Prepared for:
Dominion Energy, Inc.

BART Analysis for the Kincaid Power Plant

ENSR Corporation
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Executive Summary

Federal regulations under Title 40 of the Code of Federal Regulations (CFR) Part 51 Appendix Y provide guidance and regulatory authority for the application of Best Available Retrofit Technology (BART) to those existing eligible sources in order to help meet the targets for visibility improvement at designated Class I areas. The IEPA has identified the two coal-fired boilers, Units 1 and 2, at Dominion's Kincaid Power Plant as BART-eligible emission units. This BART analysis will be reviewed and used by the Illinois Environmental Protection Agency (IEPA) for development of the state's Regional Haze State Implementation Plan (SIP).

The BART rules require that sources that are subject to BART perform a site-specific BART analysis including a control technology review and CALPUFF modeling to assess the visibility impact of the emission units. Additionally, for large Electric Generating Units (EGU) affected by the rule, the source should meet presumptive control levels for nitrogen oxide (NO_X) and sulfur dioxide (SO_2) unless it is determined that alternative control levels are justified or equivalent in effectiveness. The presumptive BART limits for these units are continuous year-round operation of the existing SCR systems at 0.10 pound per million British thermal unit (lb/MMBtu) for NO_X and 0.15 lb/MMBtu or 95 percent control for SO_2.

This report documents the case-by-case BART analysis conducted for NO_x, SO_2, and PM_{10} emissions from Kincaid Units 1 and 2. The following BART control scenarios were evaluated:

- Case 1. Firing 0.3%-sulfur PRB sub-bituminous coal, Dry Sorbent Injection (DSI) with Trona capable of achieving an SO_2 emissions level of 0.20 lb/MMBtu and enhanced year-round operation of the SCR at a NO_x emission level of 0.07 lb/MMBtu.
- Case 1a. Firing 0.3%-sulfur PRB sub-bituminous coal, enhanced DSI with Trona capable of achieving an SO_2 emissions level of 0.18 lb/MMBtu (if achievable), enhanced year-round operation of the SCR at a NO_x emission level of 0.07 lb/MMBtu, and replacement of the existing Electrostatic Precipitators (ESP) with Fabric Filters (FF).
- Case 2. Firing 0.5%-sulfur PRB sub-bituminous coal, Dry Scrubber/Fabric Filter (DS/FF) capable of achieving an SO_2 emissions level of 0.15 lb/MMBtu and year-round operation of the SCR at a NO_x emission level of 0.10 lb/MMBtu.
- Case 3. Firing 1.62%-sulfur Illinois Basin bituminous coal, Wet Flue Gas Desulfurization (WFGD) capable of achieving an SO_2 emissions level of 0.15 lb/MMBtu and year-round operation of the SCR at a NO_x emission level of 0.10 lb/MMBtu.

Kincaid Units 1 and 2 currently employ high-efficiency Electrostatic Precipitators (ESP) to control Particulate Matter (PM) emissions. Based upon peak stack test measurements in 1999, the baseline PM emission rates for Units No. 1 and 2 are 0.011 and 0.008 lb/MMBtu, respectively. These emissions are significantly below the permitted PM emission limit of 0.10 lb/MMBtu. The new FF, DS/FF or WFGD systems are capable of achieving a vendor-guaranteed filterable PM emission level of 0.015 lb/MMBtu. The DSI with Trona system has the potential for significant reductions in PM emissions[1]. However, for conservatism, Dominion has assumed that there will not be any appreciable effect on filterable PM emission levels, and they are assumed to remain at the baseline levels. However, we do account for an estimated 50% reduction in H_2SO_4 removal due to Trona injection.

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[1] PM_{10} filterable and condensable emissions were reduced by approximately 47% during the demonstration testing at the Mirant Potomac River Station. The test report can be found at: http://www.mirant.com/our_business/where_we_work/Unredacted_Trona_Test_Report_011706BC.pdf

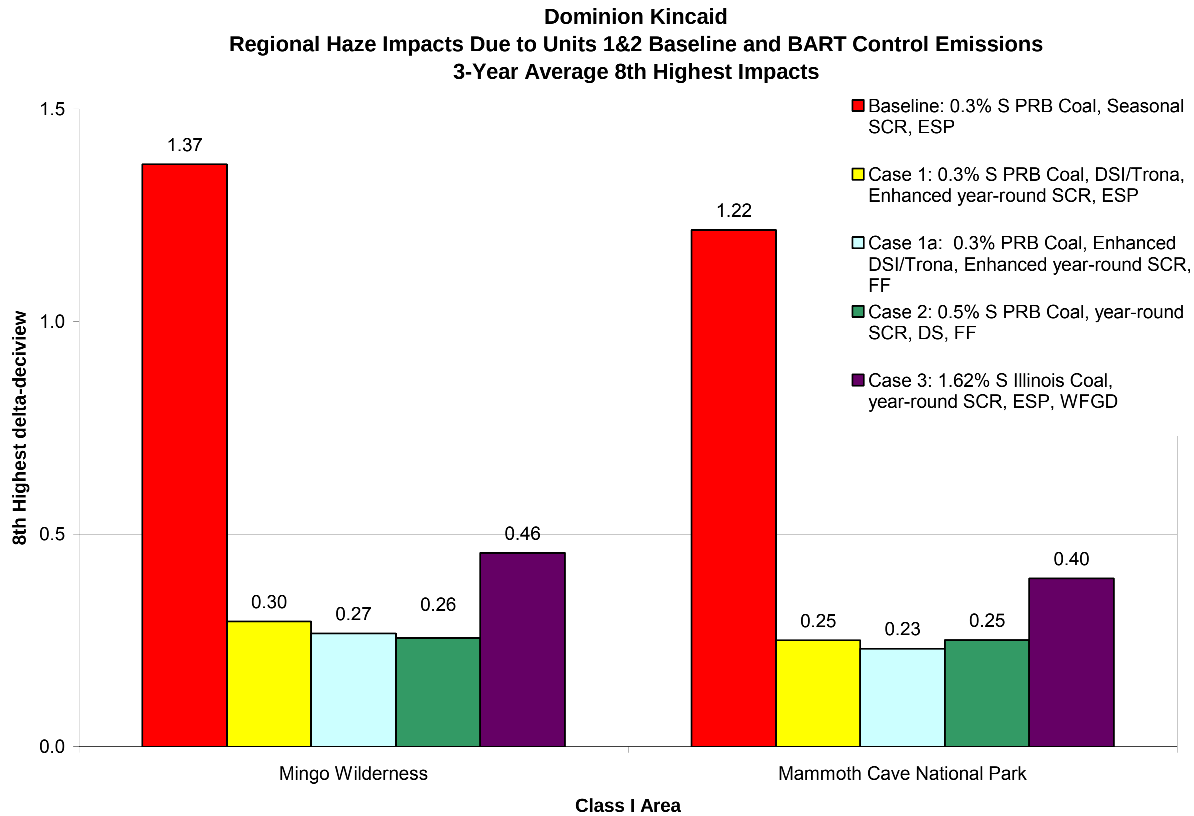
CALPUFF modeling results for meteorological database years 2002-2004 were obtained for the two PSD Class I areas within 300 km of the Kincaid Generating Station: Mingo Wilderness Area in Missouri and Mammoth Cave National Park in Kentucky. The results of the baseline emissions indicate that the 8th highest visibility impacts at Mingo and Mammoth Cave are above the 0.5 delta deciview significance threshold. Therefore, a BART determination analysis was conducted.

CALPUFF modeling results for visibility improvements due to application of the four SO_2 control cases at the two Class I areas are tabulated in Table ES-1 and graphically plotted in Figure ES-1. The table indicates that substantial visibility improvements occur with the implementation of the Case 1 or 1a (dry sorbent injection with Trona) and Case 2 (dry scrubber/fabric filter) controls, with lesser improvement for the Case 3 (WFGD) controls. In fact, no perceptible visibility impacts (defined by a 98th percentile change of at least 0.5 delta-deciview) occur at either Class I area in any modeled year with the implementation of emission controls associated with Cases 1/1a or 2.

Table ES-1 Regional Haze Impacts Due to Baseline and BART Control

Class I Area	BART Controls	Met Year 2002				Met Year 2003				Met Year 2004				3-Yr Ave
		Days above		MAX Δ dv	8th Highest Δ dv	Days above		MAX Δ dv	8th Highest Δ dv	Days above		MAX Δ dv	8th Highest Δ dv	8th Highest Δ dv
		0.5 Δ dv	1.0 Δ dv			0.5 Δ dv	1.0 Δ dv			0.5 Δ dv	1.0 Δ dv			
Current IMPROVE Equation, Annual Average Background														
Mingo Wilderness	Baseline: 0.3% S PRB Coal, Seasonal SCR, ESP	26	12	3.49	1.30	38	18	2.88	1.45	33	13	1.93	1.36	1.37
	Case 1: 0.3% S PRB Coal, DSI/Trona, Enhanced year-round SCR, ESP	1	0	0.54	0.26	1	0	0.52	0.33	0	0	0.49	0.29	0.30
	Case 1a: 0.3% PRB Coal, Enhanced DSI/Trona, Enhanced year-round SCR, FF	1	0	0.51	0.24	0	0	0.47	0.29	0	0	0.44	0.27	0.27
	Case 2: 0.5% S PRB Coal, year-round SCR, DS, FF	1	0	0.65	0.22	2	0	0.63	0.26	0	0	0.40	0.29	0.26
	Case 3: 1.62% S Illinois Coal, year-round SCR, ESP, WFGD	5	0	0.91	0.40	8	1	1.08	0.53	5	0	0.77	0.44	0.46
Mammoth Cave National Park	Baseline: 0.3% S PRB Coal, Seasonal SCR, ESP	21	3	1.70	0.70	40	17	3.55	1.74	22	10	3.51	1.21	1.22
	Case 1: 0.3% S PRB Coal, DSI/Trona, Enhanced year-round SCR, ESP	0	0	0.36	0.16	2	0	0.84	0.36	2	0	0.70	0.23	0.25
	Case 1a: 0.3% PRB Coal, Enhanced DSI/Trona, Enhanced year-round SCR, FF	0	0	0.33	0.14	2	0	0.75	0.34	2	0	0.65	0.21	0.23
	Case 2: 0.5% S PRB Coal, year-round SCR, DS, FF	0	0	0.31	0.15	2	0	0.67	0.36	2	0	0.67	0.24	0.25
	Case 3: 1.62% S Illinois Coal, year-round SCR, ESP, WFGD	0	0	0.44	0.25	11	0	0.90	0.54	5	0	0.94	0.40	0.40

Figure ES-1 8th Highest Regional Haze Impacts Averaged Over 3 Years Due to Baseline and BART Control Case



Tables ES-2 and ES-3 list the projected annualized control cost that is a function of the capital and annual operating costs, as well as fixed capital charges estimated by Dominion Energy. The table also presents a computation of each control case's visibility improvement effectiveness and cost relative to the baseline conditions, since each control case is independent of the others. The visibility results in Tables ES-2 and ES-3 are based on the 8th highest regional haze impacts at Mingo and Mammoth Cave, respectively, averaged over the three years. Figure ES-2 presents a graph of visibility improvements as a function of the cost for each control case. It is evident from the figure that BART Case 1/1a (DSI with Trona) is clearly the most cost-effective case for the visibility improvement attained (although the incremental improvement from Case 1 to 1a has a markedly steeper cost slope than from the baseline to Case 1, almost as steep as the slope for the Case 2 and 3 options). Therefore, we conclude that the recommended BART control case is Case 1: the use of Trona injection and enhanced SCR performance operation. The ability for an SO_2 emission rate lower than 0.20 lb/MMBtu to be achieved in practice with the use of DSI with Trona will be determined from operational experience.

Table ES- 2 Visibility Improvement and Annual Costs for Each Control Case at Mingo WA

Control Case[a]	8th Highest at Mingo 3-Yr Ave (delta-dv)	Annualized Cost for Unit 1 & 2 ($/Year)	Incremental Cost Effectiveness from Baseline ($/dv)
Baseline: 0.3%S PRB Coal, Seasonal SCR, ESP	1.37	$0	$0
Case 1: 0.3% S PRB Coal, DSI/Trona, Enhanced year-round SCR, ESP	0.30	$24,820,000[b]	$23,100,000
Case 1a: 0.3% S PRB Coal, enhanced DSI with Trona, Enhanced year-round SCR, FF	0.27	$32,210,000[c]	$29,210,000
Case 2: 0.5% S PRB Coal, year-round SCR, DS, FF	0.26	$94,700,000[d]	$85,060,000
Case 3: 1.62%S Illinois Coal, year-round SCR, ESP, WFGD	0.46	$125,370,000[e]	$137,220,000

[a] These costs are based on 2008 dollars.

[b] When Case 1 costs are projected to 2014 dollars (based upon a 2014 installation date), the annualized cost becomes $30,660,000 and the incremental cost effectiveness from the baseline becomes $28,530,000.

[c] When Case 1a costs are projected to 2014 dollars (based upon a 2014 installation date), the annualized cost becomes $41,320,000 and the incremental cost effectiveness from the baseline becomes $37,470,000.

[d] When Case 2 costs are projected to 2017 dollars (based upon a 2017 installation date), the annualized cost becomes $156,110,000 and the incremental cost effectiveness from the baseline becomes $140,220,000.

[e] When Case 3 costs are projected to 2017 dollars (based upon a 2017 installation date), the annualized cost becomes $200,430,000 and the incremental cost effectiveness from the baseline becomes $219,370,000.

