AECOM Environment

Prepared for:
Constellation Power Source Generation
Baltimore, MD

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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 Maryland Department of the Environment (MDE) has identified the coal-fired boiler, Unit 2, at Constellation's C.P. Crane Generating Station as a BART-eligible emission unit. 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.

This report documents the case-by-case BART analysis conducted for NO_X, SO_2, and PM_{10} emissions from Crane Unit 2. This analysis addresses the five statutory factors required by the Section 169A (g)(7) of the Clean Air Act that states must consider in making BART determinations:

(1) the costs of compliance,

(2) the energy and non-air quality environmental impacts of compliance,

(3) any existing pollution control technology in use at the source,

(4) the remaining useful life of the source, and

(5) the degree of improvement in visibility which may reasonably be anticipated to results from the use of such technology

The following emission scenarios were evaluated for the BART analysis:

- Baseline (2001-2003 period)- Maximum daily emissions of SO_2 and NO_X as well as the maximum daily heat input to Unit 2 during the baseline period were used to calculate the SO_2 and NO_X emission levels of the boiler for that period. The higher of the results of the two stack test conducted during the baseline period was used to calculate the filterable PM emission rate of the boiler. Therefore, the following emission rates of haze causing pollutants were used to model the baseline visibility impacts of Unit 2: SO_2 = 3.30 lb/MMBtu, NO_X = 1.50 lb/MMBtu and total PM_{10} = 0.079 lb/MMBtu.
- Control Case - The current (2009-2010 period) NO_X, SO_2, and PM_{10} emissions signature of Unit 2 which assumes firing Powder River Basin (PRB) coal and year-round operation of the existing SNCR and existing baghouse to achieve SO_2 emissions level of 0.90 lb/MMBtu, NO_X emissions level of 0.30 lb/MMBtu and total PM_{10} emissions level of 0.034 lb/MMBtu.

CALPUFF modeling of baseline emissions showed that Unit 2 is subject to BART based on a 3-year average eighth highest delta deciview impact of 1.65 dv at Shenandoah National Park. CALPUFF modeling results show that substantial visibility improvement occurs with the implementation of Control Case emission controls. For the Control Case, the 3-year average eighth highest delta deciview impact at Shenandoah National Park is 0.43 dv.

Therefore, the recommended BART for Crane Unit 2 is firing Powder River Basin coal (~0.4% S) and year-round operation of the existing SNCR and fabric filter to achieve SO_2 emissions level of 0.90 lb/MMBtu and a NO_X emissions level of 0.30 lb/MMBtu.

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 Maryland Department of the Environment (MDE) for development of the state's Regional Haze State Implementation Plan (SIP). The MDE has identified the coal-fired boiler, Unit 2 at Constellation's C.P. Crane Generating Station as a BART-eligible emission unit.

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 (EGUs) 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 BART analysis was conducted in accordance with the procedures contained in the Final BART Guidelines published by the USEPA on July 6, 2005 (Federal Register Volume 70, No. 128). 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 baseline period for BART analysis as specified in 40 CFR 51 is 2001-2003.

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 Unit 2 at the Crane Generating Station. Section 2.0 provides a description of Crane Unit 2 and its baseline emissions. Section 3.0 provides a discussion of available SO_2, NO_X and PM control technologies. The available meteorological data and the CALPUFF modeling procedures are described in Section 4.0. The results of the visibility improvement modeling using CALPUFF are presented in Section 5.0, along with the BART recommendation. References are listed in Section 6.0.

2.0 Baseline Data

2.1 Overview of BART Emission Unit (Unit 2)

The BART-affected emission unit at the Crane Generating Station is Units 2. Unit 2 was installed in February 1963 and began operation during the time period (1962-1977) targeted by the Regional Haze BART Rule. Unit 2 is a utility boiler fired by four cyclone burners. The boiler powers a Westinghouse turbine generator with a nominal rating of 200 MW gross. Natural gas is used as a start-up fuel.

