Environment

Prepared for:
Constellation Power Source Generation
Baltimore, MD

Prepared by:
AECOM
Westford, MA
60159393-1
August 2, 2010

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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 3, at Constellation's H.A. Wagner 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 Wagner Unit 3. 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 result 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 3 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 tests 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 3: SO_2 = 1.5 lb/MMBtu, NO_X = 0.40 lb/MMBtu and total PM_{10} = 0.024 lb/MMBtu.

- Control Case 1- The current (2009-2010 period) NO_X, SO_2, and PM_{10} emissions signature of Unit 3 which assumed firing low-sulfur eastern bituminous coal and year-round operation of the existing SCR and existing ESP to achieve SO_2 emissions level of 1.20 lb/MMBtu, NO_X emissions level of 0.10 lb/MMBtu and total PM_{10} emissions level of 0.024 lb/MMBtu.
- Control Case 2- Firing low-sulfur eastern bituminous coal, installation of a wet flue gas desulfurization (WFGD) system and year-round operation of the existing SCR and ESP to achieve an SO_2 emissions level of 0.12 lb/MMBtu, NO_X emissions level of 0.10 lb/MMBtu and total PM_{10} emissions level of 0.024 lb/MMBtu.

CALPUFF modeling of baseline emissions showed that Unit 3 is subject to BART based on a 3-year average eighth highest delta deciview impact of 1.24 dv at Shenandoah National Park. CALPUFF modeling results show that substantial visibility improvement occurs with the implementation of Case 1 emission controls. For Control Case 1, the 3-year average eighth highest delta deciview impact at Shenandoah National Park is 0.87dv. Installation of a WFGD unit on Wagner Unit 3 would provide additional visibility benefit. However, the extremely high annual capital and operating cost of this control alternative per deciview of visibility improvement ($48,000,000/dv) achieved, shows that this option is cannot be justified as BART.

Therefore, the recommended BART for Wagner Unit 3 is firing low sulfur eastern bituminous coal (~0.7% S) and year-round operation of the existing SCR and existing ESP to achieve SO_2 emissions level of 1.20 lb/MMBtu and a NO_X emissions level of 0.10 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 3 at Constellation's H.A. Wagner 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 presumptive BART limit for this unit is 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 90 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 (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 3 at the H.A. Wagner Generating Station. Section 2.0 provides a description of Wagner Unit 3 and its baseline emissions. Section 3.0 provides a discussion of available SO_2, NO_X and PM control technologies and improvements in emissions of SO_2, NO_X and PM. 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 also 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 3)

The BART-affected emission unit at the Wagner Generating Station is Units 3. Unit 3 was installed in August 1966 and began operation during the time period (1962-1977) targeted by the Regional Haze BART Rule. Unit 3 is a Babcock and Wilcox supercritical, once-through coal-fired boiler with a rated input capacity of 2,740 MMBtu/hr. The turbine generator is rated at 350 MW. Natural gas is used as a start-up fuel. Because the Wagner Station has a total rated capacity in excess of 750 MW, Unit 3 is subject to presumptive BART controls in accordance with the Regional Haze BART Rule.

2.2 Current Control Technologies

Wagner Unit 3 is equipped with over fire air (OFA), low NO_X burners and selective catalytic reduction (SCR) to control NO_X emissions. Wagner's Title V permit requires the SCR system need only be operated during the ozone season (May 1st through September 30th). Unit 3 is also equipped with a cold-side electrostatic precipitator (ESP) to control PM emissions. The ESP must achieve a filterable PM emission level of at least 0.03 grains per dry standard cubic feet (gr/dscf), according to the station's Title V permit. Unit 3 currently burns low-sulfur Eastern bituminous coal. Based on historical (baseline) emissions, the sulfur content of the eastern bituminous coal is approximately 1% by weight. Unit 3 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 (April 2001 and July 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. For a dry-bottom PC boiler equipped with an ESP, 67% of PM emissions are PM_{10}, and 29% are 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) + 0.015 (for SCR)), and
F2 is the control factor (51% control for an air pre-heater and 51% control for a cold-side ESP).

- For pulverized coal-fired boilers burning coal with a sulfur content of ~1%, condensable organic PM_{10} emission 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).

