Office of the Registrar of Regulations,
Legislative Council,
State of Delaware

BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

CITY OF DOVER MCKEE RUN GENERATING STATION BART ANALYSIS AND PROPOSAL

Prepared in accordance with:
40 CFR Part 51, Subpart P and Appendix Y

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1. BART ANALYSIS AND PROPOSAL

1.1 INTRODUCTION

The City of Dover owns and operates an electric generating station referred to as the McKee Run Generating Station (McKee Run) located in Dover, Delaware. McKee Run qualifies as a major source under the Clean Air Act regulatory programs including both the Federal and Delaware programs. Several of the emissions units at McKee Run were originally constructed between 1962 and 1977. As a result of the installation dates as well as the fact that McKee Run qualifies as one of the 26 major source categories listed in the regulation, McKee Run is subject to the Best Available Retrofit Technology (BART) requirements that are part of the Regional Haze Rules specified in 40 CFR Part 51, Subpart P Protection of Visibility.

The State of Delaware Department of Natural Resources & Environmental Control (DNREC) originally notified McKee Run and other BART-eligible facilities in the state regarding the potential applicability of the rule on January 4, 2007. The letter identifies four potential options for addressing the BART requirements of the Federal Regional Haze Program. The options are to:

1. Demonstrate that the units at your facility are not BART-eligible;

2. Establish a permit limit to restrict the combined emissions from BART-eligible sources to below 250 tons per year for each visibility impairing pollutant by March 1, 2007; or

3. Submit the facility's plans to implement the Clean Air Interstate Regulation (CAIR) and/or Delaware's Multi-Pollutant regulation to satisfy BART for SO_2 and NO_X by June 1, 2007; and

4. Conduct and submit a BART analysis and proposal based on an engineering analysis of control options for each BART-eligible unit at the facility for each visibility impairing pollutant not otherwise addressed above.

Boiler 3 is the only BART-eligible source at the facility since it is a fossil-fuel fired steam electric plant of more than 250 million British thermal units (BTU) per hour constructed between 1962 and 1977. Since the Boiler 3 emissions of several visibility impairing pollutants are significantly over 250 tons per year, McKee Run cannot accept the new emission limits that would be necessary under Option 2 to avoid the rule applicability. However, the facility will implement CAIR and/or the Delaware Multi-Pollutant regulation for SO_2 and NO_X control at Boiler 3. Consequently, McKee Run has prepared this BART analysis and proposal to satisfy Option 4, specifically for particulate matter of ten microns (PM_{10}) for Boiler 3. As specified by DNREC, the BART proposal has been conducted in accordance with U.S. EPA guidance published in Appendix Y of 40 CFR Part 51 (Guidelines for BART Determinations Under the Regional Haze Rule).

1.2 DOCUMENT ORGANIZATION

As noted above, McKee Run has prepared this BART proposal as requested by DNREC and in accordance with the guidance included in Appendix Y of 40 CFR Part 51 Subpart P. McKee Run believes that all of the information required for a complete BART proposal is included herein. The remainder of this document is organized as follows:

- Section 2 Overview of BART Process
- Section 3 Boiler 3 BART Analysis
- Section 4 Visibility Modeling Analysis
- Section 5 Summary of McKee Run BART Proposal

2. OVERVIEW OF BART PROCESS

2.1 BACKGROUND

The Regional Haze regulations in 40 CFR 51.308(e) require states to develop State Implementation Plans (SIPs) that contain emission limitations representing Best Available Retrofit Technology (BART) for certain sources that may reasonably be anticipated to cause or contribute to visibility impairment at a Class I area. The BART requirements apply to sources in any of 26 major source categories that were in existence before August 7, 1977 and in operation after August 7, 1962, and that have the potential to emit 250 tons per year of any single visibility impairing pollutant. Visibility impairing pollutants (VIPs) are considered to include SO_2, NO_X, condensable and filterable PM_{10}, (including PM_{10} sub-species), VOC and Ammonia.

States are required to determine BART for each eligible source based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable. The analysis must take into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from use of the technology.

As stated previously, DNREC has asked Delaware BART-eligible facilities to conduct the BART analysis required by the Regional Haze rule and submit a BART proposal. In the January 4, 2007 guidance that was sent to the BART-eligible facilities, DNREC stated that the visibility impairing pollutants to be addressed in the BART analysis include SO_2, NO_X and PM_{10}. Therefore, the BART analysis will not include an analysis for VOC and ammonia from the facility. The January 4, 2007 guidance also indicated that sources subject to the CAIR and/or Delaware's Multi-Pollutant regulation could address the facility's plan to implement those rules

to satisfy BART for SO_2 and NO_X. Since McKee Run is subject to both the CAIR and Delaware Multi-Pollutant regulations the BART analysis will only be conducted for PM_{10} at Boiler 3.

Delaware's implementation of CAIR supersedes the BART provisions for the visibility impairing pollutants of SO_2 and NO_X for electric generating units. The CAIR Supplemental Notice of Proposed Rulemaking (SNPR) preamble summarizes these findings by stating *"EPA proposes that BART-eligible EGUs in any state affected by CAIR may be exempted from BART controls for SO_2 and NO_X if that state complies with the CAIR requirements through adoption of the CAIR cap-and-trade programs for SO_2 and NO_X emissions."* A Federal Register notice on April 28, 2006 included Delaware in the CAIR Final Rule. As stated in 40 CFR Part 51 Subpart P *"A state that opts to participate in the CAIR cap-and-trade program under Part 96 AAA-EEE need not require affected BART-eligible EGU's to install, operate, and maintain BART."*

The City of Dover's McKee Run facility is developing a compliance plan with DNREC in regards to the Delaware Multi-Pollutant regulation. After correspondence between DNREC and the McKee Run facility it was agreed that the CAIR and Delaware Multi-Pollutant regulation do not need to be addressed in the BART analysis and proposal. This was agreed to by both John Sipple and Mohammed Majeed of DNREC via electronic correspondence on May 2, 2007. The McKee Run facility will submit a compliance plan for Boiler 3 NO_X control options by July 1, 2007. For this reason the BART proposal does not address the facility's plan to implement the Delaware Multi-Pollutant and CAIR regulation.

Provided below in Table 2-1 is a summary of how McKee Run anticipates meeting the requirements of BART for each VIP and whether or not an engineering analysis was conducted for the source.

Table 2-1
McKee Run Generating Station BART Eligible Sources

Emission Unit	*Source Description*	*Visibility Impairing Pollutant*	*Compliance Method for Visibility Improvement*
3	Boiler 3	NO_x	CAIR/Delaware Multi-Pollutant Regulation
3	Boiler 3	SO_2	CAIR/Delaware Multi-Pollutant Regulation
3	Boiler 3	PM_{10}	BART Engineering Analysis and Proposal

2.2 CASE-BY-CASE BART ANALYSIS

BART determinations are case-by-case engineering analyses that involve an assessment of the availability of applicable technologies capable of sufficiently reducing the emissions of a specific visibility-impairing pollutant, as well as the economic, energy, and environmental impacts of using each technology.