2.2 Current Control Technologies

In 1999, Unit 2 was retrofitted with natural gas reburn (NGR) systems to reduce NO_X emissions. Subsequently, an over-fire air system (OFA) was installed to replace the NGR as the NO_X control system. Constellation commenced operation of the add-on NO_X control system (an SNCR) on Unit 2 in August 2008. Based on baseline emissions, the sulfur content of the eastern bituminous coal which the Unit 2 had been burning during the baseline period was approximately 2.58% by weight.

Unit 2 is equipped with continuous emissions monitoring system (CEMS) for NO_X, CO_2, and SO_2 and a continuous opacity monitor (COM) for opacity.

2.3 Baseline Emissions

SO_2 and NO_X baseline emissions were determined using monitored data collected by the CEMS during the baseline period i.e. years 2001 through 2003. Filterable PM baseline emissions were determined using the highest results of the stack tests conducted during the baseline period (October 2001 and August 2003). Speciation of the particulate matter emissions into filterable and condensable PM_{10} components was conducted using the following approach:

- Filterable PM was subdivided by size category consistent with the default approach cited in AP-42, Table 1.1-6. Size distributions applicable to a dry bottom pulverized coal fired boiler equipped with a baghouse were used (based on Table 1.1-6, since size distribution data for a baghouse controlled wet bottom cyclone boiler were not available in AP-42). Based on Table 1.1-6, 92% of filterable PM is total PM_{10} and 53% is fine PM_{10} ($PM_{2.5}$). Coarse PM_{10} is the difference between total PM_{10} and fine PM_{10}, i.e., $PM_{2.5}$.
- 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 (0.0082 for eastern bituminous coal), and
F2 is the control factor (51% control for an air pre-heater and 90% control for a baghouse).

- For pulverized coal-fired boilers burning coal with a sulfur content of 2.58%, total condensable organic PM_{10} emissions factor is 0.2 × (0.1S-0.03) lb/MMBtu based on AP-42, Table 1.1-5. Fuel sulfur content was determined based on the baseline SO_2 emissions (lb/MMBtu) and the heating value of coal (Btu/lb).

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 provides the stack parameters that were used in the baseline modeling analysis.

Table 2-1 Crane Generating Station – Baseline Emissions for Unit 2

Facility	Unit	Description	Max. Heat Input (a)	Fuel S Content (b)	Coal Heating Value	Maximum SO_2 Emissions (a)		Maximum NO_X Emissions (a)		Maximum Filterable PM Emissions (c)		Filterable PM_{10}					Condensible PM_{10}			Total PM_{10}
												Total	Coarse	Fine			Total	H2SO4	Organic	
														Fine Total	Fine Soil	EC				
			MMBtu/hr	%	Btu/lb	lb/day	lb/hr	lb/day	lb/hr	lb/MMBtu	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
C P Crane	2	200 MWe wet bottom cyclone fired boiler rated at 1,865 MMBtu/hr and equipped with a baghouse	2,072	2.58	12,769	162,414	6,767	74,774	3,116	0.034	70.44	64.80 (d)	27.47 (d)	37.33 (d)	35.95	1.38 (e)	99.75 (f)	5.15 (f)	94.60 (g)	164.56 (h)