Note that, although Unit 3 was equipped with an SCR in June 2002, the maximum daily NO_X baseline emissions occurred when the SCR system was off-line during the non-ozone season. 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 Wagner Generating Station – Baseline Emissions for Unit 3

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
H.A. Wagner Station	3	Pulverized coal dry bottom boiler, cold-side ESP, 2,740 MMBtu/hr (Rated capacity 350 MW gross)	3,289	1.0	12,282	117,466	4,894	31,936	1,331	0.008	26.31	17.63 (d)	10.00 (d)	7.63 (d)	7.35	0.28 (e)	63.48 (f)	16.38 (f)	47.10 (g)	81.11 (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 = 0.008 lb/MMBtu).
(d) For a dry bottom boiler equipped with an ESP, 67% of filterable PM is total PM10 and 29% is fine PM10 (PM2.5) based on AP-42, Table 1.1-6. 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 12,282 Btu/lb based on DOE NETL's Coal Plant Database. H2SO4 control is 51% for an air preheater and 51% for a cold side ESP for low sulfur eastern bituminous coal 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 Wagner Generating Station – Baseline Stack Parameters for Unit 3

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)
Baseline	39.177	-76.527	3.0	109.7	4.67	425.19	500.21	29.17

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 in this section.

The following BART control scenarios were evaluated:

- Case 1. The current (2009-2010 period) NO_X, SO_2, and PM_{10} emissions signature of Unit 3. Firing low-sulfur eastern bituminous coal (with a sulfur content of approximately 0.7%) and year-round operation of the existing SCR and existing ESP to achieve SO_2 emissions level of 1.20 lb/MMBtu, NO_X emissions level of 0.10 lb/MMBtu and total PM_{10} emissions level of 0.024 lb/MMBtu.
- Case 2. Firing low-sulfur eastern bituminous coal (with a sulfur content of approximately 0.7%), installation of a WFGD system and year-round operation of the existing SCR and ESP to achieve SO_2 emissions level of 0.12 lb/MMBtu, NO_X emissions level of 0 .10 lb/MMBtu and total PM_{10} emissions level of 0.024 lb/MMBtu.

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 control options were evaluated for this BART analysis:

- *Case 1* - The Unit 3 boiler had been burning eastern bituminous coal (containing approximately 1% S by weight) during the baseline period. Sulfur dioxide emissions during the baseline period were on the order of 1.50 lb/MMBtu. Currently (2009 – 2010 time period), the boiler is performing at an SO_2 emission level of 1.20 lb/MMBtu which is attributable to the lower S content of coal (approximately 0.7%). This represents an improvement of approximately 20% compared to the baseline. Emission levels and stack parameters corresponding to this improvement are shown in Table 3-1 and Table 3-2, respectively.
- *Case 2* - An add-on control technology available to reduce SO_2 emissions from Wagner Unit 3 includes Wet Flue Gas Desulfurization (WFGD) with lime/limestone injection capable of achieving 90% control. Emission levels corresponding to this control case are shown in Table 3-3. Table 3-4 shows the stack parameters for this control case.

Lime Dry Scrubber/Fabric Filter (capable of achieving 80 to 90% control) and Dry Sorbent Injection with Trona (capable of achieving approximately 60% control) were not evaluated since they offer relatively low control advantage compared to their annual cost.

Since control case 1 has already been implemented at Wagner Unit 3, the technical feasibility, performance, and economic, energy, and environmental impacts of only the other SO_2 control option (WGFD) are addressed in this section.

3.1.1 Technical Feasibility of Wet Flue Gas Desulfurization

The technical feasibility and performance levels of WFGD are evaluated below in terms of their application to Wagner Unit 3.

WFGD typically uses limestone or lime to react with the 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:

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

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

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 re-circulated 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 additional solid waste and liquid waste streams. 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 of at least 90%.

For the purposes of the visibility analysis, it is assumed that the WFGD system will be applied to Unit 3 firing ~1% sulfur eastern bituminous coal and will achieve an outlet SO_2 emission level of 0.12 lb/MMBtu (90% control compared to the current emission level of 1.20 lb/MMBtu), better than the presumptive BART limit. Emissions improvement post application of this control technology is given in Table 3-3.