U.S. EPA's Appendix Y Guidance specifies that the BART analysis be conducted using a step by step approach. Specifically, a BART Analysis includes the following 5 basic steps:

- Step 1 – Identify all Available Retrofit Control Technologies.
- Step 2 – Eliminate Technically Infeasible Options.
- Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies.
- Step 4 – Evaluate Impacts and Document Results.
- Step 5 – Evaluate Visibility Impacts

Step 1 – Identify all Available Retrofit Control Technologies.

The first step in the BART control technology analysis is to develop a comprehensive list of potential control technologies available and applicable to the source-pollutant combination. The Guidance indicates that a technology is considered available if it has been used in full-scale practice for the source category, or if it has been used for similar source categories or gas streams. Technologies that have been used by other similar sources to comply with BACT or LAER requirements must be included as potential control alternatives. The Guidance does not require the consideration of all available levels of control for a given control technology as long as the maximum level of control for that technology is included. Controls representing BACT, LAER or MACT can be considered to be BART assuming that new cost-effective control technologies have not become available since implementation of the BACT, LAER or MACT emission limit. If the most stringent technology available is selected as BART, the remainder of the BART analysis in steps 2 through 5 does not need to be completed. However, McKee Run is not proposing the most stringent technology available for BART and will complete steps 2 through 5 of the BART analysis.

Using the Appendix Y guidance, McKee Run identified a list of potentially applicable retrofit control technologies representing the full range of demonstrated alternatives for the BART-eligible source. McKee Run developed this list using a wide variety of sources, including those listed in Section IV (D) of Appendix Y.

Step 2 – Eliminate Technically Infeasible Options.

The Appendix Y guidance states that control technologies are to be considered technically feasible if they have been installed and operated successfully on the same or a similar type of source. Technical infeasibility must be demonstrated based on physical, chemical or engineering principles that preclude its application to a particular emission unit. Technical infeasibility can also be shown by demonstrating that there are unresolvable technical problems with the

implementation of the control technology such as size of the emission unit; location of the emission unit; site constraints for deploying the control technology; reliability; and adverse impacts to the rest of the facility. Where the resolution of technical difficulties is only a matter of increased cost, the technology must be considered technically feasible. McKee Run has used these guidelines in determining the technical feasibility of the potential control options.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies.

The Appendix Y guidance specifies two issues that are important when evaluating the control effectiveness of the technically feasible control options: expressing the degree of control for each technology using an appropriate and consistent metric, and giving appropriate consideration to control techniques that can operate over a wide range of performance levels. The guidance recommends expressing emission performance in terms of an average steady state emission level per unit of product produced or processed. For control techniques that have a wide range of emission performance levels, the guidance states that at a minimum, the most stringent control level must be considered. When lesser control levels would have widely varying cost and other impacts, the control levels should likely be analyzed as well.

In the BART analyses, McKee Run determined the expected emissions reductions for each control technology on a consistent, comparable basis (i.e., lb/MMBtu, lb/ton, etc.). For each technology, McKee Run determined the most stringent emissions level capable of being achieved, and any other lesser control levels that made sense for the source and technology.

Step 4 – Evaluate Impacts and Document Results.

The Appendix Y guidance specifies that the impact analysis be conducted in the following four parts:

Part 1: Cost of Compliance
Part 2: Energy Impacts
Part 3: Non-Air Quality Environmental Impacts

Part 4: Remaining Useful Life

Part 1: Cost of Compliance. The guidance recommends that the costs of compliance for each BART control technology be determined in terms of average cost effectiveness, and where appropriate, incremental cost effectiveness. Cost effectiveness, expressed in terms of dollars per ton of VIP removed, or by other appropriate measure such as dollars per deciview of improvement, should be calculated as specified in the *OAQPS Air Pollution Control Cost Manual*. Average cost effectiveness is determined by dividing the annualized cost of the technology by the tons of pollutant removed per year (or by the deciview improvement). The annualized cost is derived from the capital and operating costs for installation and operation of the control technology. The basis for the costs used in the analysis must be documented, and should take any site-specific design or retrofit issues into consideration.

McKee Run completed a streamlined version of costs associated with each control option identified. McKee Run calculated the average cost effectiveness for each technically feasible control option in terms of dollars per ton of VIP removed and in terms of dollars per deciview of improvement. McKee Run also calculated the incremental cost effectiveness for comparison of control options. The results of the cost analysis are included in Section 3.2.4.

Part 2: Energy Impacts. The guidance specifies that the energy requirements of a control technology be examined to determine if it results in energy penalties or benefits for the source. If there is an energy penalty, such as increased cost for the use of additional electricity or fuel, that impact can simply be factored into the cost analysis. Indirect energy impacts, such as the energy to produce raw materials for construction of control equipment, are not to be considered in the impacts analysis unless they are unusual or significant. The energy impact analysis may also consider whether there are relative differences between control options that would impact the use of locally or regionally available fuels or raw materials, and if that would cause a significant economic disruption or unemployment.

McKee Run followed the guidance in conducting the energy impacts analyses. McKee Run did not include energy impacts as a part of the cost analysis since the fuel switching options do not result in significant energy impacts.

Part 3: Non-Air Quality Environmental Impacts. The guidance suggests that the following non-air quality environmental impacts could be examined: solid and hazardous waste generation and disposal; water usage; wastewater discharges; irreversible or irretrievable commitment of resources; noise; radiant heat; and dissipated static electrical energy. McKee Run did not evaluate non-air quality impacts as no significant impacts would be expected for the control options, as specified in the guidance.

Part 4: Remaining Useful Life. The guidance indicates that an emission unit's "remaining useful life" may be considered a part of the overall cost analysis if the remaining useful life is less than the time period used for amortizing costs. In such a case, the shorter time period should be used in the cost calculations. McKee Run did not use remaining useful life to adjust the amortization period for any of the cost calculations.

Step 5 – Evaluate Visibility Impacts

The last step in the BART analysis is to evaluate the visibility impacts. The guidance specifies that the visibility improvement determination expected at a Class I area be conducted using CALPUFF or other appropriate dispersion modeling for the potential BART control technologies. The steps to determine the visibility impacts from an individual source using the dispersion model include: 1) development of a modeling protocol, 2) modeling the pre- and post-control emission rates, 3) determining the net visibility improvement, 4) using a comparison threshold, and 5) comparing the 98th percentile days for pre and post control runs. If the most stringent control option available is selected, the facility is not required to conduct a visibility improvement determination. If a less stringent control option is selected, a modeling analysis is required to determine the visibility impacts.

McKee Run submitted a visibility modeling protocol to DNREC on April 24, 2007. The protocol, which followed the Appendix Y guidance, is included in Attachment A. The visibility modeling for the BART analyses was conducted in accordance with that protocol.