(a) Maximum daily/24 hour heat input, SO2 and NOx emissions are based on Part 75 monitoring data (Clean Air Markets Database) for the period between 2001 - 2003.
(b) Maximum sulfur content of coal calculated using the maximum daily SO2 emission factor and the average annual heating value of coal.
(c) Maximum filterable PM emissions are based on higher of the two available emissions testing results (Method 5) for testing conducted in 2001 and 2003 (PM = 0.034 lb/MMBtu).
(d) Size distributions applicable to a dry bottom pulverized coal fired boiler equipped with a baghouse were used (based on Table 1.1-6, since size distribution data for a baghouse controlled wet bottom cyclone boiler were not available in AP-42). Based on Table 1.1-6, 92% of filterable PM is total PM10 and 53% is fine PM10 (PM2.5). Coarse PM10 is the difference between total PM10 and fine PM10.
(e) 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.
(f) Total condensible PM10 is the sum of H2SO4 and organic condensible PM10 emissions. H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants", Technical Update March 2007, J. Edward Cichanowicz. H2SO4 emission rate, before control, equals 0.0082 x %S/100 x 1/(heating value of coal) x 1,000,000 x Heat Input x 98.06/32.07 based on Table 4-1 of the referenced document. Coal heating value (avg.) is 12,769 Btu/lb based on DOE NETL's Coal Plant Database. H2SO4 control is 51% for an air preheater and 90% for a baghouse based on Tables 3-1 and 3-2 of the referenced document.
(g) Organic condensible PM10 is 0.20 x (0.1S -0.03) lb/MMBtu based on AP-42 Table 1.1-5.
(h) Total PM10 is the sum of filterable PM10 and condensable PM10.

Table 2-2 Crane Generating Station – Baseline Stack Parameters for Unit 2

Latitude (deg)	Longitude (deg)	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)
39.32	-76.36	2	117.0	5.33	412.32	316.95	14.18

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.

The following BART control scenario was evaluated:

- Control Case - The current (2009-2010 period) NO_X, SO_2, and PM_{10} emissions signature of Unit 2 which includes firing Powder River Basin (PRB) coal and year-round operation of the existing SNCR and existing baghouse to achieve SO_2 emissions level of 0.70 lb/MMBtu, NO_X emissions level of 0.30 lb/MMBtu and total PM_{10} emissions level of 0.079 lb/MMBtu. Emission levels corresponding to this improvement are shown in Table 3-1 and associated stack parameters are listed in Table 3-2.

3.1 SO_2 Emission Controls

Sulfur dioxide emissions are generated in fossil fuel-fired combustion units as a result of 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 following SO_2 control option was evaluated for this BART analysis:

- *SO_2 Control Case* - The Unit 2 boiler had been burning eastern bituminous coal (approximately 2.58% S) during the baseline period. Sulfur dioxide emissions during the baseline period were on the order of 3.30 lb/MMBtu. However, the Station switched to the use of PRB coal in 2006 and has been able to achieve SO_2 emissions on the order of 0.70 lb/MMBtu (equivalent to 0.3% S coal). Currently (2009 – 2010 time period), the boiler is performing at an SO_2 emission level of 0.7 lb/MMBtu which equates to a control efficiency of 88% compared to baseline and is attributable to the lower S content of PRB coal . Emission levels corresponding to this scenario are shown in Table 3-1 and the associated stack parameters are shown in Table 3-2.

Table 3-1 Crane Generating Station – Emissions for Control Case

Facility	Unit	Description	Max. Heat Input (a)	SO2 Emission Factor	NOx Emission Factor	Maximum SO2 Emissions (a)	Maximum NOX Emissions (a)	Maximum Filterable PM Emissions (c)		Filterable PM_{10}					Condensible PM_{10}			Total PM_{10}
										Total	Coarse	Fine			Total	H2SO4 (b)	Organic	
												Fine Total	Fine Soil	EC				
			MMBtu/hr	(lb/MMBtu)	(lb/MMBtu)	lb/hr	lb/hr	lb/MMBtu	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
C P Crane	2	200 MWe wet bottom cyclone fired boiler rated at 1,865 MMBtu/hr and equipped with a baghouse	2,072	0.90	0.30	1,865	622	0.034	70.44	64.80 (d)	27.47 (d)	37.33 (d)	35.95	1.38 (e)	4.41 (f)	0.26 (f)	4.14 (g)	69.21 (h)

(a) Maximum daily/24 hour heat input is based on Part 75 monitoring data (Clean Air Markets Database) for the period between 2001 - 2003. Max. SO2 and Nox emissions for the future case are based on data from Constellation (SO2 = 0.7 lb/MMBtu (PRB coal) & NOx = 0.3 lb/MMBtu (OFA and SNCR))

(b) H2SO4 emissions calculated using sulfur content of coal as described in Note (f) below. Sulfur content of coal calculated using the maximum daily SO2 emission factor and the average annual heating value of coal. Sulfur content of coal calculated to be = 0.4%.