Table 3-1 Wagner Generating Station – Emissions Control Case 1

Facility	Unit	Description	Max. Heat Input (a)	Fuel S Content (b)	Coal Heating Value	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	Organic	
												Fine Total	Fine Soil	EC				
			MMBtu/hr	%	Btu/lb	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
H.A. Wagner Station	3	Pulverized coal dry bottom boiler, cold-side ESP, 2,740 MMBtu/hr (Rated capacity 350 MW gross)	3,289	0.7	12,282	3,946	329	0.008	26.31	17.63 (d)	10.00 (d)	7.63 (d)	7.35	0.28 (e)	62.35 (f)	33.61 (f)	28.74 (g)	79.97 (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 = 1.2 lb/MMBtu (current coal) & NOx = 0.1 lb/MMBtu (SCR))
(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 = 0.008 lb/MMBtu).
(d) For a dry bottom boiler equipped with an ESP, 67% of filterable PM is total PM10 and 29% is fine PM10 (PM2.5) based on AP-42, Table 1.1-6. 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+0.015) 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 12,282 Btu/lb based on DOE NETL's Coal Plant Database. H2SO4 control is 51% for an air preheater and 51% for a cold side ESP (no flue gas conditioning) for low sulfur eastern bituminous coal based on Tables 3-1 and 3-2 of the referenced document. An SCR was installed for NOx control in the year 2002. H2SO4 emissions produced by an SCR are assumed to be 1.5% based on the middle of the range for SO2 oxidation rate given on pg. 4-6 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 3-2 Wagner Generating Station – Stack Parameters Control Case 1

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)
Case 1	39.177	-76.527	3.0	109.7	4.67	425.19	500.21	29.17

Table 3-3 Wagner Generating Station – Emissions Control Case 2 (Future Emissions – WFGD)

Facility	Unit	Description	Max. Heat Input (a)	Fuel S Content (b)	Coal Heating Value	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	Organic	
												Fine Total	Fine Soil	EC				
			MMBtu/hr	%	Btu/lb	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
H.A. Wagner Station	3	Pulverized coal dry bottom boiler, cold-side ESP, 2,740 MMBtu/hr (Rated capacity 350 MW gross)	3,289	0.7	12,282	395	329	0.008	26.31	17.63 (d)	10.00 (d)	7.63 (d)	7.35	0.28 (e)	62.35 (f)	33.61 (f)	28.74 (g)	79.97 (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 = 1.2 lb/MMBtu and 90% SO2 control (current coal and wet FGD) & NOx = 0.1 lb/MMBtu (SCR))
(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 = 0.008 lb/MMBtu).
(d) For a dry bottom boiler equipped with an ESP, 67% of filterable PM is total PM10 and 29% is fine PM10 (PM2.5) based on AP-42, Table 1.1-6. 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+0.015) 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 12,282 Btu/lb based on DOE NETL's Coal Plant Database. H2SO4 control is 51% for an air preheater and 51% for a cold side ESP (no flue gas conditioning) for low sulfur eastern bituminous coal based on Tables 3-1 and 3-2 of the referenced document. An SCR was installed for NOx control in the year 2002. H2SO4 emissions produced by an SCR are assumed to be 1.5% based on the middle of the range for SO2 oxidation rate given on pg. 4-6 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 3-4 Wagner Generating Station – Stack Parameters for Control Case 2 (with WFGD)

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)
Case 2	39.177	-76.527	3.0	109.7	4.67	324.82	500.21	29.17

3.1.2 Impacts of Wet Flue Gas Desulfurization

This section documents the economic, non-air environmental, and energy impacts associated with applying WFGD to Wagner Unit 3.

Economic Impacts

Table 3-5 presents the first-year annual capital and annual operating costs associated with WFGD applied to Wagner Unit 3. The capital costs for the application of WFGD were calculated using EPA's CUECost. The annual fixed capital charges and annual operating costs were also estimated using CUECost and information from Constellation. An interest rate of 7% and an amortization period of 15 years were assumed in the calculation of the annualized costs for this BART control case.