The Appendix Y guidelines provide only limited guidance on how to evaluate the visibility impacts of the pre- and post- control modeling results. The guidance indicates that states have flexibility in how they assess visibility improvements, and may consider the frequency, magnitude and duration components of visibility impairment. The guidance further provides two suggestions for making a net visibility improvement determination:

- Use of a comparison threshold for the visibility improvement. Examples for using a comparison threshold are to compare the number of days that a visibility threshold is exceeded, compare the visibility improvement to a threshold representing a significant change in impact, and compare the visibility improvement to a threshold representing a percent change in improvement
- Comparison of the 98th percentile days for the pre- and post- control runs.

Because no further guidance was provided by DNREC, McKee Run calculated the visibility improvement for each considered control technology in terms of all of the comparison methods suggested in the guidance. For all but the comparison of the number of days that a visibility threshold is exceeded, McKee Run was able to calculate the visibility improvement for a particular control technology without knowing the threshold level that DNREC would find appropriate for the comparison. For purposes of comparing the number of days that a visibility threshold is exceeded, McKee Run used a threshold of 0.5 deciviews, which at the 98th percentile level, is the threshold specified by U.S. EPA for determining whether a source contributes to visibility impairment.

BART Proposal

For the BART-eligible source, McKee Run prepared a summary table documenting the results of the BART analysis. The table presents the control options evaluated, the average and incremental cost effectiveness, and the modeled visibility improvements. Giving consideration to all of the factors, McKee Run selected what it believed to be BART for the source, and has proposed that technology for DNREC's consideration.

3. BOILER 3 (EMISSION UNIT 3)

3.1 BOILER 3 DESCRIPTION

Boiler 3 (Emission Unit 3) is a front-wall-fired Riley Stoker (Babcock Power) boiler that burns No. 6 fuel oil with a 1% sulfur by weight limitation and natural gas. Boiler 3 incorporates a mechanical cyclone separator and ash re-injection system to collect combustible ash and re-inject the ash into the furnace to complete the combustion process. This unit is also equipped with low-NOx burners and over-fire air for NOx control.

The products of combustion (flue gases) are pulled up through the boiler, over the superheater tubes, through the generating section and out of the boiler by the induced draft (ID) fans. The heat generated by the combustion of the fuel transfers to the furnace walls, the tubes of the superheater, and the generating section of the boiler by radiation and convection. Steam produced by the boiler flows through turbine generators to make electricity. The ID fans maintain a constant, slightly negative pressure (draft) in the furnace by drawing out the combustion gases as they are created. The ID fans discharge these gases to a duct leading to the multi-tube cyclone system for the removal of ash. The gases exit through a common stack for release into the atmosphere.

Boiler 3 emits the following VIPs NO_X, SO_2, and $PM_{10,}$ however as discussed previously only PM_{10} requires a BART analysis. The NO_X and SO_2 BART analysis are fulfilled through the CAIR and/or Delaware's Multi-Pollutant regulation. The BART Analysis for PM_{10} is provided below.

3.2 PM_{10} BART ANALYSIS

PM_{10} emissions from Boiler 3 are generated as part of the combustion process. PM_{10} emissions due to the combustion of fuel oil are based on the ash content of the fuel and the completeness of

the combustion process. Natural gas is a relatively clean burning fuel and generates minor amounts of PM_{10}.

An analysis to determine the best available retrofit PM_{10} control technology is provided in the following subsections.

3.2.1 Identification of All Available Retrofit Control Technologies (Step 1)

Based on the data review process described previously, a list of technologies with the potential for controlling PM_{10} emissions from Boiler 3 was formulated. McKee Run identified the following potential control technologies, which have been successfully demonstrated on oil-fired industrial and/or utility boilers. The control technologies below are ranked in order from the most effective to the least effective:

1. Switch from 1% sulfur by weight No. 6 fuel oil to natural gas.
2. Switch from 1% sulfur by weight No. 6 fuel oil to 0.3% sulfur No. 2 fuel oil.
3. Use an add-on control technology of a wet electro-static precipitator (ESP).
4. Switch from 1% sulfur by weight No. 6 fuel oil to 0.3% sulfur by weight No. 4 fuel oil.
5. Switch from 1% sulfur by weight No. 6 fuel oil to 0.5% sulfur by weight No. 6 fuel oil.
6. Use an add-on control technology of a dry electro-static precipitator (ESP).
7. Use an add-on control technology of a baghouse.

3.2.2 Discussion of Technical Feasibility (Step 2)

The next step in the top-down BART analysis is an evaluation of the technical feasibility of each of the identified control options. Each of the potential control technologies considered is described below along with a discussion of the technical feasibility with respect to Boiler 3.

3.2.2.1 Switch from 1% sulfur by weight No. 6 fuel oil to natural gas

As discussed previously, the combustion of fuel oil results in the formation of particulate due to the sulfur and ash content of the fuel. Boiler 3 will be required to reduce the sulfur content of the fuel oil to comply with Delaware's Multi-Pollutant regulation for SO_2. The reduction of sulfur and ash present in the fuel will result in a reduction of particulate, therefore the fuel switch option is considered a control option for PM_{10}. According to AP-42 the PM_{10} emissions associated with the combustion of natural gas results in 0.007 lb/MMBtu PM_{10} or an 89% reduction of PM_{10} from the current emission rate of 0.069 lb/MMBtu. The substitution of natural gas from 1% sulfur by weight No. 6 fuel oil may require upgrades to the superheater tubes to exclusively combust natural gas at Boiler 3, but the option is considered technically feasible.

McKee Run considers the switch to natural gas from 1% sulfur by weight No. 6 fuel oil a technically feasible option.

3.2.2.2 Switch from 1% sulfur by weight No. 6 fuel oil to 0.3% sulfur by weight No. 2 fuel oil.

As discussed previously, the combustion of fuel oil results in the formation of particulate due to the sulfur and ash content of the fuel. Boiler 3 will be required to reduce the sulfur content of the fuel oil to comply with Delaware's Multi-Pollutant regulation for SO_2. The reduction of sulfur and ash present in the fuel will result in a reduction of particulate, therefore the fuel switch option is considered a control option for PM_{10}. According to AP-42 the PM_{10} emissions associated with the combustion of 0.3% sulfur by weight No. 2 fuel oil results in 0.024 lb/MMBtu PM_{10} or a 66% reduction of PM_{10} from the current emission rate of 0.069 lb/MMBtu. Substituting the combustion of 0.3% sulfur by weight No. 2 fuel oil from 1% sulfur by weight No. 6 fuel oil is technically feasible and does not require any modification to the existing boiler. The substitution of 0.3% sulfur by weight No. 2 fuel oil from 1% sulfur by weight No. 6 fuel oil may require upgrades to pumps, motors, burner tips and other auxiliary equipment to combust No. 2 fuel oil at Boiler 3, but the option is considered technically feasible.

McKee Run considers the switch to 0.3% sulfur by weight No. 2 fuel oil from 1% sulfur by weight No. 6 fuel oil a technically feasible option.