(c) Maximum filterable PM emissions are based on higher of the two available emissions testing results (Method 5) for testing conducted in 2001 and 2003 (PM = 0.034 lb/MMBtu).

(d) Size distributions applicable to a dry bottom pulverized coal fired boiler equipped with a baghouse were used (based on Table 1.1-6, since size distribution data for a baghouse controlled wet bottom boiler were not available in AP-42). Based on Table 1.1-6, 92% of filterable PM is total PM10 and 53% is fine PM10 (PM2.5). Coarse PM10 is the difference between total PM10 and fine PM10.

(e) 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.

(f) Total condensible PM10 is the sum of H2SO4 and organic condensible PM10 emissions. H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants", Technical Update March 2007, J. Edward Cichanowicz. H2SO4 emission rate, before control, equals 0.0018 x %S/100 x 1/(heating value of coal) x 1,000,000 x Heat Input x 98.06/32.07 based on Table 4-1 of the referenced document. Heating value for PRB coal is 8,500 Btu/lb based on DOE NETL's Coal Plant Database. H2SO4 control is 51% for an air preheater and 90% for a baghouse based on Tables 3-1 and 3-2 of the referenced document. SNCR does not add to H2SO4 emissions.

(g) Organic condensible PM10 is 0.20 x (0.01) lb/MMBtu based on AP-42 Table 1.1-5.

(h) Total PM10 is the sum of filterable PM10 and condensable PM10.

Table 3-2 Crane Generating Station – Stack Parameters for Control Case

Latitude (deg)	Longitude (deg)	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)
39.32	-76.36	2	117.0	5.33	412.32	316.95	14.18

3.1.1 Discussion of Candidate SO_2 Control Technologies

Since, use of PRB coal as opposed to eastern bituminous coal alone resulted in a control of ~88% of SO_2 emissions, no add-on SO_2 controls were considered as part of this BART analysis. Moreover, as discussed later in Section 5, the visibility improvements resulting from switching the fuel to PRB coal are significant.

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 Unit 2 already incorporates combustion controls, this analysis is limited to the following post-combustion control technologies:

- Selective catalytic reduction capable of 75 to 80 percent control; and
- Selective non-catalytic reduction capable of 30 to 50 percent control.

Unit 2 currently has an SNCR for the control of NO_X emissions during the ozone season.

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 Crane.

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 NO_X 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 is 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-NO_X 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 ammonium 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 Unit 2. Performance data from coal fired units indicate that the SCR systems are capable of NO_X removal efficiencies ranging from 75 to 80%.

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 Unit 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.

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. However, Crane Unit 2 already has an SNCR in place for controlling NO_X emissions which offers a control efficiency of 80% compared to baseline NO_X levels. Therefore, continuous operation of the existing SNCR system with a rolling 30-day emission rate of 0.30 lb/MMBtu is recommended as BART for Crane Unit 2.

3.3 PM Emission Control

Crane Unit 2 currently employs a fabric filter to control PM emissions. The baseline PM emission rate for Crane Unit 2 is 0.016 gr/dscf (0.034 lb/MMBtu) which is well below its permit limit of 0.03 gr/dscf. Moreover, PM emissions are not a significant contributor to the visibility impacts as seen in the modeling analysis.

Visibility modeling shows that PM emissions have a relatively minor contribution to the overall visibility impacts. Given the high performance level of the existing baghouse, these PM control devices are considered BART for Unit 2 and no additional PM controls were considered as part of this analysis.