Table ES-3 Visibility Improvement and Annual Costs for Each Control Case at Mammoth Cave

Control Case[a]	8th Highest at Mammoth Cave 3-Yr Ave (delta-dv)	Annualized Cost for Unit 1 & 2 ($/Year)	Incremental Cost Effectiveness from Baseline ($/dv)
Baseline: 0.3%S PRB Coal, Seasonal SCR, ESP	1.22	$0	$0
Case 1: 0.3% S PRB Coal, DSI with Trona, Enhanced year-round SCR, ESP	0.25	$24,820,000[b]	$25,720,000
Case 1a: 0.3% S PRB Coal, enhanced DSI with Trona, Enhanced year-round SCR, FF	0.23	$32,210,000[c]	$32,710,000
Case 2: 0.5% S PRB Coal, year-round SCR, DS, FF	0.25	$94,700,000[d]	$98,200,000
Case 3: 1.62%S Illinois Coal, year-round SCR, ESP, WFGD	0.40	$125,370,000[e]	$152,950,000

[a] These costs are based on 2008 dollars.

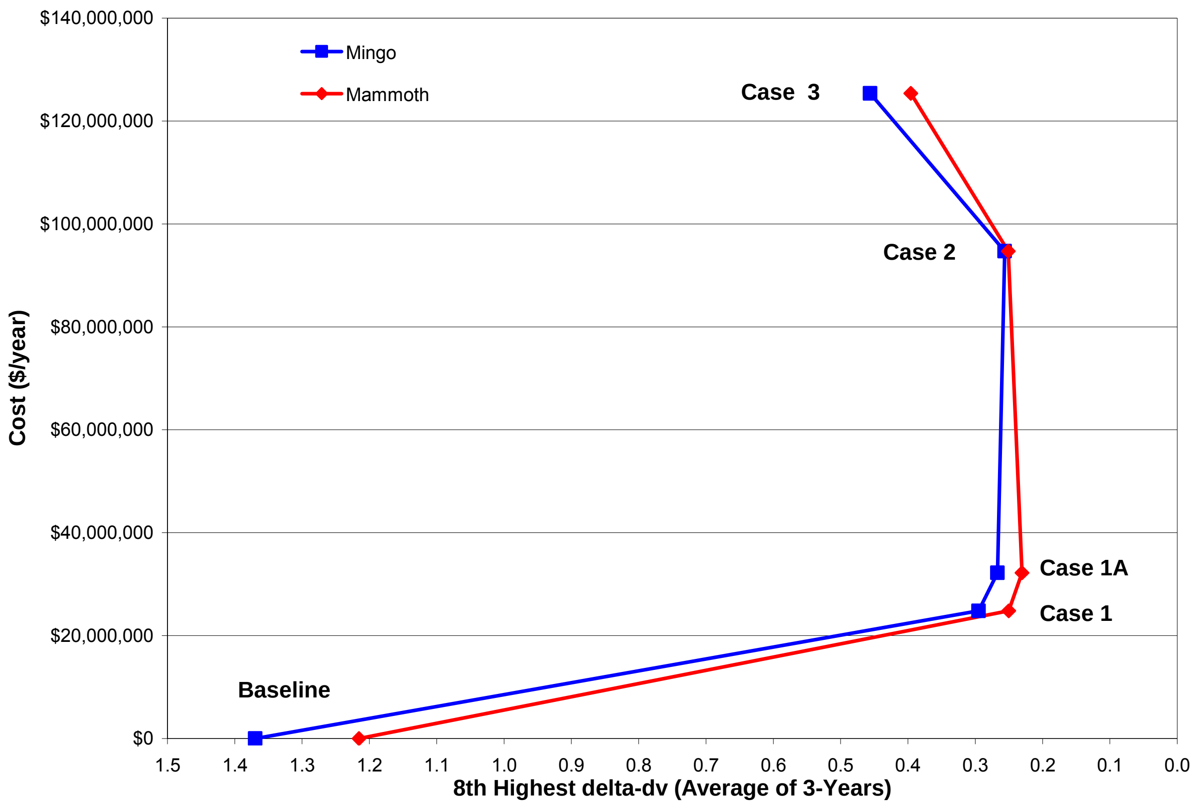
[b] When Case 1 costs are escalated to 2014 dollars (based upon 2014 installation date) the Annualized Cost becomes $30,660,000 and the Incremental Cost Effectiveness from the baseline becomes $31,770,000.

[c] When Case 1a costs are projected to 2014 dollars (based upon a 2014 installation date), the annualized cost becomes $41,320,000 and the incremental cost effectiveness from the baseline becomes $41,960,000.

[d] When Case 2 costs are escalated to 2017 dollars (based upon 2017 installation date) the Annualized Cost becomes $156,110,000 and the Incremental Cost Effectiveness from the baseline becomes $161,880,000

[e] When Case 3 costs are escalated to 2017 dollars (based upon 2017 installation date) the Annualized Cost becomes $200,430,000 and the Incremental Cost Effectiveness from the baseline becomes $244,530,000.

Figure ES-2 Annual Costs vs. Visibility Improvements



1.0 Introduction

Federal regulations under Title 40 of the Code of Federal Regulations (CFR) Part 51 Appendix Y provide guidance and regulatory authority for conducting a visibility impairment analysis for designated eligible sources. The program requires the application of Best Available Retrofit Technology (BART) to those existing eligible sources in order to help meet the targets for visibility improvement at designated Class I areas. The BART analysis will be reviewed and used by the Illinois Environmental Protection Agency (IEPA) for development of the state's Regional Haze State Implementation Plan (SIP). The IEPA has identified the two coal-fired boilers, Units 1 and 2, at Dominion's Kincaid Power Plant as BART-eligible emission units.

The BART rules require that sources that are subject to BART perform a site-specific BART analysis including a control technology review and CALPUFF modeling to assess the visibility impact of the emission units. Additionally, for large Electric Generating Units (EGU) affected by the rule, the source should meet presumptive control levels for nitrogen oxide (NO_X) and sulfur dioxide (SO_2) unless it is determined that alternative control levels are justified or equivalent in effectiveness. The presumptive BART limits for these units are continuous year-round operation of the existing SCR systems at 0.10 pound per million British thermal unit (lb/MMBtu) for NO_X and 0.15 lb/MMBtu or 95 percent control for SO_2.

The BART analysis was conducted in accordance with the procedures contained in the Final BART Guidelines published by the USEPA on July 6, 2005. Consistent with the BART Guidelines, the five steps for a case-by-case BART analysis were followed.

1. Step 1 – Identify all available control technologies for the unit including improvements to existing control equipment or installation of new add-on control equipment.

2. Step 2 – Eliminate technically infeasible options considering the commercial availability of the technology, space constraints, operating problems and reliability, and adverse side effects on the rest of the facility.

3. Step 3 – Evaluate the control effectiveness of the remaining technologies based on current pollutant concentrations, flue gas properties and composition, control technology performance, and other factors.

4. Step 4 – Evaluate the annual and incremental costs of each feasible option in accordance with approved EPA methods, as well as the associated energy and non-air quality environmental impacts.

5. Step 5 – Determine the visibility impairment associated with baseline emissions and the visibility improvements provided by the control technologies considered in the engineering analysis.

The regulation further requires a formal choice of BART based on the above data, plus the degree of improvement in visibility (impacts), which may be reasonably anticipated to result from the installation or implementation of the proposed BART. Economic analysis, remaining useful life of the plant, and impacts on facility operation that are a cost consequence of air pollution control equipment may be considered in the final BART decision-making process.

This report documents the case-by-case BART analysis conducted for SO_2, NO_x and PM emissions from Units 1 and 2 at the Kincaid Power Station. Section 2.0 provides a description of Kincaid Units 1 and 2 and their baseline emissions. Section 3.0 provides a discussion of SO_2, NO_x and PM control technologies. The available meteorological data and the CALPUFF modeling procedures are described in Sections 4.0 and 5.0, respectively. The results of the visibility improvement modeling using CALPUFF are presented in Section 6.0, along with the BART recommendation. References are listed in Section 7.0.

2.0 Background Data

2.1 Overview of BART Emission Units

The BART-affected emission units at the Kincaid Power Plant are Units 1 and 2. Units 1 and 2 commenced commercial operation in 1967 and 1968, respectively. The two units began operation during the time period (1962-1977) targeted by the Regional Haze BART Rule. Units 1 and 2 are cyclone-fired boilers manufactured Babcock & Wilcox. These two units each have a rated capacity of 4,200,000 lb/hr of superheated steam at 2,620 psig and 1,005°F. The steam is directed to dedicated turbine-generators each with a rated capacity of 660 MW. Because the plant has a total rated capacity in excess of 750 MW, Units 1 and 2 are subject to presumptive BART controls in accordance with the Regional Haze BART Rule.

2.2 Existing Control Technologies

Kincaid Units 1 and 2 are both equipped with over fire air (OFA) systems and selective catalytic reduction (SCR) to control NO_x emissions. Kincaid's permit requires the SCR system need only be operated during the ozone season (May 1st through September 30th) and must achieve a NO_x emission level of 0.15 lb/MMBtu during that period. Units 1 and 2 are also equipped with electrostatic precipitators (ESPs) to control PM emissions. The ESPs must achieve a filterable PM emission level of at least 0.10 lb/MMBtu according to the station's permits. Units 1 and 2 currently burn low-sulfur Powder River Basin (PRB) sub-bituminous coal to control SO_2 emissions. Based on historical emissions, the sulfur content of the PRB coal generally does not exceed 0.3% by weight.

2.3 Baseline Emissions

For the purposes of determining BART eligibility, the SO_2 and NO_x baseline emissions were determined using measurement data collected by the continuous emissions monitoring system (CEMS) during the years 2002 through 2006. Filterable PM baseline emissions were determined using the highest results of the latest stack tests conducted in November 1999.

The SO_2 and NO_x baseline emission rates were derived from maximum daily emissions measured by the CEMS) during the years 2002 through 2006. The PM emissions were derived from the results of stack tests conducted in November 1999. Speciation of the particulate matter emissions into filterable and condensable PM_{10} components was determined using the following approach:

- Filterable PM was subdivided by size category consistent with the default approach cited in AP-42, Table 1.1-8. For cyclone furnaces equipped with ESPs, 68% of the filterable PM emissions are filterable PM_{10} and 36% of the PM emissions are fine filterable PM_{10} emissions (less than 2.5 microns in size).
- For coal-fired boilers, elemental carbon is expected to be 3.7% of fine filterable PM_{10} based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
- Condensable inorganic PM_{10} emissions, assumed to consist of H_2SO_4, are based on procedures presented in "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007 (and reaffirmed in a March 2008 update). For coal-fired boilers, H_2SO_4 emissions are determined by the following relationship:

$E = (Q)(98.06/64.04)(F1)(F2)$

where: E is the H_2SO_4 emission rate (lb/hr),
Q is the baseline SO_2 emission rate (lb/hr),
F1 is the fuel factor (0.0018 for PRB sub-bituminous coal), and
F2 is the control factor (0.56 for an air pre-heater and 0.73 for a cold-side ESP).

Note that, although Units 1 and 2 are equipped with SCR, the maximum daily NO_x baseline emissions occur when the SCR system is off-line during the non-ozone season.

- For pulverized coal-fired boilers burning coal with a sulfur content of 0.5% or less, total condensable organic PM_{10} emissions factor is 0.002 lb/MMBtu based on AP-42, Table 1.1-5. Because AP-does not have an emission factor for total condensable organic PM_{10} emissions from cyclone boilers, AP-42 directs you to the use the pulverized coal emission factor for cyclone boilers.

Table 2-1 provides a summary of the SO_2, NO_x, and PM emissions that were used in the modeling analysis for baseline conditions. Table 2-2 then provides the stack parameters that were used in the baseline conditions modeling analysis.

Table 2-1 Kincaid Baseline Emissions

Unit	Description	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	Maximum NOx Emissions		Maximum SO2 Emissions			Maximum Filterable PM Emissions			Filterable PM10					Condensable PM10			Total PM10	Total PM10
													total	coarse	Fine			total	SO_4	organic		
															fine total	fine soil	EC					
		MMBtu/hr (a)	Btu/lb (b)	% wt. (b)	lb/MMBtu (c)	lb/hr	lb/MMBtu (c)	lb/day	lb/hr	lb/MMBtu (d)	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/MMBtu
1	PRB Sub-bituminous Coal, 660 MW, Cyclone Boiler, Seasonal SCR, ESP	6,634	8,800	~0.3%	0.810	5,371	0.623	99,124	4,130	0.0110	72.97	Stack Test	49.62 (e)	23.35	26.27 (e)	25.30	0.97 (f)	44.37	17.47 (g)	26.54 (h)	94.00	0.0142
2	PRB Sub-bituminous Coal, 660 MW, Cyclone Boiler, Seasonal SCR, ESP	6,406	8,800	~0.3%	0.830	5,317	0.638	98,054	4,086	0.0080	51.25	Stack Test	34.85 (e)	16.40	18.45 (e)	17.77	0.68 (f)	43.27	17.29 (g)	25.62 (h)	78.12	0.0122

(a) Maximum heat input rate are based on actual data provided by Dominion on November 7, 2007.
(b) Higher heating values and sulfur content are based on the average values for calendar year 2006.
(c) Maximum NOx and SO2 emissions are based on CEMS data for calendar years 2002 through 2006.
(d) Maximum PM emissions are based on stack tests conducted in November 1999.
(e) For cyclone-fired boilers equipped with ESPs, total filterable PM10 is 68% of filterable PM and fine filterable PM10 is 36% of filterable PM based on AP-42, Table 1.1-6.
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. H2SO4 emissions are determined from the relationship "(SO2)(98.06/64.04)(F1)(F2)" where Q is the SO2 emission rate in lb/hr, F1 is the fuel factor (0.0018 for PRB coal), F3 is the technology impact factor (0.17 for SCR), and F2 is the control factor (0.56 for an air preheater and 0.73 for a cold-side ESP).
(h) For pulverized coal-fired boilers, total condensable organic PM10 emissions factor is (0.1S-0.03) lb/MMBtu based on AP-42, Table 1.1-5.