3.2.2.3 Switch from 1% sulfur by weight No. 6 fuel oil to 0.3% sulfur by weight No. 4 fuel oil

As discussed previously, the combustion of fuel oil results in the formation of particulate due to the sulfur and ash content of the fuel. Boiler 3 will be required to reduce the sulfur content of the fuel oil to comply with Delaware's Multi-Pollutant regulation for SO_2. The reduction of sulfur and ash present in the fuel will result in a reduction of particulate, therefore the fuel switch option is considered a control option for PM_{10}. According to AP-42 the PM_{10} emissions associated with the combustion of 0.3% sulfur by weight No. 4 fuel oil results in 0.045 lb/MMBtu PM_{10} or a 35% reduction of PM_{10} from the current emission rate of 0.069 lb/MMBtu. Substituting the combustion of 0.3% sulfur by weight No. 4 fuel oil from 1% sulfur by weight No. 6 fuel oil is technically feasible and would only require minimal upgrades to the existing boiler and auxiliary equipment.

McKee Run considers the switch to 0.3% sulfur by weight No. 4 fuel oil from 1% sulfur by weight No. 6 fuel oil a technically feasible option.

3.2.2.4 Switch from 1% to 0.5% sulfur by weight No. 6 fuel oil

As discussed previously, the combustion of fuel oil results in the formation of particulate due to the ash content of the fuel. Boiler 3 will be required to reduce the sulfur content of the fuel oil to comply with Delaware's Multi-Pollutant regulation for SO_2. For this reason the sulfur content fuel reduction is also considered a control option for PM_{10}. According to AP-42 the PM_{10} emissions associated with the combustion of 0.5% sulfur by weight No. 6 fuel oil results in 0.047 lb/MMBtu PM_{10} or a 32% reduction of PM_{10} from the current emission rate of 0.069 lb/MMBtu.

Substituting the combustion of 0.5% sulfur by weight No. 6 fuel oil from 1% sulfur by weight No. 6 fuel oil is technically feasible and does not require any modification to the existing boiler.

McKee Run considers the switch to 0.5% sulfur by weight No. 6 fuel oil from 1% sulfur by weight No. 6 fuel oil a technically feasible option.

3.2.2.5 Use of add-on control technologies

The use of add-on control technologies was considered for control of PM_{10} at Boiler 3. The effectiveness of the add-on control technologies was considered with Boiler 3 combusting both the baseline 1% sulfur No. 6 fuel oil and the 0.5% sulfur No. 6 fuel oil since beginning on January 1, 2009 the Delaware Multi-Pollutant regulation will require EGUs firing residual oil to limit the sulfur content of the fuel to 0.5% sulfur. Therefore, if McKee Run were required to install BART controls it would occur after the date when the facility is required to meet the lower sulfur content fuel requirements.

After discussions with control technology vendors, specifically Babcock-Wilcox and Southern Environmental Inc. it was determined that the best application of an add-on control device for a residual oil fired boiler is a wet ESP. Other add-on control technologies including a dry ESP and baghouse were considered. However, after discussions with the vendors these two options were considered difficult applications for an oil-fired boiler as discussed below. In addition, a RACT-BACT-LAER Clearinghouse (RBLC) search was completed for PM_{10} control on an oil-fired boiler. As shown in Table 3-1 the vast majority of PM_{10} controls for an oil-fired boiler are to combust low sulfur fuel, limit fuel oil combustion, and the practice of good combustion control. Only a single search result indicated the use of an add-on control technology of a single stage dust collector/ESP. The RBLC search listed a PM_{10} emission standard of 0.10 lb/MMBtu, which is higher than the existing PM_{10} baseline emission rate of 0.069 lb/MMBtu.

Table 3-1
City of Dover
McKee Run Generating Station
RBLC Data for Oil-Fired Boilers - PM_{10}

RBLCID	FACILITY NAME	COMPANY NAME	PERMIT DATE	PROCESS NAME	CONTROL DESCRIPTION	EMISSION LIMIT	UNITS
NE-0031	OPPD - NEBRASKA CITY STATION	OMAHA PUBLIC POWER DISTRICT	3/9/2005	AUXILIARY BOILER 2, ULSD	DISTILLATE OIL WITH 0.05% SULFUR	0.0010	LB/MMBTU
PA-0187	GRAYS FERRY COGEN PARTNERSHIP	GRAYS FERRY COGEN PARTNERSHIP	3/21/2001	AUXILIARY BOILER, NATURAL GAS	GOOD COMBUSTION PRACTICE	0.0032	LB/MMBTU
GA-0084	RAYONIER SPECIALTY PULP PRODUCTS	RAYONIER SPECIALTY PULP PRODUCTS	6/16/1997	BOILER , NATURAL GAS	LIMITED SULFUR CONTENT OF FUEL	0.0050	LB/MMBTU
SC-0091	COLUMBIA ENERGY CENTER	COLUMBIA ENERGY CENTER	7/3/2003	BOILER, NATURAL GAS	GOOD COMBUSTION PRACTICE	0.0050	LB/MMBTU
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	BEAR ISLAND PAPER COMPANY, L.P.	10/30/1992	BOILER, NATURAL GAS	FUEL SPEC: CLEAN BURN FUEL	0.0052	LB/MMBTU
VA-0171	MECKLENBURG COGENERATION LIMITED PARTNERSHIP	MECKLENBURG COGENERATION LIMITED PARTNERSHIP	5/9/1990	BOILER, AUX, NO. 2 FUEL OIL	GOOD COMBUSTION/OPERATING PRACTICES	0.0100	LB/MMBTU
SC-0091	COLUMBIA ENERGY CENTER	COLUMBIA ENERGY CENTER	7/3/2003	BOILER, NO. 2 FUEL OIL	GOOD COMBUSTION PRACTICE	0.0240	LB/MMBTU
*PA-0249	RIVER HILL POWER COMPANY, LLC	RIVER HILL POWER COMPANY, LLC	7/21/2005	AUXILIARY BOILER, NO.2 FUEL OIL		0.0300	LB/MMBTU
SC-0061	COLUMBIA ENERGY LLC	COLUMBIA ENERGY LLC	4/9/2001	BOILERS, NO. 2 FUEL OIL	COMBUSTION OF LOW SULFUR FUELS	0.0300	LB/MMBTU
SC-0071	COLUMBIA ENERGY CENTER I-26 & US HWY 21 SOUTH	COLUMBIA ENERGY CENTER	4/9/2001	BOILER, AUXILIARY, NO. 2 FUEL OIL	GOOD COMBUSTION PRACTICES AND COMBUSTION OF CLEAN FUELS	0.0300	LB/MMBTU
NY-0066	INDECK SILVER-SPRING COGENERATION	INDECK SILVER-SPRING COGENERATION	5/12/1993	AUXILIARY BOILER, NO. 2 FUEL OIL	NO CONTROLS	0.0320	LB/MMBTU
OH-0269	BIOMASS ENERGY, LLC-SOUTH POINT POWER	BIOMASS ENERGY	1/5/2004	AUXILIARY BOILER, NO. 2 FUEL OIL		0.0400	LB/MMBTU
OH-0269	BIOMASS ENERGY, LLC-SOUTH POINT POWER	BIOMASS ENERGY	1/5/2004	AUXILIARY BOILER, NO. 2 FUEL OIL	FUEL OIL BURNING LIMITED TO 50 HRS/YR	0.0400	LB/MMBTU

