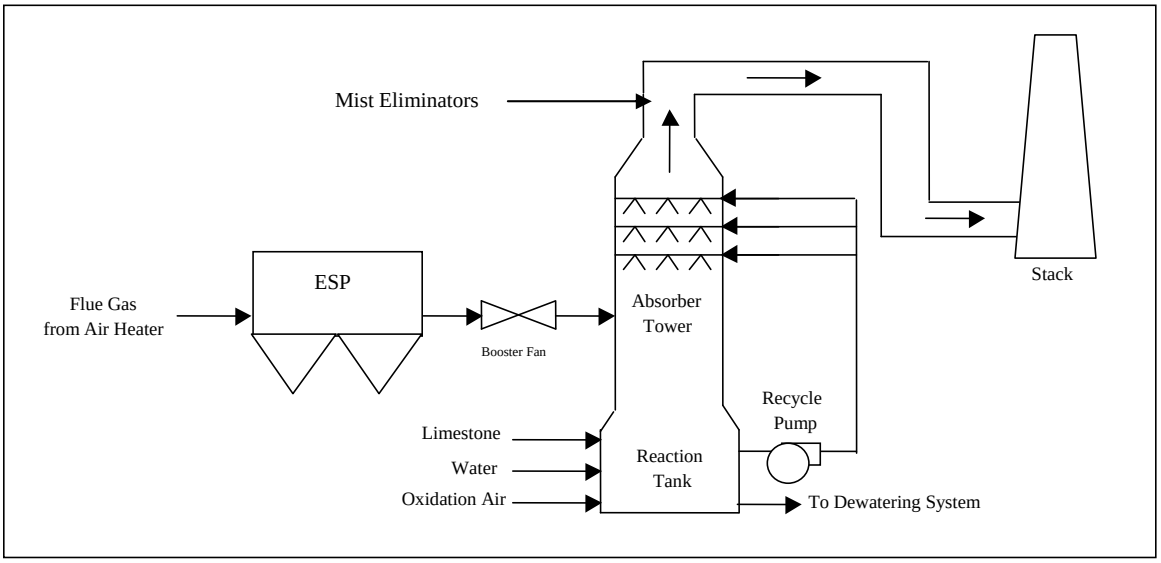
Fuel switching can be a viable method of fuel sulfur content reduction in certain situations. The PRB burned by BSP Unit I is one of the lower sulfur coals available in the U.S. and switching to a lower sulfur coal (if available) would achieve little to no additional reduction in SO_2 emissions. Therefore, for the purpose of this BART analysis, fuel switching is not considered a viable option for SO_2 control.

B1.2 Wet Flue Gas Desulfurization

Wet FGD technology utilizing lime or limestone as the reagent and employing forced oxidation to produce gypsum (calcium sulfate dihydrate, $CaSO_4 \cdot 2H_2O$) as the byproduct, is commonly applied to coal-fired boilers. The gypsum byproduct is either landfilled or sold for commercial reuse.

A flow diagram of the wet FGD process is provided in Figure B-1. In the wet FGD process, a slurry of finely ground limestone ($CaCO_3$) in water is recirculated through an absorber tower where it is brought into turbulent contact with the flue gas. The contact between the flue gas and the slurry cools and saturates the gas via evaporation of water from the slurry. SO_2 is simultaneously absorbed into the slurry where it forms sulfurous acid which reacts with the limestone, forming calcium sulfite hemihydrate ($CaSO_3 \bullet ½H_2O$) which can then be disposed of as a waste product or oxidized to calcium sulfate dihydrate or gypsum ($CaSO_4 \bullet 2H_2O$) before disposal or for commercial reuse. No commercial uses for sulfite waste products have been identified.

Figure B-1. Wet FGD Process Flow Diagram



Chemical reactions between the limestone and the absorbed SO_2 take place within the slurry in the absorber, and in the absorber reaction tank, resulting in the formation of particles of $CaSO_3 \cdot ½ H_2O$. Some of the oxygen in the flue gas may participate in the reaction, resulting in the formation of particles of $CaSO_4 \bullet 2H_2O$ as well. Air may be injected into the absorber sump to promote the formation of gypsum and minimize the formation of calcium sulfite solids where a gypsum product is desired, either for ease of disposal or commercial use. The resultant slurry is then processed in a dewatering system prior to disposal or commercial use.

As the limestone reagent in the recirculating slurry is depleted, it is replenished with fresh slurry prepared by wet grinding of crushed limestone using reclaimed liquid from the dewatering system. Fresh water is also required to replace water lost to evaporation in the flue gas cooling process. Fresh water is often used to wash the mist eliminators, devices located at the scrubber exit to capture slurry droplets entrained in the exiting flue gas stream and return them to the scrubber. The mist eliminator wash removes accumulated materials from the mist eliminator chevrons, thus preventing solids buildup and pluggage. In addition, depending upon the mineral content of the coal, a portion of the reclaimed liquid from the dewatering process may be blown down, or disposed of, to prevent excessive accumulation of mineral salts in the slurry which could result in mineral scaling within the absorber equipment. The blow down rate varies with each plant. Fresh water makeup, both through the mist eliminator wash system and in the limestone grinding process, replaces the blow down and evaporative losses.

Lime scrubbers are very similar to limestone scrubbers. The use of lime rather than limestone can reduce the liquid-to-gas ratio and/or absorber size required to achieve a given SO_2 removal rate. Lime is sometimes used in wet FGD systems where extremely high SO_2 removal rates are desired or where limestone is not readily available. However, since lime is more expensive than limestone, the reagent cost is much higher for a lime system. Therefore, the vast majority of wet FGD systems are designed to use limestone as the neutralizing reagent.

Tow advantages of the wet FGD systems include lower reagent costs, primarily due to the ability to use limestone instead of lime as a reagent and the production of a salable by-product and high removal efficiency. Also, wet FGD systems have a high turndown capability and plant operational flexibility is not hindered to the same degree as the semi-dry processes. This last advantage is important where wet FGD systems are applied to load following units. Disadvantages of wet FGD systems include corrosion due to a wet environment with corrosive chemicals including salts of sulfurous and sulfuric acid and hydrochloric acid. Also, because the wet systems are more mechanically complex, they typically require larger maintenance staff than the semi-dry, CFB and FDA alternatives. The greater mechanical complexity also contributes to a greater capital cost for wet FGD systems. Finally, because wet FGD systems completely saturate the flue gas stream, nearly all the SO_3 or H_2SO_4 vapor in the entering flue gas is condensed into aerosol droplets which are too small to be efficiently captured in the scrubber. Fifty percent or more of these droplets pass right through the scrubber. Where units are burning high sulfur fuels, this can cause a plume opacity problem. Wet FGD systems commonly achieve 95% percent SO_2 removal efficiencies in commercial applications.

B1.3 Semi-Dry Flue Gas Desulfurization

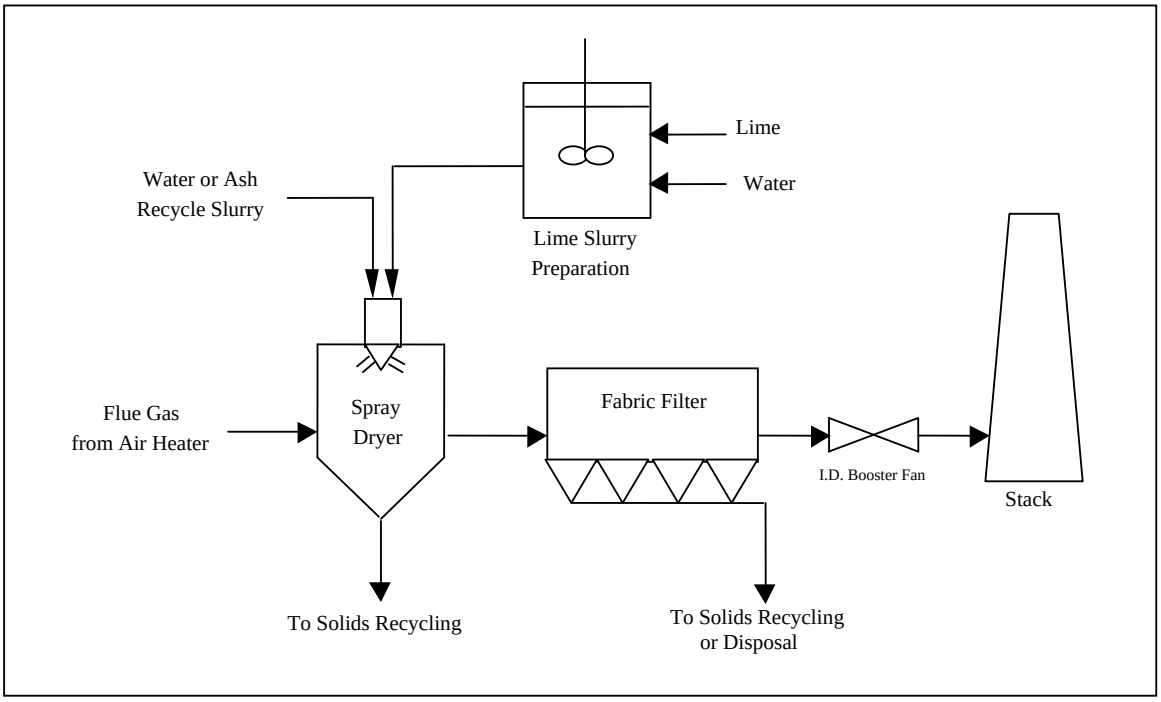
As an alternative to wet FGD technology, the control of SO_2 emissions can be accomplished using semi-dry FGD technology. The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a fabric filter for downstream particulate collection. The semi-dry FGD process became popular in the U.S. beginning in the late 1970s as a way to comply with the New Source Performance Standards (NSPS) for electric utility steam generating units for which construction commenced after September 18, 1978 (40 CFR Part 60, Subpart Da). These standards require that all new coal-fired electric utility boilers be equipped with a “continuous system of emission reduction” for SO_2. However, the standards allowed SO_2 removal efficiency as low as 70

percent for facilities burning low-sulfur coal. The semi-dry FGD process could meet this requirement, and was often selected as the SO_2 control technology for many new coal-fired power plants that were built in the 1970s and 1980s and designed to burn low-sulfur western coal. In the late 1980s and through the 1990s, most of the new coal-fired boilers built in the U.S. were for small Independent Power Producer (IPP) projects, and many of these also selected the semi-dry/lime FGD process.

There are several variations of the semi-dry process in use today. This section addresses the spray dryer FGD process. Two other variations, the Novel Integrated Desulfurization and Circulating Fluidized Bed absorber are similar processes. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling. They are considered similar technologies and are not discussed further.

A schematic diagram of the spray dryer FGD process is provided in Figure B-2. In the spray dryer FGD process, boiler flue gas is introduced into a Spray Dryer Absorber (SDA) into which hydrated lime (calcium hydroxide, $Ca(OH)_2$) and water are added as dispersed droplets. The $Ca(OH)_2$ reacts with SO_2 that has been absorbed into the water to form primarily calcium sulfite and some calcium sulfate. The heat from the flue gas causes the water to evaporate, cooling the gas and drying the reaction products. Because the total water feed rate is much lower than that of the wet FGD process, the reaction products are dried in the SDA and the flue gas is only partially saturated. The amount of water added to the process is carefully controlled so that the flue gas temperature is maintained well above the saturation, or dewpoint, temperature (typically 30-40 ^{0}F above saturation) to avoid corrosion problems. Cooling the gas to this point significantly increases the SO_2 control efficiency over injection into hot, dry flue gas. The reaction product leaves the SDA as fine dry particles entrained in the flue gas. The flue gas enters the SDA at the top and flows downward, co-current with the introduced neutralizing agent. This characteristic is the opposite of the wet FGD system which introduces flue gas into the bottom of the absorber, countercurrent to the falling slurry spray.

Figure B-2 Spray Dryer FGD Process Flow Diagram



In the lime spray drying process, quicklime (CaO) is slaked with water to form lime slurry which is then injected into the SDA along with additional water through a rotary atomizer or dual fluid nozzle or similar apparatus. Recycled PM from the PM control equipment downstream of the SDA is often mixed with the lime slurry before injection into the SDA to provide additional surface area for SO_2 absorption. The flue gas is introduced into the SDA in a manner designed to maximize the contact between the gas and the droplets and to prevent slurry impingement on the walls of the SDA. The turbulent mixing of the flue gas and the slurry droplets promotes rapid absorption of SO_2 into the water of the slurry droplets. The chemical reactions between the absorbed SO_2 and the calcium hydroxide take place within the droplet as the flue gas moves through the SDA. The flue gas is cooled and partially humidified as the water evaporates, leaving a mixture of fly ash and dry powdered reaction product entrained in the flue gas. Some of the solid particles fall to the bottom of the reactor and are collected by a waste handling system. Entrained particles are collected in an electrostatic precipitator (ESP) or fabric filter (FF) downstream of the SDA.

An additional distinguishing characteristic of the SDA is that it must be located upstream of a particulate control device, as opposed to the wet FGD process which is normally the last flue gas treatment process before discharge to the stack. For new plants, this point is not of such great importance. However, when retrofitting FGD equipment to an existing coal-fired plant, which

already has particulate control equipment installed, this becomes an important point. If a suitable location exists for the insertion of a new SDA upstream of an existing PM control device, and if the performance of the existing PM control device would not be overly degraded by the additional PM loading, then the retrofit process would consist only of installation of the SDA, reagent preparation and waste handling systems. However, many times one, or both, of these conditions do not exist and the choice to utilize an SDA requires the installation of a new PM control device, such as an ESP or fabric filter. Where this situation exists, the capital cost of the SDA option increases significantly.

Semi-dry processes have some notable advantages compared to wet FGD processes including a dry byproduct which can be handled with conventional ash handling systems. Because the semi-dry system does not have a truly wet zone, corrosion problems in the SDA are eliminated, or significantly reduced, to the point exotic materials of construction are not required. Spray dryer systems utilize less complex equipment resulting in a reduced capital cost and allowing somewhat smaller operations and maintenance staff. Where a fabric filter is utilized as the downstream particulate control device for a semi-dry process, the lime content of the filter cake on the fabric filter reacts with condensed SO_3 in the flue gas stream capturing and neutralizing the acid aerosol. Consequently, semi-dry FGD options, paired with a fabric filter for PM control, have virtually zero emissions of acid aerosols.

The primary disadvantages of the lime spray dryer process make it less likely to be applied to large power plant boilers, especially those firing high-sulfur coal. The lime spray dryer requires the use of lime, which is much more expensive than limestone. While lime contains approximately 1.8 times more calcium than limestone on a mass basis, lime can cost up to five times more than limestone on a mass basis. Therefore, reagent costs for a lime based process are typically higher than a limestone-based process for a given application.

Wastes from semi-dry processes have very limited possibility for reuse due to fly ash contamination. Also, where fly ash might be sold for other uses, contamination with the semi-dry FGD reaction products typically eliminates commercial options for reuse. Where fly ash sales are to be maintained, a second PM control device would be required for the semi-dry FGD system exhaust stream, increasing both capital and O&M costs.

SDAs have much more stringent size limitations than wet FGD scrubbers. Typically units larger than 250 to 300 MW will require at least two SDAs, thus driving up capital costs and system complexity for larger units, while wet FGD systems can handle up to 1000 MW in a single absorber module.

SDAs do not have the same turndown capabilities as wet FGD absorbers, further limiting applicability for load following units. Finally, lime spray dryer systems do not have the same level of experience with high SO_2 removal requirements in high sulfur applications that wet FGD systems have.

No variation of semi-dry FGD systems has clearly demonstrated the ability to achieve SO_2 removal levels similar to wet FGD systems in the U.S. Table B-1 lists many of the recent lime spray dryer system installations in the U.S. The information in Table B-1 was obtained from the RACT/BACT/LAER Clearing House. As can be seen in the column titled Efficiency, two units were permitted with an SO_2 removal efficiency of 94.5% and one with 95%. However, these units typically use a lower sulfur fuel and achieve an emissions limit in the range of 0.12 to 0.17 lb SO_2/mmBtu.

Table B-1 – Recent Dry FGD Permits From RBLC

RBLC ID	Facility	Process	Fuel	Size	Unit	Control Device	Emission Limit (lb/mmBtu)	Estimated Efficiency	Permit Date
*NE-0018	Whelan Energy Center	Unit 2 Utility Boiler	PRB coal	2,210	mmBtu/hr	Spray Dryer Absorber (SDA)	0.12	NA	3/30/2004
AR-0074	Plum Point Energy	Boiler , Unit 1 - SN-01	Bituminous Coal	800	MW	Dry Flue Gas Desulfurization	0.16	NA	8/20/2003
MT-0022	Bull Mountain, No. 1, LLC - Roundup Power Project	Boiler, PC No. 1	Coal	390	MW	Dry Flue Gas Desulfurization (FGD)	0.12	94.5	7/21/2003
MT-0022		Boiler, PC No. 2	Coal	390	MW	Dry Flue Gas Desulfurization (FGD)	0.12	94.5	7/21/2003
IA-0067	MidAmerican Energy Company	CBEC 4 Boiler	PRB Coal	7,675	mmBtu/hr	Lime Spray Dryer Flue Gas Desulfurization	0.1	92	6/17/2003
KS-0026	Holcomb Unit #2	Boiler, PC	Subbituminous Coal	660	MW	Dry Flue Gas Desulfurization	0.12	94	10/08/2002
WY-0057	WYGEN 2	500 MW PC Boiler	Subbituminous Coal	500	MW	Semi-Dry Lime Spray Dryer Absorber	0.1	NA	9/25/2002
MO-0050	Kansas City Power & Light Co. - Hawthorn Station	PC Boiler,	Coal	384	T/H	Dry Flue Gas Desulfurization	0.12	NA	8/17/1999
WY-0039	Two Elk Generation Partners, Limited Partnership	PC Fired Boiler	Coal	250	MW	Lime Spray Dry Scrubber	0.17	91	2/27/1998
WY-0047	Encoal Corporation-Encoal North Rochelle Facility	PC Fired Boiler	Subbituminous Coal	3,960	mmBtu/hr	Lime Spray Dryer	0.2	73	10/10/1997
WY-0048	Wygen, Inc. - Wygen Unit One	Boiler, PC	Subbituminous Coal	80	MW	Circulating Dry Scrubber	0.2	92	9/6/1996
PA-0133	Mon Valley Energy Limited Partnership	PC Fired Boiler	Bituminous Coal	966	mmBtu/hr	Spray Dry Absorption	0.25	92	8/8/1995

Table B-1 – Recent Dry FGD Permits From RBLC (cont.)