4.0 CALPUFF Modeling Inputs and Procedures

This section provides a summary of the modeling procedures that were used for the refined CALPUFF analysis conducted for the BART unit at Crane Generating Station.

4.1 Location of Source vs. Relevant Class I Areas

Figure 4-1 shows the location of the Crane Generating Station relative to nearby Class I areas. There are four Class I areas within 300 km of the plant: Brigantine National Wildlife Refuge (NJ), Shenandoah National Park (VA), Dolly Sods Wilderness Area (WV), and Otter Creek Wilderness Area (WV). James River Face Wilderness Area (VA) was also included in the visibility modeling even though it is located 324 km from the site. The BART modeling analysis has been conducted for all of these Class I areas in accordance with the referenced Visibility Improvement State and Tribal Association of the Southwest (VISTAS) common BART modeling protocol and FLAG 2008 guidance.

4.2 General Modeling Procedures

Class I modeling was conducted using three years (2001-2003) of CALMET meteorological database. The database was developed for use in BART assessment in VISTAS. VISTAS has developed five sub-regional 4-km CALMET meteorological databases. Class I modeling for Crane Generating Station was done using sub-domain #5.

CALMET processing procedures are fully described in the VISTAS common BART modeling protocol, available at http://www.vistas-sesarm.org/documents/BARTModelingProtocol_rev3.2_31Aug06.pdf.

The receptors used for each of the Class I areas are based on the National Park Service database of Class I receptors, available at http://www.nature.nps.gov/air/maps/Receptors/index.cfm.

4.3 Model Version

The EPA-approved version of CALPUFF was used to model the emissions and Version 6 of CALPOST was used to process the regional haze impacts with Method 8 (New IMPROVE equation). CALPUFF Version 5.8, Level 070623 and CALPOST Version 6.221, Level 080724 were used.

These programs are available at http://www.src.com/calpuff/calpuff1.htm.

4.4 Background Air Quality Data

CALPUFF modeling was conducted with the hourly background ozone data that was developed for VISTAS sub domain #5 and a monthly ambient ammonia background of 0.5 ppb. This ammonia background corresponds to the value listed in the VISTAS BART protocol.

4.5 Light Extinction and Haze Impact Calculations

The FLAG 2008 document (dated June 26, 2008) provides guidance on the recommended new IMPROVE equation application. CALPOST Version 6.221 defines this application as Method 8, Mode 5. The assessment of visibility impacts at the Class I areas used CALPOST Method 8.

The CALPOST postprocessor was used for the calculation of the impact of the modeled source's primary and secondary particulate matter concentrations on light extinction. In the new IMPROVE equation, the total sulfate, nitrate, and organic carbon compound concentrations are each split into two fractions, representing small and large size distributions of those components. New terms, such as sea salt (important for coastal locations), absorption by NO_2 (only used where NO_2 data are available), and site-specific Rayleigh scattering have been added to the equation. The new IMPROVE equation for calculating light extinction is shown below.

$$
\begin{aligned}
b_{ext} = \; & 2.2 \times f_S(RH) \times [\text{Small Sulfate}] + 4.8 \times f_L(RH) \times [\text{Large Sulfate}] \\
& + 2.4 \times f_S(RH) \times [\text{Small Nitrate}] + 5.1 \times f_L(RH) \times [\text{Large Nitrate}] \\
& + 2.8 \times [\text{Small Organic Mass}] + 6.1 \times [\text{Large Organic Mass}] \\
& + 10 \times [\text{Elemental Carbon}] \\
& + 1 \times [\text{Fine Soil}] \\
& + 0.6 \times [\text{Coarse Mass}] \\
& + 1.7 \times f_{SS}(RH) \times [\text{Sea Salt}] \\
& + \text{Rayleigh Scattering (Site Specific)} \\
& + 0.33 \times [NO_2\ (\text{ppb})] \ \ \{\text{or as: } 0.1755 \times [NO_2\ (\mu g/m^3)]\}
\end{aligned}
$$