Table 3-1
City of Dover
McKee Run Generating Station
RBLC Data for Oil-Fired Boilers - PM_{10}

RBLCID	FACILITY NAME	COMPANY NAME	PERMIT DATE	PROCESS NAME	CONTROL DESCRIPTION	EMISSION LIMIT	UNITS
GA-0084	RAYONIER SPECIALTY PULP PRODUCTS	RAYONIER SPECIALTY PULP PRODUCTS	6/16/1997	BOILER, NO. 2 FUEL OIL	LIMITED SULFUR CONTENT OF FUEL	0.0500	LB/MMBTU
GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	TEMPLE INLAND, INC.	10/13/2004	BOILER, NO. 2 FUEL OIL & NATURAL GAS	LIMITED SULFUR CONTENT OF FUEL TO 0.05 WT% SULFUR	0.0500	LB/MMBTU
GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	TEMPLE INLAND, INC.	10/13/2004	BOILER, NO.2 FUEL OIL		0.0500	LB/MMBTU
NY-0050	SITHE/INDEPENDENCE POWER PARTNERS	SITHE/INDEPENDENCE POWER PARTNERS	11/24/1992	BOILERS, AUXILIARY (FUEL OIL)	COMBUSTION CONTROLS	0.0500	LB/MMBTU
KY-0084	THOROUGHBRED GENERATING STATION	THOROUGHBRED GENERATING COMPANY, LLC	10/11/2002	BOILER, AUXILIARY, DIESEL	GOOD OPERATING PRACTICE, OPERATION LIMIT < 500 H/YR	0.0600	LB/MMBTU
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER MANSFIELD MILL	8/14/2001	POWER BOILER #1 & #2, FUEL OIL	SINGLE STAGE DUST COLLECTOR/ESP, LIMIT SULFUR CONTENT OF FUEL TO 0.7 WT% SULFUR	0.1000	LB/MMBTU
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	BEAR ISLAND PAPER COMPANY, L.P.	10/30/1992	BOILER , NO. 2 FUEL OIL	FUEL SPEC: CLEAN BURN FUEL	0.1000	LB/MMBTU
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	BEAR ISLAND PAPER COMPANY, L.P.	10/30/1992	BOILER, PACKAGE, NO. 2 FUEL OIL	FUEL SPEC: CLEAN BURN FUEL	0.1000	LB/MMBTU
WA-0303	LONGVIEW FIBRE COMPANY	LONGVIEW FIBRE COMPANY	12/10/2001	POWER BOILER 20, FUEL OIL		0.0480	GR/DSCF @ 7% O2
WA-0303	LONGVIEW FIBRE COMPANY	LONGVIEW FIBRE COMPANY	12/10/2001	POWER BOILERS 12 AND 13		0.0480	GR/DSCF @ 7% O2
WA-0303	LONGVIEW FIBRE COMPANY	LONGVIEW FIBRE COMPANY	12/10/2001	POWER BOILER 16, FUEL OIL		0.1000	GR/DSCF @ 7% O2
WA-0303	LONGVIEW FIBRE COMPANY	LONGVIEW FIBRE COMPANY	12/10/2001	POWER BOILER 17, FUEL OIL		0.1000	GR/DSCF @ 7% O2

The two options considered difficult applications are the dry ESP and baghouse. The dry ESP would require multiple fields for an effective PM_{10} reduction, thus increasing the energy demand to operate Boiler 3. Even considering a multiple field dry ESP the application could have difficulty in particle collection due to the conductivity of the high carbon content associated with the oil laden flue gas stream because the ESP relies on the electrical force to collect particles on the plates. The baghouse application is also considered a difficult application for an oil-fired unit. The control technology vendor would not recommend a baghouse on an oil-fired unit without at least an upstream conditioner such as a spray-drier. Even with the upstream conditioning the oil laden flue gases can cause blinding of the filter cloth in a baghouse.

If an add-on control technology is to be considered a wet ESP is the most technically feasible option. An ESP is a particle control device that uses electrical forces to move the particles out of the exhaust gas stream and onto a collecting surface. The wet ESP application uses a water flushing system to remove the particles from the collecting surface. The gas stream is either saturated before entering the collection area or the collecting surface is continually wetted to prevent agglomerations from forming. Wet ESPs are typically effective on acid mist, oil and tar based condensed aerosols, or applications where dry dust particles combine with condensables to form paste like residues. However, a wet ESP has the disadvantage of the increased complexity due to the wash and the fact that the collected slurry must be handled more carefully than a dry product, adding to the expense of disposal.

The control technology vendor anticipated that for the Boiler 3 application, an emission standard of 0.02 grains per standard cubic foot of exhaust gas could be met with a wet ESP on a residual oil-fired boiler. This equates to approximately 0.039 lb/MMBtu or a 43% reduction of PM_{10} from the current emission rate of 0.069 lb/MMBtu. However, it is important to note that this is only a 11% reduction above the PM_{10} control rate achieved by the fuel sulfur reduction from 1% to 0.5% required by Delaware's Multi-Pollutant regulation.

Since McKee Run is considering employing fuel switching only control options with a greater PM_{10} reduction than the combination of fuel switching and add-on control (i.e., wet ESP) and since two of the control technologies are considered difficult applications (i.e., dry ESP and baghouse), in order to streamline the PM_{10} control technologies analysis, the combination of fuel switching and the add-on control technologies have not been further evaluated.

3.2.3 Evaluate Control Effectiveness of Remaining Technically Feasible Control Technologies (Step 3)

Based on the discussion outlined above, McKee Run has identified the following control technologies as technically feasible, ranked in order of most effective to least effective:

1. Switch from 1% sulfur by weight No. 6 fuel oil to natural gas – PM_{10} reductions of up to 89%.
2. Switch from 1% sulfur by weight No. 6 fuel oil to 0.3% sulfur No. 2 fuel oil – PM_{10} reductions of up to 66%.
3. Use an add-on control technology of a wet electro-static precipitator (ESP) – PM_{10} reductions of up to 43%.
4. Switch from 1% sulfur by weight No. 6 fuel oil to 0.3% sulfur by weight No. 4 fuel oil – PM_{10} reductions of up to 35%.
5. Switch from 1% sulfur by weight No. 6 fuel oil to 0.5% sulfur by No. 6 fuel oil – PM_{10} reductions of up to 32%.
6. Use an add-on control technology of a dry electro-static precipitator (ESP) – PM_{10} not effective due to technical feasibility.
7. Use an add-on control technology of a baghouse –PM_{10} reductions not effective due to technical feasibility.