Table 3-5 Total Capital and Annual Costs Associated with WFGD Applied to Wagner Unit 3

Control Technology	Total Installed Cost ($)	Capital Recovery ($/yr)	Annual O&M Costs ($/yr)	Total Annual Costs [a] ($/yr)
WFGD	$205,632,000	$22,577,000	$8,833,000	$31,410,000
a. All costs are based on 2014 dollars.				

Non-Air Quality Environmental Impacts

The non-air quality environmental impacts of WFGD include:

- high water consumption and 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.

Energy Impacts

Wet Flue Gas Desulfurization consumes a significant amount of electrical energy. The high electrical energy consumption for WFGD is primarily 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. The increased emissions of SO_2 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

Since it is capable of offering significant emission control, the SO_2 control technology identified for BART evaluation is WFGD. WFGD is capable of high SO_2 control efficiencies ranging from 90 to 95%, with the higher end of the control efficiency applicable to higher sulfur coal. The WFGD system, however, has high capital and annual operating costs. Moreover, installation of a 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. Additionally, it entails a high cost of $48,000,000 per deciview of visibility improvement offered. Therefore, it is rejected as BART.

Hence, BART for SO_2 is the current emissions signature of Wagner Unit 3 i.e. an SO_2 emission rate of 1.20 lb/MMBtu.

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 may also be 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 overfire air (OFA), and post-combustion techniques, such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR).

The Unit 3 boiler currently has an 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 control would need to be operated continuously to meet the presumptive BART requirements (0.1 lb/MMBtu NO_X).

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 Wagner Unit 3.

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 3. Performance data from Unit 3 indicates that the SCR systems are capable of NO_X removal efficiencies up to 80%. Based on these performance data, continuous operation of the SCR system will ensure that Unit 3 complies with the presumptive BART limit for PC boilers 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 Unit 3. However, NO_X removal efficiencies with SNCR are lower than those with 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 PC boilers. Accordingly, continuous operation of the already installed SCR system on Unit 3 with a rolling 30-day emission rate of 0.10 lb/MMBtu is recommended as BART for the boiler.

3.3 PM Emission Control

Wagner Unit 3 currently employs a high-efficiency Electro-Static Precipitator (ESP) to control PM emissions. The baseline PM emission rate for Wagner Unit 3 is 0.004 gr/dscf (0.008 lb/MMBtu) which is well below its permit limit of 0.03 gr/dscf. Moreover, the contribution of PM emissions to visibility impairment is relatively small.

Visibility modeling shows that PM emissions have a relatively minor contribution to the overall visibility impacts. Given the high performance levels of the existing ESP, these PM control devices are considered BART for Unit 3 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 Wagner.

4.1 Location of Source vs. Relevant Class I Areas

Figure 4-1 shows the location of the Wagner Generating Station relative to nearby Class I areas. There are five Class I areas within 300 km of the plant: Brigantine National Wildlife Refuge (NJ), Shenandoah National Park (VA), James River Face Wilderness Area (VA), Dolly Sods Wilderness Area (WV), and Otter Creek Wilderness Area (WV). 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 Wagner 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.