Where:

[ ] indicates concentrations in $\mu g/m^3$

$f_S(RH)$ = Relative humidity adjustment factor for small sulfate and nitrate

$f_L(RH)$ = Relative humidity adjustment factor for large sulfate and nitrate

$f_{SS}(RH)$ = Relative humidity adjustment factor for sea salt

For Total Sulfate < 20 $\mu g/m^3$:

$$[\text{Large Sulfate}] = ([\text{Total Sulfate}] / 20\ \mu g/m^3) \times [\text{Total Sulfate}]$$

For Total Sulfate $\geq$ 20 $\mu g/m^3$:

$$[\text{Large Sulfate}] = [\text{Total Sulfate}]$$

And:

$$[\text{Small Sulfate}] = [\text{Total Sulfate}] - [\text{Large Sulfate}]$$

To calculate large and small nitrate and organic mass, substitute ({Large, Small, Total} {Nitrate, Organic Mass}) for Sulfate.

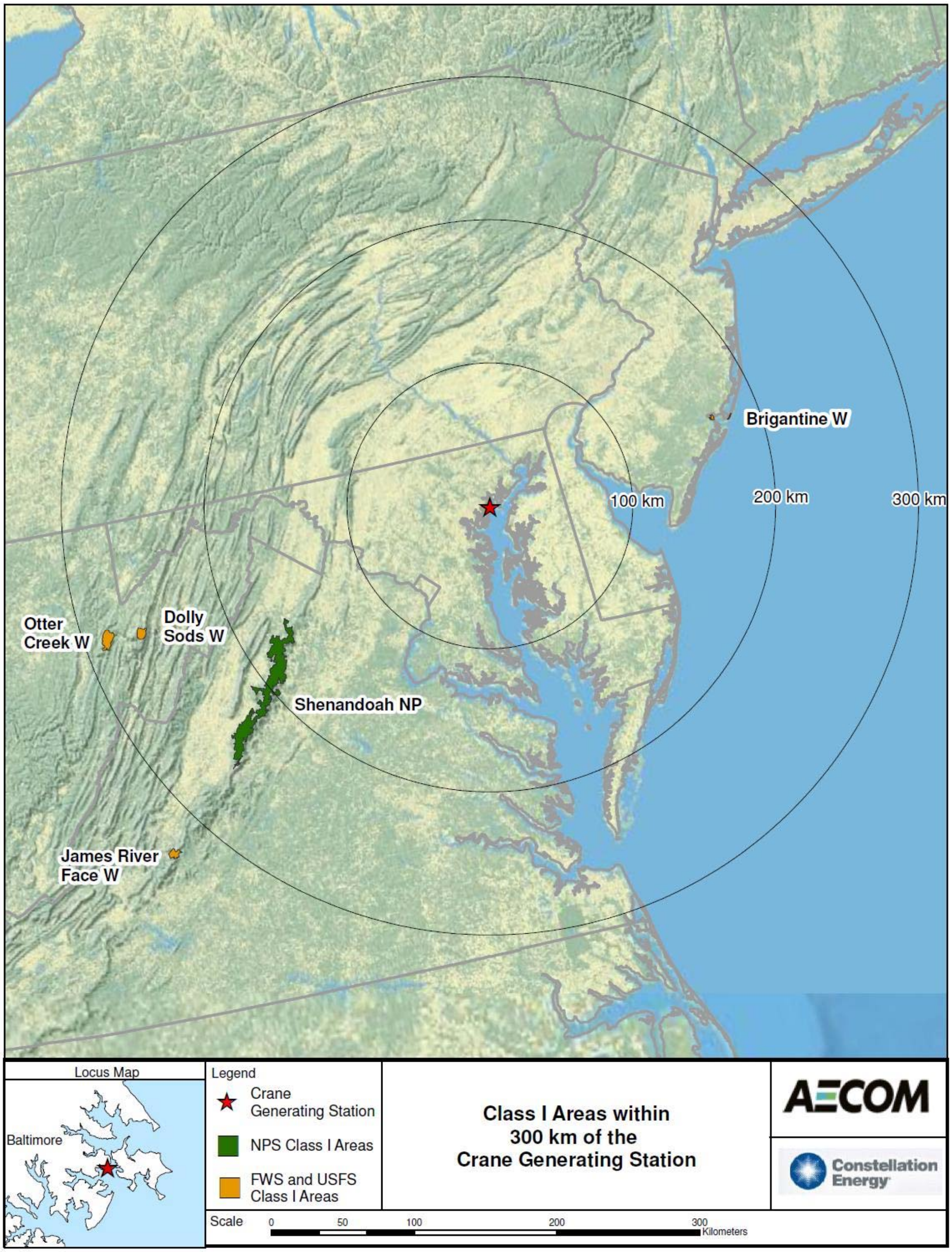
The FLAG 2008 document provides inputs to the new IMPROVE equation that are based on either the 20% best or annual average natural conditions. AECOM elected to use inputs that are based on the 20% best days natural conditions.