As discussed previously, control options 3, 6, and 7 (the use of add-on controls with either a wet or dry ESP, or baghouse) have not been carried forward for further BART analysis since the

control options offer a similar or lesser level of PM_{10} control than those already identified in the fuel switching options.

3.2.4 Evaluate Impacts and Document Results (Step 4)

The following evaluation considers economic, energy, and non-air impacts to apply the four technically feasible PM_{10} control options selected for further analysis.

3.2.4.1 Economic Impacts of Control Technologies

Provided below in Table 3-2 is a summary of the economic impact analysis for the feasible control technologies. McKee Run followed a streamlined procedure from that outlined in 40 CFR Part 51, Appendix Y and the *OAQPS Air Pollution Cost Control Manual 6th Edition.* The simplified cost evaluation spreadsheets are provided in Tables B-1 through B-4 of Attachment B.

Numerous compliance cost determinations are displayed in the summary table below. The average cost effectiveness for each control technology was determined from the annualized costs presented in the cost evaluation spreadsheets of Tables B-1 through B-4 of Attachment B per the ton per year reduction of the corresponding visibility impairing pollutant. The cost effectiveness per deciview was determined from the annualized cost per the maximum 98th percentile impact deciview improvement from the dispersion modeling. An incremental cost calculation was completed when appropriate. The incremental cost effectiveness compares the costs and performance level of a control option to those of the next most stringent control option. If the next most stringent option had a higher annualized cost than the more stringent control option, an incremental cost calculation was not completed.

The compliance cost determinations for the fuel switching options were simplified by only considering the annual costs associated with the fuel prices. As discussed previously in Section 3.2.2 the site could have also considered possible upgrades and associated engineering costs for each fuel switching option.

Table 3-2
Summary of Economic Impact Analysis for PM_{10} Controls at Boiler 3

Control Technology	*Projected Emission Rate (tons/yr)*	*Emissions Performance Level*	*Expected Emissions Reductions (tons/yr)*	*Costs of Compliance*
Switch from 1% S No. 6 Fuel Oil to Natural Gas	328.2	89%	292.8	Total Annualized Cost: $19,027,596 Average Cost Effectiveness: $64,986/ton Cost Effectiveness per dV: $243,943,538/dV Incremental Cost: Not calculated due to the high annual cost of the fuel switching option to No. 2 FO.
Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 2 Fuel Oil	328.2	66%	216.1	Total Annualized Cost: $57,082,788 Average Cost Effectiveness: $264,137/ton Cost Effectiveness per dV: $1,001,452,421/dV Incremental Cost: $190,906/incremental ton (No. 6 FO to No. 2 FO vs. No. 6 FO to No. 4 FO)
Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 4 Fuel Oil	328.2	35%	116.4	Total Annualized Cost: $38,055,192 Average Cost Effectiveness: $326,821/ton Cost Effectiveness per dV: $731,830,615/dV Incremental Cost: $2,918,484/incremental ton (No. 6 FO to No. 4 FO vs. No. 6 FO 1% to No. 6 FO 0.5%)
Switch from 1% S No. 6 Fuel Oil to 0.5% S No. 6 Fuel Oil	328.2	32%	106.7	Total Annualized Cost: $9,513,798 Average Cost Effectiveness: $89,197/ton Cost Effectiveness per dV: $221,251,116/dV

3.2.4.2 Energy and Environmental Impacts of Control Technologies

The next items to consider in determining impacts from a control technology are the energy and non-air environmental impacts.

No significant energy and/or environmental impacts would be expected to occur as a result of the use of any of the four fuel switching options.

3.2.5 Evaluate Visibility Impacts (Step 5)

McKee Run used the individual source attribution approach (dispersion modeling) to determine the visibility improvement that would result from adding VIP controls to Boiler 3. For the various control scenarios, the modeling determined the number of days during the year that the impact of Boiler 3 would be greater than 1 deciview, the number of days that the impact would be greater than 0.5 deciviews, the highest daily impact on visibility (in deciviews), and the 98th percentile daily impact on visibility, which is the 8th highest day in a year. The dispersion modeling and detailed results are provided in Section 4 of this document.

Table 3-2 and Table 3-3 show the modeled visibility impact of VIP emissions from Boiler 3 on the two Class I areas that are located within 300 km of the McKee Run Generating Station.

Table 3-3
Pre-Control Visibility Impacts of Boiler 3

Class I Area	*Days over 1 dV**	*Days over 0.5 dV**	*2001 Highest Impact (dV)*	*2002 Highest Impact (dV)*	*2003 Highest Impact (dV)*
Brigantine	0.3	6	0.96	0.58	1.57
Shenandoah	0	1.3	0.29	0.40	0.97

* Note the pre-control visibility impacts represented above for days over 1 dV and 0.5 dV is the average of the three modeled years.

Table 3-4
Pre-Control Visibility Impacts of Boiler 3

Class I Area	*2001 98th Percentile Impact (dV)*	*2002 98th Percentile Impact (dV)*	*2003 98th Percentile Impact (dV)*
Brigantine	0.52	0.39	0.47
Shenandoah	0.20	0.17	0.44

U.S. EPA's Appendix Y guidance states that a source should be considered to cause visibility impairment if the 98th percentile impact is greater than 1 deciview and to contribute to visibility impairment if the 98th percentile impact is greater than 0.5 deciview. Based on this guidance, the pre-control modeling results show that Boiler 3 does not cause nor contribute to visibility impairment in any of the Class I areas.

The pre-control modeling results also show that Boiler 3 has a higher visibility impact in the Brigantine Wildlife Refuge than the Shenandoah National Park Class I area within 300 km of the McKee Run Generating Station. Consequently, to simplify the BART analysis, McKee Run conducted BART post-control modeling assessments using visibility impacts for the Brigantine Wildlife Refuge as a reference for visibility improvement determination.

Visibility Improvement from Potential BART Controls

Table 3-4 shows the visibility improvement that would occur on the highest impact day for each of the potential BART control technologies.

Table 3-5
Visibility Improvement on Highest Impact Day

Control Technology	*Control Efficiency*	*Brigantine Improvement (dV)*
Switch from 1% S No. 6 Fuel Oil to Natural Gas	89%	0.08
Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 2 Fuel Oil	66%	0.06
Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 4 Fuel Oil	35%	0.04
Switch from 1% S No. 6 Fuel Oil to 0.5% S No. 6 Fuel Oil	32%	0.04

Table 3-5 shows the visibility improvement for the 98th percentile impact day (8th highest impact day in a year) that would occur for each of the potential BART control technologies.