RBLC ID	Facility	Process	Fuel	Size	Unit	Control Device	Emission Limit (lb/mmBtu)	Estimated Efficiency	Permit Date
VA-0213	SEI Birchwood, Inc.	PC Fired Boiler	Coal	2,200	mmBtu/hr	Lime Spray Drying System (FGD System)	220	94	8/23/1993
WY-0046	Black Hills P&L Neil Simpson U	PC Fired Boiler	Coal	80	MW	Circulating Dry Scrubber	0.17	95	4/14/1993
MI-0228	Indelk Energy Services Of Otsego	Boiler (Coal)	Coal	778	mmBtu/hr	Dry Scrubber	0.32	90	3/16/1993
NC-0057	Roanoke Valley Project Ii	Boiler, PC-Fired	Coal	517	mmBtu/hr	Dry Lime Scrubbing	0.187	93	12/7/1992
SC-0027	South Carolina Electric And Gas Company	Boiler, PC-Fired Unit No. 1	Coal	385	MW	Spray Dryer Absorber	0.25	93	7/15/1992
SC-0027		PC-Fired Boiler, Unit No. 2	Coal	385	MW	Spray Dryer Absorber	0.17	93	7/15/1992
SC-0027		PC-Fired Boiler, Unit No. 3	Coal	385	MW	Spray Dryer Absorber	0.17	93	7/15/1992
NJ-0015	Keystone Cogeneration Systems, Inc.	PC-Fired Boiler	Coal, Bituminous	2,116	mmBtu/hr	Spray Dryer Absorber	0.16	93	9/6/1991
NC-0054	Roanoke Valley Project	Boiler, PC-Fired	Coal	1,700	mmBtu/hr	Dry Lime FGD	0.213	92	1/24/1991
NJ-0014	Chambers Cogeneration Limited Partnership	2 PC-Fired Boilers	Coal	1,389	mmBtu/hr (each)	Spray Dryer Absorber	0.22	93	12/26/1990
VA-0176	Hadson Power 13	Boiler	Coal	30,228	lb/hr coal	Lime Spray Dryer	0.162	92	8/17/1990
VA-0171	Mecklenburg Cogeneration Limited Partnership	PC Fired, Boiler, 4 Units	Bituminous Coal	834.5	mmBtu/hr	Spray Dryer, Fabric Filter	0.172	92	5/9/1990

APPENDIX C

Technical Description of Particulate Matter Controls (C1)

Appendix C1 – Technical Description of Particulate Matter Controls

C1.0 FABRIC FILTER (FF)

A fabric filter or baghouse removes particulate by passing flue gas through filter bags. A pulse-jet fabric filter (PJFF) unit (like the current Big Stone PM controls) consists of isolatable compartments with common inlet and outlet manifolds containing rows of fabric filter bags. The filter bags are made from a synthetic felted material that are suspended from a tube sheet mounted at the top of each fabric filter compartment. The tube sheet separates the particulate laden flue gas from the clean flue gas. This tube sheet is a flat sheet of carbon steel with holes designed to accommodate filter bags through which the bags are hung. The flue gas passes through the PJFF by flowing from the outside of the bag to the inside, up the center of the bag through the hole in the tube sheet and out the PJFF. Fly ash particles are collected on the outside of the bags, and the cleaned gas stream passes through the fabric filter and on to the chimney. A long narrow wire cage is located within the bag to prevent collapse of the bag as the flue gas passes through it. Each filter bag alternates between relatively long periods of filtering and short periods of cleaning. During the cleaning period, fly ash that has accumulated on the bags is removed by pulses of air and then falls into a hopper for storage and subsequent disposal.

Cleaning is either initiated at a preset differential pressure across the tubesheet or based on a maximum time between cleanings. Bags in a PJFF are cleaned by directing a pulse of pressurized air down the filter bag countercurrent to the flue gas flow to induce a traveling ripple (pulse) in the filter bag. This pulse travels the length of the bag, deflecting the bag outward and separating the dust cake as it moves.

An advantage of a fabric filter over an ESP is that a fabric filter is not dependent on the resistivity of the fly ash. Since the fabric filter uses bags instead of an electric charge to remove the particles, the resistivity of the particles is not an issue. Fabric filters also have a lower dependence on particle size than ESPs. A disadvantage of fabric filters is that they have a tendency to corrode and clog with high sulfur coal applications. The high sulfur coals produce more SO_3, which tends to create problems with the fabric filters. Therefore, ESPs are typically used on high sulfur coal applications instead of fabric filters. Another disadvantage of fabric filters is the associated pressure drop. The bags, which collect a cake of particles, create an obstruction to the gas path. Fabric filters typically have approximately three times the pressure

drop of an ESP. Fabric filters have been proven to control PM removal efficiency in excess of 99%.

C1.1 ELECTROSTATIC PRECIPITATOR (ESP)

ESPs are commonly used as the primary filterable PM control device on coal fired units. The ESP discharge electrodes generate a high voltage electrical field that gives the particulate matter an electric charge (positive or negative). The charged particles will then be collected on a collection plate. A rapper or hammer system will be utilized to vibrate the collected particles off of the plates so they can fall into the hoppers for storage and subsequent disposal.

The advantages of an ESP include the fact that an ESP can be applied to high sulfur coals, and the pressure drop across an ESP is relatively low compared to other alternatives such as a fabric filter. Unlike the fabric filter, which uses bags as the filter media, an ESP does not contain elements that can plug in the presence of SO_3. The unobstructed design of the ESP results in a pressure drop that is approximately 1/3 of a corresponding fabric filter. The disadvantage of the ESP is that its effectiveness to remove particulate is dependant on the resistivity of the fly ash and particle size. ESPs have been proven to control PM removal efficiency in excess of 99%.

C1.1 COMPACT HYBRID PARTICULATE COLLECTOR (COHPAC)

A COmpact Hybrid PArticulate Collector (COHPAC) is a high air-to-cloth ratio pulse jet fabric filter located downstream of an existing ESP. The COHPAC acts as a polishing device for control of particulate emissions. The difference between a COHPAC and the fabric filter described above is that a COHPAC is installed after an ESP. The ESP prior to the COHPAC will remove the majority of the fly ash. This allows the COHPAC to have a higher air-to-cloth ratio than a typical fabric filter. The air-to-cloth ratio for a COHPAC unit is typically greater than or equal to 6 ACFM/ft^2 while the air-to-cloth ratio for a typical pulse jet fabric filter is approximately 3.5 to 4.0 ACFM/ft^2. Because Big Stone Plant does not have an ESP and already uses a fabric filter for particulate control, the use of a COHPAC is not considered further.

Appendix D

Federal Land Managers' Comments
and
DENR's Response

DRAFT

SOUTH DAKOTA'S

REGIONAL HAZE

STATE IMPLEMENTATION PLAN

RESPONSE TO COMMENTS

DURING FEDERAL LAND MANAGER REVIEW

South Dakota Department of Environment and Natural Resources

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1.0 Introduction

In accordance with Title 40 of the Code of Federal Regulations (CFR), § 51.308(i)(2), the state must provide the Federal Land Manager with an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on an implementation plan (or plan revisions) for regional haze. On January 15, 2010, DENR fulfilled this obligation and submitted South Dakota's draft Regional Haze Program to the following Federal Land Managers:

1. Tim Allen, U.S. Fish & Wildlife Service, Lakewood, Colorado;
2. Trent Wickman, USDA Forest Service, Great Lakes National Forests – Eastern Region;
3. John Bunyak, National Park Service, Air Resources Division, Lakewood, Colorado;
4. John Notar, National Park Service, Air Resources Division, Lakewood, Colorado;
5. Brian Kenner, National Park Service, Badlands National Park; and
6. Ken Hyde, National Park Service, Wind Cave National Park.

In addition, DENR took this opportunity to solicit comments from the following:

1. Laurel Dygowski, EPA Region VIII;
2. Amy Platt, EPA Region VIII;
3. Monica Morales, EPA Region VIII;
4. Catherine Nueschler and Anne Jackson, State of Minnesota;
5. Teresa Cooper and Asad Khan, State of Michigan;
6. Shelley Schneider and Katryna Schaf, State of Nebraska;
7. Dana Mount and Tom Bachman, State of North Dakota;
8. Curtis Taipale, State of Colorado;
9. Dave Klemp, State of Montana;
10. Tina Anderson, State of Wyoming;
11. Jim Strain, South Dakota Department of Agriculture;
12. Gene Nelson, GCC Dacotah, Rapid City, SD;
13. Tim Rogers, Black Hills Corporation, Rapid City, SD;
14. Danielle Weibers, Pete Lien and Sons, Rapid City, SD;
15. Clint Allen, Hills Materials Company, Rapid City, SD; and
16. Terry Graumann, Otter Tail Power Company, Big Stone I.

DENR requested comments by March 16, 2010. DENR received comments from the United States Department of Agriculture – Forest Service, United States Department of Interior – National Park Service, Otter Tail Power Company, and the United States Environmental Protection Agency (EPA) – Region 8. The comments may be reviewed in Appendix A.

This document contains DENR's responses to the comments received during the opportunity for consultation from the federal land managers, EPA and Otter Tail Power Company. A summary of the comments and DENR's responses follows.

2.0 Comments on Executive Summary

1. EPA states the BART emission limits, compliance schedule, monitoring, recordkeeping, and compliance determining methods for Big Stone I must be specified in the text of the Regional Haze State Implementation Plan or in a permit that is incorporated into the State Implementation Plan. EPA notes the public notice for the Regional Haze State Implementation Plan needs to include notification that an air quality permit to address BART requirements is incorporated as part of the State Implementation Plan.

   Response: DENR reviewed 40 CFR §308(1)(e) to determine the BART requirements that need to be included in the state implementation plan. In Section 6.1 and 6.2 of the state implementation plan, DENR describes the BART review that took place to determine which facilities were subject to BART (40 CFR §308(1)(e)(1)(i). Section 6.3 describes the case-by-case BART determination for Otter Tail Power Company's Big Stone I facility, which is the only facility in South Dakota subject to BART. DENR did not establish a technological or economic limitation for BART; therefore, 40 CFR §308(1)(e)(1)(iii) is not applicable.

   In accordance with 40 CFR §308(1)(e)(1)(iv), DENR identified Otter Tail Power Company must install BART as expeditiously as practicable, but no later than 5 years from EPA's approval of South Dakota's state implementation plan in Section 6.4. DENR will also add this language to ARSD 74:36:21:06.

   In accordance with 40 CFR §308(1)(e)(1)(v), DENR is required to include a requirement that each source subject to BART maintain the control equipment and establish procedures to ensure the equipment is properly operated and maintained. This requirement is summarized in Section 6.4. DENR included these requirements in ARSD 74:36:21:07. However, DENR did not identify the minimum requirements for the operation, maintenance, and monitoring requirements; therefore, DENR will include the minimum requirements in ARSD 74:36:21:07.

   DENR did not include a statement that met the requirements of 40 CFR §308(e)(5); therefore, DENR added a statement to Section 6.4 which specifies that Otter Tail Power Company is subject to the requirements of South Dakota's state implementation plan in the same manner as other sources once they have installed and are meeting the BART requirements.

   DENR is not planning on implementing an emission trading program or the Clean Air Interstate Rule (CAIR); therefore, 40 CFR §308(e)(2), (3), and (4) are not applicable. Otter Tail Power Company has not requested an exemption; therefore 40 CFR §308(e)(6) is not applicable.

   DENR did not find in 40 CFR §308(e) where it required the actual BART permit to be incorporated in the State Implementation Plan. DENR established the requirements of 40 CFR §308(e) in the written portion of the state implementation plan and in ARSD 74:36:21, which will be adopted in South Dakota's state implementation plan. In addition, DENR will

establish the permit limits for Otter Tail Power Company's BART eligible unit in ARSD 74:36:21:10. Therefore, DENR believes it has met the requirements for including the BART requirements in the state implementation plan.

2. EPA requested the timeline for removing the permit requirements related to Big Stone II from the existing permit.

   Response: Otter Tail Power Company's current Title V air quality permit includes requirements for Big Stone I and II. Because of the time and expense of revising a Title V air quality permit, DENR does not plan on removing the requirements for Big Stone II from the Title V air quality permit until either Otter Tail Power Company requests a revision or their Title V air quality permit is up for renewal. DENR anticipates revising Otter Tail Power Company permit to include the BART requirements once EPA approves DENR state implementation plan. If Big Stone II has not been removed by the time the BART requirements are incorporated in the Title V air quality permit, DENR will removed Big Stone II at that time.

3. EPA mentioned they did not receive the information in the last sentence of the Executive Summary which references Chapter 12.0 of the state implementation plan. Therefore, EPA was unable to review and comment on it.

   Response: Chapter 12.0 identifies the documents DENR referenced during the development of the state implementation plan. These documents are typically published by EPA and readily available to the public.

3.0 Baseline, Natural and Uniform Rate of Improvement

4. EPA mentioned it appears Appendix A will contain the IMPROVE data used to determine baseline visibility; but the data was not included in the draft document they received.

   Response: DENR did not include the IMPROVE data in the draft but the final document will contain the IMPROVE data.

5. Based on EPA's review of WRAP's Visibility Information Exchange Web System (VIEWS) and information from the United States Forest Service, EPA indicates there are errors in the baseline and natural background figures in Table 3-1, 3-5, and 3-7. EPA mentioned they were aware that the United States Forest Service raised concerns with these tables and requested the values be revised accordingly.

   Response: Since EPA did not specify what information in the tables was in error, DENR reviewed the data in each table. DENR based the baseline and natural background data on the IMPROVE data it gathered from the federal land managers IMPROVE website. DENR checked the data in Table 3-1 and determined it matches the IMPROVE data that will be included in Appendix A. DENR also reviewed the natural background data based on the new formula in Table 3-5 and did not find any errors based on the IMPROVE data in Appendix

A. DENR agreed to use the default values for natural background which resulted in values in Table 3-7 needing to be revised to match the values in Table 3-1 and 3-5. DENR made the appropriate changes.

As far as EPA's comment on the United States Forest Service raising concerns with DENR on the values in the tables. The only concern the United States Forest Service raised in their comment letter was on the use of the default natural conditions which will be addressed in Comment #6 of this document.

6. The National Park Service recommended DENR use EPA's default values for natural conditions available on the VIEWS website for this current state implementation plan and defer refinements to a later state implementation plan. In addition, the United States Forest Service recommended DENR use Western Regional Air Partnership/Technical Support System (WRAP/TSS) natural conditions values, which were derived from EPA's natural condition guidance. EPA indicated states must use EPA's default values for natural conditions in the current State Implementation Plan and any refinements deferred to future planning periods.

   Response: DENR reviewed 40 CFR § 51.308 and EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* and could not find were it required a state to use the default values for natural conditions in the initial state implementation plan for regional haze as stated by EPA. EPA's guidance does state the natural conditions estimates developed using the default approach is adequate to satisfy the requirements of the regional haze rule for the initial state implementation plan submittals. Therefore, DENR will use the default values in EPA's guidance for the initial state implementation plan and will reevaluate natural conditions in future reviews.

7. EPA stated the footnotes referring to Trijonis estimates for the Eastern United States do not need to be included in Table 3-6.

   Response: DENR agrees and made the appropriate change.

8. EPA stated a column must be added to Table 3-7 to highlight the deciview improvement required for both the best and worst days.

   Response: DENR agrees and made the appropriate change.

9. EPA recommend several changes to the Uniform Rate of Progress which are listed below:
   a. EPA stated Figure 3-11 was omitted in their draft document.

   Response: Figure 3-11 is an equation not a graph and was included in their draft document. Since listing an equation as a figure appears to be confusing, DENR will identify equations as "Equation" instead of a figure and renumber the figures appropriately.

b. EPA stated Table 3-8 needs to include the uniform rate of improvement of the 1st planning period (2018) for the most and least impaired days, rather than leave it to the reader to calculate from the annual numbers provided.

Response: Instead of listing the uniform rate of improvement for the 1st planning period in Table 3-8, DENR provided the uniform rate of improvement for the 1st planning period for the most impaired days in Figure 3-5(a) and (b). There is no uniform rate of improvement for the least impaired days. DENR is only required to ensure there is no degradation of the 20% least impaired days. DENR agrees that it should display to the reader how we calculated the improvement needed by 2018 and will add a paragraph before Figure 3-5 describing this calculation and direct the reader to Figure 3-5 to view the uniform rate of improvement needed by 2018 for each Class I area.

c. EPA was unable to determine the source of the 2018 numbers and thought it should be 14.89 deciviews for the Badlands and 13.94 deciviews for Wind Cave.

Response: DENR agrees and added a paragraph prior to Figure 3-5 describing how the uniform rate of improvement was calculated.

4.0 IMPROVE Data for Class I Areas

10. The National Park Service stated fires are an insignificant contributor to ammonium sulfate compared to fossil fuel combustion and recommended DENR delete the reference in Section 4.1 (fourth paragraph) and the last paragraph of Section 4.2.

Response: The National Park Service referenced Table 5-1 of the draft document for comparison of sulfur dioxide emissions from point versus forest fires. DENR agrees that point source emissions of sulfur dioxide are comparably greater than sulfur dioxide emissions from fires. However, in both cases mentioned by the National Park Service, DENR is identifying sources of ammonia sulfate emissions and not the activity that contributes the most. DENR does not recommend any changes.

11. The National Park Service and United States Forest Service recommended DENR expand its analysis of the contribution of wildfire to visibility impairment. The National Park Service requested the expansion because wildfires are a major contributor of organic carbon and elemental carbon. While the United States Forest Service noted that high organic carbon concentrations do not necessarily mean fire impacts, as noted in the draft Regional Haze State Implementation Plan. One method of expanding the analysis would be to look at aerosol contributions on individual days during the 2000-2004 baseline period to identify elevated organic and elemental carbon that could indicate fire impacts. A back trajectory analysis could then be conducted to assist in separating impacts from local agricultural, prescribed fires, or point sources that might be controllable. Another approach they suggested would be to compare the seasonality of prescribed fire with wildfire. For example, South Dakota could get prescribed fire activity information from the burners in the states and see if it matches measured high organic compound impact days.

Response: DENR agrees that wildfire and prescribed fires contribute to visibility impairment at both the Badlands and Wind Cave National Parks. This is apparent from the evaluation DENR conducted on the IMPROVE data for the base year and WRAPS' attribution analysis. As part of DENR's long term strategy, DENR will review the IMPROVE data for the base year and future years to determine which fires (e.g., size, type of combustibles, distance from the Class I area) contribute to visibility impairment in South Dakota's two Class I areas. DENR will use this information and compare to the best management practices that are being used across the nation and implement those practices that best fit the needs of South Dakota. DENR plans on implementing a Smoke Management Plan in calendar year 2013.

12. In the seventh paragraph of Section 4.2, the National Park Service disagrees with DENR's conclusion that local sources are not contributing to visibility impairment during the 20% least impaired days based on both National Parks having a good comparison of concentrations for each aerosol during the 20% least impaired days. The National Park Service recommends this statement be rephrased.

    Response: DENR based its conclusion that local sources were not impacting the 20% least impaired days because one would expect the concentrations during the 20% least impaired days to be different, not similar, because the Badlands National Park is prairie grasses, bare rock and sand and the Wind Cave National Park is prairie grasses and ponderosa pine forest. Impacts from regional influences would tend to create uniform concentrations throughout the area while local sources would impact one but not the other. However, DENR does agree 5-year averaging would also smooth this out. DENR will need to evaluate this further to determine if there are any impacts from local sources hidden by the 5-year average and/or if regional influence is the main reason for the elevated concentrations on the 20% least impaired days. DENR agrees to rephrase this paragraph in Section 4.2.

13. In the second paragraph of Section 4.3.3, the National Park Service indicated that visibility "impairment" appears to be declining rather than visibility declining.

    Response: DENR agrees and actually included visibility impairment in several other appropriate places in this section.

14. In addition to the visibility trends data presented in Figure 4-7 and 4-8, the National Park Service recommended looking at similar time series plots for the individual aerosol components to illustrate whether sulfates and nitrates (those components dominated by anthropogenic, controllable sources) are declining more than organic carbon mass (an indicator of fire). The National Park Service also recommended keeping the y axis scale in Figure 4-8 equivalent for a better comparison.

    Response: DENR displays a similar time series plot for the individual aerosols for each national park in Figures 4-5 and 4-6 using an extinction comparison. DENR mentions that it reviewed this data and could not observe any trends because the aerosol components fluctuated. DENR does agree that the y axis scale should be equivalent not only with all the charts in Figure 4-8 but also Figure 4-7 and adjusted the scale of the y axis to a maximum of

25 deciviews for each graph. After reviewing the revised charts, DENR adjusted its analysis for the Wind Cave National Park.

5.0 Source Apportionment

15. EPA states WRAP's emission inventory for this planning period is adequate but expects future reviews be updated to the most current emission inventory (e.g., include oil and gas emission estimates).

    Response: DENR agrees and already mentioned in Section 5.1.5 of the draft that future emission inventories should be expanded and improved.

16. EPA requested DENR elaborate on the "compliance initiative" related to volatile organic compound emissions from secondary oil and gas production in northwestern South Dakota. In particular, EPA asked what state mechanisms are in place to ensure these four thermal oxidizers are operating at a control efficiency of greater than 98%.

    Response: DENR agrees and expanded its discussion by adding the permit mechanism and the destruction efficiency requirement in Section 5.1.3.

17. EPA mentioned there is a large discrepancy between South Dakota's oil and gas volatile organic compound emissions and the WRAP TSS numbers which needs to be explained in greater detail. In addition, EPA wanted it explained if these numbers were used for modeling and reasonable progress purposes.