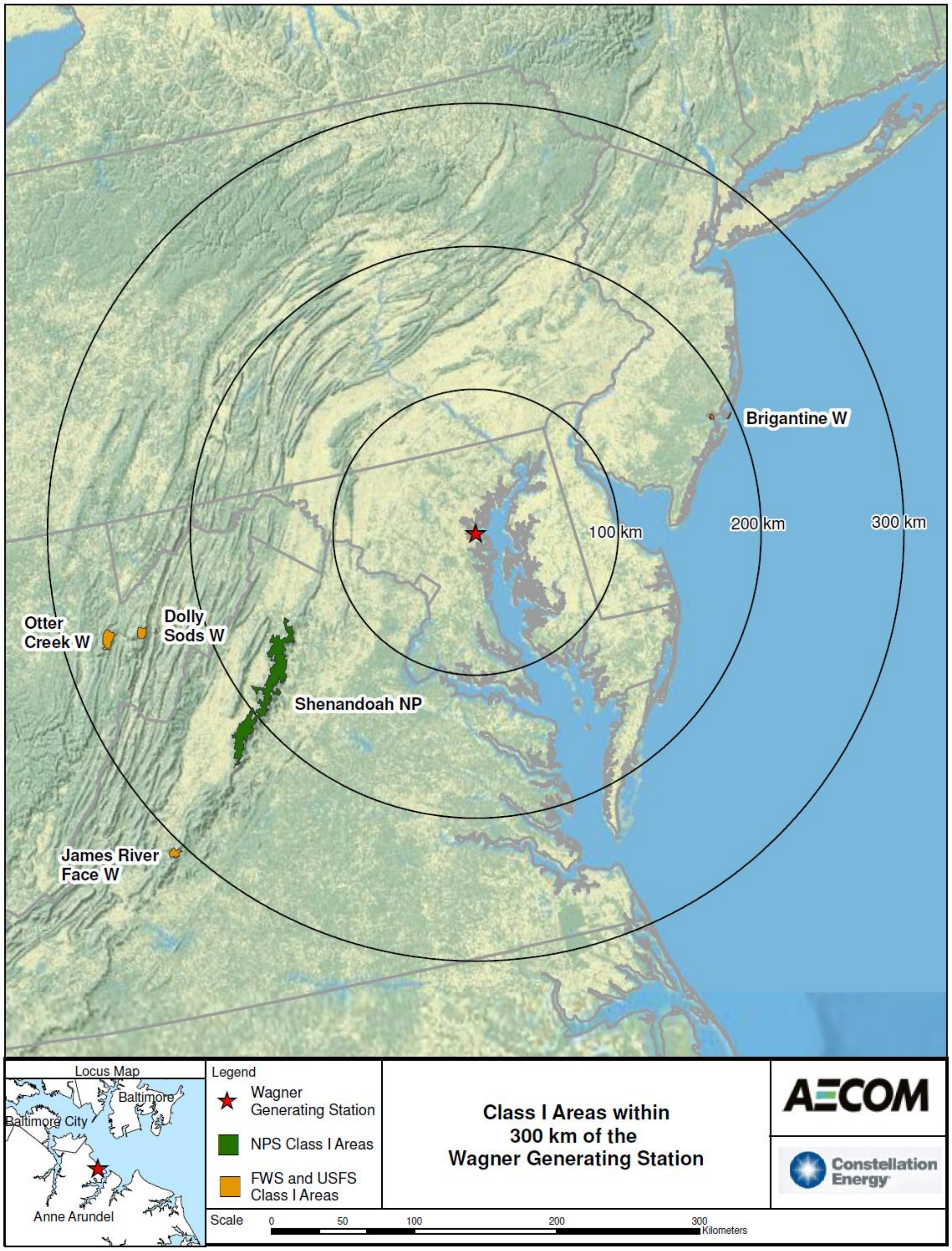
The FLAG 2008 document provides inputs to the new IMPROVE equation that are based on either the 20% best or annual average natural conditions. AECOM elected to use inputs that are based on the 20% best days natural conditions.

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 Wagner 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 Wagner Unit 3.

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 98th 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 98th-percentile statistic for comparing visibility improvements due to BART control options.

The results of the baseline emissions analysis indicate that the Wagner Generating Station Unit 3 has predicted visibility impacts exceeding 0.5 deciviews in at least one Class I area. Therefore, per 40 CFR Part 51, Appendix Y, Unit 3 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}	8th Highest dv ΔB_{ext}	days > 0.5 dv ΔB_{ext}	days > 1.0 dv ΔB_{ext}	MAX dv ΔB_{ext}	8th Highest dv ΔB_{ext}	days > 0.5 dv ΔB_{ext}	days > 1.0 dv ΔB_{ext}	MAX dv ΔB_{ext}	8th Highest dv ΔB_{ext}	8th Highest dv ΔB_{ext}
Shenandoah NP	19	7	2.0	0.99	20	6	1.8	0.85	38	15	3.6	1.87	1.24
Brigantine W	21	5	2.0	0.90	10	1	1.0	0.58	18	3	2.3	0.82	0.77
Otter Creek W	1	0	0.6	0.34	5	1	1.1	0.34	7	2	2.3	0.50	0.39
Dolly Sods W	3	0	0.6	0.43	6	0	0.9	0.37	9	3	2.7	0.55	0.45
James River Face W	5	1	1.5	0.36	8	0	0.8	0.52	10	2	2.3	0.63	0.51

5.2 Modeling Results for the BART Control Cases

CALPUFF modeling results of the two control cases, the current emissions case and future WFGD emissions case, are presented in Tables 5-2 and 5-3, respectively. Modeling was conducted for all three years of CALMET meteorological data (2001-2003) for the five Class I areas to determine the effects of the existing controls and future SO_2 control (WFGD) on Unit 3. Emission rates that were used in modeling the BART control cases 1 and 2 are listed in Tables 3-1 and 3-3, respectively. Stack parameters associated with the control cases 1 and 2 are given in Tables 3-2 and 3-4, respectively.