Table 3-6
Visibility Improvement in 98th Percentile Impact

Control Technology	*Control Efficiency*	*Brigantine Improvement (dV)*
Switch from 1% S No. 6 Fuel Oil to Natural Gas	89%	0.07
Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 2 Fuel Oil	66%	0.05
Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 4 Fuel Oil	35%	0.04
Switch from 1% S No. 6 Fuel Oil to 0.5% S No. 6 Fuel Oil	32%	0.04

4. VISIBILITY MODELING ANALYSIS

McKee Run submitted a visibility modeling protocol to DNREC on April 24, 2007. This protocol presented the specific methodologies that McKee Run employed for visibility modeling analyses relating to BART. McKee Run conducted a base case visibility modeling analysis, as well as control scenario analyses for Boiler 3. The basic assumptions behind these analyses and the results are shown in the subsequent sections. Attachment C of this report includes a CD-ROM that contains all pertinent modeling files for the visibility modeling analyses.

4.1 MODELING METHODOLOGY

McKee Run used the CALPUFF (version 5.754) dispersion model to predict visibility impacts at Class I areas within 300 km of the McKee Run Generating Station. McKee Run followed the April 2007 modeling protocol that was submitted to DNREC for all visibility modeling analyses. The April 2007 modeling protocol followed the guidance found in the VISTAS common modeling protocol ("VISTAS protocol", VISTAS 2005). The following summarizes the assumptions used by McKee Run that were not specifically identified in the VISTAS protocol:

- Natural background light extinction values were calculated using data from U.S. EPA's "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program", (U.S. EPA 2003) guidance document. Average background concentrations of sulfates, nitrates, organic secondary aerosol, elemental carbon, soil, and coarse filterable particulate were taken from Table 2-1, while f[RH] factors were taken from Table A-3 of the U.S. EPA 2003 document for each Class I area. A Rayleigh scattering efficiency of 10 Mm^{-1} was used for all Class I areas.

- Two Class I areas were modeled: The Shenandoah National Park and Brigantine Wildlife Refuge. Figure 4-1 shows the location of each Class I area in relation to the McKee Run Generating Station. Receptors from the National Park Service (NPS) were used in the analysis. NPS makes the receptor data available at http://www2.nature.nps.gov/air/Maps/Receptors/index.cfm.

- The VISTAS 12-km CALMET data were used to run CALPUFF. These data include CALMET runs for 2001, 2002, and 2003.

- Observed non-urban ozone data for the 2001-2003 CASTnet and AIRS monitoring networks were used. These ozone data represent daily daytime averages from 6 AM to 6 PM.

- A background ammonia concentration of 0.5 ppb was used for all months. This is the value recommended by VISTAS for the 12-km modeling domain, and is equivalent to the value identified in the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report (FLAG, December 2000).

The complete April 2007 visibility modeling protocol is included as Attachment A of this report.

4.2 BASE CASE MODELING ANALYSIS

McKee Run conducted a visibility modeling analysis to determine the visibility impacts associated with Boiler 3. This base-case run served as a standard with which to gauge the potential visibility improvement associated with controls for PM_{10}.

McKee Run calculated the maximum 24-hr average emission rate from Boiler 3, using projected future operating parameters. The projected future emission rate for Boiler 3 was based on a 101.5 Megawatt (1086.05 MMBtu/hr) operation with a PM_{10} emission rate of 0.069 lb/MMBtu. Table 4-1 shows these emission rate for reference, along with location and stack parameter information for Boiler 3.

The results of the base-case modeling analysis at each Class I area within 300 km of the McKee Run Generating Station is shown in Table 4-2. McKee Run conducted BART post control modeling assessments using visibility impacts for the Brigantine Wildlife Refuge as a reference.

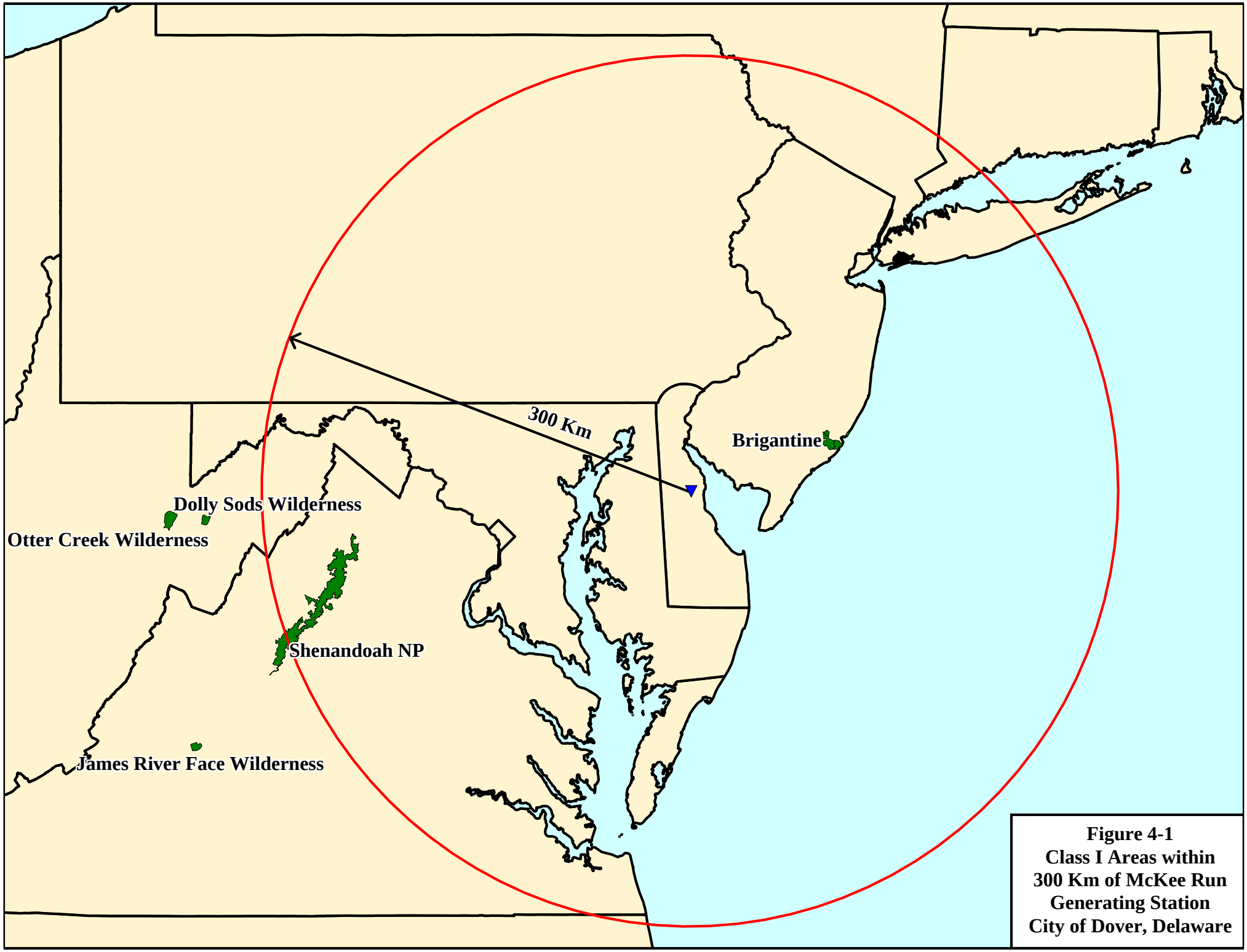

Figure 4-1
Class I Areas within 300 Km of McKee Run Generating Station City of Dover, Delaware