    Response: DENR believes the discrepancy between DENR and WRAP on this issue is explained sufficiently. WRAP did not use the 33,433 tons of volatile organic compound emissions from secondary oil and gas production in northwestern South Dakota in its 2002 modeling; but the reductions achieved are represented in the modeling for 2018 and reasonable progress purposes. DENR will add a paragraph at the end of Section 5.1.1 to explain EPA's second concern.

18. EPA has questions about the large difference in baseline sulfur dioxide emissions for area sources found in Table 5-1 (10,159 tons) and 5-2 (1,071 tons) and requested this be explained in further detail. In addition, EPA pointed out a typographical error on the footnotes for Table 5-4. The National Park Service also requested that this large difference be explained.

    Response: DENR agrees and added an explanation in the sixth paragraph of Section 5.1.1 and corrected the typographical error in the footnotes of Table 5-4.

19. EPA noted that emission inventories from other states that submitted their plans does not match what DENR has in Tables 5-6 and 5-7 and requested that we verify their emission inventory numbers.

Response: As discussed, DENR derived the emission inventory numbers from WRAP's website. It would be safe to state that if North Dakota used WRAP's emission inventory numbers they would not match up with South Dakota's since we are correcting the emission inventory in the state implementation plan just like DENR is assuming North Dakota is doing in their state implementation plan. DENR does not propose any changes; but plans on updating emission inventories from others states as already stated in Section 5.1.5.

20. EPA identified a typographical error in the last paragraph on page 54 and second paragraph on page 56 and stated the text is not consistent with the figures which show a slight change between 2002 and 2018 for both the least and most impaired days.

    Response: DENR agrees there is a typographical error where "most" was used and should have been "least" impaired days on both pages. However, the text is correct in stating the contributors from 2002 and 2018 for sulfate at each Class I area did not change. Essentially, DENR was comparing what areas the sulfate emissions were being generated from (e.g., Outside Domain, Canada) and not what type of sources were contributing. DENR corrected the typographical errors but made no other changes.

21. EPA requested the first paragraph, second to last sentence on page 58 should be clarified to read that "Natural fire related organic carbon mass generated in Montana contributes approximately 34% of the organic carbon mass in Badlands National Park."

    Response: DENR agrees and will make the appropriate change.

22. The National Park Service requested DENR separate out Big Stone I emissions in Table 5-2 to make it easier to compare data from Table 5-2 to Table 5-4, 6-1, and 6-3. The United States Forest Service also requested Big Stone I emissions be separated out to show how big of a part it is of South Dakota's point source emission inventory.

    Response: DENR agrees and identified the total emissions from Big Stone I, which are included in the "Point" source emissions for comparison purposes.

23. Based on the sulfur dioxide emissions for the four new point sources in Table 5-4 and all other point sources together projected to emit 2,458 tons of sulfur dioxide emissions in 2018 and area sources projected to emit 1,662 tons by 2018, the National Park Service believes these emissions should be assessed in determining if there are reasonable control measures. The National Park Service also mentioned the Prevention of Significant Deterioration permit application DENR received from Basin Electric for a natural gas fired combined cycle power generating facility in Brookings County, South Dakota.

    Response: DENR has already addressed the projected emissions from Big Stone I through a BART analysis which will reduce projected sulfur dioxide emissions from 3,425 to 2,212 tons per year; nitrogen oxide emissions from 15,323 to 2,457 tons per year; and particulate matter from 318 to 295 tons per year. On December 1, 2009, Otter Tail Power Company relinquished all rights and obligations granted through and by the PSD permit that was issued for Big Stone II. Therefore, the Big Stone II emissions in Table 5-4 will be eliminated.

The Hyperion Energy Center, which is a proposed combined oil refinery and electric power plant, and the Basin Electric's proposed natural gas fired combined cycle power generating facility went through a Prevention of Significant Deterioration permit review to ensure air emissions from each of these facilities would not cause or contribute to visibility impairment in a Class I area. DENR will include the air emissions from Basin Electric's proposed natural gas fired combined cycle power generating facility in the next 2018 evaluation.

Basin Electric's NextGen coal-fired electric power plant will also be required to go through a Prevention of Significant Deterioration permit review to ensure its air emissions would not cause or contribute to visibility impairment in a Class I area. Currently this permit application is on hold.

DENR's evaluation on if area sources of sulfur dioxide emissions should be assessed to determine if there are reasonable control measures was based on the attribution section of the draft Regional Haze State Implementation Plan. According to the attribution analysis, sulfur dioxide emissions from all sources in South Dakota are minimal and after Big Stone I installs the required controls under BART, sulfur dioxide emissions will be even further reduced.

24. Otter Tail Power Company requested it be clarified that even though Big Stone II emissions may be included in the 2018 emission projections, Big Stone II is no longer proceeding.

    Response: DENR agrees and will make the appropriate changes to the fourth paragraph of Section 5.1.3.

25. The National Park Service requested a clarification on the assumptions used for the WRAP regional modeling compared to those used in the Big Stone Unit 1 BART modeling. The National Park Service indicated that Table 5-2, 5-4, 6-1, and 6-3 do not appear consistent and requested DENR clarify what each table represents. The following summarizes the National Park Service's questions on the emission inventory comparison:

    a. Does Table 6-3 refer to potential emissions?

    Response: Table 6-3 represent the results of WRAP's modeling analysis of Big Stone Unit 1's visibility impact on Class I areas. The emissions 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 and was based on WRAP's modeling protocol. The website location for the modeling protocol is included just before Table 6-3. To clarify this, DENR will describe how the emissions were determined.

    b. Table 6-3 WRAP BART modeling results based on 88% and 75% of all SD point source SO2 and NOx emissions in 2002. Is this correct?

    Response: Table 6-3 would not represent an apple to apple comparison for determining Big Stone Unit 1's sulfur dioxide and nitrogen oxide emissions compared to other sources in South Dakota. Table 5-2 would be a good comparison. Based on Table 5-2, Big Stone Unit

1's sulfur dioxide and nitrogen oxide emissions compared to point sources represents 80% and 70%, respectively.

c. Did DENR include assumptions or BART controls for Big Stone Unit 1 in the WRAP 2018PRP18b regional modeling?

Response: The emissions from Big Stone Unit 1 in Table 5-4 were used in WRAP's 2018PRP18b regional modeling analysis and based on Big Stone II being built and routing air emissions from Unit 1 through some of the control equipment associated with Big Stone II. The emissions from Unit 1 would pass through the wet scrubber but not the SCR associated with Big Stone II. The proposed BART emission limits were not used in WRAP's 2018PRP18b regional modeling analysis.

d. In Table 5-4, Big Stone Unit 1 is projected to emit 3,425 tons SO2 in 2018, 18% of the value in Table 6-1 or 28% of the value in Table 6-3. How does this relate to the 90% control efficiency listed for dry scrubbing in Table 6-6?

Response: Again, the emission rates for each Table are not comparable because they are based on different assumption.

e. In Table 5-4, Big Stone Unit 1 NOx emissions in 2018 (15,580 tons) appear to be the same as used as the baseline for the BART analysis reported in Table 6-3. Does this mean that WRAP regional modeling assumed SO_2 controls but not NOx controls for Big Stone Unit 1?

Response: As described earlier, the emissions from Big Stone Unit 1 in Table 5-4 were used in WRAP's 2018PRP18b regional modeling analysis and based on Big Stone II being built and routing air emissions from Unit 1 through some of the control equipment associated with Big Stone II. The emissions from Unit 1 would pass through the wet scrubber but not the SCR associated with Big Stone II.

6.0 Best Available Retrofit Technology (BART)

26. EPA identified a typographical error in the second sentence of the first paragraph dealing with Pete Lien and Sons' operations. EPA recommended the wording be "…not in operation prior to August 7, 1962…" instead of "in operation".

    Response: DENR agrees and will make the appropriate change.

27. EPA agreed it was correct to include Pete Lien and Sons in the WRAP subject-to-BART modeling analysis. EPA noted Pete Lien and Sons' existing Title V air quality permit still includes the vertical kiln and there has not been a permit modification to address any such dismantling and closure. EPA recommends the permit be modified to reflect this change in status of the vertical kiln or the modeling needs to be re-run to correct the input errors and accurately determine whether Pete Lien and Sons is subject to BART.

Response: DENR disagrees with EPA that Pete Lien and Sons' Title V air quality permit should be revised to reflect the dismantling and closure of the vertical kiln or the modeling needs to be re-run. In permit condition 1.1, the footnote for Table 1-1 requires Pete Lien and Sons to shutdown and disassemble the vertical kiln before the initial startup of Unit #45, which is a newer kiln. Pete Lien and Sons notified DENR on March 13, 2009, that the vertical kiln was shutdown and dismantled. DENR does agree to clarify in the discussion in Section 6.1.2 that the permit requires them to shutdown and disassemble the vertical kiln and that has been completed. This discussion is included in the last paragraph of Section 6.1.2.

28. EPA stated the modeling inputs and outputs for Otter Tail Power Company's Big Stone I BART assessment need to be incorporated in the State Implementation Plan for documentation and public review.

    Response: In Section 6.2, this section states the modeling Otter Tail Power Company completed for Big Stone I's BART assessment will be available in Appendix D – Otter Tail Power Company's Visibility Impact Analysis. DENR did not include this when they sent out the review because EPA and the federal land managers had already received copies of the modeling analysis. The modeling inputs and outputs were included as part of the modeling analysis and will be available to the public in Appendix D.

29. In Section 6.3.2.4, page 83, footnote 3, EPA requested DENR explain how the 18,000 tons per year sulfur dioxide baseline figure was obtained and why it is different from the 19,863 tons per year identified in Table 6-1. On Table 6-10, page 88, EPA (15) identified a typographical error in footnote 3 and should be "nitrogen oxide" instead of "sulfur dioxide". EPA would like a further explanation on how DENR determined 18,000 tons per year of nitrogen oxide emissions for baseline instead of 17,179 tons per year from Table 6-1. In Section 6.3.4, second paragraph, page 89, EPA (16) requested that the 18,000 tons per year of sulfur dioxide and nitrogen oxide emissions for baseline determination should be explained further.

    Response: Table 6-1 displays what units at a facility are BART eligible sources and is based on the unit's potential to emit. 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 19,863 tons of sulfur dioxide per year identified in Table 6-1 was based on a heat input rating of 4,560 million Btus per hour, operating 8,760 hours per year, and the potential sulfur dioxide emission rate of approximately 1 pound per million Btus. The 18,000 tons of sulfur dioxide per year identified in the BART analysis 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.

    The 17,179 tons of nitrogen oxide per year identified in Table 6-1 is the unit's potential to emit and is based on a heat input rating of 4,560 million Btus per hour, operating 8,760 hours per year, and a nitrogen oxide emission rate of 0.86 pounds per million Btus. The 18,000 tons

of nitrogen oxide per year identified in the BART analysis 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.

Table 6-1 and the annual emission rate used in the BART analysis should not be compared to each other. Based on the BART guidelines, the baseline emissions should be the 18,000 tons per year for sulfur dioxide and nitrogen oxide. To clarify, DENR added "Potential to Emit" as a header to Table 6-1 and will add a paragraph to Section 6.3.2.4 and 6.3.3.4 to explain the annual emissions used in the BART analysis.

DENR agrees with the typographical error and will change it appropriately.

30. In Section 6.3.3.2, page 85-86, EPA had not completed a thorough review of this section on the "Technically Feasible Nitrogen Oxide Control Technologies" and may have additional comments during the public comment period.

    Response: Does not require a response.

31. On Table 6-9, page 87, footnote 5, EPA states the control efficiency of the selective catalytic reduction (SCR) and separated over-fire air (SOFA) system should be better than the 90% control efficiency of a SCR alone and believes the proposed limit should be lower than the proposed 0.1 pounds per million Btu limit. In Section 6.3.3.3, the National Park Service requested DENR state the control effectiveness and resulting emission rate that it believes to be appropriate for each control technology option. The National Park Service suggests a 30-day rolling average limit of 0.06 pounds of nitrogen oxide per million Btus. The National Park Service based its proposed nitrogen oxide emission limit on an Illinois permit for two cyclone boilers firing Powder River Basin subbituminous coal and equipped with over-fire air and selective catalytic reductions system at Dominion Energy's Kincaid Generating Station. Illinois required a nitrogen oxide emission limit of 0.07 pounds per million Btus on an annual based. In Section 6.3.5.3, the National Park Service believes the Kincaid cyclone boilers in Illinois have demonstrated the ability of a SCR to reduce nitrogen oxide emissions below the limit proposed by DENR and suggest a 30-day rolling average limit of 0.06 pounds per million Btus would be appropriate.

    Response: EPA appears to be basing the BART emission limit on an assumed control efficiency and an arbitrary emission rate from Otter Tail Power Company's Big Stone I facility. In considering what emission limit represents BART, one needs to consider the operation of the emission unit and the control device. DENR considers it inappropriate to take an arbitrary emission rate Otter Tail Power Company has actually emitted and multiply it by an arbitrary control efficiency to develop an emission limit.

    The control efficiency is variable as recognized by EPA's fact sheet (EPA-452/F-03-024) for fabric filters controlling particulate matter emissions. The fact sheet notes a fabric filter is a constant outlet device and not a constant collection efficiency device. This fact sheet also notes the collection efficiency of the fabric filter is constantly changing and average collection efficiencies are based on tests with a constant inlet pollutant loading. EPA also

recognized the variability in another fact sheet (EPA-452/F-03-032) for selective catalytic reduction systems controlling nitrogen oxide emissions. In this fact sheet, EPA states control efficiencies greater than 70 percent may be achieved with nitrogen oxide concentrations as low as 20 parts per million and that higher nitrogen oxide levels result in increased performance.

EPA acknowledges this concept in rule. In accordance with 40 CFR §60.482-10, a vapor recovery system shall be designed and operated to recover the volatile organic compound emissions vented to them with an efficiency of 95 percent or greater or to an exit concentration of 20 parts per million by volume, whichever is less stringent.

Depending on the document reviewed, the control efficiency of a selective catalytic reduction system varies from 35 to 90 percent. This range is based on EPA's fact sheet (EPA-452/F-03-032) for selective catalytic reduction systems and Babcock/Wilcox's webpage at http://www.babcock.com. EPA's fact sheet notes the efficiency is greater than 70 percent with nitrogen oxide concentrations as low as 20 parts per million. Using EPA's Method 19 to convert the concentration, 20 parts per million is equivalent to approximately 0.083 pounds per million Btus at 15% oxygen. This emission rate is at the range of the emission limits being discussed. Babcock/Wilcox webpage notes a selective catalytic reduction system should obtain a nitrogen oxide control efficiency in the range of 70 to 90 percent. None of the documents identify under what operating conditions these control efficiencies will occur (e.g., low, mid or high loads); the time period for demonstrating compliance (e.g., hourly or 30-day average emission rate); and/or the inlet pollutant loading rate.

To illustrate the problem of just multiplying an emission rate by a control efficiency, DENR reviewed Otter Tail Power Company's hourly nitrogen oxide emissions by obtaining data from EPA website - Clean Air Markets – Data and Maps. In calendar year 2006, 2007, and 2008, and not considering periods of startup and shutdown, the hourly nitrogen oxide emission rates ranged from approximately 0.46 to 1.324 pounds per million Btus. Using the 70 to 90 percent range, the controlled emission rates would range from 0.05 to 0.39 pounds per million Btus on an hourly basis.

DENR also reviewed Otter Tail Power Company's 30-day rolling average nitrogen oxide emission rate from the same data. In calendar year 2006, 2007, and 2008, and not considering days that Otter Tail Power Company was not in operation, the 30-day rolling average nitrogen oxide emission rate ranged from 0.66 to 0.84 pounds per million Btus. Using the 70 to 90 percent range, the controlled emission rates would range from 0.07 to 0.25 pounds per million Btus.

DENR reviewed EPA's Reasonable Achievable Control Technology, Best Available Control Technology, and Lowest Achievable Emission Rate Clearinghouse (RBLC) for permits issued after calendar year 2000 on the emission limits established for coal fired boilers using a selective catalytic reduction system. The RBLC notes that the best available control technology emission limits for new coal fired boilers using a selective catalytic reduction system were in the range from 0.05 to 0.1 pounds per million Btus. A new boiler is more capable of meeting these limits because the system can be designed into the construction of

the facility. An existing boiler does not have the advantage of maximizing and optimizing the operation of a control device compared to a new unit because the control device must be designed and constructed within the constraints of the existing operation and design. Therefore, DENR would not expect Otter Tail Power Company installing a new selective catalytic on an existing coal fired boiler to meet the lower range of the best available control technology emission limit.

DENR reviewed the operation of the Kincaid Generating Station in Illinois mentioned by the National Park Service. The Kincaid Generating Station is an existing coal fired boiler burning sub-bituminous coal and using a selective catalytic reduction system. Based on the Kincaid Generating Station's air quality permit, during May through September of each year, the facility must meet a nitrogen oxide emission limit of 0.25 pounds per million Btus. DENR reviewed Kincaid Generating Station's hourly nitrogen oxide emissions by obtaining data from EPA website - Clean Air Markets – Data and Maps for calendar year 2008. The 30-day nitrogen oxide rolling average for May through September ranged from 0.06 to 0.10 pounds per million Btus. For the other months (January, February, March, April, October, November, and December), Kincaid Generating Station's 30-day nitrogen oxide rolling average ranged from 0.60 to 0.83 pounds per million Btus.

Manufacturers will report a control efficiency range in its manuals or brochures; but in general and in DENR's experience, most manufacturers give emission rate guarantees in an outlet concentration and not as a control efficiency. Therefore, DENR does not believe citing a control efficiency is relevant in determining BART. DENR does not recommend any changes.

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 reviewed Otter Tail Power Company's BART analysis and compared their results to other results we identify in the state implementation plan and verified the nitrogen oxide emission limit of 0.1 pounds per million Btu is BART. DENR does not recommend any changes.

32. In Section 6.3.3.4, page 87, EPA indicated they do not recommend relying on the CUECost model for estimating costs. EPA states the BART Guidelines requires cost estimates to be based on the OAQPS Control Cost Manual in order to maintain and improve consistency. The National Park Service stated Otter Tail Power Company should have used EPA's control Cost Manual as advised by the BART guidelines and by EPA Region 8 or at least provided its CUECost output data.

    Response: DENR reviewed 40 CFR Part 51, Appendix Y – BART Guidelines to determine if the guideline actually requires that cost estimates be based on the OAQPS Control Cost Manuals as stated by EPA. One of the key words in the title indicates the OAQPS Control Cost Manual is not required and that word is "Guideline". In addition, in several locations in the guideline, it states, "In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible." The words "should be" and

"where possible" do not require the use of the OAQPS Control Cost Manual. Therefore, DENR is not required to use the OAQPS Control Cost Manual.

The Sixth Edition of EPA's Air Pollution Control Cost Manual notes EPA has not developed a method for several of the identified controls. For example, cost estimates for controlling nitrogen oxide such as fuel switching, low NOx burners, steam/water injection, natural gas reburn and non-selective catalytic reduction are not available. The manual lists just two cost estimates for selective non-catalytic reduction and selective catalytic reduction to control nitrogen oxide emissions.

Otter Tail Power Company provided Burns and McDonald's December 7, 2009, letter which was in response to DENR's request for additional information. In this letter Burns and McDonald note the selective catalytic reduction and separated over-fire air system cost effectiveness using the CUEcost of $825 per ton of nitrogen oxide reduced was similar to the OAQPS Control Cost Manual of $900 per ton of nitrogen oxide reduced. Regardless of the manual used, DENR considered the submitted cost as a reasonable cost on a $ per ton basis.

DENR does not propose any changes.

33. On Table 6-12, page 89, footnote 2, EPA states the rounded modeling values in parentheses were used to compare the subject to BART threshold; but actually the unrounded modeled value must be used for determining whether a source exceeds the threshold.

Response: 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. Appendix Y does not specify the rounding method (e.g., conventional, truncate); therefore DENR determined it should be conventional rounded to the tenth decimal since both deciview values are to the tenth value.