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 3-year average regional haze impacts are reduced by about 0.37 delta-dv (30% reduction) at Shenandoah and by 0.20 delta-dv (~26% improvement) at Brigantine relative to the baseline case with the current emissions signature of Unit3. The visibility improvement is much more significant with the use of the WFGD controls. Addition of WFGD would reduce visibility impacts by about 1.0 delta-dv (83% improvement) at Shenandoah NP and by 0.63 delta-dv (82 % reduction) at Brigantine Wilderness from the baseline case.

Table 5-2 Regional Haze Impacts Due to Control Case 1 (Current Emissions 2009-2010 period)

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}	8th Highest dv ΔB_{ext}	days > 0.5 dv ΔB_{ext}	days > 1.0 dv ΔB_{ext}	MAX dv ΔB_{ext}	8th Highest dv ΔB_{ext}	days > 0.5 dv ΔB_{ext}	days > 1.0 dv ΔB_{ext}	MAX dv ΔB_{ext}	8th Highest dv ΔB_{ext}	8th Highest dv ΔB_{ext}
Shenandoah NP	14	3	1.5	0.76	12	3	1.5	0.58	26	11	2.8	1.27	0.87
Brigantine W	10	2	1.7	0.71	6	0	0.8	0.46	9	3	1.8	0.55	0.57
Otter Creek W	0	0	0.4	0.25	3	0	0.8	0.25	5	1	1.7	0.36	0.29
Dolly Sods W	0	0	0.4	0.30	4	0	0.7	0.27	4	3	1.9	0.38	0.32
James River Face W	3	1	1.2	0.27	1	0	0.5	0.34	7	1	1.6	0.50	0.37

Table 5-3 Regional Haze Impacts Due to Control Case 2 (Installation of the WFGD)

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}	8th Highest dv ΔB_{ext}	days > 0.5 dv ΔB_{ext}	days > 1.0 dv ΔB_{ext}	MAX dv ΔB_{ext}	8th Highest dv ΔB_{ext}	days > 0.5 dv ΔB_{ext}	days > 1.0 dv ΔB_{ext}	MAX dv ΔB_{ext}	8th Highest dv ΔB_{ext}	8th Highest dv ΔB_{ext}
Shenandoah NP	0	0	0.3	0.19	0	0	0.4	0.17	1	0	0.8	0.26	0.21
Brigantine W	0	0	0.3	0.13	0	0	0.2	0.10	0	0	0.4	0.18	0.14
Otter Creek W	0	0	0.1	0.04	0	0	0.2	0.04	0	0	0.3	0.06	0.05
Dolly Sods W	0	0	0.1	0.05	0	0	0.2	0.06	0	0	0.4	0.07	0.06
James River Face W	0	0	0.2	0.05	0	0	0.2	0.06	0	0	0.5	0.08	0.06

5.3 Emission Control Cost and Visibility Improvement

Table 5-4 summarizes the annualized control cost that is a function of the capital and annual operating costs, as well as fixed capital charges estimated by Constellation for the installation of a WFGD on Unit 3. The table also presents a computation of WFGD's visibility improvement effectiveness and cost relative to the current conditions. The visibility results are based on the 8th highest regional haze impacts and averaged over the three modeled years. As Table 5-4 indicates, the incremental cost effectiveness of proceeding to WFGD from the current emissions signature exceeds $47 million/dv. Therefore, this option is not considered BART due to its high cost for a small visibility improvement.