Table 2-2 Kincaid Baseline Stack Parameters

Case	UTM Northing (m)	UTM Easting (m)	Base Elevation (m)	Stack Height (m)	Stack Diameter (m)	Flue Gas Temperature (°K)	Flue Gas Flow Rate (m^3/s)	Flue Gas Velocity (m/s)
Baseline	4,385,605.6	284,850.0	182.87	186.69	9.03	410.93	1,673.26	26.21

3.0 Emission Control Alternatives

The visibility impairing pollutants discussed in this section include NO_X, SO_2, and PM. Information on control of these pollutants through application of a control device, combination of devices, and/or operational change is provided.

3.1 SO_2 Control

Sulfur dioxide emissions are generated in fossil fuel-fired combustion units from the oxidation of sulfur present in the fuel. Approximately 98% of the sulfur in coal is emitted upon combustion as gaseous sulfur oxides, SO_2 and SO_3. Uncontrolled emissions of SO_2 are directly related to the fuel sulfur content, and not by the firing mechanism, boiler size, or operation. Many coal-fired boilers in the U.S. limit emissions of SO_2 through the use of low sulfur western coals, including Powder River Basin Coal. Compared with higher sulfur eastern bituminous coal that may contain as much as 4% sulfur, the practice of burning western coal can reduce SO_2 emissions by approximately 70% to 90%. However, control equipment can generally remove a higher percentage of the SO_2 from higher sulfur coal than lower sulfur coal. The selection of coal type and sulfur content, therefore, is an important aspect of the determination of BART and needs to be considered in conjunction with add-on control alternatives when performing the BART analysis.

The Unit 1 and 2 boilers currently burn low-sulfur PRB coal to limit SO_2 emissions. Alternative SO_2 control technologies available to further reduce SO_2 emission from the coal-fired boilers include Dry Scrubber/Fabric Filter (DS/FF), Wet Flue Gas Desulfurization (WFGD) and Dry Sorbent Injection (DSI) with Trona. This analysis is limited to these control technologies:

- Lime or limestone based WFGD capable of achieving 90 to 95% control;
- Lime DS/FF capable of achieving 80 to 90% control;
- DSI with Trona capable of achieving approximately 60% control;

The technical feasibility, performance, and economic, energy, and environmental impacts of the alternative SO_2 control technologies are addressed in the remainder of this section.

3.1.1 Technical Feasibility of Alternative SO_2 Controls

The technical feasibility and performance levels of the alternative SO_2 control technologies are evaluated below in terms of their application to Kincaid Units 1 and 2.

Wet Flue Gas Desulfurization

WFGD typically uses limestone or lime to react with SO_2 from coal-fired boilers. The temperature of the flue gas is reduced to its adiabatic saturation temperature and the SO_2 is removed from the flue gas by reaction with the alkaline medium. SO_2 is absorbed into the scrubbing slurry, which falls into the lower section of the vessel known as the reaction tank. Finely ground limestone and make-up water are added to the reaction tank to neutralize and regenerate the scrubbing slurry.

Limestone scrubbing introduces limestone slurry into the scrubber. The sulfur dioxide is absorbed, neutralized, and partially oxidized to calcium sulfite and calcium sulfate. The overall reactions are shown in the following equations:

$$CaCO_3 + SO_2 \rightarrow CaSO_3 \bullet 1/2\ H_2O + CO_2$$

$$CaSO_3 \bullet 1/2\ H_2O + 3H_2O + O_2 \rightarrow 2\ CaSO_4 \bullet 2\ H_2O$$

Lime scrubbing is similar to limestone scrubbing in equipment and process flow, except that lime is a more reactive reagent than limestone. The reactions for lime scrubbing are as follows:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \cdot 1/2\ H_2O + 1/2\ H_2O$$

$$Ca(OH)_2 + SO_2 + 1/2\ O_2 + H_2O \rightarrow CaSO_4 \cdot 2\ H_2O$$

Whether limestone or lime is used as the reagent for SO_2 removal, additional equipment is needed for preparing the lime/limestone slurry and collecting and concentrating the resultant sludge. Calcium sulfite sludge is difficult to mechanically dewater and is typically stabilized with fly ash for landfilling. Calcium sulfate sludge is stable and is readily mechanically dewatered. To produce calcium sulfate, an air injection blower is needed to supply the oxygen for the second reaction to occur (forced oxidation).

WFGD is most effective in reducing SO_2 emissions resulting from combustion of high-sulfur coals. In addition, the water consumption in a WFGD system is high due to water retained in the sludge and water losses to the atmosphere. Make-up water is added to the reaction tank and is recirculated through the gas stream. A WFGD will consume approximately 8 to 10% more water than a spray dryer system. In addition to higher water demand, a WFGD system has a number of environmental impacts including generating an additional solid waste stream and an additional liquid waste stream.

WFGD has been applied on many coal-fired boilers in the United States. These installations have been demonstrated to consistently achieve SO_2 removal efficiencies ranging from 90% to in excess of 95%. These high SO_2 control efficiencies would provide Dominion with an opportunity to use higher sulfur Illinois bituminous coal and still meet the presumptive BART limit of 0.15 lb/MMBtu. Although the delivered price for PRB sub-bituminous coal currently is less than that for local Illinois bituminous coal, rail transportation costs have recently been increasing dramatically due to increases in the price of diesel fuel, so the price differential between PRB and local Illinois coal could narrow considerably or disappear in the future. Over the past two years alone, transportation costs have almost doubled and are expected to continue rising with the price of diesel fuel. There is also a concern about the reliability of the rail transportation from Wyoming, due to recent incidents of derailments and delays in PRB coal shipments.

If Dominion were required to install WFGD for SO_2 control, therefore, they would consider the use of medium-sulfur (<2.5%) sulfur Illinois coal to allay concerns about the rising costs of transporting PRB sub-bituminous coal to the site and to promote the use of locally mined coal to improve the Illinois economy. For the purposes of the visibility analysis, it is assumed that the WFGD system will be applied to Units 1 and 2 firing ~1.62% sulfur Illinois-bituminous coal and will achieve an outlet SO_2 emission level of 0.15 lb/MMBtu, consistent with the presumptive BART limit.

Dry Scrubber and Fabric Filter

Use of a dry scrubber technology requires a dry scrubber to be located upstream of the particulate collection device. The flue gas passes through a spray dryer vessel, where it encounters a finely atomized alkaline lime slurry. The lime slurry is injected into the dry scrubber through either a rotary atomizer or fluid nozzles. Evaporation of the water produces a finely divided particle of mixed salt and un-reacted alkali and reduces flue gas temperatures. The flue gas is cooled to approximately 20 to 30°F above the adiabatic saturation temperature of the flue gas. A portion of the dry powder drops to the bottom of the scrubbing vessel, while the flue gases containing the remaining reacted salts and un-reacted lime are delivered to the particulate collection device. The calcium salts have a moisture content of approximately 2 to 3%, which drops to 1% before reaching the particulate control device.

In the absorbing chamber, the water in the slurry droplets is rapidly evaporated by the hot flue gases. The SO_2 are absorbed onto the hydrated lime particles and react to form calcium salts. The reduction in flue gas temperature provided by the evaporating water has been shown to be a major factor influencing the removal of acid gases. Studies have shown that SO_2 removal efficiencies are significantly higher when the dry

scrubber is operated at temperatures approaching the saturation temperature of the flue gas. As a result of the scrubbing process, a dry, free-flowing powder is produced consisting of un-reacted lime and reacted salts (most prevalent being $CaSO_3$ and $CaSO_4$). The largest of these particles are separated by gravity from the gas in the absorbing chamber by gravity and fall to the bottom. The smaller particles are carried to the PM control device for separation from the flue gas.

When a fabric filter is used as the particulate control device, it allows for further reaction of the lime captured in the filter media with the SO_2 in the flue gas. This is due to the layer of porous filter cake on the surface of the filter that contains the reagent that all flue gas must pass through. This allows for increased efficiency of control of SO_2 and H_2SO_4 as compared to wet scrubbers. This filter cake is credited with controlling pressure drops, dampening surges or pollutant spikes, providing a site for increased reagent utilization, and increasing equipment reliability.

Dry scrubbers have been applied primarily in combination with fabric filters (FFs) on many coal-fired boilers in the United States. These installations have been demonstrated to consistently achieve SO_2 removal efficiencies of 80 to 90%. For the purposes of the visibility analysis, it is assumed that the DS/FF combination will be applied to Units 1 and 2 firing 0.5% sulfur PRB sub-bituminous coal and will achieve an outlet SO_2 emission level of 0.15 lb/MMBtu consistent with the presumptive BART limit.

Dry Sorbent Injection (DSI) with Trona

A variety of manufacturers have developed DSI systems for SO_2 control on coal-fired boilers. This technology uses very standard process equipment, including carbon steel storage silos, material handling equipment, blowers, and pneumatic transport piping, all of which are commodity components available from multiple vendors at similar cost. In order to remove SO_2 compounds from hot exhaust gases, finely ground Trona, sodium sesquicarbonate [$Na_3(HCO_3)$], can be injected into the hot gas stream to react with the SO_2 and form sodium sulfite (Na_2SO_3). The reacted salt would then be removed from the flue gas stream by the existing downstream particulate control devices. The main chemical reaction is as follows:

$$2(Na_3(HCO_3)\bullet(CO_3)\bullet 2H_2O) + 3SO_2 \rightarrow 3Na_2SO_3 + 5H_2O + 4CO_2$$

A plant's operating conditions will ultimately affect the effectiveness of DSI with Trona in removing SO_2. The most important variables for high removal efficiency are injection temperature, SO_2 concentration, fine particle size (~10 microns), retention time (the time the acid gases are in contact with the sorbent) and the type of coal utilized.

DSI with Trona has demonstrated the following SO_2 removal rates during the short term demonstration tests discussed below. In 2005 the Mirant Potomac River Station[2] demonstrated a maximum SO_2 control of ≈80% while burning Central Appalachian and Columbian coals. In 2008, We Energies Presque Isle Power Plant demonstrated a maximum SO_2 control of ≈70% while burning Powder River Basin (PRB) coal. Dominion estimates that for the purposes of BART implementation, DSI with Trona injection will be able to achieve an average SO_2 control of ≈60% and an SO_2 emission rate of 0.20 lb/MMBtu based upon a 30-day rolling average. Dominion has assumed 60% SO_2 removal for PRB coal at Kincaid for several reasons, related to differences in the units, the limited testing scope at Presque Isle and the impact on mercury removal. Higher Trona injection rates during the Presque Isle tests contributed to reduced rates of mercury removal from Activated Carbon Injection, an issue which must be evaluated for Kincaid. Further, the Presque Isle tests consisted of only 8-hour injections of Trona in a 90 MW unit. Effective utilization of Trona will be more difficult for Kincaid's much larger 660 MW units and a 30-day rolling average presents a much greater challenge than an 8-hour test under optimum conditions. For example, during normal operations Kincaid operates at reduced loads and lower temperatures at night, which typically which reduces the reactivity of Trona. The

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[2] http://www.mirant.com/our_business/where_we_work/Unredacted_Trona_Test_Report_011706BC.pdf

Presque Isle units were tested with Trona injection upstream of a bag house while Kincaid utilizes an electrostatic precipitator for particulate removal.

One advantage of the DSI with Trona injection process is that the stack temperature is not diminished compared to the WFGD processes that involve the use of significant amounts of water. Aside from the environmental benefits that result from avoiding the use of the water spray, the increased stack gas temperature will tend to avoid the local impacts of increased H_2SO_4 emissions associated with oxidation of SO_2 to SO_3 by the SCR catalyst and the subsequent formation of H_2SO_4 in the control equipment.

DSI with Trona requires much lower capital investment, less physical space, and less modification to existing ductwork compared to a spray dryer absorber or wet scrubber. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending upon the amount of sorbent injected into the ductwork.

Two cases are presented for Trona injection for SO_2 control (Cases 1 and 1a), with slightly different SO_2 emission rates (0.20 lb/MMBtu for Case 1 and 0.18 lb/MMBtu for Case 1a). Although the lower SO_2 emission rate is preferred, it may not be achievable, depending upon the coal sulfur content and the effectiveness of the Trona removal for this specific application.

3.1.2 Impacts of Alternative SO_2 Controls

The alternative control technologies available to control SO_2 emissions from Units 1 and 2 are DSI with Trona, DS/FF and WFGD. This section documents the economic, non-air environmental, and energy impacts associated with applying alternative control technologies to Units 1 and 2.

Economic Impacts

Table 3-1 presents the first-year annual capital and annual costs associated with DSI with Trona, DS/FF and WFGD applied to Kincaid Units 1 and 2. The capital costs for the technically feasible SO_2 control technologies were provided by Dominion Energy. The annual fixed capital charges and annual operating costs were also provided by Dominion. An interest rate of 9.8% and an amortization period of 20 years were assumed in the calculation of the annualized costs for the BART control cases.

Table 3-1 Total Capital and Annual Costs Associated with Technically Feasible SO_2 Control Technologies Applied to Kincaid Units 1 and 2

Control Case [c]	Control Technology	Total Capital Cost ($) [a]	Fixed Capital Costs ($/yr) [b]	Annual O&M Costs ($/yr)	Total Annual Costs ($/yr)
1	Dry Sorbent Injection (PRB Coal)	$60,000,000	$7,000,000	$17,820,000	$24,820,000
1a	Enhanced DSI/FF (PRB Coal)	$163,000,000	$19,000,000	$13,210,000	$32,210,000
2	Dry Scrubber/FF (PRB Coal)	$732,580,000	$85,000,000	$9,700,000	$94,700,000
3	WFGD (Bituminous Coal)	$840,710,000	$97,000,000	$28,370,000	$125,370,000

[a] Total capital costs for Cases 2 and 3 include $17,900,000 for removal of existing equipment; this cost for Case 1a is $6,000,000. In addition, total capital costs for Cases 1a and 2 include expenses associated with the fabric filter.