Inputs to the CALPOST Method 8 calculations for each Class I area were obtained from the FLAG 2008 document tables referenced below.

Table 4-1 References to the New IMPROVE Equation CALPOST Inputs

Sea salt concentration	FLAG 2008 Table V.1-2
Rayleigh scattering	FLAG 2008 Table V.1-2
Monthly f_L (RH)	FLAG 2008 Table V.1-3
Monthly f_S (RH)	FLAG 2008 Table V.1-4
Monthly f_{SS} (RH)	FLAG 2008 Table V.1-5

Figure 4-1 Location of Class I Areas in Relation to the Crane Generating Station



5.0 CALPUFF Modeling and BART Determination Results

This section presents the recommended BART determination and provides a summary of the modeled visibility improvement as a result of applying BART to Crane Unit 2.

5.1 Baseline CALPUFF Modeling Results

CALPUFF modeling results of the baseline emissions at five Class I areas are presented in Table 5-1. Modeling was conducted for all three years of CALMET meteorological data (2001-2003). Emission rates that were used in modeling the baseline emissions are listed in Table 2-1.

For each Class I area and year, Table 5-1 lists the 98th percentile (8th highest day's) delta-deciview. The results indicate that the higher visibility impacts generally occur at Shenandoah National Park and Brigantine Wilderness. Higher impacts at these Class I area are due to their proximity to the site and local meteorological conditions.

EPA recommends in its BART Guidelines that the 98^{th} percentile value of the modeling results should be compared to the threshold of 0.5 deciviews to determine if a source contributes to visibility impairment. The Guidelines also recommend using the 98^{th}-percentile statistic for comparing visibility improvements due to BART control options.

The results of the baseline emissions analysis indicate that the Crane Generating Station Unit 2 has predicted visibility impacts exceeding 0.5 deciviews in at least one Class I area. Therefore, per 40 CFR Part 51, Appendix Y, Unit 2 is presumed to be subject to BART because its emissions may reasonably be anticipated to cause or contribute to visibility impairment at a nearby Class I area.

Table 5-1 Regional Haze Impacts Due to Baseline Emissions

Class I Area	2001				2002				2003				3- year Avg
	days > 0.5 dv ΔB_{ext}	days > 1.0 dv ΔB_{ext}	MAX dv ΔB_{ext}	8^{th} Highest dv ΔB_{ext}	days > 0.5 dv ΔB_{ext}	days > 1.0 dv ΔB_{ext}	MAX dv ΔB_{ext}	8^{th} Highest dv ΔB_{ext}	days > 0.5 dv ΔB_{ext}	days > 1.0 dv ΔB_{ext}	MAX dv ΔB_{ext}	8^{th} Highest dv ΔB_{ext}	8^{th} Highest dv ΔB_{ext}
Shenandoah NP	29	14	3.1	1.19	29	11	3.8	1.42	45	18	5.0	2.33	1.65
Brigantine W	36	12	3.2	1.34	29	5	1.4	0.83	39	12	3.0	1.35	1.17
Otter Creek W	7	0	0.9	0.43	8	3	1.2	0.55	14	3	3.3	0.70	0.56
Dolly Sods W	9	1	1.0	0.54	8	3	1.3	0.53	13	6	4.0	0.77	0.62
James River Face W	7	5	1.4	0.48	9	2	1.2	0.62	11	4	1.9	0.78	0.63