Rounding a numerical value means replacing it by another value that is approximately equal but as a shorter, simpler, or more explicit representation. Rounding is also done to indicate the accuracy of a computed number. In this case, the computer models results are to the thousandths and DENR is rounded the results to the nearest tenth for comparison to the standards. In addition, the rounding methodology implemented is one of the most common methods used. Just because the model gives the results out to three decimal points or to the thousandth does not mean that the threshold is required to be to the thousandth.

As noted in 40 CFR Part 51, Appendix Y, states remain free to use a threshold lower than 0.5 deciviews if they conclude that a Class I area justifies this approach. South Dakota identified it's contribute threshold as equal to or greater than 0.5 deciviews. This threshold means a visibility impact of 0.450 or greater is considered to contribute to visibility impairment.

Appendix Y does not specify the rounding method (e.g., conventional, truncate); therefore DENR determined it should be conventional rounded to the tenth decimal since both

deciview values are to the tenth value. The rounding convention proposed by South Dakota meets the requirements specified in the guideline. DENR does not recommend any changes.

34. EPA assumed compliance with DENR's proposed particulate matter BART limit for Big Stone I of 0.012 pounds per million Btu is based on a 30-day rolling average basis, as required. EPA requested we clarify in the state implementation plan.

Response: DENR reviewed 40 CFR §51.308 and 40 CFR Part 51, Appendix Y to determine if particulate emission limits are required to be based on a 30-day rolling average and found no federal requirement. In 40 CFR Part 51, Appendix Y, it states, "…you must establish enforceable emission limits that reflect the BART requirements and require compliance with a given period of time." In addition, it states, "Section 302(k) of the CAA requires emission limits such as BART to be met on a continuous basis." Section 302(k) of the CAA defines an emission limit as a requirement established by the state or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction, and any design, equipment, work practice or operational standard promulgated under this chapter. 40 CFR Part 51, Appendix Y further states, "In light of the above, the permit must … specify a reasonable averaging time consistent with established reference methods" and "… For EGUS, specify an averaging time of a 30-day rolling average…"

Otter Tail Power Company proposed to base its pounds per hour limit on a 30-day rolling average based on the following equations and methodology.

$$DailyRate = \frac{\sum_{n=1}^{k}(HeatInput)\times(EmissionRate)}{k}$$

Where:

- Daily Rate = the average pounds per hour emission rate per day;
- Heat Input = the hourly heat input recorded from the continuous emission monitor;
- Emission Rate = the pounds per million Btus emission rate as determined by the most recent performance test. The performance test is based on the average of three 1-hour runs; and
- k = the number of hours the boiler operated in the day.

$$30Day = \frac{\sum_{n=1}^{30}(DailyRate)}{30}$$

Where:

- 30 Day = the 30-day rolling average; and
- Daily Rate = the average pounds per hour emission rate per day.

DENR did not include the 30-day rolling average since theoretically, if the performance test demonstrates compliance with the pounds per hour limit and the pounds per million Btu limit, it will comply with the same limit on a 30-day rolling average. The pounds per hour limit is based on the maximum heat input to the boiler multiplied by the pounds per million Btu emission rate. As long as the performance test demonstrates compliance, the only theoretical way that the 30-day rolling average would exceed the limit is if Otter Tail Power Company operated above is maximum heat input of the boiler. If Otter Tail Power Company operates greater than is maximum heat input, Otter Tail Power Company would be in violation of its permit. Therefore, DENR did not believe it is worth the manpower to calculate a 30-day rolling average when compliance is determined by the performance test itself.

DENR also contends the citation EPA is referencing is for an emission limit where a continuous emission monitor is being used to demonstrate compliance such as for sulfur dioxide and nitrogen oxide. In the case of the particulate emission limit, compliance on a continuous basis will be based on an annual stack test and compliance assurance and periodic monitoring as required in the Title V air quality permit program. As noted in 40 CFR Part 51, Appendix Y, the particulate emission limit is consistent with the proposed reference method (e.g., performance test).

DENR does not recommend any changes.

35. EPA assumed compliance with DENR's proposed sulfur dioxide BART limit for Big Stone I of 0.09 pounds per million Btu is based on a 30-day rolling average basis, as required. EPA requested that we clarify in the state implementation plan.

    Response: In the last paragraph of Section 6.3.5.2, compliance with the proposed emission limit was stated as "should" be based on the continuous emission monitoring system and on a 30-day rolling average. DENR is clarifying this by stating it "shall" be based on the continuous emission monitoring system and on a 30-day rolling average. In this case, since a continuous emission monitoring system is being used to demonstrate compliance, the 30-day rolling average requirement is applicable.

36. EPA indicates there is no bright line regarding cost effectiveness and each determination must be made taking into account a full five factor BART analysis. EPA states it is reasonable to assume that SCR is generally cost-effective on large cyclone units.

    Response: No response required.

37. EPA requested DENR clarify that DENR's BART determination is SCR plus SOFA at 0.10 pounds per million Btus with compliance based on a 30-day rolling average.

    Response: DENR agrees and revised Section 6.3.5.3 appropriately.

38. EPA is requesting a justification for proposing a separate hourly startup/shutdown limit for particulate matter, sulfur dioxide, and nitrogen oxide in the state implementation plan as well

as whether the selected value represents BART. EPA asked in their comments if DENR evaluated potential impacts of the separate startup/shutdown limit on visibility in the Class I areas? EPA states the BART guideline contemplates pounds per million Btu limit that apply continuously with a 30-day rolling average period to accommodate potential short term fluctuations in the emission rate that may results during startup, shutdown, and other conditions.

Response: DENR explained in Section 6.3.1 and 6.3.5.1 why a baghouse was considered the top particulate matter control technology and determined what the particulate matter emission limit should be based on our recent Prevention of Significant Deterioration evaluation of Big Stone II. DENR explained in the Section 6.3.2 and 6.3.5.2 what the top sulfur dioxide control technology is and determined what the sulfur dioxide emission limit should be. DENR explained in the Section 6.3.3 and 6.3.5.3 what the top nitrogen oxide control technology is and determined what the nitrogen oxide emission limit should be. DENR is uncertain what additional information EPA is requesting since EPA did not provide any justification on why the selected value did not represent BART.

DENR disagrees that 40 CFR Part 51, Appendix Y requires compliance with the emission limit to be based on a 30-day rolling average if a continuous emission monitoring device is not used to demonstrate compliance. Otter Tail Power Company is using continuous emissions monitoring devices to demonstrate compliance on a 30-day rolling average for sulfur dioxide and nitrogen oxide. For particulate matter, DENR is requiring Otter Tail Power Company to demonstrate continuous compliance using annual stack tests and compliance assurance monitoring and periodic monitoring requirements in the Title V air quality permit. Fluctuations in the emission rate resulting during startup, shutdown, and other conditions will not be discovered from an annual stack test. These fluctuations will be observed based on the compliance assurance and/or periodic monitoring requirements in the Title V air quality permit.

In regards to how will days be accounted for that include some, but not all, hours of startup/shutdown. The calculation would be the same as the calculation used to determine the daily rate when the boiler operated some, but not all, hours during the day. The equations would look like the following:

$$DailyRate = \frac{\sum_{n=1}^{k} \left(EmissionRate\right)}{k}$$

Where:

- Daily Rate = the average pounds per million Btus emission rate per day;
- Emission Rate = the pounds per million Btus emission rate as determined by the continuous emission monitoring; and
- k = the number of hours the boiler operated in the day, excluding hours that contain startup and shutdown.

$$30Day = \frac{\sum_{n=1}^{30}(DailyRate)}{30}$$

Where:

- 30 Day = the 30-day rolling average; and
- Daily Rate = the average pounds per million Btus emission rate per day.

As defined in 40 CFR §51.301, *Best Available Retrofit Technology (BART)* means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established on a case-by-case basis taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. As noted in the definition, the units that represent BART are not defined. The emission limitation may be in pounds per hour, pounds per ton, pounds per million Btus, etc.

DENR established a pound per hour emission limit for particulate mater, sulfur dioxide, and nitrogen oxide to represent BART, which covers all normal operations including startup and shutdown. These hourly limits will be included in the permit because they were used in the visibility analysis to demonstrate Otter Tail Power Company was not causing visibility impairment in a Class I area.

When comparing control technology's and emission limits across or within industrial sectors a generalized emission rate is used. The generalized emission rate such as a pound per million Btus allows emission rates across boilers of varying sizes to be compared. A pounds per hour emission rate is difficult to compare from one boiler to the next if the heat input of the boilers are not identical. Whereas, the pound per hour emission rate is a case-by-case emission limit and is specific to an emission unit.

DENR does not recommend any changes.

39. In Section 6.4, page 99, EPA is concerned that without seeing the permit for a BART source, they will not be able to determine if this section of the State Implementation Plan adequately addresses requirements for enforceability, including appropriate averaging times, compliance verification procedures, recordkeeping and reporting requirements, and proper operation and maintenance procedures.

    Response: DENR believes EPA's concerns are relieved by the fact the state implementation plan identifies what the emission limit will be and how they will demonstrate compliance; the proposed Administrative Rules of South Dakota (ARSD) section 74:36:21:10 requires the BART source to modify its permit to include BART limits and requirements; ARSD section 74:36:21:07 requires a BART source to establish written procedures to ensure the BART

control equipment is properly operated and maintained; ARSD section 74:36:21:08 requires the BART sources to conduct periodic monitoring, recordkeeping, and reporting as required in ARSD chapter 74:36:13 and section 74:36:05:16.01(9); and ARSD section 74:36:21:12 requires consultation with federal land managers. The periodic monitoring, recordkeeping and reporting section specified in these sections are from the Title V air quality program which EPA has already approved. All of these requirements will be in a proposed construction permit program that will be part of South Dakota's State Implementation Plan and DENR's approved Title V air quality program. Both of which requires public input and in the case of the Title V air quality program, EPA's concurrence.

In addition, Otter Tail Power Company is already required to meet the requirements under ARSD 74:3616:01 – Acid Rain Program. South Dakota's continuous emission monitoring requirements for the Acid Rain program are the same as EPA's (40 CFR Part 75). 40 CFR Part 75 specifies monitoring provisions, operation and maintenance requirements, missing data substitution procedures, recordkeeping and reporting requirements for the monitored data. These same requirements will be used to verify compliance with the BART sulfur dioxide and nitrogen oxide emission limits. South Dakota performance test requirements (ARSD 74:36:11) specifies the performance tests must be conducted in accordance with the applicable method specified in 40 CFR Part 60, Appendix A, Part 63, Appendix A and Part 51, Appendix M. The test methods specify the monitoring provisions to conduct a proper test. Therefore, these requirements will be used to verify compliance with the BART particulate matter emission limits.

DENR believes the BART requirements for Otter Tail Power Company are identified in the state implementation plan and will be incorporated in a permit issued by DENR that is federally enforceable. To ensure the requirements are federally enforceable, DENR added ARSD section 74:36:21:10, which specifies the particulate matter, sulfur dioxide, and nitrogen oxide BART emission rates for BART-eligible coal-fire power plants.

40. In Section 6.3.2.3, the National Park Service requested DENR state the control effectiveness and resulting emission rate that it believes to be appropriate for each control technology option. The National Park Service agreed with DENR's analysis, but suggests the baseline for annual sulfur dioxide emissions should reflect anticipated uncontrolled annual emissions which according to EPA's Clean Air Market database have averaged 0.66 pounds per million Btus over the 2000 through 2008 period.

    Response: The National Park Service appears to be requesting DENR specify a control effectiveness of 90% for the dry scrubber and calculate an emission limit using that control effectiveness on an uncontrolled emission rate of 0.66 pounds per million Btus. In considering what emission limit represents BART, one needs to consider the operation of the emission unit and the control device. DENR considers it inappropriate to take an arbitrary emission rate Otter Tail Power Company has actually emitted and multiply it by an arbitrary control efficiency to develop an emission limit.

    The control efficiency is variable as recognized by EPA's fact sheet (EPA-452/F-03-024) for fabric filters controlling particulate matter emissions. The fact sheet notes a fabric filter is a

constant outlet device and not a constant collection efficiency device. This fact sheet also notes the collection efficiency of the fabric filter is constantly changing and average collection efficiencies are based on tests with a constant inlet pollutant loading. EPA also recognized the variability in another fact sheet (EPA-452/F-03-034) for flue gas desulfurization (wet and dry) controlling sulfur dioxide emissions. In this fact sheet, EPA states control efficiencies range from 50 percent to 98 percent. EPA acknowledges this concept in rule. In accordance with 40 CFR §60.482-10, a vapor recovery system shall be designed and operated to recover the volatile organic compound emissions vented to them with an efficiency of 95 percent or greater or to an exit concentration of 20 parts per million by volume, whichever is less stringent.

Depending on the document reviewed, the control efficiency of a selective catalytic reduction system varies from 50 to 98 percent. This range is based on EPA's fact sheet (EPA-452/F-03-032) for flue gas desulfurization systems. This fact sheet does note that typically a dry scrubber has a reduction efficiency less than 80 percent but newer designs are capable of higher control efficiencies on the order of 90%. EPA's document does not identify under what operating conditions these control efficiencies will occur (e.g., low, mid or high loads); the time period for demonstrating compliance (e.g., hourly or 30-day average emission rate); and/or the inlet pollutant loading rate.

To illustrate the problem of just multiplying an emission rate by a control efficiency, DENR reviewed Otter Tail Power Company's hourly sulfur dioxide emissions by obtaining data from EPA website - Clean Air Markets – Data and Maps. In calendar year 2006, 2007, and 2008, and not considering periods of startup and shutdown, the hourly sulfur dioxide emission rates ranged from approximately 0.5 to 1.3 pounds per million Btus. Using an 80 to 90 percent range, the controlled emission rates would range from 0.05 to 0.26 pounds per million Btus on an hourly basis.

DENR also reviewed Otter Tail Power Company's 30-day rolling average nitrogen oxide emission rate from the same data. In calendar year 2006, 2007, and 2008, and not considering days that Otter Tail Power Company was not in operation, the 30-day rolling average nitrogen oxide emission rate ranged from 0.59 to 0.89 pounds per million Btus. Using an 80 to 90 percent range, the controlled emission rates would range from 0.06 to 0.18 pounds per million Btus.

DENR reviewed EPA's Reasonable Achievable Control Technology, Best Available Control Technology, and Lowest Achievable Emission Rate Clearinghouse (RBLC) for permits issued after calendar year 2000 on the emission limits established for coal fired boilers using a flue gas desulfurization system. The RBLC notes that the best available control technology emission limits for new coal fired boilers using a flue gas desulfurization system were in the range from 0.04 to 0.17 pounds per million Btus. A new boiler is more capable of meeting these limits because the system can be designed into the construction of the facility. An existing boiler does not have the advantage of maximizing and optimizing the operation of a control device compared to a new unit because the control device must be designed and constructed within the constraints of the existing operation and design. Therefore, DENR would not expect Otter Tail Power Company installing a flue gas desulfurization on an

existing coal fired boiler to meet the lower range of the best available control technology emission limit.

Manufacturers will report a control efficiency range in its manuals or brochures; but in general and in DENR's experience, most manufacturers give emission rate guarantees in an outlet concentration and not as a control efficiency. Therefore, DENR does not believe citing a control efficiency is relevant in determining BART. DENR does not recommend any changes.

DENR reviewed Otter Tail Power Company's BART analysis and compared their results to other results we identify in the state implementation plan and verified the sulfur dioxide emission limit of 0.09 pounds per million Btu is BART. DENR does not recommend any changes.

41. In Section 6.3.2.4, the National Park Service stated Otter Tail Power Company should have used EPA's control Cost Manual as advised by the BART guidelines and by EPA Region 8 or at least provided its CUECost output data.

    Response: DENR reviewed 40 CFR Part 51, Appendix Y – BART Guidelines to determine if the guideline actually requires that cost estimates be based on the OAQPS Control Cost Manuals as stated by the National Park Service and EPA. One of the key words in the title indicates the OAQPS Control Cost Manual is not required and that word is "Guideline". In addition, in several locations in the guideline, it states, "In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible." The words "should be" and "where possible" do not require the use of the OAQPS Control Cost Manual. Therefore, DENR is not required to use the OAQPS Control Cost Manual.

    The Sixth Edition of EPA's Air Pollution Control Cost Manual notes EPA has not developed a method for several of the identified controls. For example, cost estimates for controlling sulfur dioxide such as wet and dry flue gas desulfurization systems are not available. The manual identifies this in the Table of Contents as a Planned Chapter.

    Even though the specific CUECost output file identified by the National Park Service was not provided, Otter Tail Power Company provided the CUECost input files and summarized the estimated costs from the CUECost output files in its BART analysis. Otter Tail Power Company identified the cost per ton as $1,492 per ton. Regardless of the manual used, DENR considered the submitted cost as a reasonable cost on a $ per ton basis.

    DENR does not propose any changes.

42. The National Park Service recommended DENR provide an additional table which illustrates the cumulative $/dv for the control options in Table 6-15.

    Response: Instead of adding an additional table, DENR added a row for the cumulative $/deciview for each option in Table 6-15.

43. Otter Tail Power Company requested the fourth sentence in Section 6.3.1.1 be revised as follows: “As such, the filterable particulate may be collected by placing a control device in the flue gas stream prior to the stack.”

    Response: DENR agrees and made the appropriate changes.

44. Otter Tail Power Company requested footnote 4 for Table 6-9 be clarified to represent Best Available Control Technology for Basin’s NextGen project is for a new pulverized-fired boiler equipped with a low-NOx burner combustion technology which produces lower levels of nitrogen oxide emissions entering the selective catalytic reduction than are achievable with an existing cyclone-fired boiler.

    Response: DENR agrees to clarify the BACT analysis is for a new pulverized-fired boiler equipped with a low-NOx burner combustion technology.

45. Otter Tail Power Company requested it be clarified that the number of significant digits Otter Tail Power Company reported for its deciview impacts included in Table 6-12 and 6-14 are consistent with WRAP modeling results presented in Table 6-3 and are also consistent with accepted industry practices.

    Response: DENR agrees to state the reporting of the visibility impact to three significant digits is consistent with how WRAP reported its modeling results in footnote 2 of Table 6-12 and the paragraph just before Table 6-14.

46. Otter Tail Power Company requested the last sentence of the second paragraph in Section 6.3.5.1 be revised to reference the annual performance test and the number of hours the boiler operated that day.

    Response: DENR agrees and will clarify the most recent annual performance test.

7.0 Reasonable Progress

47. EPA was unable to determine in Table 7-1 and Section 7.2.1 if 16.50 and 15.28 deciview for the Badlands and Wind Cave, respectively were DENR’s reasonable progress goals and indicated the numbers do not match those shown in Figure 8-1. EPA requested clarification and documentation on how these numbers were derived. EPA also stated in accordance with 40 CFR §51.308(d)(2)(iv)(A), DENR is required in the state implementation plan to include the deciview difference between the baseline and natural conditions for the best and worst days for the first planning period (2018). EPA also stated in accordance with 40 CFR §51.308(d)(1)(ii), the state implementation plan must provide the number of years necessary to reach natural conditions when the reasonable progress goal is less than the uniform rate of progress.

Response: DENR clarified where the baseline, uniform progress and reasonable progress for 2018 were derived from by adding footnotes to Table 7-1. The baseline values were derived from Table 3-7. The uniform progress goals for 2018 were derived from Figure 3-5. The reasonable progress goals for 2018 were derived from WRAP's modeling.

DENR realized that Figure 8-1 is actually a table and re-labeled it as Table 8-1. Table 8-1 was derived from WRAP's reasonable progress analysis at the Badlands and Wind Cave National Parks using what was considered background and natural conditions at the time. DENR clarified where the baseline conditions and deciview values for baseline, natural conditions and uniform rate of progress were derived in the footnotes. The baseline conditions were derived from Table 4.3(b) and 4.4(b) for the Badlands and Wind Cave National Parks, respectively. The deciview values were derived from Table 3-7 for the baseline and natural conditions and Figure 3-5 for the uniform rate of progress.