[b] Fixed capital charges are based on a capital recovery factor of 0.1159, assuming an interest rate of 9.8% and an amortization period of 20 years.

[c] All costs are based on 2008 dollars.

Non-Air Quality Environmental Impacts

The preceding technology evaluation identified DSI with Trona, DS/FF and WFGD as the available SO_2 control technologies providing the highest removal efficiencies relative to other technologies. Of the two scrubber options, the DS/FF combination is considered the preferred control technology. The disadvantages of WFGD compared to DS/FF system include:

- higher water consumption or wastewater treatment requirement resulting in increased energy and utility operating costs;
- liquid effluent from the wet scrubber requires pretreatment to meet regulatory requirements before discharge to a municipal sewer;
- problems associated with the disposal of wet sludge resulting from the process, requiring extensive sludge thickening and dewatering equipment;
- a relatively low stack gas temperature resulting in reduced buoyancy and lower plume rise, and hence poorer dispersion of the residual pollutants;
- visible steam plume under most meteorological conditions, especially during periods of high relative humidity; and
- corrosion, scaling and fouling of scrubber internals, requiring costly acid corrosion resistant construction materials for scrubber and downstream equipment.

Furthermore, available test data demonstrate the superior effectiveness of DS/FF systems for SO_2 and other acid gas emissions, as well as the control of secondary pollutant (i.e., trace organics and trace metals).

As noted above, the DSI with Trona option provides significant non-air quality benefits over both scrubbing options:

- no use of additional water in the FGD treatment
- a higher stack temperature, leading to improved local air quality due to increased buoyancy and higher plume rise, and hence greater dispersion of the residual pollutants and
- a lower likelihood of visible plumes, as well as fogging and icing potential.

Energy Impacts

The WFGD option would consume significantly more electrical energy than the DS/FF option, while the DSI with Trona option would consume the least energy of any of the options. For example, the higher electrical energy consumption for WFGD relative to DS/FF and DSI with Trona primarily is due to the power required for the increased fan static pressure required to overcome the pressure drop across the scrubber vessel, as well as for dewatering, re-circulating pumps and material handling. WFGD applied to both units would consume approximately 82,000 kWh, compared to 65,000 kWh for the DS/FF compared to 13,000 kWh for the DSI with Trona. The increased emissions of criteria pollutants required to maintain the net electrical output have not been incorporated into the visibility modeling.

3.1.3 Discussion of Candidate SO_2 Control Technologies

The SO_2 control technologies identified for evaluation include DSI with Trona (two possible SO_2 emission rates), DS/FF and WFGD. Of these technologies, WFGD is capable of higher SO_2 control efficiencies ranging from 90 to 95%, providing Dominion with the flexibility of using medium-sulfur Illinois bituminous coal. The DS/FF, on the other hand, is capable of achieving SO_2 control efficiencies ranging from 80 to 90%, limiting Dominion options to low-sulfur PRB sub-bituminous or eastern bituminous coals. The DSI with Trona option can achieve SO_2 removal rates of up to 70% when firing low-sulfur PRB coals as demonstrated at the We Energies Presque Isle Power Plant. The WFGD system, however, has significant disadvantages compared

with the other SO_2 removal options. The WFGD system has substantially higher capital and annual operating costs than the other SO_2 removal options. Compared with these other options, WFGD would result in significant environmental and energy impacts, including increased power requirements, increased water consumption, liquid effluent requiring pretreatment, wet sludge requiring dewatering, and cooler and less buoyant plume.

3.2 NO_X Emission Controls

Nitrogen oxides formed during the combustion of coal are generally classified as either thermal NO_x or fuel-bound NO_x. Thermal NO_x is formed when elemental nitrogen in the combustion air is oxidized at the high temperatures in the primary combustion zone yielding nitrogen oxide (NO) and nitrogen dioxide (NO_2). The rate of formation of thermal NO_x is a function of residence time and free oxygen, and increases exponentially with peak flame temperatures. Thermal NO_x from coal combustion can be effectively controlled by techniques that limit available oxygen or reduce peak flame temperatures in the primary combustion zone. Fuel-bound NO_x is formed by the oxidation of chemically bound nitrogen in the fuel. The rate of formation of fuel-bound NO_x is primarily a function of fuel bound nitrogen content, but is affected by fuel/air mixing.

The technologies available to control NO_X from coal-fired boilers include combustion controls, such as low-NO_x burners (LNB), and post-combustion techniques, such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). Because Units 1 and 2 already incorporate combustion controls, this analysis is limited to the following post-combustion control technologies:

- Selective catalytic reduction capable of 80 to 90 percent control; and
- Selective non-catalytic reduction capable of 30 to 50 percent control.

The Unit 1 and 2 boilers currently incorporate SCR for the control of NO_x emissions during the ozone season. As demonstrated below, this control technology is considered the most effective in reducing NO_x emissions from coal-fired boilers. The SCR controls would need to be operated continuously to meet the presumptive BART requirements

3.2.1 Technical Feasibility of Alternative NO_x Controls

The technical feasibility and performance levels of the alternative NO_x control technologies are evaluated below in terms of their application to Kincaid Units 1 and 2.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is a process that involves post-combustion removal of NO_x from flue gas utilizing a catalytic reactor. In the SCR process, ammonia injected into the flue gas reacts with NO_x and oxygen to form nitrogen and water vapor. The SCR process converts NOx to nitrogen and water by the following general reactions:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction to about 375 to 750°F, depending on the specific catalyst and other contaminants in the flue gas. The factors affecting SCR performance are catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system.

The SCR system is comprised of a number of subsystems, including the SCR reactor, ammonia injection system, and ammonia storage and delivery system. Typically, the SCR reactor would be located downstream of the economizer and upstream of the air pre-heater and the particulate control system. From the

economizer outlet, the flue gas would first pass through a low-pressure ammonia/air injection grid designed to provide optimal mixing of ammonia with flue gas. The ammonia treated flue gas would then flow through the catalyst bed and exit to the air pre-heater. The SCR system for a coal boiler typically uses a fixed bed catalyst in a vertical down-flow, multi-stage reactor.

Reduction catalysts are divided into two groups: base metal, primarily vanadium, platinum or titanium, (lower temperature), and zeolite (higher temperature). Both groups exhibit advantages and disadvantages in terms of operating temperature, ammonia-NOx ratio, and optimum oxygen concentration. The optimum operating temperature for a vanadium-titanium catalyst system is in the range of 550° to 750°F, which is significantly higher than for platinum catalyst systems. However, the vanadium-titanium catalyst systems begin to break down when operating at temperatures above this range. Operation above the maximum temperature results in oxidation of ammonia to ammonia sulfate and NO_x, thereby actually increasing NO_x emissions.

SCR with ammonia injection technology is a demonstrated, commercially available technology. SCR has been used with other coal-fired boilers; therefore, SCR is technically feasible for the control of NO_X emissions from Units 1 and 2. Performance data from Units 1 and 2 indicate that the SCR systems are capable of NO_x removal efficiencies ranging from 85 to 90%. Based on these performance data, continuous operation of the SCR system will ensure that Units 1 and 2 will comply with the presumptive BART limit for cyclone furnaces of 0.10 lb/MMBtu.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction is a post-combustion control technology that involves ammonia or urea injection into the flue gases without the presence of a catalyst. SNCR, similar to SCR, involves the reaction of NO_X with ammonia, where a portion of the NO_X is converted to molecular nitrogen and water. Without the use of a catalyst or supplemental fuel injection, the NO_X reduction reaction temperature must be tightly controlled between 1,600 and 2,200°F (between 1,600 and 1,800°F for optimum efficiency). Below 1,600°F ammonia will not fully react, resulting in un-reacted ammonia that is emitted into the atmosphere, (referred to as ammonia slip). If the temperature rises above 2,200°F, the ammonia added will be oxidized resulting in an increased level of NO_X emissions.

SNCR with ammonia injection technology is a demonstrated, commercially available technology. SNCR has been used with other coal-fired boilers; therefore, SNCR is indeed technically feasible for the control of NO_X emissions from Units 1 and 2. However, NO_X removal efficiencies with SNCR are lower than SCR, typically ranging from 30 to 50% depending on the combustion process and inlet NO_x concentrations. Based on such performance estimates, SNCR system is not capable of achieving the presumptive BART limit of 0.10 lb/MMBtu. Because SNCR is less effective than SCR, this technology is not considered further in this analysis.

3.2.2 Discussion of Candidate NO_x Control Technologies

The NO_X post-combustion control technologies identified for evaluation are SCR and SNCR. Of these technologies, SCR has been demonstrated to be the most effective technology in minimizing NO_x emissions from coal-fired boilers. Further, SCR is the only technology capable of achieving the presumptive BART limit for cyclone furnaces. Accordingly, continuous operation of the SCR systems with a rolling 30-day emission rate of 0.10 lb/MMBtu is recommended as BART for Kincaid Units 1 and 2.

3.3 PM Emission Control

Kincaid Units 1 and 2 currently employ high-efficiency Electro-Static Precipitators (ESP) to control Particulate Matter (PM) emissions. The baseline PM emission rates for Units No. 1 and 2 are 0.011 and 0.008 lb/MMBtu, respectively. These emissions are significantly below the permitted PM emission limit of 0.10 lb/MMBtu. A new FF, DS/FF or WFGD are capable of achieving a vendor-guaranteed filterable PM emission level of 0.015

lb/MMBtu. The DSI with Trona system has been shown significant reductions in PM[3]. Dominion has conservatively assumed that there will not be any appreciable effect on PM emission levels and are assumed to remain at the baseline levels. Given the high performance levels of the existing ESPs, these PM control devices are considered BART for Unit 1 and 2 and no additional PM controls were considered in this analysis.

3.4 Control Scenarios

A number of different control scenarios are possible for reduction of visibility impairing pollutants from the Kincaid Power Plant. Based on the anticipated performance levels, the proposed NO_x and particulate control technologies are considered BART for Units 1 and 2. Therefore, the following SO_2 control scenarios are included in the modeling assessment:

- Case 1. Firing 0.3%-sulfur PRB sub-bituminous coal, Dry Sorbent Injection (DSI) with Trona capable of achieving an SO_2 emissions level of 0.20 lb/MMBtu and enhanced year-round operation of the SCR at a NO_x emission level of 0.07 lb/MMBtu.
- Case 1a. Firing 0.3%-sulfur PRB sub-bituminous coal, enhanced DSI with Trona capable of achieving an SO_2 emissions level of 0.18 lb/MMBtu (if achievable), enhanced year-round operation of the SCR at a NO_x emission level of 0.07 lb/MMBtu, and replacement of the existing Electrostatic Precipitators (ESP) with Fabric Filters (FF).
- Case 2. Firing 0.5%-sulfur PRB sub-bituminous coal, Dry Scrubber/Fabric Filter (DS/FF) capable of achieving an SO_2 emissions level of 0.15 lb/MMBtu and year-round operation of the SCR at a NO_x emission level of 0.10 lb/MMBtu.
- Case 3. Firing 1.62%-sulfur Illinois Basin bituminous coal, Wet Flue Gas Desulfurization (WFGD) capable of achieving an SO_2 emissions level of 0.15 lb/MMBtu and year-round operation of the SCR at a NO_x emission level of 0.10 lb/MMBtu.

A DS/FF or WFGD system is capable of achieving a filterable PM emission level of 0.015 lb/MMBtu. The DSI with Trona system has shown significant reductions in PM[4]. Dominion has conservatively assumed that there will not be any appreciable effect on PM emission levels and are assumed to remain at the baseline. As noted previously, Units 1 and 2 already incorporate OFA and SCR for NO_x control. The NO_x controls have been demonstrated of being capable of achieving a NO_x emission level of 0.10 lb/MMBtu. For the DSI with Trona options, Dominion would commit to a NO_x emission rate of 0.070 lb/MMBtu.

The alternative control technologies will not only affect SO_2 and NO_X emission levels from Units 1 and 2, but also will affect the emissions and speciation of PM_{10}. The PM_{10} emissions and speciation for modeling purposes were determined using the following approach:

- Filterable PM was subdivided by size category consistent with the default approach cited in AP-42, Table 1.1-6. For coal-fired boilers equipped with fabric filters, 92 percent of the filterable PM emissions are filterable PM_{10} and 53 percent of the PM emissions are fine filterable PM_{10} emissions (less than 2.5 microns in size). Although not as effective in controlling fine PM, WFGD was assumed to have the same particle size distribution for the purposes of the visibility analysis.
- For coal-fired boilers, elemental carbon is expected to be 3.7 percent of fine PM_{10} based on the best estimate for electric utility coal combustion in Table 6 of “Catalog of Global Emissions Inventories and

[3] PM_{10} filterable and condensable emissions were reduced by ≈47% during the demonstration testing at the Mirant Potomac River Station. The test report can be found at: http://www.mirant.com/our_business/where_we_work/Unredacted_Trona_Test_Report_011706BC.pdf

[4] PM_{10} filterable and condensable emissions were reduced by ≈47% during the demonstration testing at the Mirant Potomac River Station. The test report can be found at: http://www.mirant.com/our_business/where_we_work/Unredacted_Trona_Test_Report_011706BC.pdf

Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.