Table 5-4 Annual Costs versus Visibility Improvement at Each Class I Area

Class I Area	Visibility Improvement Relative to the Current Levels (delta-dv)	Annualized Cost ($/Year) [a]	Incremental Cost Effectiveness from Baseline ($/dv)
Shenandoah NP	0.66	$31,410,000	$47,566,885
Brigantine W	0.43	$31,410,000	$72,428,901
Otter Creek W	0.24	$31,410,000	$131,239,554
Dolly Sods W	0.26	$31,410,000	$122,059,585
James River Face W	0.31	$31,410,000	$102,535,365

a. Annual capital and operating cost for a WFGD was computed using EPA's CUECost and information from Constellation.

5.4 BART Results and Discussion

As discussed earlier in this section, visibility improvements resulting from the current emissions level of Unit 3 are on the order of 25 – 30%. Installation of a WFGD offers a visibility improvement of up to 90% compared to the baseline. However, the extremely high annual capital and operating cost of this control alternative per deciview of visibility improvement achieved (> $47,000,000), does not justify its use as BART. The existing emission controls on Unit 3 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).

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).

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

WFGD Cost Information

WFGD Capital Cost Estimate [a]		
	Cost	
PURCHASED EQUIPMENT		
(a) Primary and Auxiliary Equipment	$	134,094,000
(b) Sales Tax	Included in item a above	
(c) Freight	Included in item a above	
TOTAL PURCHASED EQUIPMENT COST (PEC)	$	134,094,000
Total Plant Investment	$	200,685,160
Pre-production costs	$	4,848,364
Inventory Capital	$	98,760
TOTAL INSTALLED COST (TIC)	**$**	**205,632,000**
(a) Total Installed Cost based on EPA's CUECost and information from Constellation. Cost is presented in 2014 dollars.		

Constellation's Wagner Generating Station Unit 3- WFGD Cost Effectiveness		
	Cost	Basis
Capital Cost		
Total Installed Cost [(a)]	$ 205,632,000	Total Installed Cost of a WFGD derived using EPA's CUECost program and information from Constellation.
Deciviews before Control, dv/yr	0.87	CALPUFF Modeling for visibility at Shenandoah NP (Current w /o WFGD)
Deciviews after Control, dv/yr	0.21	CALPUFF Modeling for visibility at Shenandoah NP (Future w / WFGD)
Delta dv, dv	0.66	
Annual Costs, $/yr		
Capital Recovery	$ 22,577,000	7.0%, 15 years, 0.1098 TCI; EPA's Control Cost Manual. 15 years amortization @ 7% interest rate.
Fixed O&M Costs	$ 6,072,000	Fixed O&M costs of a WFGD derived using EPA's CUECost program and information from Constellation.
Variable O&M Costs	$ 2,761,000	Variable O&M costs of a WFGD derived using EPA's CUECost program and information from Constellation.
Total Annual Cost	**$ 31,410,000**	
Cost Effectiveness (Shenandoah NP), $ per deciview	***$47,566,885***	Total annual cost divided by the deciview s improvement
	Cost	**Basis**
Capital Cost		
Total Installed Cost [(a)]	$ 205,632,000	Total Installed Cost of a WFGD derived using EPA's CUECost program and information from Constellation.
Deciviews before Control, dv/yr	0.57	CALPUFF Modeling for visibility at Brigantine W (Current w /o WFGD)
Deciviews after Control, dv/yr	0.14	CALPUFF Modeling for visibility at Brigantine W (Future w / WFGD)
Delta dv, dv	0.43	
Annual Costs, $/yr		
(a) Total Installed Cost based on EPA's CUECost and information from Constellation. Cost is presented in 2014 dollars.	$ 22,577,000	7.0%, 15 years, 0.1098 TCI; EPA's Control Cost Manual. 15 years amortization @ 7% interest rate.
Fixed O&M Costs	$ 6,072,000	Fixed O&M costs of a WFGD derived using EPA's CUECost program and information from Constellation.
Variable O&M Costs	$ 2,761,000	Variable O&M costs of a WFGD derived using EPA's CUECost program and information from Constellation.
Total Annual Cost	**$ 31,410,000**	
Cost Effectiveness (Brigantine W), $ per deciview	***$72,428,901***	Total annual cost divided by the deciview s improvement

Appendix B

Modeling Archive (CD Available on Request from MDE)