40 CFR §51.308(d)(2)(iv)(A) states the following, "For the first implementation plan addressing the requirements of paragraphs (d) and (e) of this section, the number of deciviews by which baseline conditions exceed natural visibility conditions for the most impaired and least impaired days." DENR compared the baseline and natural visibility condition values but did not display the difference. Therefore, DENR changed Table 3-7 to include the difference.

DENR reviewed 40 CFR §51.308(d)(1)(ii) and agrees with EPA's interpretation. DENR explained its intentions in Section 10.3; but understands the explanation should be in more detail and revised this section to explain.

48. EPA stated the public must be provided a calculation of the number of years required to reach natural conditions if the Reasonable Progress Goal provides a slower rate of improvement than that needed to attain natural conditions by 2064 per 40 CFR §51.308(d)(1)(ii). The State Implementation Plan must include DENR's best estimate of number of years to reach natural condition with the Reasonable Progress Goals. The National Park Service stated that because modeled progress in improving visibility by 2018 is less than the uniform rate of progress necessary to achieve natural visibility by 2064, DENR needs to define when natural conditions are expected to be achieved given the reasonable progress goals by 2018.

    Response: DENR reviewed 40 CFR §51.308(d)(1)(ii) and agrees with EPA's interpretation. DENR explained its intentions in Section 10.3; but understands the explanation should be in more detail and revised this section to explain.

49. EPA indicated a four factor analysis must be conducted as part of the Reasonable Progress Goals as well as justifying a Reasonable Progress Goal that is less than the Uniform Rate of Progress. The National Park Service indicated DENR is missing the required four factor analysis of potential emissions controls. The Forest Service believes a four factor analysis is required but depending on Big Stone I's emission contribution, a simple analysis may be justified and requested DENR use the information and analysis provided by WRAP.

Response: To determine if a four factor analysis is warranted, DENR looked at the air pollutants being emitted from point sources that were not meeting the glide path for each National Park. Based on Figure 7-1(a), the air pollutant not meeting the glide path at the Badlands National Park is ammonia sulfate and organic carbon mass. Based on Figure 7-1(b), the air pollutant not meeting the glide path at the Wind Cave National Park is ammonia sulfate, organic carbon mass, and ammonia nitrate.

Next, DENR reviewed WRAP's attribution analysis to determine the major contributors of ammonia sulfate, organic carbon mass, and ammonia nitrate in South Dakota's two Class I areas. For the Badlands and Wind Cave National Parks, the major contributors of ammonia sulfate are from sources not in South Dakota. South Dakota's ammonia sulfate contribution for 2002 and 2018 is minimal at both national parks at approximately 0.04 micrograms per cubic meter. South Dakota's contribution represents 3% of the ammonia sulfate concentrations for 2018 at both national parks. Of the 3%, approximately 1.5% is generated from point sources and 1.5% is generated from mobile and other sources.

The major contributor of organic carbon mass in both National Parks is natural fires with point source contributions minimal. Organic carbon mass emissions from natural and prescribed fires will be evaluated in a smoke management plan which is part of DENR's long term strategy.

Ammonia nitrate was only a concern for the Wind Cave National Park since it was on the glide path at the Badlands National Park. At the Wind Cave National Park, the major contributors to ammonia nitrate are Canada followed by Wyoming, Outside the Domain, and South Dakota. South Dakota's ammonia nitrate contribution for 2002 and 2018 is approximately 0.135 and 0.105 micrograms per cubic meter, respectively. South Dakota's contribution represents 10% of the ammonia nitrate concentration for 2018 at the Wind Cave National Park. Of the 10%, approximately 4% is generated from point sources and 6% is generated from mobile and other sources.

DENR determined that a four factor analysis is not warranted at this time because of the minimal contribution point sources contribute to visibility impairment in South Dakota's Class I areas. DENR will re-evaluate this decision during periodic reviews of the Regional Haze State Implementation Plan. This will also give DENR time to determine if the implementation of each state's Regional Haze Program will bring ammonia sulfate, ammonia nitrates, and organic carbon mass emissions in line with the Uniform Rate of Progress.

50. The National Park Service indicated DENR should state explicitly that the reasonable progress goals for South Dakota's Class I areas are the same as the WRAP CMAQ modeling results for 2018 and DENR did not include any other emissions reductions beyond those modeled by WRAP in setting the reasonable progress goals.

    Response: DENR disagrees since the BART determination for Otter Tail Power Company's Big Stone I facility is not included entirely in WRAP's modeling analysis of reasonable progress goals. In addition, DENR is proposing rules that will require new major sources and a modification to an existing major source that are not subject to New Source Review to

conduct a visibility impact analysis to ensure the proposal will not contribute to adverse impact on visibility in an mandatory Class I area. The later was not mentioned in the draft Regional Haze State Implementation Plan and will be included in Section 7.1.

8.0 Long Term Strategy

51. In accordance with 40 CFR §51.306(c), EPA states DENR must revise its plan to provide for a coordinated long term strategy for addressing both reasonably attributable and regional haze visibility impairment and future coordinated long term strategies must be submitted consistent with the schedule for periodic progress reports set forth in 40 CFR §51.308(g). Currently, the requirements in 40 CFR §51.306(c) are under a Federal Implementation Plan. EPA has not determined how to coordinate a reasonable attributable long-term strategy under a Federal Implementation Plan with a regional haze long-term strategy State Implementation Plan. EPA states the simplest approach would be for DENR to adopt a reasonable attributable program and asked if DENR was interested in this concept.

    Response: Because EPA has not determined how to coordinate a reasonable attributable long-term strategy under a Federal Implementation Plan with a regional haze long-term strategy State Implementation Plan does not mean DENR is required to adopt a reasonable attributable program. EPA, under the Federal Implementation Plan, must submit their long term strategy for addressing reasonably attributable visibility impairment in accordance with 40 CFR §51.306(c). Currently DENR is not interested in developing a reasonable attributable program to replace EPA's program; but will coordinate with EPA in developing a long term strategy that addresses both programs. DENR clarified this commitment in Section 11.2.

52. In Section 8.1, page 105, EPA states DENR must quantify South Dakota's impact to the Class I areas outside the state (similar to that noted in Table 6-4).

    Response: DENR is unsure of what EPA is requesting. In accordance with 40 CFR § 51.308(d)(3)(i), the long term strategy for each state that causes or contributes to impairment in a Class I area is required to demonstrate that it has included in its state implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goals for the Class I area. DENR determined that Otter Tail Power Company's Big Stone I facility is the only source in South Dakota that is reasonable anticipated to contribute to visibility impairment in Class I areas in other states. DENR discusses how the impacts will be addressed in Chapter 6.0. Table 6-4, which EPA referenced in their comment, quantifies Otter Tail Power Company's impact. DENR does not believe it needs to be repeated in Section 8.1. DENR does not recommend any changes.

53. In Section 8.3, page 106, EPA recommended DENR add the website addresses and/or references to where the technical analyses are located and how they will be maintained going forward. In addition, DENR should specify its commitment to continue compilation and analysis of the technical requirements for the Regional Haze State Implementation Plan regardless of future uncertainness in the WRAP's role.

Response: DENR is confident WRAP will remain a viable resource for states to use in their Regional Haze updates in the future. DENR will continue to support the WRAP along with the tools developed including the Technical Support System (TSS), Visibility Information Exchange Web System (VIEWS), Emissions Data Management System (EDMS), Fire Emissions Tracking System (FETS), etc. In the event that the WRAP should cease to exist, DENR will continue to monitor and model data for technical analyses to accomplish the goals of South Dakota's Regional Haze State Implementation Plan. DENR will include the technical analyses website at:

http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx

54. EPA indicated there is currently a Federal Implementation Plan in place for the original visibility new source review requirements under 40 CFR §51.307, which incorporated by reference the requirements in 40 CFR §51.28 (see 40 CFR §51.2179(b)). EPA asked if DENR's intention was to use the proposed regional haze rules under Administrative Rules of South Dakota, Chapter 74:36:21 to replace the nonattainment new source review visibility analysis requirements. If so, EPA would provide input on such revision.

    Response: The Administrative Rules of South Dakota, Chapter 74:36:21 is being adopted to implement the Regional Haze Program. DENR does not anticipate adopting the original visibility program at this time.

55. In Section 8.5.5, page 109-110, in accordance with 40 CFR §51.308(d)(3)(v)(E), EPA states that in establishing DENR's long term strategy, DENR must consider smoke management techniques for agricultural and forestry management purposes including plans as currently exist with the state for these purposes. At least some preliminary steps, in coordination with the federal land managers, must be included along with citing to existing South Dakota burning provisions. The National Park Service would like to see a more complete discussion of local options to address emissions of organic carbon mass, elemental carbon, and course mass because the source apportionment analyses indicates organic carbon from natural fires is a major contributor on the 20% most impaired days. In addition, a more complete discussion of options to control smoke from unplanned wildland fires and the relative importance of prescribed burns and agricultural burns in the state. In Section 8.5.5, DENR states agricultural burning occurs in the eastern part of the state but the National Park Service states that does not preclude transport of smoke to the west on some days. The National Park Service acknowledges the emissions from prescribed burns in the national parks are contributing to visibility impairment and would like to participate in an effective smoke management plan. The United States Forest Service offered to assist DENR in developing the smoke management plan.

    Response: DENR agrees that in accordance with 40 CFR §51.308(d)(3)(v)(E), smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the states for these purposes must be considered once DENR determines the impacts local burning practices have on the monitoring data being collected at the Badlands and Wind Cave National Parks. As noted in Section 8.5.5, we do not believe

agricultural burning has much of an impact at our Class I areas because of the distance, the size of the burns, and none of 20% most impaired days indicated issues from an eastern agricultural burn. But DENR does believe that forestry management including planned prescribed burning may have an impact based on the 20% most impaired days indicating a large fire impacting one or both Class I areas in South Dakota. DENR committed to developing and implementing a smoke management plan in the "Executive Summary" but did not make that clear in this section. DENR will clarify that in Section 8.5.5, that DENR will develop and implement a smoke management plan.

Over the past few years DENR has taken the initial steps in developing a smoke management plan by contacting those groups that DENR believes would need to be involved, including the South Dakota Department of Agriculture, National Park Service and U.S. Forest Service, among others. The response from these agencies has been positive and all have offered to assist in developing a smoke management plan for South Dakota. More recently, DENR has been in contact with the South Dakota Division of Wildland Fire Suppression, which maintains a prescribed fire database of fires throughout South Dakota and along our borders in neighboring states. DENR will use this database to track fires and compare the fire data (e.g., size of fire, material being burned, distance from the Class I areas, dates) to the IMPROVE data from our Class I areas to see what the impacts are to the visibility. DENR will also research the Best Management Practices for controlling prescribed fires.

Using this information will be the basis of our smoke management plan and the direction we go in development of the smoke management plan will depend on the outcome of the data analysis. To start with, the main focus of the smoke management plan will consist of the Black Hills region and the areas around the two Class I areas. DENR will work with the federal land managers, other state agencies, and local governments during the development and implementation of the smoke management plan.

DENR will discuss this in further detail in Section 8.5.5.

56. In Section 8.5.6, page 110-111, EPA recognized that DENR plans on establishing the Big Stone I BART limits and control measure requirements in either a construction permit or Title V permit. EPA states the BART requirements need to be incorporated in the State Implementation Plan and does not believe it appropriate for DENR to rely on the construction permit since it has not been approved in our State Implementation Plan yet.

    Response: In accordance with 40 CFR §308(1)(e)(1)(v), DENR is required to include a requirement that BART-eligible sources maintain the control equipment and establish procedures to ensure the equipment is properly operated and maintained. DENR plans on adopting these requirements in ARSD Chapter 74:36:21 and submit these rules to EPA to be included in the Regional Haze State Implementation Plan. DENR also agreed to establish the permit limits for Otter Tail Power Company's BART eligible unit in ARSD 74:36:21:10, which will be included in the State Implementation Plan submitted to EPA. DENR will expand on this in Section 8.5.6.

57. The National Park Service believes South Dakota should commit in the Regional Haze State Implementation Plan to expand regulations requiring public and private construction and road projects to limit fugitive dust emissions as part of the long term strategy.

    Response: A majority of the coarse particulate matter emissions are generated from wind blown dust (e.g., approximately 54% at the Badlands National Park and 33% at the Wind Cave National Park). Based on the coarse particulate matter contributions (see Table 5-7), the contribution of coarse particulate matter from fugitive emissions is approximately 8% and 5% at the Badlands and Wind Cave National Parks, respectively. Public and private road construction represents a portion of the fugitive emissions. Therefore, DENR disagrees; but will always re-evaluate this request during the periodic reviews.

9.0 Monitoring Strategy

58. EPA indicated there is currently a Federal Implementation Plan in place for the original visibility monitoring requirements under 40 CFR §51.305, which incorporated by reference the requirements in 40 CFR §51.26 (see 40 CFR §51.2179(b)). EPA asked if DENR's intention was to use the monitoring strategy outlined in Chapter 9.0 of South Dakota's Regional Haze Program to replace the current Federal Implementation Plan visibility monitoring requirements. If so, they would provide input on such revision.

    Response: The monitoring strategy in Chapter 9.0 of South Dakota's Regional Haze Program is being implemented for South Dakota's Regional Haze Program. DENR does not anticipate adopting the original visibility monitoring program at this time.

10.0 Consultation Requirements

59. In Section 10.2, page 118-119, EPA requested that we identify the dates and outcomes of the discussions for each consultation. EPA asked if DENR planned to include tribal consultation on the public comment version of the State Implementation Plan.

    Response: There is no tribal air quality program approved by EPA within South Dakota. Therefore, officially EPA represents South Dakota tribes on air quality matters. However, during the public notice phase of adopting the Regional Haze State Implementation Plan, tribes and tribal members will have an opportunity to provide input.

    As noted previously, DENR has been a participant in WRAP since its inception and considers its involvement as fulfilling part of the requirements for consultation. Within WRAP, the Implementation Work Group (IWG) was formed to address states' issues regarding Regional Haze and conducted numerous face-to-face meetings and monthly calls. All western states, EPA, Tribes and Federal Land Mangers participated in the WRAP actives and were involved throughout the process. Beyond WRAP, South Dakota was involved with the Northern Class I Areas workgroup which had monthly conference calls and included Minnesota, Michigan, Iowa, along with other Midwestern states. In addition, South Dakota consulted with Minnesota directly starting in August of 2007 through emails and phone calls,

which continued through December of 2009 when Minnesota submitted its Regional Haze State Implementation Plan to EPA. DENR also consulted directly with the State of Nebraska over the past few years through email and phone calls, mostly in regards to impacts the Gerald Gentleman Power Plant has on visibility impairment in Class I areas in South Dakota and their plans to control emissions from the Gerald Gentlemen Power Plant.

In addition, DENR provided South Dakota's draft Regional Haze State Implementation Plan to all of the neighboring states and Michigan for comments on January 15, 2010. DENR did not receive any comments from these states.

60. In Section 11.2, page 121, EPA recommended that as part of continuing consultation required under 40 CFR §51.308(i)(4), we clarify item 7, regarding the monitoring strategy, to note that we will consult with EPA and the federal land managers on any revisions deemed necessary.

Response: Continuing consultation with the federal land managers is addressed in Section 10.1.2. In this section it specifies DENR is required to consult with the federal land managers during the 5-year progress reports. The submittal of the 5-year progress report is to EPA which ensures EPA's involvement. Therefore, DENR believes this is already addressed and does not recommend any changes.

11.0 Proposed ARSD 74:36:21 Rules

61. In ARSD 74:36:21:02, EPA recommended the following changes to the definitions:

a. The definition of a "BART-eligible source" must cite to an existing stationary facility as defined in ARSD 74:36:21:03.

Response: DENR identified in ARSD 74:36:21:02 that a "BART-eligible source" is an existing stationary facility. In ARSD 74:36:21:03, DENR defined an "existing stationary facility". This is similar to how EPA defined "BART-eligible source" and "existing stationary facility". The only difference, which DENR believes is EPA's concern, is DENR's definition for "BART-eligible source" does not state at the end of the definition, "as defined in this section". DENR believes this is already required when it states at the beginning of this section that "unless otherwise specified, the terms used in this article mean." The style and format of the proposed rule is reviewed by the South Dakota's Legislative Research Council and if they recommend changing it in this matter, DENR will oblige.

b. The definition of "visibility impairment" does not mirror the federal definition in 40 CFR §51.301 and must be revised accordingly.

Response: DENR tried to combined the term "visibility impairment" and "adverse impact on visibility" to make it clearer to the public and regulated entities what is visibility impairment. Since this is not acceptable by EPA, DENR revised the definition of "visibility impairment" to be consistent with 40 CFR §51.301 and added the phrase "adverse impact on

visibility" and defined it consistently with 40 CFR §51.301. By doing so, DENR went through the proposed rules and replaced "visibility impairment" with "adverse impact on visibility".

c. The definition of "contribute to visibility impairment" is not appropriate in the regional haze context and must be removed since there is no threshold for such a contribution.

Response: DENR revised the term "contribute to visibility impairment" to "contribute to adverse impact on visibility" based on EPA's earlier concern with the term "visibility impairment". "Contribute to adverse impact on visibility" is used in both the Prevention of Significant Deterioration and in the New Source Review programs to determine the visibility impacts on mandatory Class I federal areas. The five-tenths deciview threshold is identified in EPA's draft New Source Review Manual, the federal land managers draft FLAG document (page 34), and in EPA's BART guidelines. DENR believes it is appropriate as part of its long term strategy to ensure new sources and modifications to existing sources, not covered already by the Prevention of Significant Deterioration or New Source Review, should demonstrate they will not contribute to adverse impact on visibility. DENR reviewed 40 CFR §51.308 and did not see where this was prohibited. DENR does not recommend any changes.

d. The definition of "major source" must site to 40 CFR §51.166 and DENR must include the definition of "major modification" from 40 CFR §51.166 since the definition of major stationary source under the regional haze regulations includes major modifications.

Response: EPA is referencing a "major source" and "major modification" covered under the New Source Review Program, which is already addressed in ARSD 74:36:09 – Prevention of Significant Deterioration and 74:36:10 – New Source Review. Both of these programs are part of South Dakota's State Implementation Plan. The major sources addressed under ARSD 74:36:21 – Regional Haze Program are defined in ARSD 74:36:21:02(6), which identifies a major source as a source that meets the definition of a major source under the Title V air quality permit program for criteria pollutants. The definition does not include a major source under the New Source Review Program. The term "modification" is already defined in ARSD 74:36:01:10 – Modification Defined, and was not reiterated in ARSD 74:36:21. DENR does not recommend any changes.

62. In ARSD 74:36:21:04, EPA states this section must be revised to clarify the existing provisions of 74:36:09 are not replaced by this new section. EPA also asked what DENR's intention with this new provision.

Response: DENR believes it would be appropriate to clarify that Chapter 74:36:21 does not apply to major sources and major modifications under the New Source Review Program. To accomplish this, DENR added a sentence to ARSD 74:36:21:01 that states this chapter does not apply to a source applicable to the Prevention of Significant Deterioration Program or New Source Review Program.

63. In ARSD 74:36:21:07, EPA recommends to improve clarity, this section should include more detail, such as specifying the minimum criteria for an acceptable operation and maintenance plan and when the source specific operation and maintenance to meet such criteria shall be submitted for permitting authority approval.

    Response: DENR believes it would be appropriate to identify the minimum requirements for the operation and maintenance of controls and added the minimum requirements to ARSD 74:36:21:07. DENR disagrees the written plan needs to be submitted to DENR for approval since a BART source is required to be inspected at least once per year and submits periodic reports to DENR to ensure compliance with the permit requirements.

64. In ARSD 74:36:21:08, EPA is concerned this provision is not clear whether all of the sulfur dioxide and nitrogen dioxide emissions from the BART-eligible source will be routed to the main stack. The term "main stack" implies the presence of other stack(s) which is/are not equipped with continuing emission monitoring system(s) as is the "main stack". EPA recommended alternative language.