- Condensable inorganic PM_{10} emissions, assumed to consist of H_2SO_4, are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. For coal-fired boilers equipped with SCR, H_2SO_4 emissions are determined by the following relationship:

  E = (Q)(98.06/64.04)(F1+S2 F3)(F2)

  where: E is the H_2SO_2 emission rate (lb/hr),
  Q is the baseline SO_2 emission rate (lb/hr),
  F1 is the fuel factor (0.00111 for PRB sub-bituminous coal and 0.016 for medium-sulfur eastern bituminous coal),
  S2 is the SCR catalyst SO_2 oxidation rate (0.003 for PRB sub-bituminous coal and 0.005 for eastern bituminous coal)
  F3 is the technology impact factor (0.17 for PRB sub-bituminous coal and 1.00 for eastern bituminous coal),
  F2 is the control factor (0.56 and 0.85 for an air heater PRB coal and bituminous coal, respectively, 0.73 and 0.77 for an ESP for PRB coal and bituminous coal, respectively, 0.5 for DSI, 0.47 for wet scrubbers, and 0.01 for a DS/FF).

- For coal-fired boilers with FGD, the total condensable organic PM_{10} emission factor is 0.004 lb/MMBtu based on AP-42, Table 1.1-5.

Tables 3-2, 3-3, 3-4, and 3-5 provide summaries of the SO_2, NO_x, and PM emissions that were used in the modeling analysis for cases 1, 1a, 2, and 3 respectively. Table 3-6 provides the stack parameters that were used in the modeling for these cases.

Table 3-2 Kincaid Future DSI with Trona Emissions (Case 1)

Unit	Description	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	Enhanced DSI Sulfur Removal	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions		Filterable PM10					Condensable PM10			Total PM10	Total PM10
												total	coarse	Fine			total	SO_4	organic		
														fine total	fine soil	EC					
		MMBtu/hr (a)	Btu/lb (b)	% wt. (b)	%	lb/MMBtu (c)	lb/hr	lb/MMBtu (c)	lb/hr	lb/MMBtu (d)	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/MMBtu
1	PRB Sub-bituminous Coal, 660 MW, Cyclone Boiler, DSI with Trona, Enhanced Year-Round SCR, ESP	6,634	8,800	0.30%	71%	0.070	464.38	0.200	1,326.80	0.0110	72.97	49.62 (e)	23.35	26.27 (e)	25.30	0.97 (f)	36.30	9.57 (g)	26.54 (h)	85.93	0.0130
2	PRB Sub-bituminous Coal, 660 MW, Cyclone Boiler, DSI with Trona, Enhanced Year-Round SCR, ESP	6,406	8,800	0.30%	71%	0.070	448.42	0.200	1,281.20	0.0080	51.25	34.85 (f)	16.40	18.45 (f)	17.77	0.68 (f)	35.06	9.24 (g)	25.62 (h)	69.91	0.0109

(a) Maximum heat input rate are based on design data provided by Dominion.
(b) Higher heating values and sulfur content are based on fuel data provided by Dominion.
(c) Maximum NOx and SO2 emissions are based on projected emissions firing <0.3% sulfur PRB coal with continuous operation of SCR and installation of Trona injection system (based on 0.20 lb/MMBtu SO2 outlet).
(d) Maximum PM emissions are based on stack tests conducted in November 1999.
(e) For cyclone-fired boilers equipped with ESPs, total filterable PM10 is 68% of filterable PM and fine filterable PM10 is 36% of filterable PM based on AP-42, Table 1.1-6.
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. H2SO4 emissions are determined from the relationship "(SO2)(98.06/64.04)(F1+S2*F3)(F2)" where Q is the SO2 emission rate in lb/hr, F1 is the fuel factor (0.0018 for PRB sub-bituminous coal), S2 is the SCR catalyst SO2 oxidation rate (3.0% for PRB sub-bituminous coal), F3 is the technology impact factor (0.17 for PRB sub-bituminous coal), and F2 is the control factor (for PRB sub-bituminous coal, 0.56 for an air preheater, 0.50 for DSI and 0.73 for a cold-side ESP).
(h) For pulverized coal-fired equipped with FGD, total condensable organic PM10 emissions factor is 0.004 lb/MMBtu based on AP-42, Table 1.1-5.

Table 3-3 Kincaid Future Enhanced DSI with Trona Emissions (Case 1a)

Unit	Description	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	DSI Sulfur Removal	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions		Filterable PM10					Condensable PM10			Total PM10	Total PM10
												total	coarse	Fine			total	SO_4	organic		
														fine total	fine soil	EC					
		MMBtu/hr (a)	Btu/lb (b)	% wt. (b)	%	lb/MMBtu (c)	lb/hr	lb/MMBtu (c)	lb/hr	lb/MMBtu (d)	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/MMBtu
1	PRB Sub-bituminous Coal, 660 MW, Cyclone Boiler, Enhanced DSI with Trona, Enhanced Year-Round SCR, FF	6,634	8,800	0.30%	74%	0.070	464.38	0.180	1,194.12	0.0150	99.51	91.55 (e)	38.81	52.74 (e)	50.79	1.95 (f)	27.87	1.31 (g)	26.54 (h)	119.42	0.0180
2	PRB Sub-bituminous Coal, 660 MW, Cyclone Boiler, Enhanced DSI with Trona, Enhanced Year-Round SCR, FF	6,406	8,800	0.30%	74%	0.070	448.42	0.180	1,153.08	0.0150	96.09	88.40 (f)	37.48	50.93 (f)	49.04	1.88 (f)	26.92	1.27 (g)	25.62 (h)	115.32	0.0180

(a) Maximum heat input rate are based on design data provided by Dominion.
(b) Higher heating values and sulfur content are based on fuel data provided by Dominion.
(c) Maximum NOx and SO2 emissions are based on projected emissions firing <0.3% sulfur PRB coal with continuous operation of SCR and installation of Trona injection system (based on 0.20 lb/MMBtu SO2 outlet).
(d) Maximum PM emissions are based on stack tests conducted in November 1999.
(e) For dry-bottom boilers equipped with FFs, total filterable PM10 is 92% of filterable PM and fine filterable PM10 is 53% of filterable PM based on AP-42, Table 1.1-6.
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. H2SO4 emissions are determined from the relationship "(SO2)(98.06/64.04)(F1+S2*F3)(F2)" where Q is the SO2 emission rate in lb/hr, F1 is the fuel factor (0.0018 for PRB sub-bituminous coal), S2 is the SCR catalyst SO2 oxidation rate (3.0% for PRB sub-bituminous coal), F3 is the technology impact factor (0.17 for PRB sub-bituminous coal), and F2 is the control factor (for PRB sub-bituminous coal, 0.56 for an air preheater, 0.50 for DSI and 0.10 for a FF).
(h) For pulverized coal-fired equipped with FGD, total condensable organic PM10 emissions factor is 0.004 lb/MMBtu based on AP-42, Table 1.1-5.

Table 3-4 Kincaid Future DS/FF Emissions (Case 2)

Unit	Description	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	SDA/FF Sulfur Removal	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions		Filterable PM10					Condensable PM10			Total PM10	Total PM10
												total	coarse	Fine: fine total	Fine: fine soil	Fine: EC	total	SO_4	organic		
		MMBtu/hr (a)	Btu/lb (b)	% wt. (b)	%	lb/MMBtu (c)	lb/hr	lb/MMBtu (c)	lb/hr	lb/MMBtu (d)	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/MMBtu
1	PRB Sub-bituminous Coal, 660 MW, Cyclone Boiler, Year-Round SCR, DS, FF	6,634	8,800	0.50%	87%	0.100	663.40	0.150	995.10	0.0150	99.51	91.55 (e)	38.81	52.74 (e)	50.79	1.95 (f)	26.98	0.44 (g)	26.54 (h)	118.53	0.0179
2	PRB Sub-bituminous Coal, 660 MW, Cyclone Boiler, Year-Round SCR, DS, FF	6,406	8,800	0.50%	87%	0.100	640.60	0.150	960.90	0.0150	96.09	88.40 (f)	37.48	50.93 (f)	49.04	1.88 (f)	26.05	0.42 (g)	25.62 (h)	114.46	0.0179

(a) Maximum heat input rate are based on design data provided by Dominion.
(b) Higher heating values and sulfur content are based on fuel data provided by Dominion.
(c) Maximum NOx and SO2 emissions are based on projected emissions firing 0.5% sulfur PRB coal with continuous operation of SCR and installation of SDA/FF (based on 0.15 lb/MMBtu SO2 outlet).
(d) Maximum PM emissions are based on projected emissions following installation of SDA/FF (based on 0.015 lb/MMBtu PM outlet).
(e) For dry-bottom boilers equipped with FFs, total filterable PM10 is 92% of filterable PM and fine filterable PM10 is 53% of filterable PM based on AP-42, Table 1.1-6.
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. H2SO4 emissions are determined from the relationship "(SO2)(98.06/64.04)(F1+S2*F3)(F2)" where Q is the SO2 emission rate in lb/hr, F1 is the fuel factor (0.0018 for PRB sub-bituminous coal), S2 is the SCR catalyst SO2 oxidation rate (3.0% for PRB sub-bituminous coal), F3 is the technology impact factor (0.17 for PRB sub-bituminous coal), and F2 is the control factor (for PRB sub-bituminous coal, 0.56 for an air preheater, 0.73 for a cold-side ESP, and 0.01 for SDA/FF).
(h) For pulverized coal-fired equipped with FGD, total condensable organic PM10 emissions factor is 0.004 lb/MMBtu based on AP-42, Table 1.1-5.

Table 3-5 Kincaid Future WFGD Emissions (Case 3)

Unit	Description	Max. Heat Input	Higher Heating Value	Fuel Sulfur Content	Wet FGD Sulfur Removal	Maximum NOx Emissions		Maximum SO2 Emissions		Maximum Filterable PM Emissions		Filterable PM10					Condensable PM10			Total PM10	Total PM10
												total	coarse	Fine			total	SO_4	organic		
														fine total	fine soil	EC					
		MMBtu/hr (a)	Btu/lb (b)	% wt. (b)	%	lb/MMBtu (c)	lb/hr	lb/MMBtu (c)	lb/hr	lb/MMBtu (d)	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/MMBtu
1	Illinois Basin Bituminous Coal, 660 MW, Cyclone Boiler, Year-Round SCR, ESP, WFGD	6,634	10,800	1.62%	95%	0.100	663.40	0.150	995.10	0.0150	99.51	91.55 (e)	38.81	52.74 (e)	50.79	1.95 (f)	204.65	174.48 (g)	26.54 (h)	296.20	0.0446
2	Illinois Basin Bituminous Coal, 660 MW, Cyclone Boiler, Year-Round SCR, ESP, WFGD	6,406	10,800	1.62%	95%	0.100	640.60	0.150	960.90	0.0150	96.09	88.40 (f)	37.48	50.93 (f)	49.04	1.88 (f)	197.62	168.48 (g)	25.62 (h)	286.02	0.0446

(a) Maximum heat input rate are based on design data provided by Dominion.
(b) Higher heating values and sulfur content are based on fuel data provided by Dominion.
(c) Maximum NOx and SO2 emissions are based on projected emissions firing 1.62% sulfur bituminous coal with continuous operation of SCR and installation of wet FGD (based on 95% SO2 removal).
(d) Maximum PM emissions are based on projected emissions following installation of the wet FGD (based on 0.015 lb/MMBtu PM outlet).
(e) For dry-bottom boilers equipped with wet scrubbers, total and fine filterable PM10 assumed to be equivalent to that associated with a FF (Wet scrubbers have lower removal efficiencies for total and fine PM10 than FFs).
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, March 2007. H2SO4 emissions are determined from the relationship "(SO2)(98.06/64.04)(F1+S2*F3)(F2)" where Q is the SO2 emission rate in lb/hr, F1 is the fuel factor (0.016 for eastern bituminous coal), S2 is the SCR catalyst SO2 oxidation rate (0.3% for eastern bituminous coal), F3 is the technology impact factor (1.00 for eastern bituminous coal), and F2 is the control factor (for high-sulfur bituminous coal, 0.85 for an air preheater, 0.77 for a cold-side ESP, and 0.47 for wet FGD).
(h) For pulverized coal-fired equipped with FGD, total condensable organic PM10 emissions factor is 0.004 lb/MMBtu based on AP-42, Table 1.1-5.

Table 3-6 Kincaid Future DSI with Trona, DS/FF and WFGD Stack Parameters

Case	Description	UTM Northing (m)	UTM Easting (m)	Base Elevation (m)	Stack Height (m)	Stack Diameter (m)	Flue Gas Temperature (°K)	Flue Gas Flow Rate (m^3/s)	Flue Gas Velocity (m/s)
1	DSI, Enhanced SCR, ESP	4,385,605.6	284,850.0	182.87	186.69	9.03	410.93	1,673.26	26.21
1a	Enhanced DSI, Enhanced SCR, FF,	4,385,605.6	284,850.0	182.87	186.69	9.03	410.93	1,673.26	26.21
2	SCR, Dry Scrubber, FF	4,385,605.6	284,850.0	182.87	186.69	9.03	352.59	1,463.18	22.86
3	SCR, ESP, WFGD	4,385,605.6	284,850.0	182.87	186.69	9.03	324.82	1,373.33	21.46

4.0 Meteorological Data used in Visibility Improvement Modeling

This section discusses refinements to the Lake Michigan Air Directors Consortium (LADCO) and Midwest Regional Planning Organization (MRPO) meteorological database that was used for the Kincaid BART modeling.