5.2 Modeling Results for the BART Control Cases

The BART control case's CALPUFF modeling results are presented in Table 5-2. Modeling was conducted for all three years of CALMET meteorological data (2001-2003) and for five Class I areas to determine the effects of the existing controls on Unit 2. Emission rates that were used in modeling the BART control option are listed in Table 3-1. Associated stack parameters with the control options are given in Table 3-2.

For each Class I area and year, the tables below list the 98th percentile delta-deciview values, number of days above 0.5 and 1.0 delta-deciview due to the BART emission controls.

Class I modeling results show that the averaged regional haze impacts with the existing emissions controls are reduced by about 1.22 delta-dv at Shenandoah, by 0.86 delta-dv at Brigantine, 0.41 delta-dv at Otter Creek, 0.45 delta-dv at Dolly Sods and 0.47 delta-dv at James River Face Wilderness (relative to the baseline case).

Table 5-2 Regional Haze Impacts Due to the Control Case (Current Emissions 2009-2010 period)

Class I Area	2001				2002				2003				3- year Avg
	days > 0.5 dv Δ B_{ext}	days > 1.0 dv Δ B_{ext}	MAX dv Δ B_{ext}	8th Highest dv Δ B_{ext}	days > 0.5 dv Δ B_{ext}	days > 1.0 dv Δ B_{ext}	MAX dv Δ B_{ext}	8th Highest dv Δ B_{ext}	days > 0.5 dv Δ B_{ext}	days > 1.0 dv Δ B_{ext}	MAX dv Δ B_{ext}	8th Highest dv Δ B_{ext}	8th Highest dv Δ B_{ext}
Shenandoah NP	3	0	0.9	0.33	5	0	1.0	0.35	10	2	1.5	0.60	0.43
Brigantine W	2	0	1.0	0.35	0	0	0.4	0.23	3	0	0.9	0.36	0.31
Otter Creek W	0	0	0.2	0.12	0	0	0.3	0.15	1	0	0.9	0.19	0.15
Dolly Sods W	0	0	0.3	0.14	0	0	0.3	0.14	1	1	1.1	0.21	0.16
James River Face W	0	0	0.4	0.12	0	0	0.3	0.17	0	0	0.5	0.20	0.16

5.3 BART Results and Discussion

As discussed earlier in this section, visibility improvements resulting from the current emissions level of Unit 2 are on the order of 70-75% compared to the baseline. Therefore, we conclude that the existing emission controls including the use of low sulfur coal (PRB coal) for SO_2 control, an SNCR for NO_X control and a baghouse for PM control, provide adequate visibility benefits, provide for reasonable progress, and therefore, represent BART.

6.0 References

Environmental Protection Agency (EPA), AP 42, Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, January, 1995

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

Environmental Protection Agency (EPA), Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program, EPA 454/B-03-005, September 2003b

Environmental Protection Agency (EPA), Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts, EPA-454/R-98-019, December, 1998

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).

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Federal Land Managers' Air Quality Related Values Workgroup (FLAG). Phase I Report Revised Draft, June 2008.

Visibility Improvement State and Tribal Association of the Southeast (VISTAS), Revision 3, Protocol for the Application of the CALPUFF Model for Analyses of Best Available Retrofit Technology (BART), updated July 18, 2006.

Appendix A

Modeling Archive (CD Available on Request from MDE)