    Response: DENR agrees and will make the appropriate changes.

65. In ARSD 74:36:21:11, EPA stated that as required in the regional haze rule, federal land managers must be provided a 60-day consultation period prior to any public hearing on the regional haze state implementation plan. EPA argues that since a BART permit is an integral part of the regional haze state implementation plan, this 60-day consultation period must extend to the federal land managers BART permit review as well. EPA also argues that since any BART permit must be incorporated into the regional haze state implementation plan, the 30-day public notice for the state implementation plan needs to identify the inclusion of any BART permits.

    Response: South Dakota's draft Regional Haze State Implementation Plan was submitted to the federal land managers on January 15, 2010 and DENR plans on holding the public hearing in September 2010. Therefore, DENR provided the federal land managers more than 60-day consultation prior to the public hearing on the Regional Haze State Implementation Plan. In accordance with 40 CFR § 51.308(e)(1)(i), the draft Regional Haze State Implementation Plan contains a list of BART-eligible sources in Section 6.1. In accordance with 40 CFR § 51.308(e)(1)(ii), the draft Regional Haze State Implementation Plan contains the BART determination for each BART-eligible source in Section 6.2 and 6.3 and Appendix C, D, and E. In accordance with 40 CFR § 51.308(e)(1)(iv), each source subject to BART is required to install and operate BART no later than 5 years after approval of the Regional Haze State Implementation Plan as required in ARSD 74:36:21:06. In accordance with 40 CFR § 51.308(e)(1)(v), each source subject to BART must install the control equipment required by the BART determination and establish procedures to ensure such equipment is operated and maintained as discussed in Section 6.3 and 6.4 of the Regional Haze State Implementation Plan and in accordance with ARSD 74:36:21:07. In addition, DENR has already agreed to include the BART emission limits for Big Stone I in ARSD 74:36:21:10.

DENR believes the BART requirements are specified in South Dakota's draft Regional Haze State Implementation Plan and DENR provided the federal land managers more than a 60-day consultation period before the public hearing. DENR was unable to determine what federal regulation EPA is using to state the BART permit must be included in the state implementation plan. However, this is a mute point since DENR added the BART emissions limits for Big Stone I in ARSD 74:36:21:10.

12.0 General Comments

66. In Chapter 1.0, EPA requested DENR clarify the 1977 Clean Air Act Amendments and EPA's 1980 reasonable attributable visibility impairment regulations addressed visibility impairment caused or contributed to by one or a small group of sources.

    Response: DENR reviewed Section 169A of the Clean Air Act and agree major sources built and operated during a certain timeframe that "…may reasonably be anticipated to cause or contribute to visibility impairment…" are required to install Best Available Retrofit Technology. Therefore, DENR changed the language in the fourth paragraph of the "Introduction" to reflect the change.

    DENR reviewed 40 CFR Part 51, Subpart P which discusses EPA's 1980 rules on visibility protection and the language is similar to how DENR represented it. DENR does not recommend any changes.

67. EPA requested DENR revise the date of delegation of the Prevention of Significant Deterioration program from September 15, 1994 to July 6, 1994.

    Response: September 15, 1994 is the date of the federal register notice for the final rule and the effective date is July 6, 1994. DENR agrees and will make the appropriate change in the third paragraph of the "Introduction".

68. EPA indicated the "Date of Reconstruction" definition in Section 6.1 did not quite match the federal definition.

    Response: DENR reviewed the definition and agrees. Instead of stating, "…must occur between August 7, 1962 and August 7, 1977…" the definition will be revised to state "…must occur during the August 7, 1962 to August 7, 1977 time period…"

69. EPA indicated the last sentence of the definition for "Potential to Emit" in Section 6.1 contains a typographical error and should be "26" instead of "28".

    Response: DENR reviewed the definition and agrees. DENR will make the appropriate change.

70. EPA requested it be clarified in Sections 7.1 and 8.5.1 that although some of the cited Administrative Rules of South Dakota control emissions of pollutants that ultimately

contribute to visibility impairment, the rules were not written specifically to address visibility impairment.

Response: Section 7.1 identifies state and federal rules in place and those planned for the future that will help South Dakota achieve reasonable progress in protecting and improving visibility in our Class I areas. Section 8.5.1 references 40 CFR § 51.308(d)(3)(v)(A), which requires an assessment of emission reductions due to ongoing air pollution control programs. DENR provided an assessment of which existing state rules assist in reducing air emissions and help achieve reasonable progress. Since the EPA reviewer(s) did not reference a federal regulation which specifically requires EPA's requests, DENR believes these comments are a preference and not a requirement. DENR does not propose any changes.

71. In Section 8.5, page 107, EPA believes there is a typographical error and it should state "emissions reductions" instead of "emissions" in the last paragraph.

    Response: DENR agrees that it should be "emission reductions" and made the appropriate changes.

72. The National Park Service requested DENR add footnotes to the tables and graphs throughout the document to define the abbreviations used, especially for organic carbon mass, particulate organic aerosol, elemental carbon, and fine mass elemental carbon. The terms vary depending on the data source used and can be confusing to the reader.

    Response: DENR agrees and made the appropriate changes.

Appendix A

Comment Letters on South Dakota's

Draft Regional Haze Program

United States Department of Agriculture
Forest Service
Superior National Forest
8901 Grand Ave. Place
Duluth, MN 55808-1122
Phone: (218) 626-4300
Fax: (218) 626-4398

File Code: 2580-2
Date: February 24, 2010

Rick Boddicker
Senior Environmental Scientist
SD DENR
523 East Capitol
Pierre, SD 57501

RECEIVED
FEB 26 2010
AIR QUALITY PROGRAM

Dear Mr. Boddicker:

On January 15, 2010, the State of South Dakota submitted a draft implementation plan describing your proposal to improve air quality regional haze impacts at mandatory Class I areas across your region. We appreciate the opportunity to work closely with the State through the initial evaluation, development, and, now, subsequent review of this plan. Cooperative efforts such as these ensure that together we will continue to make progress toward the Clean Air Act's goal of natural visibility conditions at our Class I wilderness areas and parks.

This letter acknowledges that the U.S. Department of Agriculture Forest Service has received and conducted a substantive review of your proposed Regional Haze Rule implementation plan. Please note, however, that only the U.S. Environmental Protection Agency (EPA) can make a final determination about the document's completeness, and therefore, only the EPA has the ability to approve the document. Participation by the Forest Service in the State of South Dakota's administrative process does not waive any legal defenses or sovereignty rights it may have under the laws of the United States, including the Clean Air Act and its implementing regulations.

As outlined in a letter to South Dakota dated November 1, 2006, our review focused on eight basic content areas. The content areas reflect priorities for the Federal Land Manager agencies, and we have attached comments to this letter associated with these priorities. We look forward to your response required by 40 CFR 51.308(i)(3). For further information, please contact Eastern Region Air Resource Specialist Trent Wickman at (218) 626-4372 or Rocky Mountain Region Air Resource Specialist Jeff Sorkin at (406) 329-3672.

Again, we appreciate the opportunity to work closely with the State of South Dakota. The Forest Service compliments you on your hard work and dedication to significant improvement in our nation's air quality values and visibility.

Sincerely,

JAMES W. SANDERS
Forest Supervisor

cc: Charles E Sams, Jeff A Sorkin, Terry Svalberg, Amy Platt, Don Shepherd, Tim Allen

Technical Comments

1) In regards to your approach to estimating natural conditions, for consistency, we would prefer that South Dakota (SD) use the standard Western Regional Air Partnership/ Technical Support System (WRAP/TSS) natural conditions values unless there is a justification for your alternate values.

2) We want to be involved in the development of your smoke management plan (SMP). We will give a local Forest Service contact when requested.

3) We note that high organic carbon (OC) concentrations don't necessarily mean fire impacts, as noted in the draft SIP. Please provide more analysis on individual high OC days (for example use back trajectories) to see where the OC came from. Another approach that could be used would compare the seasonality of prescribed fire with wildfire. Using calendar quarters are not a fine enough temporal resolution for this task. For example SD could get prescribed fire activity info from the burners in the state and see if it matches measured high OC impact days.

4) We commend SD for selecting selective catalytic reduction as BART for Big Stone.

5) Please show how big a part of the state's point source emission inventory Big Stone is.

6) It is our view that the regional haze regulations require a four factor analysis. Depending on the answer to question 5) above, a simple analysis may be justified. Please make use of information and analyses provided by WRAP.

United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE® IN AMERICA

IN REPLY REFER TO:

February 25, 2010

N3615 (2350)

RECEIVED
MAR 01 2010
AIR QUALITY PROGRAM

Mr. Brian Gustafson
Administrator, Air Quality Program
South Dakota Department of Environment and Natural Resources
523 E Capitol
Pierre, SD 57501

Dear Mr. Gustafson:

On January 15, 2010, we received South Dakota's draft regional haze implementation plan for review. We appreciate the opportunity to work closely with the State through the development and review of this plan. Cooperative efforts such as these ensure that, together, we will continue to make progress toward achieving natural visibility conditions at our National Parks and Wilderness Areas.

This letter acknowledges that the U.S. Department of the Interior, National Park Service (NPS), in consultation with the U.S. Fish and Wildlife Service, has received and conducted a substantive review of the South Dakota draft Regional Haze Rule implementation plan in fulfillment of your requirements under the federal regulations 40 CFR 51.308(i)(2). Please note, however, that only the U.S. Environmental Protection Agency (EPA) can make a final determination regarding the document's completeness and, therefore, ability to receive federal approval from EPA.

As outlined in a letter to each State dated August 1, 2006, our review focused on eight basic content areas. The content areas reflect priorities for the Federal Land Manager agencies, and we have enclosed comments associated with these priorities. Overall the draft implementation plan was well organized and addressed most of the key elements outlined in our letter. We are very pleased to see South Dakota's commitment to semi-dry flue gas desulfurization for sulfur dioxide (SO_2) controls and selective catalytic reduction for nitrogen oxide controls as best available retrofit technology for the Otter Tail Big Stone Unit 1 coal-fired power plant. However, we have two primary concerns with the draft plan: 1) the reasonable progress analyses should include a four factor analysis of potential controls on SO_2 emissions from point and areas sources, and 2) the long-term strategy should provide more discussion of activities to reduce smoke impacts from fires and to reduce fugitive dust from construction and road projects.

We look forward to your response, as per section 40 CFR 51.308(i)(3). For further information regarding our comments, please contact Pat Brewer of my staff, at (303) 969-2153.

Again, we appreciate the opportunity to work closely with the State of South Dakota and compliment you on your hard work and dedication to significant improvement in visibility in our Class I national parks and wilderness areas.

Sincerely,

John Burzyk

for Christine L. Shaver
Chief, Air Resources Division

Enclosure

Cc: Gail Fallon
Air Quality Planning Unit (8P-AR)
US EPA Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

National Park Service Comments
South Dakota Draft State Implementation Plan for Regional Haze
February 25, 2010

General Comments

South Dakota's draft State Implementation Plan (SIP) is well organized and addresses most of the key elements of a regional haze SIP as outlined in our August 2006 letter to the states. South Dakota has defined current and natural visibility conditions and has applied technical analyses provided by the Western Regional Air Partnership (WRAP) to describe emissions inventories, state and source sector contributions to haze at Class I areas, and visibility response to expected emissions controls by 2018. SD has proposed controls for the Otter Tail Big Stone electric generating plant under Best Available Retrofit Technology (BART). We are pleased to see these substantive reductions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions. SD has defined reasonable progress goals and addressed a long-term strategy to improve visibility in SD Class I areas. We would like to see a more developed four factor analysis of emissions control options, but overall SD has demonstrated a commitment to protecting visibility in our national parks and wilderness areas.

Specific Comments

Please add footnotes to the tables and graphs throughout the document to define the abbreviations used, especially for organic carbon mass, particulate organic aerosol, elemental carbon, and fine mass elemental carbon. The terms vary depending on the data source used and can be confusing to the reader.

Chapter 3 Baseline, Natural and Uniform Rate of Improvement

As stated on page 12, EPA's guidance on determining natural conditions provides default assumptions for natural background visibility and allows states to refine estimates. For Class I areas in and near SD, the greatest uncertainty is related to the contributions of organic carbon and elemental carbon from natural wildland fires. SD's revisions to fine soil and coarse matter assumptions are based on 2000-2004 IMPROVE monitoring and effectively suggest that natural background should be lower than the default assumption. This revision would require even greater reductions in current anthropogenic sources of fine soil and coarse matter to achieve the revised natural background conditions. Given the large uncertainties, we recommend that SD retain EPA's default assumptions using natural background values available on the VIEWS website for this current SIP and defer refinements to a later SIP.

Chapter 4 IMPROVE Data for Class I Areas

Chapter 4 describes the IMPROVE data used as the current baseline visibility. Contributions of aerosol components to the 20% least and the 20% most impaired days are informative for developing priorities for emissions reductions. Page 21, second paragraph, and page 26, second paragraph, refer to combustion of organic mass in forest fires and grasslands as a source of

ammonium sulfate. Fires are actually an insignificant contribution to ammonium sulfate compared to fossil fuel combustion (see Table 5-1 SO_2 emissions by source sector), and we recommend that you delete the references to fires as a source of ammonium sulfate.

Wildland fires are major contributors to organic carbon and elemental carbon, and we recommend that you expand the analysis of the contribution of wildfire to visibility impairment at the SD Class I areas. Tables 4.1 and 4.2 indicate that for both Badlands and Wind Cave National Parks (NPs), on the 20% worst days, organic carbon mass (OCM) is greater than ammonium sulfate mass. In addition to the averages of the 20% least and 20% most impaired days and quarterly averages, if you look at the aerosol contributions on individual days during the 2000-2004 baseline period, you could identify frequency of elevated organic and elemental carbon that could indicate fire impacts. It is likely that OCM from fires dominates aerosol concentrations on some 20% worst days. Back trajectory analyses could assist in defining source areas for exceptional fire events such as referenced for July 2, 2008, and October 25, 2005, and could assist separating impacts from local agricultural or prescribed fires that might be controllable from major wildland fires. Considering aerosol composition on individual days will also assist in assessing the relative contributions from other sources (fossil fuel combustion, biogenic, etc).

On page 25, SD concludes, based on the similarity in aerosol composition between Badlands and Wind Cave NPs, that it is reasonable to assume that the contribution to visibility impairment on the 20% best days is not being impacted by local sources. It is likely that the neighboring parks are influenced by similar sources, but the data do not support the conclusion that local sources are not contributing. Please rephrase this statement.

On page 33, second paragraph should indicate that visibility <u>impairment</u> appears to be declining (rather than visibility declining).

The visibility trends data presented in Figures 4-7 and 4-8 are helpful. Looking at similar time series plots for the individual aerosol components would illustrate whether sulfate and nitrate, those components dominated by anthropogenic, controllable, sources, are declining more than OCM, an indicator of fire. Figure 4-8-a uses a narrow scale for the y axis (14 to 17 dv), different from the other plots in the series (0-25 dv). This compressed scale gives the impression of a much larger change in dv than if the full scale were presented. By looking at individual aerosol components, SD could better understand the contributions to this trend in total aerosol extinction.

Section 5.0 Source Apportionment

Section 5.1 discusses SD's emissions inventory, which relies on well documented WRAP analyses. In Tables 5-1 and 5-2, 2002 SO_2 emissions from SD area sources drop from 10,159 tons/yr to 1,071 tons/yr. WRAP documentation of differences between the WRAP 2002 Base 2002b and 2002d inventories includes revisions to SD area source categories. Please clarify the basis for the revised area source estimate. Were some SD area source categories reclassified as point sources?

It would be helpful to understand the contribution from Big Stone Unit 1 to 2002 total point source SO_2 and NO_x emissions. In Table 5-2, 2002d South Dakota Emissions Inventory, please list the SO_2 and NO_x emissions from Big Stone 1 separately from the other point sources. This will make it easier to compare data in Table 5-2 to Table 5-4, 2018 SD Emissions, Table 6.1, Emissions from BART-eligible sources, and Table 6-3 WRAP Modeling Results for Big Stone Unit 1.

The 2018 point source emissions in Table 5-4 include emissions from planned new facilities; two of these (Big Stone II and Basin Electric's NextGen) are now on hold. These two facilities represent 45% of total SO_2 point source emissions and 15% of total NO_x point source emissions in 2018. These facilities may become operational by 2018 so it is appropriate that WRAP modeling results accounted for new generation by 2018. Separate from this regional haze SIP, we received notice of a Draft Environmental Impact Statement for a proposed new 300 megawatt natural gas-fired, combined-cycle electric generating facility in eastern South Dakota. The emissions from this proposed new facility were not included in this SIP emissions discussion nor in the WRAP 2018 emissions projections.

In addition to the four electric generating units listed in Table 5-4, all other point sources together are projected to emit 2458 tons SO_2/year in 2018. Area sources are projected to contribute another 1662 tons/yr. In Section 7 under the reasonable progress analysis, these emissions should be assessed to determine if there are reasonable control measures.

Tables 5-6 and 5-7 are helpful in illustrating SD's emissions relative to neighboring states.

Section 5.2 discusses Source Apportionment Analyses. WRAP PSAT analyses (Figure 5-1) project that point sources dominate contributions to sulfate at the SD Class I areas. Neighboring states of WY and ND have a greater contribution to sulfate at the SD Class I areas on the 20% worst days than SD point sources. SD area sources are as important as SD point sources, suggesting that emissions controls for area sources could have measureable benefits at the Class I areas. WRAP Weighted Emissions Potential (WEP) analyses indicate that SD is the largest contributor to organic carbon, elemental carbon, and coarse mass at the SD Class I areas. Natural fires in SD dominate the organic carbon contributions. WRAP PSAT analyses indicate that SD's contribution to nitrate is intermediate between that for sulfate and organic carbon. These analyses support SD's focus on reducing anthropogenic SO_2 and NO_x emissions and also encourage managing fire, agriculture, and construction activities to minimize emissions.

Section 6: Best Available Retrofit Technology (BART)

The SD BART analysis is one of the best that we have reviewed to date; the discussion is thorough and informative. The National Park Service (NPS) is very pleased and commends SD for concluding that for Otter Tail Big Stone 1 power plant, the best available retrofit technologies are semi-dry flue gas desulfurization for SO_2 and selective catalytic reduction (SCR) for NO_x. There are still a few areas where we offer additional suggestions:

6.3.2.3 Sulfur Dioxide Control Effectiveness

SD evaluated the control effectiveness by comparing the effectiveness in Table 6.6.

NPS: SD should state the control effectiveness and resulting emission rate that it believes to be appropriate for each control technology option. For example, it appears that SD has concluded that a semi-dry scrubber can achieve 90% SO_2 control. We agree with SD's analysis, but suggest that the baseline for annual SO_2 emissions should reflect anticipated uncontrolled annual emissions which, according to EPA's Clean Air Market Database, have averaged 0.66 lb/mmBtu (range 0.63 - 0.70) over the 2000 – 2008 period.

6.3.2.4 Sulfur Dioxide Control Technology Impacts

SD: 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.

Otter Tail: Cost estimates for the wet and semi-dry (including SDA and fabric filter) SO_2 control technologies were completed utilizing the Coal Utility Environmental Cost (CUECost) computer model (Version 1.0). The model was run with 2008 designated as the cost basis year because equipment cost estimating in the model is based on the Chemical Engineering Cost Index and the composite 2008 index is the latest version available. Following completion of the estimating on a 2008 cost basis year, all costs were escalated to a 2009 basis year utilizing the inflation rates designated in Table 1.2-3.

NPS: Otter Tail should have used the EPA Control Cost Manual as advised by the BART Guidelines and by EPA Region 8. Otter Tail should at least have provided its CUECost output data.