4.1 Elements of the Refined Analysis

ENSR made several refinements to the CALMET meteorological database produced by LADCO/MRPO for BART CALPUFF analyses for Midwestern States. The CALMET database derived by LADCO/MRPO has a domain that covers approximately a 3,492 km (east-west) by 3,240 km (north-south) area with a 36-km grid resolution. This area covers the entire continental United States east of the Rocky Mountains, but its large size limits the horizontal resolution of each grid element to 36 km. This coarse grid resolution, without further refinement, can be deemed appropriate for a screening-level analysis, but it would not be considered appropriate for a more refined analysis.

ENSR developed a refined meteorological database that included a modeling domain encompassing the two Class I areas (Mingo and Mammoth Cave), the Kincaid facility, and the appropriate buffers around the source and Class I areas for puffs recirculation. This domain covers approximately a 486 km (east-west) by 456 km (north-south) area, has a grid resolution of 6 km (6 times better than the LADCO/MRPO database in both east-west and north-south directions), and contains 10 vertical levels. The refined database utilized the same MM5 databases that were used to develop the LADCO/MRPO 36-km CALMET database.

In addition to the use of consistent MM5 databases with the LADCO-developed meteorological data, ENSR utilized similar model switches/settings, when appropriate, that were used to develop the LADCO/MRPO CALMET database. To improve the database even further, ENSR introduced actual surface, precipitation, and twice-daily upper air sounding observations into the refined meteorological database. These improvements in the CALMET database provide more accurate plume trajectories from the Kincaid facility to the distant Class I areas.

In addition, ENSR used the latest EPA-approved versions of CALMET (Version 5.8) and CALPUFF (Version 5.8), rather than the "old" EPA-approved versions suggested in the MRPO BART common protocol (available at http://www.state.in.us/idem/programs/air/workgroups/regionalhaze/docs/BART_protocol.pdf).

4.2 CALMET Processing

ENSR used refined 6-km grid spacing for the CALMET and CALPUFF models. The modeling domain was based on a 100-km buffer around the source and at least a 50-km buffer around each of the two Class I areas to account for puffs recirculation. The modeling domain is shown in Figure 4-1. This design creates a 486 km (east-west) x 456 km (north-south) domain extent at a 6-km resolution.

A Lambert Conformal Conic (LCC) coordinate system was used and is identical to the LADCO/MRPO coordinate system. The LCC projection for this analysis was based on the NAS-C datum and standard parallels of 33 and 45 degrees North, with an origin of 40 degrees North and 97 degrees West.

ENSR used the latest EPA-approved version of CALMET (Version 5.8, Level 070623) to produce three-dimensional wind fields for three years (2002-2004). Advanced meteorological data in the form of prognostic mesoscale meteorological data, such as the Fifth Generation Mesoscale Model (MM5), was used to provide a superior estimate of the initial wind fields. This application consisted of 3 years (2002-2004) of prognostic MM5 meteorological data supplied by the MRPO at a 36-km resolution.

- 2002 MM5 data set at 36 km resolution provided by CENRAP;
- 2003 MM5 data set at 36 km resolution provided by Midwest RPO;
- 2004 MM5 data set at 36 km resolution provided by Midwest RPO.

These databases are consistent with those used by LADCO/MRPO for their BART assessments.

These prognostic meteorological data sets were initially combined with the 6-km grid resolution terrain and land use data to more accurately characterize the wind flow throughout the modeling domain. The gridded terrain data was derived using the U.S. Geological Survey (USGS) 90-meter grid spacing Digital Elevation Model (DEM) files. These files were processed in the TERREL pre-processor program. The gridded land use data was derived from USGS 1:250,000 Composite Theme Grid land use files.

The Step 2 wind fields were produced using the input of all available National Weather Service (NWS) and CASTNET hourly surface and twice-daily upper air balloon sounding data within the modeling domain. Figure 4-2 shows the meteorological stations that were included in the CALMET modeling and Appendix A provides their names and locations.

Figure 4-1 Kincaid CALMET and CALPUFF Modeling Domain

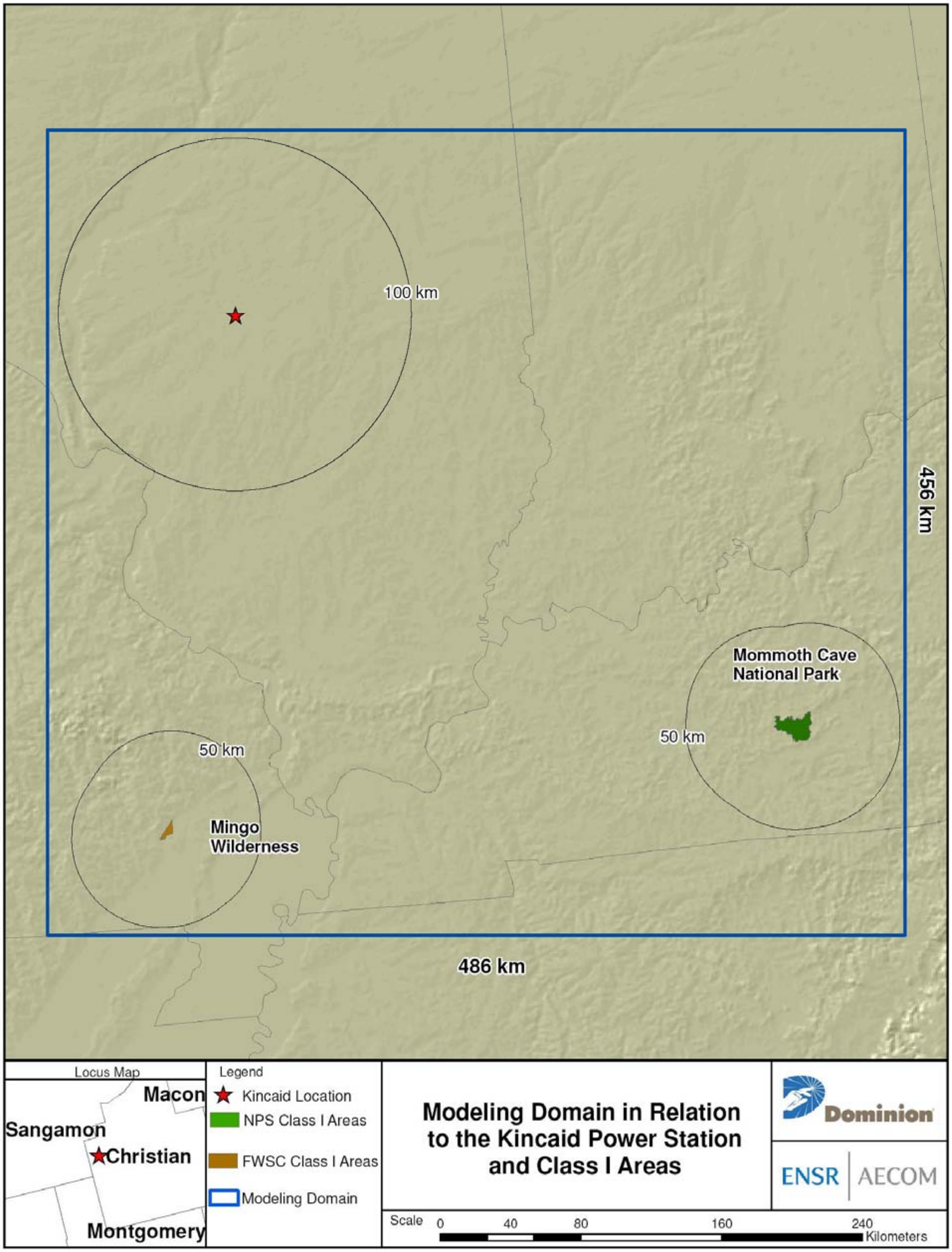
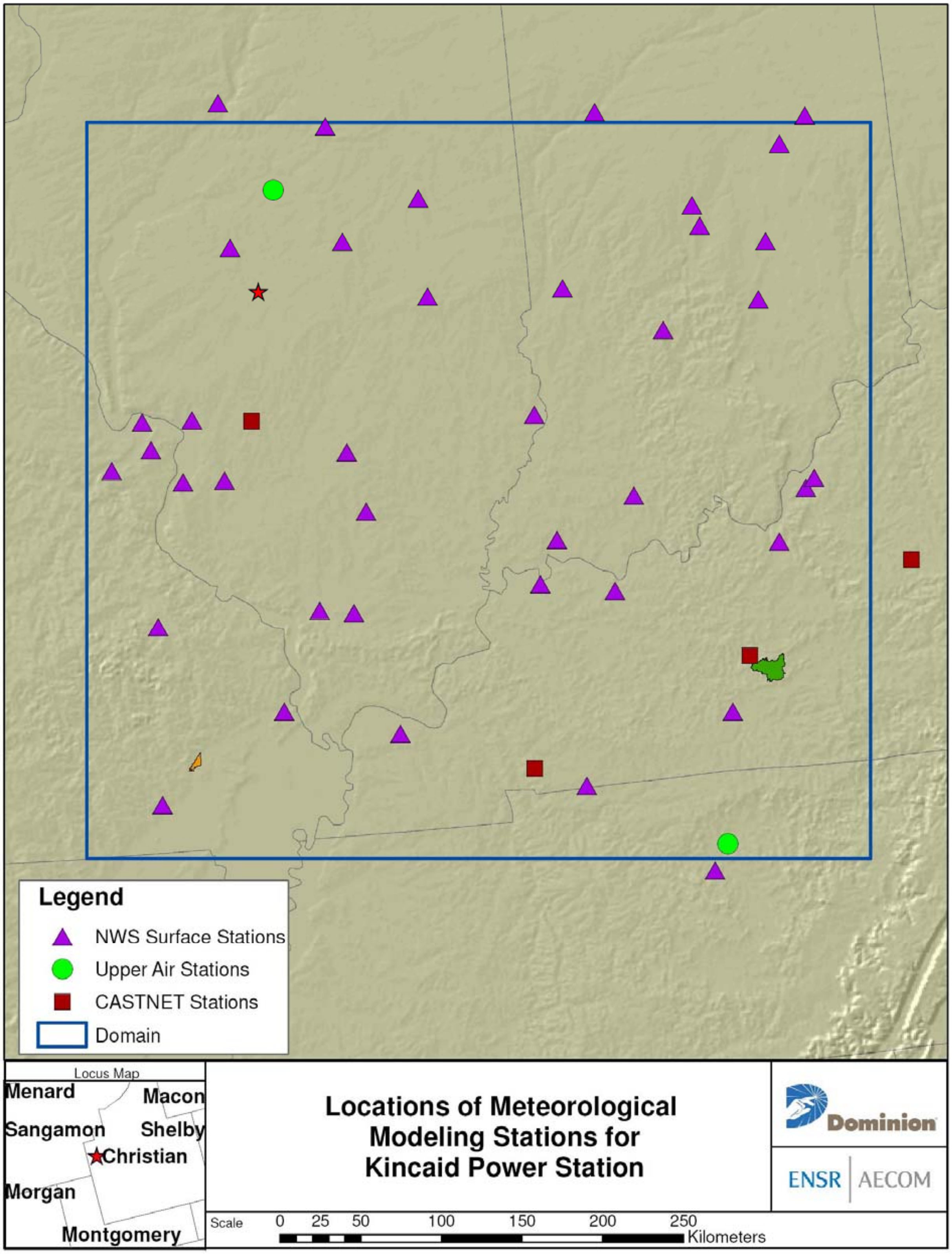


Figure 4-2 Location of Meteorological Stations used in CALMET Processing



5.0 CALPUFF Modeling Procedures

This section provides a summary of the modeling procedures that were used for the refined CALPUFF analysis conducted for the Kincaid Power Plant.

5.1 CALPUFF Modeling Domain and Receptors

ENSR used the latest EPA-approved version of CALPUFF (Version 5.8, Level 070623) that has been posted at http://www.src.com/calpuff/download/download.htm#EPA_VERSION.

The extents of the 6-km domain are shown in Figure 4-1. The modeling domain was based on a 100-km buffer around the source and at least a 50-km buffer around each of the two Class I areas plus an additional buffer to the east and to the west to account for puff re-circulations. The modeling domain is shown in Figure 4-1. This design allows for a 486 km (east-west) x 456 km (north-south) domain extent, at a 6-km resolution.

5.2 Technical Options Used in the Modeling

For CALPUFF modeling technical options, inputs, and processing steps, the Kincaid modeling procedures followed the MRPO common BART protocol.

For CALPUFF modeling, ENSR used seasonal ozone and ammonia ambient background concentrations that are identical to the MRPO common BART modeling protocol and are listed in Table 5-1.

Table 5-1 MRPO Ozone and Ammonia Seasonal Concentrations

Parameter	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
O_3 (ppb)	31	31	31	37	37	37	33	33	33	27	27	27
NH_3 (ppb)	0.3	0.3	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Due to the large distance to the nearest Class I areas, building downwash effects were not included in the CALPUFF modeling.

5.3 Natural Conditions and Monthly f(RH) at Class I Areas

Two Class I areas were modeled for the Kincaid facility. For these Class I areas, natural background conditions were established in order to determine a change in natural conditions related to a source's emissions.

For BART analyses, EPA has allowed states to accept either the annual average or 20% best day's natural background for BART exemption and determination modeling analyses. Regional Planning Organizations (RPOs) have provided guidance to states within their RPOs on what values to accept, which typically has varied based on the degree of the meteorological database refinement. For example, the VISTAS RPO has generally adopted the annual average background because it has provided member states with refined meteorological data sets. Since MRPO used the 36-km database with no observations, as a measure of conservatism, MRPO/LADCO recommended to states that the 20% best day's background be incorporated into the analysis as opposed to the annual average. This measure of conservatism was taken due to concerns by EPA Region 5 and FLMs on the accuracy of the 36-km meteorological data in "NO-OBS" mode. However, Wisconsin and Indiana, both MRPO states, have stated that they would allow sources to use the annual

average background with the 98th percentile day as opposed to the 20% best days *if a site-specific meteorological database is developed*.