6.3.3.3 Nitrogen Oxide Control Effectiveness

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

NPS: SD should state the control effectiveness and resulting emission rate that it believes to be appropriate for each control technology option. For example, it appears that SD has concluded that SOFA+SCR can achieve 88% NO_x control. However, if SOFA can reduce NO_x emissions to 0.50 lb/mmBtu, then it is reasonable to expect that addition of SCR would reduce NO_x emissions by another 90% or down to 0.05 lb/mmBtu on an annual average. For example, the Illinois EPA has proposed that the two cyclone boilers firing PRB coal at Dominion Energy's Kincaid Generating Station should achieve 0.07 lb/mmBtu on an annual basis with over-fire air (OFA) and SCR. (Please see 02/16/2010 email from Don Shepherd to Kyrik Rombough for Excel spreadsheet of NO_x performance at Kincaid.) To meet that limit, the Kincaid SCRs would reduce inlet NO_x emission by slightly over 89%. It should be feasible for Big Stone #1 to achieve a lower limit because of the superior initial NO_x reductions that can be achieved with SOFA versus the OFA at Kincaid. We suggest that, to allow for some operational flexibility, a 30-day rolling average limit of 0.06 lb/mmBtu would be appropriate for Big Stone #1 if equipped with current-technology SOFA+SCR.

6.3.3.4 Nitrogen Oxide Control Technology Impacts

SD: Otter Tail Power Company identified cost estimates for five control options. Table 6-10 summarizes Otter Tail Power Company's estimated costs.
NPS: Otter Tail has applied a generalized "unit cost factor" of $172/kW to estimate a Total Capital Investment (TCI) of $81.8 million for SOFA+SCR. Applying the recommended EPA Control Cost Manual results in a TCI of $44.3 million. Otter Tail has estimated O&M costs at $4.1 million versus our $2.4 million estimate from application of the Cost Manual methods. Otter Tail has estimated a Total Annual Cost of $13.2 million to achieve 0.10 lb/mmBtu with a cost-effectiveness of $825/ton. Our Cost manual approach estimates a Total Annual Cost of $6.8 million to achieve 0.05 lb/mmBtu on an annual basis with a cost-effectiveness of $493/ton.

6.3.5.2 Sulfur Dioxide BART Recommendation
SD: As noted in Table 6-16, "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, SD considers that the semi-dry flue gas desulfurization system is considered BART....SD considers the emission limit representing BART should be 505 pounds per hour, which would include periods of startup and shutdown and 0.09 pounds per million Btus, which would not include startup and shutdown. Compliance with these emission limits should be based on the continuous emission monitoring system and on a 30-day rolling average."
NPS: Based upon the data presented by Otter Tail and summarized by SD, we agree that the difference between wet and dry scrubbing is not sufficient to justify the additional costs and impacts of wet scrubbing.

6.3.5.3 Nitrogen Oxide BART Recommendation
SD proposes a BART emission limit for NO_x of 561 pounds per hour, "which would include periods of startup and shutdown and 0.10 pounds per million Btus, which would not include startup and shutdown periods. Compliance with the emission limits would be based on the continuous emission monitoring system and on a 30-day rolling average."
NPS: We believe that the Kincaid cyclone boilers in Illinois (described above) have demonstrated the ability of SCR to reduce NO_x emissions below the limit proposed by SD. We suggest that, to allow for some operational flexibility, a 30-day rolling average limit of 0.06 lb/mmBtu would be appropriate for Big Stone #1 if equipped with current-technology SOFA+SCR.

Please clarify emissions assumptions used for the WRAP regional modeling compared to those used in the Big Stone Unit 1 BART modeling. Emissions used in Tables 5-2, 5-4, 6-1, and 6-3 do not appear to be consistent, likely because they are based on different assumptions. Does Table 6-1 refer to potential emissions, not annual emissions? If so, please clarify. Table 6.1 lists Big Stone Unit 1 SO_2 emissions as 19,363 tons and NO_x emissions as 17,179 tons. Table 5-2

indicates 14,022 tons of SO_2 and 20,697 tons of NO_x from all point sources in 2002. Does Table 6-3 refer to potential emissions? In Table 6-3 WRAP BART modeling results are based on an assumption that Big Stone Unit 1 emits 12,409 tons SO_2 and 15,580 tons of NO_x, or 88% and 75% of all SD point source SO_2 and NO_x emissions in 2002. Is this correct? Did SD include assumptions for BART controls for Big Stone Unit 1 in the WRAP 2018PRP18b regional modeling? In Table 5-4 Big Stone Unit 1is projected to emit 3,425 tons SO_2 in 2018, 18% of the value in Table 6-1 or 28% of the value in Table 6-3. How does this relate to the 90% control efficiency listed for dry scrubbing in Table 6-6? In Table 5-4 Big Stone Unit 1 NO_x emissions in 2018 (15,580 tons) appear to be the same as used as the baseline for the BART analysis reported in Table 6-3. Does this mean that WRAP regional modeling assumed SO_2 controls but not NO_x controls for Big Stone Unit 1? Please clarify.

We appreciate that SD included in Table 6-15 the costs per deciview visibility improvement for each control option and each Class I area. To demonstrate the cumulative benefits of improving visibility at all impacted Class I areas, we recommend that SD provide an additional table that illustrates the cumulative $/dv for these control options.

Section 7: Reasonable Progress

This section includes most but not all the basic components of a reasonable progress analysis. SD should state explicitly that the reasonable progress goals for SD Class I areas are the same as the WRAP CMAQ modeling results for 2018 and that SD did not include any other emissions reductions beyond those modeled by the WRAP in setting the reasonable progress goals. Because modeled progress in improving visibility by 2018 is less than the uniform rate of progress necessary to achieve natural visibility conditions by 2064, SD needs to define when natural conditions are expected to be achieved given the reasonable progress goals by 2018.

SD's discussion is missing the required four factor analysis of potential emissions controls. SD has correctly identified SO_2 as a major contributor to visibility impairment. SO_2 emissions from SD point and area sources should be evaluated to determine if there are cost-effective control options. The regional haze rule requires SD to evaluate four factors in considering potential emissions controls to improve visibility:

1) Cost of compliance
2) Time necessary for compliance
3) Energy and non-air quality environmental impacts of compliance
4) Remaining useful life of the source considering controls

In 2009, WRAP contractors (EC/R, Inc.) delivered a general four factor analysis for SO_2 and NO_x control options for major industrial and utility source sectors[1]. SD should characterize the major sources or source categories in the SD SO_2 inventory and apply the four factor information provided by WRAP for relevant sources or source categories to discuss what controls might be feasible (e.g., coal-fired industrial boilers). Reviewing SD Title V permits would assist defining

[1] http://www.wrapair.org/forums/iwg/docs.html.

whether a few large sources dominate the SO_2 inventory and whether controls are cost effective for these sources. For example, switching to a fuel oil with lower sulfur content might reduce SO_2 emissions from point or areas sources at relatively low cost. SD should also discuss options to reduce anthropogenic emissions of organic carbon (including reference to later discussion of smoke management practices).

Section 8: Long-term strategy

SD has addressed the major elements of a long-term strategy. We would like to see more complete discussion of local options to address emissions of organic carbon mass, elemental carbon, and course mass. Because WRAP source apportionment analyses indicate that organic carbon from natural fires is a major contributor to impairment on the 20% most impaired days, SD needs to provide a more complete discussion of options to control smoke from unplanned wildland fires and the relative importance of prescribed burns and agricultural burning in the state. SD stated on page 110 that agricultural burning occurs in the eastern part of the state but that does not preclude transport of smoke to the west on some days. SD is encouraged to develop a smoke management plans for prescribed burns options. We appreciate that emissions from prescribed burns in the national parks are contributing to visibility impairment. We are available to assist the parks and SD in developing effective smoke management plans.

SD references an existing regulation that limits fugitive emissions from state facilities in Rapid City. As part of the long-term strategy SD should consider expanding regulations that require public and private construction and road projects to limit fugitive dust emissions.

SD could commit in this SIP to pursuing these activities as part of the long-term strategy.

Section 9: Monitoring Strategy

We commend SD for maintaining SO_2, NO_x, Ozone, $PM_{2.5}$, PM_{10}, and meteorological measurements next to the IMPROVE sites at Badlands and Wind Cave NPs. These data will assist SD in evaluating source contributions to air quality and visibility in these Class I areas.

Section 10: Consultation Requirements

The Federal Land Managers appreciate this opportunity to consult with SD. WRAP has facilitated coordination and consultation among the WRAP states. We encourage SD to discuss directly with the neighboring states the planned controls and the contributions from neighboring states to SD Class I areas.

We look forward to continuing to work with SD to protect visibility in our Class I areas.

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OTTER TAIL
POWER COMPANY

February 25, 2010

Mr. Rick Boddicker
Senior Environmental Scientist
South Dakota Department of Environment
and Natural Resources
Joe Foss Building
523 East Capitol
Pierre, SD 57501-3181

Dear Mr. Boddicker:

Subject: Comments Draft Proposed Regional Haze SIP

The following comments are offered by Otter Tail Power Company as operating agent for Big Stone Plant. Big Stone Plant is co-owned by NorthWestern Corporation d/b/a NorthWestern Energy, Montana-Dakota Utilities Co. A Division of MDU Resources Group, Inc., and Otter Tail Power Company a wholly owned subsidiary of Otter Tail Corporation.

Otter Tail Power Company generally concurs with the DENR draft proposed Regional Haze State Implementation Plan as distributed on January 15, 2010. Otter Tail supports the DENR's selection of the existing baghouse for particulate matter control and the semi-dry spray dryer for SO2 control as BART.

While we are disappointed with the proposed designation of an SCR as BART for NOx control, we do not have any criticism of the accuracy of the DENR's evaluation methodology. Nevertheless, Big Stone Plant co-owner's customers will incur approximately $13.2 million of levelized annual costs for the SCR capital cost and ongoing SCR operation and maintenance costs as compared to SOFA levelized annual costs of $0.65 million. Furthermore, the SCR installation under Control Option 8 will result in a projected visibility improvement at Boundary Waters of only 0.354 deciview as compared to SOFA installation under Control Option 5.

We support the DENR's selection of the proposed emission rates for inclusion in the construction permit and ultimately in the Title V Operating Permit. The emission rates reflect an appropriate balance between the need for plant operational flexibility during short-term periods of plant startup and shutdown, and the emission rates during extended periods of normal plant operation.

We note that the proposed ARSD 74:36:21:06 requires "The owner or operator of a BART-eligible source required to install BART must install, operate and demonstrate compliance with BART as expeditiously as practicable but no later than five years from EPA's approval of the state implementation plan for regional haze." If the proposal is adopted, Otter Tail will work with DENR to meet their installation timing requirement.

However, Otter Tail must balance the future cost impacts on its customers in meeting this requirement. We must be allowed adequate time for thoughtful project design and selection of control technology vendors. This will also be a major construction project that is expected to take approximately three years of actual on-site construction to complete at a cost that is expected to be more than double the cost of the original plant. The construction must be tailored to minimize plant outages. Finally, technology preoperational check-out and system tuning will also need to be completed prior to a demonstration of compliance with the requirements.

Otter Tail offers the following specific comments on DENR's proposed SIP.

Page 43 – Last sentence of first paragraph. Please clarify that even though Big Stone II emissions may be included in the 2018 emissions projections, Big Stone II is no longer proceeding.

Page 79 – Section 6.3.1.1 - Please correct the following sentence as noted. As such, the filterable particulate may be collected by placing a control device in the flue gas stream prior to the stack.

Page 87 – Please clarify that the NOx emission rates for the Basin NextGen project listed in Table 6-9 represent BACT for a new pulverized-fired boiler equipped with a low-NOx burner combustion technology which produces lower levels of NOx entering the SCR than are achievable with an existing cyclone-fired boiler. As noted on page 85, low-NOx burners are not a technically feasible option for a cyclone-fired boiler.

Page 89, 91, and 92 – Please clarify that the number of significant digits that Otter Tail reported for its deciview impacts that are included in Tables 6-12 and 6-14 are consistent with WRAP modeling results presented in Table 6-3 and are also consistent with accepted industry practice.

Page 95 – Section 6.3.5.1 - Please revise the last sentence of the second paragraph to read as follows: Each day, Otter Tail Power Company will multiply the emission rate, in pounds per million Btus as determined by ~~a~~ the 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 ~~they~~ the boiler operated that day.

Sincerely,

Terry Graumann
Manager, Environmental Services

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
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DENVER, CO 80202-1129
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MAR 12 2010

Brian Gustafson, Administrator
Air Quality Program
South Dakota Department of Environment and Natural Resources
523 East Capitol Avenue
Pierre, SD 57501-3182

RE: EPA Region 8 Comments on January 15, 2010 Draft Regional Haze SIP (FLM Consultation Version)

Dear Brian:

EPA has completed a preliminary review of South Dakota's January 15, 2010 draft Regional Haze State Implementation Plan (SIP), as received via email through your Federal Land Manager (FLM) consultation process. Our comments and questions are detailed in the Enclosure to this letter.

We understand that you intend to consider all comments received on this FLM consultation version of the Regional Haze SIP prior to preparing the documents for your public notice and comment process. The final draft of the SIP, which will include a summary of the FLMs' comments and your responses, will then undergo a broader public hearing process prior to adoption and submission to EPA. We emphasize that we will only reach a final conclusion regarding the adequacy of South Dakota's Regional Haze SIP when we act on the South Dakota Regional Haze SIP revision through our own public notice and comment rulemaking.

We want to acknowledge your efforts in developing this SIP and working with us to resolve concerns related to subject-to-BART modeling for Big Stone I. This effort has helped to narrow the issues significantly; however, important issues remain. Our comments are intended to assist you in revising the draft SIP before you begin your public hearing process. Please note that our most serious concerns are summarized at the beginning of the Enclosure.

As you are aware, South Dakota received a finding of failure to submit its Regional Haze SIP by the required deadline. As a result, a 2-year clock was initiated for EPA to fully approve a SIP or promulgate a Federal Implementation Plan by January 15, 2011. In order to meet this deadline, we continue to advise you to submit the South Dakota Regional Haze SIP in a timely manner. Please do not hesitate to contact me with any concerns related to this timeline.

We have appreciated working with you during the review of this FLM consultation version of the draft Regional Haze SIP and look forward to continued communications during the public hearing process. If you have any questions on EPA's comments, please contact me at 303-312-6434, or your staff may contact Gail Fallon at 303-312-6281 or Amy Platt at 303-312-6449.

Sincerely,

Callie A. Videtich, Director
Air Program

Enclosure

cc: Chris Shaver, NPS
Sandra Silva, USFWS
Thomas Dzomba, USFS

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ENCLOSURE

EPA Region 8 Preliminary Comments on the January 15, 2010 Draft Regional Haze SIP (FLM Consultation Version)

Summary of Major Concerns – (see detailed comments for more information):

- No justification for separate startup/shutdown limits for PM, SO_2, and NO_x. See comments #18-20 below.
- No details on how the BART emission limits will be made enforceable as a practical matter. See comments #1 and #21 below.
- No identification of the number of years to reach natural conditions as required when the Reasonable Progress Goal is less than the Uniform Rate of Progress. See comment #23 below.
- No 4-factor Reasonable Progress analysis. See comment #24 below.
- No smoke management plan even though fire is identified as a major contributor. See comment #31 below.

Detailed Comments:

1. Executive Summary, pp. viii-ix:
   (A) The BART emission limits, compliance schedules, monitoring, recordkeeping, and compliance determining methods for Big Stone I must be specified in the text of the Regional Haze SIP or in a permit that is incorporated into the SIP. You note that you intend to establish the appropriate averaging times, compliance verification procedures, and recordkeeping and reporting requirements in an air quality construction permit. Since this document is not included in this draft SIP, we would like to work with you to ensure that these requirements are adequately addressed in the SIP. Note that the public notice for the Regional Haze SIP needs to include notification that an air quality permit to address BART requirements is incorporated as part of the SIP. Additionally, with MDU Resources Group's November 2, 2009 announcement that Big Stone II will not be built, does SD DENR plan to amend and/or revoke the existing permit provisions in order to reflect the Company's announcement and the forthcoming BART determination, and what is the timeline for doing so?

   (B) The last sentence references a Chapter 12 that was not included in this draft FLM consultation version of the SIP; therefore, we were unable to review and comment on it.

2. Chapter 1, Introduction, p. 1:
   (A) Please clarify that the 1977 Clean Air Act Amendments and EPA's 1980 reasonable attributable visibility impairment regulations addressed visibility impairment that was caused *or contributed to* by one or a small group of sources.

   (B) Please revise the date for delegation of the Prevention of Significant Deterioration (PSD)

program to July 6, 1994. The September 15, 1994 date is simply when EPA provided notice that the delegation had been granted as of July 6, 1994.

3. Sections 3.1, Baseline Visibility Conditions, and 3.2, Natural Visibility Conditions, pp. 11-16:
   (A) It appears that Appendix A will contain the IMPROVE data used to determine baseline visibility; however, Appendix A was not included with this draft FLM consultation version of the SIP.

   (B) Based on our review of WRAP's Visibility Information Exchange Web System (VIEWS) and information from the USFS, it appears that there are some errors in the baseline and natural background figures provided in Tables 3-1, 3-5, and 3-7. We understand that the USFS has raised these concerns with you and requested the opportunity to discuss; therefore, we will look for these figures to be revised accordingly. Please note that EPA's default values for natural conditions must be used in the current SIP and any refinements deferred to future planning periods.

   (C) Table 3-6 addresses the western natural conditions, but the footnotes refer to Trijonis estimates for both East and West. The Trijonis estimates for the East do not need to be included.

   (D) A column must be added to Table 3-7 to highlight the deciview improvement required for both best and worst days.

4. Figure 3-11, Uniform Rate of Progress, p. 17: This figure has been omitted. Perhaps with its inclusion, our following comment would be addressed.

5. Table 3-8, Annual Uniform Rate of Improvement, p. 18: This table needs to include the uniform rate of improvement for the 1st planning period (2004-2018) for the most and the least impaired days, rather than leaving it to the reader to calculate from the annual numbers provided.

6. Figure 3-12, Uniform Rate of Improvement, pp. 18-19: For both Class I areas, we could not determine the source of the 2018 numbers. For Badlands, it appears that the 2018 uniform rate of progress should be 14.89 dV (based on the 14 year 1st planning period) instead of 15.04 dV, and for Wind Cave, 13.94 dV instead of 14.01 dV. In addition, once the baseline and natural background values are revised per our comment #3 above, these values will need to be recalculated.

7. Section 5.0, Source Apportionment, pp. 37-58:
   (A) Section 5.1, Air Emission Inventory, pp. 37-38: In general, the WRAP inventories utilized are adequate for this planning period. However, there are some known shortcomings with the WRAP inventories, including the oil and gas emissions estimates. Please note that we would expect future reviews of the South Dakota Regional Haze SIP to rely on the most current, updated emissions inventory.

(B) Pages 39 & 43: Please elaborate on the "compliance initiative" related to VOC emissions from secondary oil and gas production in northwestern South Dakota. The draft document indicates that the initiative identified emissions that needed to be addressed, and it appears emission control devices were installed. What state mechanisms are in place to ensure these four thermal oxidizers are operating at greater than 98% control?

(C) Tables 5-1, 5-2, and 5-4, pp. 40-44: In Tables 5-1 and 5-2, the baseline VOC emissions from oil and gas are identified as 33,721 tons, while the 2018 projected VOC emissions from oil and gas are shown as 562 tons in Table 5-4. According to the WRAP Technical Support System (TSS), the corresponding baseline and projected VOC emissions from oil and gas are 288 tons and 562 tons, respectively. This large discrepancy between South Dakota's reported numbers and the WRAP TSS must be explained in greater detail in the SIP. In addition, please explain whether these emissions from secondary oil and gas production were used for modeling and reasonable progress purposes. We also note that Table 5-1 provides the baseline SO_2 emissions from area sources as 10,159 tons, while Table 5-2 lists 1,071 tons from the same source. This very substantial difference is consistent with values reported on the WRAP TSS; however, no explanation is provided. The SIP text must provide clarification. Finally, there appears to be a typographical error in the footnotes to Table 5-4 – two footnotes labeled "3."

(D) Tables 5-6 and 5-7, p. 46: We note some discrepancies compared with what was included in other state plans. In order to ensure consistency with other states' assumptions it would be prudent to verify their emission inventory numbers. For example, the North Dakota draft plan lists North Dakota NO_x emissions for 2018 at 171,566 tons, but the South Dakota draft plan lists North Dakota NO_x emissions at 187,032 tons for 2018.

(E) Last paragraph, p. 54, and second paragraph, p. 56: There may be typographical errors, but in any case the text is not consistent with the figures which show a slight change between 2002 and 2018 for both the least and most impaired days. Please clarify.

(F) First paragraph, 2nd to last sentence, p. 58: The text regarding Montana's organic carbon mass contribution must be clarified to read that, "Natural fire related organic carbon mass generated in Montana contributes approximately 34% of the organic carbon mass in Badlands National Park."

8. Section 6.1, BART-Eligible Sources, pp. 70-71:
(A) The definition of "Date of Reconstruction" does not quite match the Federal definition and must be revised. The Federal definition is for the date of operation, construction, or reconstruction and applies to sources that were not in operation before August 7, 1962 and in existence as of August 7, 1977 with any reconstruction occurring during the August 7, 1962 to August 7, 1977 time period.

(B) The last sentence of the definition for "Potential to Emit" contains a typographical error- should be *26* categories.

9. Section 6.1.2, Pete Lien, pp. 72-73:
(A) There appears to be a typographical error in the 2nd sentence of the first paragraph – should be worded as "*not* in operation prior to August 7, 1962…"

(B) Because there is a rotary kiln (Unit 4a) producing lime within the Pete Lien facility, Pete Lien is classified as a lime plant according to the definition in 40 CFR Part 60, Supart HH. The fact that the unit in question under BART is a vertical kiln does not exclude Pete Lien from the lime plant category, since it does have a rotary kiln producing lime within the plant. Therefore, it was the appropriate decision to include Pete Lien in the WRAP subject-to-BART modeling analysis. We were unaware that you had determined there were errors in the modeling inputs and a need for a re-run. You note that the vertical kiln was shutdown and dismantled in 2009 prior to completion of a modeling re-run. However, the November 12, 2008 Title V permit for Pete Lien still includes the vertical kiln, and there has not been a permit modification to address any such dismantling and closure. Either the permit needs to be modified to reflect this change in status of the vertical kiln, or the modeling needs to be re-run to correct the input errors and accurately determine whether Pete Lien is subject to BART.

10. Section 6.2, Otter Tail Power Company's Modeling Results, pp. 75-77: We note that the specific version of CALPUFF, coordinate grid points, wind field options, terrain, dispersion options, receptor coordinates, plume characteristics and other model parameters approved by the DENR were used for modeling. The DENR approved protocol (*i.e.*. the August 31, 2009 Revised Modeling Protocol for a BART Assessment of the Big Stone I Coal-Fired Power Plant) is acceptable to EPA; however, the modeling input and output files need to be incorporated into the SIP for documentation and public review.

11. Section 6.3.2.4, Sulfur Dioxide Control Technology Impacts, p. 83: Footnote number 3 indicates a baseline level of 18,000 tons of SO_2/year; however, according to Table 6-1 on p. 71, the baseline was 19,863 tons/year. This larger baseline figure results in an 81% emission reduction for the 3rd option, as opposed to 90% with the 18,000 tons/year figure. Please explain how the 18,000 tons/year SO_2 baseline figure was obtained.

12. Section 6.3.3.2, Technically Feasible Nitrogen Oxide Control Technologies, pp. 85-86: At this time, we have not completed a thorough review of your comments regarding commercial availability and technical feasibility of the various NO_x control technologies listed. Therefore, we may have additional comments on this section during the public comment period.

13. Table 6-9, p. 87: Footnote 5 references a 1999 EPA Technical Bulletin on NO_x controls as justification for the 35%-90% control efficiency range for the top three options. The large range in EPA's bulletin is due to inclusion of SCR, selective non-catalytic reduction (SNCR), and fuel reburning for wet-bottom boilers. It is well documented that SCR achieves the high end of the range. The EPA bulletin also lists a 30%-70% control efficiency for a group of temperature-reducing controls, including over-fire air. Therefore, the proposed BART

determination of SCR plus separated over-fire air (SOFA) should be better than the 90% control efficiency of SCR alone. It is not clear from the SIP text how the proposed emission limit was calculated; however, according to EPA's Acid Rain Database, Big Stone I NO_x emissions have averaged 0.77 lb/MMBtu over the last five years. Assuming a control efficiency greater than 90% should result in a limit lower than the proposed 0.1 lb/MMBtu.

14. Section 6.3.3.4, Nitrogen Oxide Control Technology Impacts, p. 87: We assume you are relying on Otter Tail's analysis of estimated costs, which relied on the CUECost model. While we are satisfied with the control technology conclusions of your NO_x BART determination (*i.e.*, SCR plus SOFA), in general we do not recommend relying on the CUECost model. According to the BART Guidelines, in order to maintain and improve consistency, cost estimates must be based on the OAQPS Control Cost Manual.

15. Table 6-10, p. 88: Footnote 3 contains typographical errors – should be nitrogen oxides. In addition, similar to comment #11 above, it is unclear how the baseline level of 18,000 tons/year was obtained. According to Table 6-1, p. 71, baseline NO_x emissions were 17,179 tons/year. The larger baseline figure results in an 89% emission reduction for the 1st option, as opposed to 93% with the 17,179 tons/year figure. As stated above in comment #13, a control efficiency greater than 90% is appropriate for the proposed SCR plus SOFA controls. Please explain how the 18,000 tons/year NO_x baseline figure was obtained.

16. Section 6.3.4, Visibility Impact Evaluations, 2nd paragraph, p. 89: Again, the text refers to Big Stone I baseline emissions of 18,000 tons SO_2 and 18,000 tons NO_x. Please explain how these numbers were obtained.

17. Table 6-12, p. 89: According to Footnote 2 of Table 6-12, the rounded modeling values shown in the parentheses were used to compare with the subject-to-BART threshold, but actually, the unrounded modeled value must be used for determining whether a source exceeds the threshold.

18. Section 6.3.5.1, Particulate Matter BART Recommendation, p. 95:
(A) We assume DENR's proposed particulate matter BART limit of 0.012 lb/MMBtu is on a 30-day rolling average basis, as required. Please clarify in the SIP.

(B) While we agree that a baghouse is the top particulate control technology, what is the justification for proposing a separate hourly startup/shutdown limit? The SIP must document the need for such a separate limit, as well as whether the selected value represents BART. Has DENR evaluated potential impacts of the separate startup/shutdown limit on visibility? The BART Guidelines contemplate pounds per million Btu limits that apply continuously, with a 30-day rolling average period to accommodate, among other things, potential short-term fluctuations in the emissions rate that may result during startup, shutdown, and other conditions. Presumably, your proposed 30-day rolling average limit already includes some margin of safety for operational variation. If you are able to justify the separate limits, we would work closely with you as you draft appropriate permit language to help ensure SIP approvability related to determining compliance with the normal 30-day rolling average limit

and the hourly startup/shutdown limit. For example, in calculating 30-day averages, how will days be accounted for that include some, but not all, hours of startup/shutdown?

19. Section 6.3.5.2, Sulfur Dioxide BART Recommendation, pp. 96-97:
(A) We assume DENR's proposed SO_2 BART limit of 0.09 lb/MMBtu is on a 30-day rolling average basis, as required. Please clarify in the SIP.

(B) As noted in comment #18 above, justification for proposing a separate lb/hour limit for periods of startup and shutdown must be provided. The SIP must document the need for such a separate limit, as well as whether the selected value represents BART. Has DENR evaluated potential impacts of the separate startup/shutdown limit on visibility? The BART Guidelines contemplate pounds per million Btu limits that apply continuously, with a 30-day rolling average period to accommodate, among other things, potential short-term fluctuations in the emissions rate that may result during startup, shutdown, and other conditions. Presumably, your proposed 30-day rolling average limit already includes some margin of safety for operational variation. If you are able to justify the separate limits, we would work closely with you as you draft appropriate permit language to help ensure SIP approvability related to determining compliance with the normal 30-day rolling average limit and the hourly startup/shutdown limit. For example, in calculating 30-day averages, how will days be accounted for that include some, but not all, hours of startup/shutdown?

20. Section 6.3.5.3, Nitrogen Oxide BART Recommendation, pp. 97-98:
(A) Regarding the term "threshold" in reference to $1500/ton for NO_x removal, EPA's position is that the NO_x presumptive limits were established based on the relatively low cost of less than $1500/ton for the majority of large EGUs. There is no bright line regarding cost effectiveness and each determination must be made taking into account a full five factor BART analysis. In addition, although Big Stone I has a capacity less than 750 MW, it is greater than 200 MW and operating without post-combustion controls. Per the BART Guidelines, it is reasonable to assume that SCR is generally cost-effective on large cyclone units. See 70 FR 39171, July 6, 2005.

(B) Please clarify that DENR's NO_x BART determination is SCR plus SOFA at 0.10 lb/MMBtu on a 30-day rolling average.

(C) As noted in comments #18-19 above, justification for proposing a separate lb/hour limit for periods of startup and shutdown must be provided. The SIP must document the need for such a separate limit, as well as whether the selected value represents BART. Has DENR evaluated potential impacts of the separate startup/shutdown limit on visibility? The BART Guidelines contemplate pounds per million Btu limits that apply continuously, with a 30-day rolling average period to accommodate, among other things, potential short-term fluctuations in the emissions rate that may result during startup, shutdown, and other conditions. Presumably, your proposed 30-day rolling average limit already includes some margin of safety for operational variation. If you are able to justify the separate limits, we would work closely with you as you draft appropriate permit language to help ensure SIP approvability related to determining compliance with the normal 30-day rolling average limit and the

hourly startup/shutdown limit. For example, in calculating 30-day averages, how will days be accounted for that include some, but not all, hours of startup/shutdown?

21. Section 6.4, BART Requirements, p. 99: According to your proposed revisions to the South Dakota Administrative Rules, Chapter 74:36:21:10, a permit modification will be required for your BART determination on Otter Tail's Big Stone I. Without seeing the details of such permit, it is difficult to determine whether this section of the SIP adequately addresses requirements for enforceability, including appropriate averaging times, compliance verification procedures, and recordkeeping and reporting requirements, and proper operation and maintenance procedures. As noted in comment #1 above, these requirements must be specified either in the text of the Regional Haze SIP or in a permit that is incorporated into the SIP.

22. Section 7.1, State and Federal Rules, pp. 100-101: Please clarify that although some of the cited Administrative Rules of South Dakota (ARD) control emissions of pollutants that ultimately contribute to visibility impairment, they were not written specifically to address visibility impairment.

23. Table 7-1 and Section 7.2.1, Breakdown of CMAQ Modeling Results, pp. 102-103: We were unable to determine if 16.50 dv for Badlands and 15.28 dv for Wind Cave are your Reasonable Progress Goals (RPG). These numbers don't quite match with those shown in Figure 8-1. Please clarify and document how the numbers were obtained. Also, the SIP must include the dv difference between the baseline and natural conditions for the best and worst days for the 1st planning period per 40 CFR 51.308(d)(2)(iv)(A). Finally, the SIP must provide the number of years necessary to reach natural conditions, as required by 40 CFR 51.308(d)(1)(ii) when the RPG is less than the uniform rate of progress (URP).

24. Section 7.2.2, Four Factor Analysis, p. 104: DENR's determination that a four-factor analysis is not warranted at this time is not acceptable. A four-factor analysis must be completed in establishing the RPGs for Class I areas impacted by South Dakota emissions, as well as in justifying a RPG that is less than URP. While we realize that the emissions reductions proposed under BART for Big Stone I will provide significant emissions reductions in South Dakota, remaining sources must be considered under Reasonable Progress. For example, are there any further reductions that could be obtained from GCC Dacotah, Ben French, or Pete Lien? What about potential impacts from the close proximity of Rapid City to Badlands? A simple Q/d analysis can provide a starting point. It may be reasonable for DENR to conclude, upon completion of an adequate four-factor analysis, that additional controls under Reasonable Progress are not warranted in this planning period. However, such a determination cannot be made without the analysis. Perhaps information from the WRAP's May 19, 2009 draft *Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in South Dakota*, and WRAP's May 4, 2009 draft *Supplementary Information for Four Factor Analyses by WRAP States*, can be utilized to address some of the Reasonable Progress analysis requirements. If so, our August 12, 2009 comments on the draft WRAP reports must be taken into account.

25. Section 8.0, Long Term Strategy, pp. 104-105: According to 40 CFR 51.306(c), the State must revise its plan to provide for a coordinated long-term strategy for addressing both reasonably attributable and regional haze visibility impairment, and future coordinated long-term strategies must be submitted consistent with the schedule for periodic progress reports set forth in 40 CFR 51.308(g), *i.e.*, every 5 years. South Dakota never adopted a plan to address the requirements of 40 CFR 51.306 for a reasonably attributable visibility impairment long-term strategy; therefore, a Federal Implementation Plan (FIP) was promulgated to incorporate by reference the reasonably attributable visibility impairment long-term strategy requirements described in 40 CFR 52.29. See the federally-approved South Dakota Identification of Plan section at 40 CFR 52.2179(c). At this time, it is not clear from a national perspective how to coordinate a reasonably attributable long-term strategy FIP with a regional haze long-term strategy SIP. The simplest approach would be for you to develop your own reasonably attributable long-term strategy to replace the FIP. Is this approach something you would consider? We would be happy to work with you to develop appropriate language and believe it would not take too much additional work given the effort you have already put into the draft regional haze SIP.

26. Section 8.1, Class I Areas in Other States Impacted by South Dakota, p. 105: This section must quantify South Dakota's impact to the Class I areas outside the State (similar to that noted in Table 6-4).

27. Section 8.3, Technical Basis for Modeling, Monitoring and Emissions Information, p. 106: To assist the reader, please include website addresses and/or references to where these technical analyses are housed and how they will be maintained going forward. In addition, the text must address DENR's commitment to continued compilation and analysis of the technical requirements for the Regional Haze SIP, regardless of future uncertainty in the Western Regional Air Partnership's (WRAP's) role.

28. Section 8.5, Factors in Developing Long Term Strategy, p. 107: There appear to be typographical errors in the last paragraph – should be "emissions reductions."

29. Section 8.5.1, Emission Reductions from Ongoing Air Pollution Control Programs, pp. 107-108: As noted in comment #22 above, please clarify that although some of the cited Administrative Rules of South Dakota were not written specifically to address visibility impairment, they do control emissions of pollutants that may ultimately contribute to visibility impairment.

30. Section 8.5.2, Measures to Mitigate Impacts of Construction Activities, pp. 108-109: South Dakota never adopted a plan to address the original Visibility New Source Review (NSR) requirements of 40 CFR 51.307; therefore, a Federal Implementation Plan (FIP) was promulgated to incorporate by reference the Visibility NSR requirements described in 40 CFR 52.28. See the federally-approved South Dakota Identification of Plan section at 40 CFR 52.2179(b). Is it your intention to replace the nonattainment NSR visibility analysis requirements of 40 CFR 52.2179(b) with your proposed revisions to ARSD 74:36:21? If so, we would provide input for such a revision if requested.

31. Section 8.5.5, Smoke Management, pp. 109-110: Given that your source apportionment analysis identified organic carbon mass as one of the largest contributors on the most impaired days, it is difficult to understand why DENR has deferred consideration of smoke management techniques until 2013. In establishing its long-term strategy, the State must consider smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the State for these purposes
See 40 CFR 51.308(d)(3)(v)(E). At least some preliminary steps, in coordination with the FLMs, must be included, along with citing to any existing South Dakota burning provisions.

32. Section 8.5.6, Enforceable Emission Limits and Control Measures, pp. 110-111: We note your intention to establish the Big Stone I BART limits and control measure requirements in either a construction permit or the Title V permit. Note that any air quality permit used to address BART requirements will need to be incorporated into the SIP. The South Dakota draft construction permit program regulations are currently under review by our office. Until this has been approved into the SIP, it will not be appropriate to rely upon the program for your BART permits.

33. Section 9.0, Monitoring Strategy, p. 113-116: South Dakota never adopted a plan to address the original Visibility Monitoring requirements of 40 CFR 51.305; therefore, a FIP was promulgated to incorporate by reference the Visibility Monitoring requirements described in 40 CFR 52.26. See the federally-approved South Dakota Identification of Plan section at 40 CFR 52.2179(b). Is it your intention to replace the South Dakota Visibility Monitoring FIP requirements of 40 CFR 52.2179(b) with the DENR Monitoring Strategy as outlined in Section 9.0 of the Regional Haze SIP? If so, we would provide input for such a revision if requested.

34. Section 10.2, Consultation with Other States, pp. 118-119: For clarity, it would be helpful if in each instance of consultation, the text identified the dates and outcomes of the discussions. In addition, other than their involvement in WRAP, does DENR have a plan to include tribal consultation on the public comment version of the SIP?

35. Section 10.3, Public Input, p. 119: As noted in comment #23 above, the SIP must provide the public with a calculation of the number of years required to reach natural conditions if the RPG provides a slower rate of improvement than that needed to attain natural conditions by 2064 per 40 CFR 51.308(d)(1)(ii). We understand your concerns regarding assumptions for other states included in the WRAP analysis; however, this SIP must include your best estimate of number of years to reach natural conditions with the proposed RPGs.

36. Section 11.2, Report Every 5 Years, p. 121: As part of continuing consultation required under 40 CFR 51.308(i)(4), please clarify item 7, regarding the monitoring strategy, to note that you will consult with EPA and the FLMs on any revisions deemed necessary.

37. Appendices: We are unable to comment on any of the appendices since they were not included. Information in these appendices may have been necessary for a more thorough

review by EPA. If you are able to share the draft appendices prior to the official public comment period, it would be very helpful.

38. ARSD Chapter 74:36:21, Regional Haze Program:
(A) 74:36:21:02, Definitions: The definition of "BART-eligible source" must cite to an existing stationary facility as defined in 74:36:21:03. The definition of "visibility impairment" does not mirror the federal definition contained in 40 CFR 51.301 and must be revised accordingly. The definition of "contribute to visibility impairment" is not appropriate in the regional haze context and must be removed since there is no threshold for such a contribution. Finally, the definition of "major source" must cite to 40 CFR 51.166, and you must include the definition of "major modification" from 40 CFR 51.166, since the definition of major stationary source under the regional haze regulations includes major modifications.

(B) 74:36:21:04, Visibility Impact Analysis: This section must be revised to clarify that the existing provisions of 74:36:09, Prevention of Significant Deterioration, are not replaced by this new section 74:36:21:04. Given that you do have existing regulations, what is your intent with this new provision?

(C) 74:36:21:07, Operation and Maintenance of Controls: To improve clarity, this section should include more detail, such as specifying the minimum criteria for an acceptable operation and maintenance plan and when the source specific operation and maintenance plan to meet such criteria shall be submitted for permitting authority approval.

(D) 74:36:21:08, Monitoring, Recordkeeping and Reporting: As this provision is drafted, the term "main stack" is a concern because it is not clear whether all of the sulfur dioxide and nitrogen dioxide emissions from the BART-eligible source will be routed to the main stack. The term "main stack" implies the presence of other stack(s) which is/are not equipped with continuous emission monitoring system(s) as is the "main stack." The language in 74:36:21:08 (page 8, second sentence) should be revised to read, "All sulfur dioxide and nitrogen dioxide emissions from the BART eligible source shall be routed to the main stack of the BART-eligible source. Monitoring of sulfur dioxide and nitrogen dioxide emissions from the main stack shall be conducted using a continuous emission monitoring system which complies with continuous emission monitoring system requirements in 74:36:13."

(E) 74:36:21:11, Federal Land Manager Notification and Review: As required by the Regional Haze Rule, the Federal Land Managers must be provided a 60-day consultation period prior to any public hearing on the Regional Haze SIP. Since a BART permit is an integral part of the Regional Haze SIP, this 60-day consultation period must extend to FLM BART permit review as well. In addition, since any BART permit must be incorporated into the Regional Haze SIP, the 30-day public notice for the SIP needs to identify the inclusion of any BART permits.

Appendix E

Public Notice Comments from Public and Others
and
DENR's Response

DRAFT