ENSR refined the meteorological database with a finer grid resolution (6-km) and by introducing surface observations. Having a refined meteorological database has provided ENSR with additional justification for using the annual average background, while evaluating visibility impacts based on the source's impacts at the 98th percentile day modeled results. This procedure is consistent with other eastern states and other states within the MRPO.

For the modeling described in this document, ENSR used the annual average natural background concentrations shown in Table 5-2, modified as noted below with site-specific considerations, and corresponding to the annual average natural background concentrations (EPA 2003, Appendix B).

To determine the input to CALPOST, it is first necessary to convert the deciviews to extinction using the equation:

Extinction (Mm^{-1}) = 10 exp(deciviews/10).

For example, for Mingo, 7.43 deciviews is equivalent to an extinction of 21.02 inverse megameters (Mm^{-1}); this extinction includes the default 10 Mm-1 for Rayleigh scattering. This remaining extinction is due to naturally occurring particles, and is held constant for the entire year's simulation. Therefore, the data provided to CALPOST for Mingo would be the total natural background extinction minus 10 (expressed in Mm^{-1}), or 11.02. This is most easily input as a fine soil concentration of 11.02 $\mu g/m^3$ in CALPOST, since the extinction efficiency of soil (PM-fine) is 1.0 and there is no f(RH) component. The concentration entries for all other particle constituents would be set to zero, and the fine soil concentration would be kept the same for each month of the year. The monthly values for f(RH) that CALPOST needs were taken from "Guidance for Tracking Progress Under the Regional Haze Rule" (EPA, 2003) Appendix A, Table A-3.

Table 5-2 Annual Average Natural Background Concentrations

Component Represented	Mammoth Cave	Mingo
Soil (PM fine) (deciview)	7.69	7.43
Soil (PM fine) (Mm^{-1} or $\mu g/m^3$)*	21.58	21.02

* Extinction values include Rayleigh scattering.

5.4 Light Extinction and Haze Impact Calculations

The CALPOST postprocessor was used for part of the calculation of the impact from the modeled source's primary and secondary particulate matter concentrations on light extinction. The formula that is used in CALPOST is the existing IMPROVE/EPA formula, which is applied to determine a change in light extinction due to increases in the particulate matter component concentrations. Using the notation of CALPOST, the formula is the following:

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

The concentrations, in square brackets, are in $\mu g/m^3$ and b_{ext} is in units of Mm^{-1}. The Rayleigh scattering term (b_{Ray}) has a default value of 10 Mm^{-1}, as recommended in EPA guidance for tracking reasonable progress (EPA, 2003a).

The assessment of visibility impacts at the Class I areas applied CALPOST Method 6 (as standard with all BART applications). Each hour's source-caused extinction is calculated by first using the hygroscopic components of the source-caused concentrations, due to ammonium sulfate and nitrate, and monthly Class I area-specific f(RH) values. The contribution to the total source-caused extinction from ammonium sulfate and nitrate is then added to the other, non-hygroscopic components of the particulate concentration (from coarse and fine soil, secondary organic aerosols, and from elemental carbon) to yield the total hourly source-caused extinction.

6.0 CALPUFF Modeling and BART Determination Results

This section provides a summary of the modeled visibility improvement as a result of installing BART controls on Kincaid Units 1 and 2. It also presents the recommended BART determination.

6.1 Modeled Control Scenarios

The baseline emissions were modeled along with the four alternative control emission scenarios. Tables 3-2 through 3-5 present contain the emissions associated with the alternative control scenarios for Units 1 and 2.

6.2 Modeling Results for Baseline Emissions

CALPUFF modeling results of the baseline emissions at the two Class I areas are presented in Table 6-1 and graphically plotted in Figure 6-1. Modeling was conducted for all three years of CALMET meteorological data (2002-2004). For each Class I area and year, Table 6-1 lists the number of days above 0.5 and 1.0 delta-deciview due to plant emissions as well as the maximum and the 8^{th} highest delta-deciview. Figure 6-1 indicates that the higher visibility impacts occur at Mingo Wilderness and they are due to that park's proximity to Kincaid.

The results of the baseline emissions indicate that the 8^{th} highest visibility impacts at Mingo and Mammoth Cave are above the 0.5 delta deciview threshold.

6.3 Modeling Results for the Alternative Control Cases

CALPUFF modeling results of the four control cases at the two Class I areas are presented in Table 6-1 and graphically plotted in Figure 6-1. Modeling was conducted for all three years of CALMET meteorological data (2002-2004). For each Class I area and year, Table 6-1 lists the number of days above 0.5 and 1.0 delta-deciview due to plant BART emission controls.

Figure 6-1 indicates that substantial visibility improvements occur with either Case 1/1a (DSI with Trona) and Case 2 (DS/FF) controls and that no perceptible visibility impacts (defined by a 98^{th} percentile change of at least 0.5 delta-deciview) occur at any Class I area with these controls.

The results show that the averaged regional haze impacts with dry scrubber/fabric filter controls are reduced by about 1.10 delta-dv at Mingo and by 0.96 delta-dv at Mammoth Cave (relative to the baseline case). Nearly the same visibility improvement occurs with the use of the BART Case 3 controls, and the modeling results provided here have not accounted for the larger energy requirements of these controls. Installation of WFGD results in less improvement at the Class I areas due to the higher H_2SO_4 emissions associated with WFGD. Addition of WFGD would reduce visibility impacts by about 0.96 delta-dv at Mingo and by 0.81 delta-dv at Mammoth Cave from the baseline case.

Figure 6-2 shows a comparison between the visibility improvement over the top 8 days on average for BART control cases 1 and 2. This is a more robust comparison because it uses a more stable statistical sample of peak impact days. The results indicate that the visibility improvements available from BART cases 1 and 2 are essentially equivalent.

Table 6-1 Regional Haze Impacts Due to Baseline and BART Control Emissions

Class I Area	BART Controls	Met Year 2002				Met Year 2003				Met Year 2004				3-Yr Ave
		Days above		MAX Δ dv	8th Highest Δ dv	Days above		MAX Δ dv	8th Highest Δ dv	Days above		MAX Δ dv	8th Highest Δ dv	8th Highest Δ dv
		0.5 Δ dv	1.0 Δ dv			0.5 Δ dv	1.0 Δ dv			0.5 Δ dv	1.0 Δ dv			
Current IMPROVE Equation, Annual Average Background														
Mingo Wilderness	Baseline: 0.3% S PRB Coal, Seasonal SCR, ESP	26	12	3.49	1.30	38	18	2.88	1.45	33	13	1.93	1.36	1.37
	Case 1: 0.3% S PRB Coal, DSI/Trona, Enhanced year-round SCR, ESP	1	0	0.54	0.26	1	0	0.52	0.33	0	0	0.49	0.29	0.30
	Case 1a: 0.3% PRB Coal, Enhanced DSI/Trona, Enhanced year-round SCR, FF	1	0	0.51	0.24	0	0	0.47	0.29	0	0	0.44	0.27	0.27
	Case 2: 0.5% S PRB Coal, year-round SCR, DS, FF	1	0	0.65	0.22	2	0	0.63	0.26	0	0	0.40	0.29	0.26
	Case 3: 1.62% S Illinois Coal, year-round SCR, ESP, WFGD	5	0	0.91	0.40	8	1	1.08	0.53	5	0	0.77	0.44	0.46
Mammoth Cave National Park	Baseline: 0.3% S PRB Coal, Seasonal SCR, ESP	21	3	1.70	0.70	40	17	3.55	1.74	22	10	3.51	1.21	1.22
	Case 1: 0.3% S PRB Coal, DSI/Trona, Enhanced year-round SCR, ESP	0	0	0.36	0.16	2	0	0.84	0.36	2	0	0.70	0.23	0.25
	Case 1a: 0.3% PRB Coal, Enhanced DSI/Trona, Enhanced year-round SCR, FF	0	0	0.33	0.14	2	0	0.75	0.34	2	0	0.65	0.21	0.23
	Case 2: 0.5% S PRB Coal, year-round SCR, DS, FF	0	0	0.31	0.15	2	0	0.67	0.36	2	0	0.67	0.24	0.25
	Case 3: 1.62% S Illinois Coal, year-round SCR, ESP, WFGD	0	0	0.44	0.25	11	0	0.90	0.54	5	0	0.94	0.40	0.40

Figure 6-1 8th Highest Regional Haze Impacts Averaged Over 3 Years Due to Baseline and BART Control Emissions

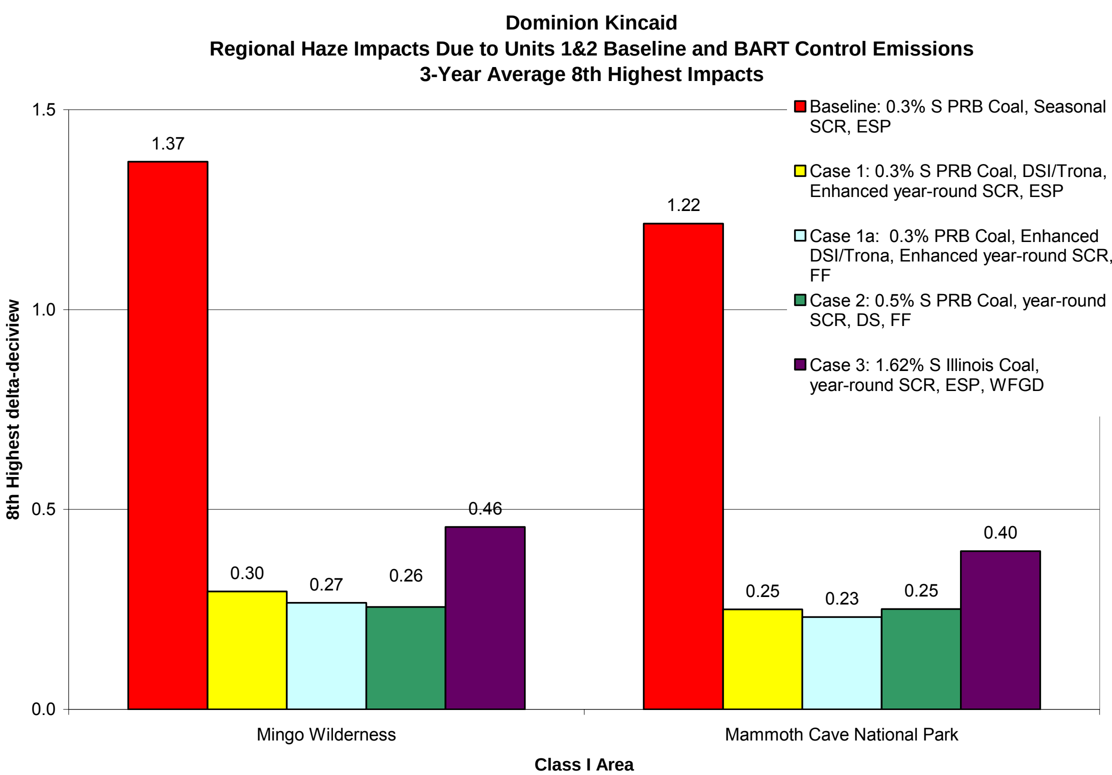
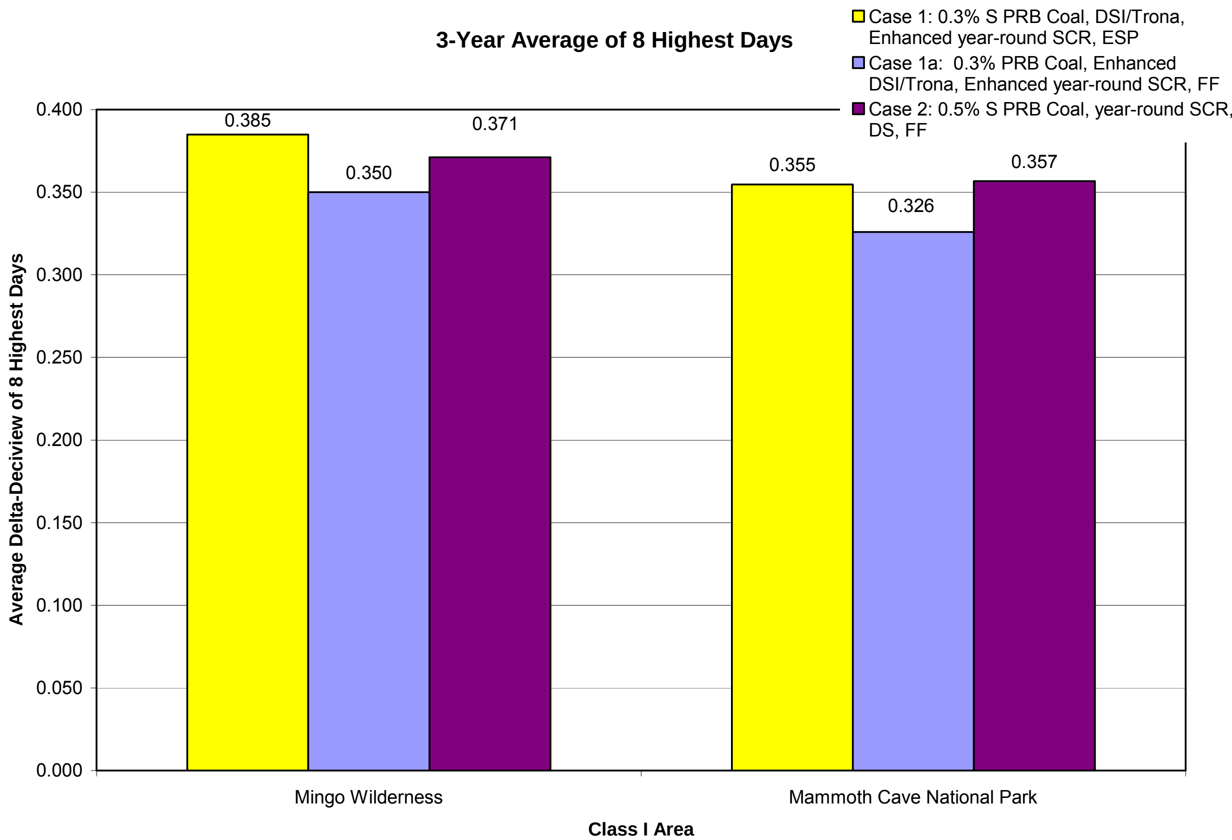


Figure 6-2 Regional Haze Impacts For Top 8 Days Averaged Over 3 Years: Cases 1, 1a, and 2



6.4 Cost of BART Control Cases

Table 6-2 summarizes the annualized control cost that is a function of the capital and annual operating costs, as well as fixed capital charges estimated by Dominion Energy. The table also presents a computation of each control case's visibility improvement effectiveness and cost relative to the baseline conditions, since each control case is independent of the others. The visibility results in Table 6-2 and Table 6-3 are based on the 8th highest regional haze impacts at Mingo and Mammoth Cave, respectively, averaged over the three years. Figure 6-3 presents a graph of visibility improvements as a function of the cost for each control case. It is clear from the figure that BART Case 1 (DSI with Trona) is clearly the most cost-effective option for the visibility improvement attained. As Figure 6-3 indicates, the incremental cost effectiveness of proceeding to Case 1a from Case 1 is steep (very little visibility improvement for the additional cost), so this step is not recommended.

Table 6-2 Visibility Improvement and Annual Costs for Each Control Case at Mingo

Control Case[a]	8th Highest at Mingo 3-Yr Ave (delta-dv)	Annualized Cost for Unit 1 & 2 ($/Year)	Incremental Cost Effectiveness from Baseline ($/dv)
Baseline: 0.3%S PRB Coal, Seasonal SCR, ESP	1.37	$0	$0
Case 1: 0.3% S PRB Coal, DSI/Trona, Enhanced year-round SCR, ESP	0.30	$24,820,000[b]	$23,100,000
Case 1a: 0.3% S PRB Coal, enhanced DSI with Trona, Enhanced year-round SCR, FF	0.27	$32,210,000[c]	$29,210,000
Case 2: 0.5% S PRB Coal, year-round SCR, DS, FF	0.26	$94,700,000[d]	$85,060,000
Case 3: 1.62%S Illinois Coal, year-round SCR, ESP, WFGD	0.46	$125,370,000[e]	$137,220,000

[a] These costs are based on 2008 dollars.

[b] When Case 1 costs are projected to 2014 dollars (based upon a 2014 installation date), the annualized cost becomes $30,660,000 and the incremental cost effectiveness from the baseline becomes $28,530,000.

[c] When Case 1a costs are projected to 2014 dollars (based upon a 2014 installation date), the annualized cost becomes $41,320,000 and the incremental cost effectiveness from the baseline becomes $37,470,000.

[d] When Case 2 costs are projected to 2017 dollars (based upon a 2017 installation date), the annualized cost becomes $156,110,000 and the incremental cost effectiveness from the baseline becomes $140,220,000.

[e] When Case 3 costs are projected to 2017 dollars (based upon a 2017 installation date), the annualized cost becomes $200,430,000 and the incremental cost effectiveness from the baseline becomes $219,370,000.

Table 6-3 Visibility Improvement and Annual Costs for Each Control Case at Mammoth Cave

Control Case[a]	8th Highest at Mammoth Cave 3-Yr Ave (delta-dv)	Annualized Cost for Unit 1 & 2 ($/Year)	Incremental Cost Effectiveness from Baseline ($/dv)
Baseline: 0.3%S PRB Coal, Seasonal SCR, ESP	1.22	$0	$0
Case 1: 0.3% S PRB Coal, DSI with Trona, Enhanced year-round SCR, ESP	0.25	$24,820,000[b]	$25,720,000
Case 1a: 0.3% S PRB Coal, enhanced DSI with Trona, Enhanced year-round SCR, FF	0.23	$32,210,000[c]	$32,710,000
Case 2: 0.5% S PRB Coal, year-round SCR, DS, FF	0.25	$94,700,000[d]	$98,200,000
Case 3: 1.62%S Illinois Coal, year-round SCR, ESP, WFGD	0.40	$125,370,000[e]	$152,950,000

[a] These costs are based on 2008 dollars.

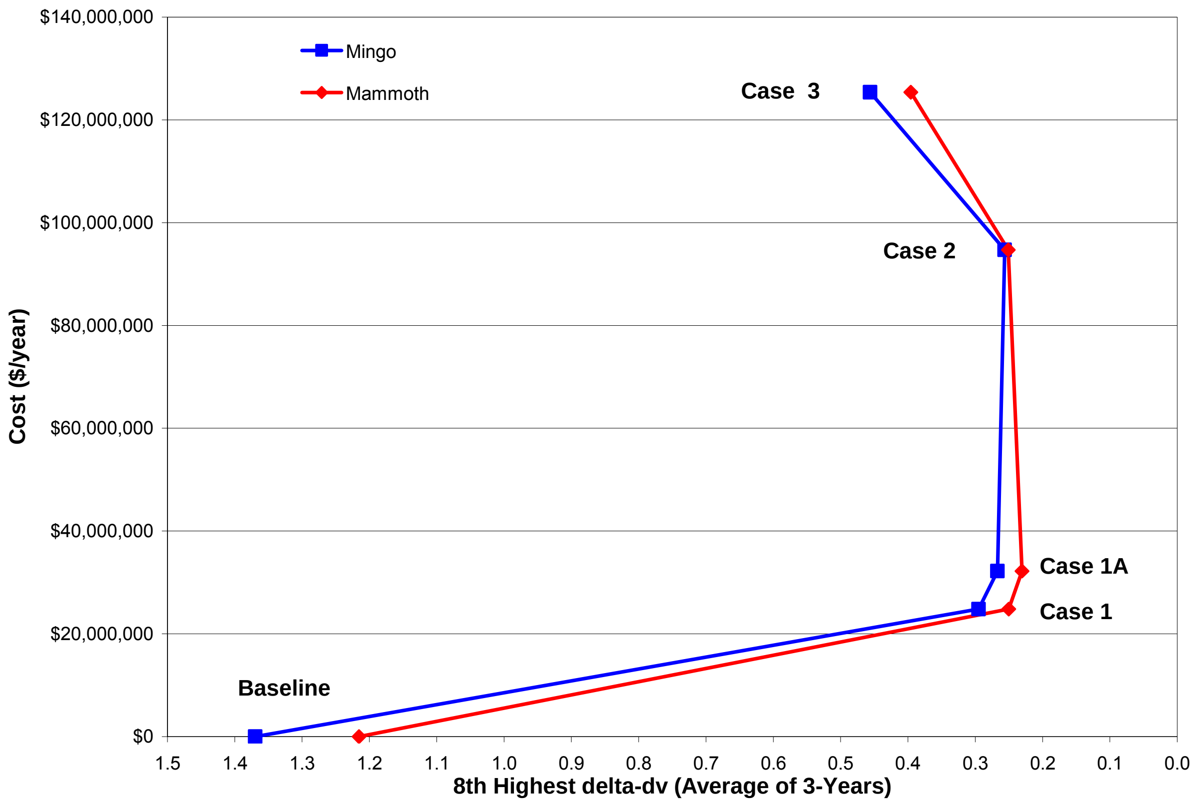
[b] When Case 1 costs are escalated to 2014 dollars (based upon 2014 installation date) the Annualized Cost becomes $30,660,000 and the Incremental Cost Effectiveness from the baseline becomes $31,770,000.

[c] When Case 1a costs are projected to 2014 dollars (based upon a 2014 installation date), the annualized cost becomes $41,320,000 and the incremental cost effectiveness from the baseline becomes $41,960,000.

[d] When Case 2 costs are escalated to 2017 dollars (based upon 2017 installation date) the Annualized Cost becomes $156,110,000 and the Incremental Cost Effectiveness from the baseline becomes $161,880,000

[e] When Case 3 costs are escalated to 2017 dollars (based upon 2017 installation date) the Annualized Cost becomes $200,430,000 and the Incremental Cost Effectiveness from the baseline becomes $244,530,000.

Figure 6-3 Annual Costs vs. Visibility Improvements



6.5 Conclusions

CALPUFF modeling of the baseline emissions and four BART control emission scenarios has been conducted. BART control cases included continuous operation of SCR and the installation of DSI with Trona, DS/FF and WFGD. Each control case was modeled to assess visibility improvements at the two Class I areas within 300 km of the plant.

The CALPUFF modeling results indicate that the use of DSI with Trona with increased SCR performance results in a visibility improvement that is about equivalent to or better than the dry or wet scrubber options, at a much reduced cost. Therefore, we conclude that the recommended BART control case is Case 1, with the use of DSI with Trona and enhanced SCR performance operation. The difference in effectiveness for regional haze reduction between BART Control Cases 1 and 1a is very small and the associated cost is relatively high. The ability for an SO_2 emission rate lower than 0.20 lb/MMBtu to be achieved in practice with the use of DSI with Trona will be determined from operational experience.

7.0 References

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Environmental Protection Agency (EPA), Guidance for Tracking Progress Under the Regional Haze Rule, EPA-454/B-03-003, Appendix A, Table A-3, September, 2003a

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EPRI. Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, EPRI, Palo Alto, CA: 2008. 1016384.

Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule (FR Vol. 70, No. 128 published July 6, 2005)

Regional Haze Regulations; Revisions to Provisions Governing Alternative to Source-Specific Best Available Retrofit Technology (BART) Determinations; Final Rule (FR Vol. 71, NO. 198 published October 13, 2006)

Single Source Modeling to Support Regional Haze BART Modeling Protocol November 17, 2005, Lake Michigan Air Directors Consortium, Des Plaines, IL

Appendix A

Meteorological Stations used in CALMET Processing

Table A-1 NWS Surface Stations used in CALMET Processing

ID	Station Name	State	Latitude	Longitude
724395	ALTON/ST LOUIS RGNL	IL	38.90	-90.05
724338	BELLEVILLE SCOTT AF	IL	38.55	-89.85
724397	BLOOMINGTON/NORMAL	IL	40.48	-88.91
725314	CAHOKIA/ST. LOUIS	IL	38.56	-90.15
724336	CARBONDALE/MURPHYSB	IL	37.78	-89.25
725315	CHAMPAIGN/URBANA	IL	40.03	-88.28
725316	DECATUR AIRPORT	IL	39.83	-88.86
725342	LAWRENCEVILLE\VIN.	IL	38.76	-87.60
724339	MARION REGIONAL	IL	37.75	-89.01
725317	MATTOON/CHARLESTON	IL	39.48	-88.28
724335	MOUNT VERNON (AWOS)	IL	38.31	-88.86
725320	PEORIA GREATER PEOR	IL	40.66	-89.68
724330	SALEM-LECKRONE	IL	38.65	-88.96
724390	SPRINGFIELD CAPITAL	IL	39.85	-89.68
724385	ANDERSON MUNICIPAL	IN	40.11	-85.61
724375	BLOOMINGTON/MONROE	IN	39.15	-86.61
724363	COLUMBUS BAKALAR	IN	39.26	-85.90
724384	EAGLE CREEK	IN	39.83	-86.30
724320	EVANSVILLE REGIONAL	IN	38.05	-87.53
724365	HUNTINGBURG	IN	38.25	-86.95
724380	INDIANAPOLIS INTL A	IN	39.71	-86.26
724386	LAFAYETTE PURDUE UN	IN	40.41	-86.93
725336	MUNCIE/JOHNSON FLD	IN	40.25	-85.40
724356	SHELBYVILLE MUNI	IN	39.58	-85.80
724373	TERRE HAUTE HULMAN	IN	39.45	-87.30
746716	BOWLING GREEN WARRE	KY	36.98	-86.43
746710	FORT CAMPBELL (AAF)	KY	36.66	-87.50
724240	FORT KNOX GODMAN AA	KY	37.90	-85.96
724238	HENDERSON CITY	KY	37.81	-87.68
724235	LOUISVILLE BOWMAN F	KY	38.23	-85.66
724230	LOUISVILLE STANDIFO	KY	38.18	-85.73
724237	OWENSBORO/DAVIESS	KY	37.73	-87.16
724350	PADUCAH BARKLEY REG	KY	37.05	-88.76
723489	CAPE GIRARDEAU MUNI	MO	37.23	-89.56
724454	FARMINGTON	MO	37.76	-90.40
723300	POPLAR BLUFF(AMOS)	MO	36.76	-90.46
724347	ST CHARLES COUNTY A	MO	38.91	-90.41
724340	ST LOUIS LAMBERT IN	MO	38.75	-90.36
724345	ST LOUIS SPIRIT OF	MO	38.65	-90.65
723270	NASHVILLE INTERNATI	TN	36.11	-86.68

Table A-2 CASTNET Surface Stations used in CALMET Processing

ID	Station Name	State	Latitude	Longitude
ALH157	Alhambra	IL	38.87	-89.62
CDZ171	Cadiz	KY	36.78	-87.85
MAC426	Mammoth Cave NP	KY	37.28	-86.26
MCK131	Mackville	KY	37.70	-85.05

Table A-3 Upper Air Stations used in CALMET Processing

WBAN ID	Station Name	State	Latitude	Longitude
4833	Lincoln-Logan	IL	40.15	-89.33
13897	Nashville	TN	36.25	-86.57