Table 4-1
Stack Parameter and Emissions Information
City of Dover McKee Run Generating Station
Dover, DE

Source Name	UTM Coordinates			LCC Coordinates[a]			Stack Height	Base Elevation	Stack Diameter	Stack Gas Temperature	Stack Gas Exit Velocity	PM_{10} Emission Rate
	Easting (m)	*Northing (m)*	*Datum*	*X (m)*	*Y (m)*	*Datum*	*m*	*m*	*m*	*K*	*m/s*	*g/s*
Unit No. 3	452,863	4,336,147	NAD27	1821.94	124.8677	NWS-84	60.96	7.01	3.10	426.48	16.77	9.44

Table 4-2
City of Dover
McKee Run Generation Station, Dover, DE
Pre Control Impacts
Unit No. 3

Source Name & Class I Area	2001				2002				2003			
	Days over 1Δdv	Days over 0.5 Δdv	Highest Impact	98th Percentile Impact (8th Highest Day)	Days over 1Δdv	Days over 0.5 Δdv	Highest Impact	98th Percentile Impact (8th Highest Day)	Days over 1Δdv	Days over 0.5 Δdv	Highest Impact	98th Percentile Impact (8th Highest Day)
Unit No. 3												
Brigantine Wildlife Refuge	0	9	0.96	0.52	0	3	0.58	0.39	1	6	1.57	0.47
Shenandoah National Park	0	0	0.29	0.20	0	0	0.40	0.17	0	4	0.97	0.44

4.3 BART CONTROL MODELING ANALYSIS

McKee Run conducted multiple modeling analyses to determine the effects that controls to Boiler 3 would have on visibility in the Brigantine Wildlife Refuge. For each technically feasible control technology identified in Section 3 of this report, McKee Run evaluated the visibility impacts using updated emission rates that reflected each control technology's assumed control efficiency.

The BART control visibility modeling was conducted on a case by case basis, with one modeling iteration performed for each possible control technology alone. This allowed McKee Run to evaluate the direct impacts that each post control could have on modeled visibility results in the Brigantine Wildlife Refuge. The assumed control efficiency of each control technology was applied to the appropriate pollutant 24-hr emission rate used for the pre-control scenarios. The emission rates used for each possible control scenario are shown in Table 4-3. The BART eligible emissions unit's individual visibility impact on the Brigantine Wildlife Refuge for each control scenario is shown in Table 4-4. A comparison between the pre control and post control scenarios, with the resulting net visibility improvement on a highest daily and 98th percentile basis is shown in Table 4-5.

The results indicate that post controls would not provide a detectable improvement in visibility at the Brigantine Wildlife Refuge. The highest 98th percentile daily visibility improvement in Brigantine Wildlife Refuge over the modeled period was a change of 0.08 deciviews in 2002 and 2003, with the most stringent PM_{10} control technology (89%) applied.

In the paper "Development and Applications of a Standard Visual Index" (Pitchford, Malm 1994), a just-noticeable change in visibility to the human eye is described as a 1 to 2 deciview change. Since the modeled visibility improvement is below the human eye's ability to perceive changes in visibility (as defined by the deciview standard), visibility can not be substantially improved in either Class I area due to the control of PM_{10} from Boiler 3. McKee Run does not believe an imperceptible level of visibility improvement justifies the addition of controls.

Table 4-3
Emissions Rates - Control Scenarios
City of Dover McKee Run Generating Station
Dover, DE

Source Name	Control Efficiency	Pollutant	SO2 Emission Rate	NOX Emission Rate	PM10 Emission Rate [a]
			g/s	*g/s*	*g/s*
Unit No. 3					
	89%	PM_{10}	143.68	68.42	1.02
	66%	PM_{10}	143.68	68.42	3.23
	32%	PM_{10}	143.68	68.42	6.37
	35%	PM_{10}	143.68	68.42	6.09

[a] These emission rates were not actually included in the CALPUFF modeling analysis. An emission rate of PM_{10} represents all condensable and filterable particulate emissions less than 10 microns in diameter (Including $PM_{2.5}$). An emission rate of $PM_{2.5}$ represents all condensable and filterable particulate emissions less than 2.5 microns in diameter. The PM emission rates used in the CALPUFF modeling analysis were refined into six different size categories. The sum of the PM emissions from the various size categories matches the value shown in this table.

Table 4-4
Individul BART Eligible Emissions Impacts - Post Control Scenarios
City of Dover - McKee Run Generating Station, Dover, DE

Source Name & Class I Area	Control Efficiency [a]	Pollutant	2001				2002				2003			
			Days over 1Δdv	Days over 0.5 Δdv	High Impact	98th Percentile Impact	Days over 1Δdv	Days over 0.5 Δdv	High Impact	98th Percentile Impact	Days over 1Δdv	Days over 0.5 Δdv	High Impact	98th Percentile Impact
Unit No. 3														
Brigantine Wildlife Refuge	89%	PM_{10}	0	5	0.87	0.46	0	1	0.52	0.31	1	5	1.48	0.40
	66%	PM_{10}	0	6	0.90	0.48	0	1	0.53	0.34	1	5	1.51	0.42
	32%	PM_{10}	0	6	0.92	0.49	0	2	0.54	0.35	1	5	1.53	0.43
	35%	PM_{10}	0	6	0.90	0.48	0	1	0.54	0.34	1	5	1.52	0.42

[a] Emissions of other VIP are held constant while the control scenario VIP emission rate is adjusted.

Table 4-5
Comparison of Annual Highest and 98th Percentile Daily Visibility Impacts in Brigantine Wildlife Refuge
City of Dover
McKee Run Generating Station, Dover, DE

Source Name & Class I Area	Control Efficiency	Pollutant	2001		2002		2003		Maximum	
			Change in High Impact	Change in 98th Percentile Impact	Change in High Impact	Change in 98th Percentile Impact	Change in High Impact	Change in 98th Percentile Impact	Change in High Impact	Change in 98th Percentile Impact
Unit No. 3										
Brigantine Wildlife Refuge	89%	PM_{10}	0.10	0.05	0.06	0.08	0.09	0.08	0.10	0.08
	66%	PM_{10}	0.06	0.04	0.05	0.05	0.06	0.06	0.06	0.06
	32%	PM_{10}	0.04	0.03	0.04	0.04	0.04	0.04	0.04	0.04
	35%	PM_{10}	0.06	0.04	0.04	0.05	0.06	0.05	0.06	0.05

4.4 PM_{10} COMPONENT TO VISIBILITY ANALYSIS

The information discussed in Subsection 4.3 considered PM_{10} visibility impacts in combination with the visibility impacts due to SO_2 and NO_X emissions. This subsection of the BART analysis has removed the visibility impacts due to non-PM_{10} emissions and focused on the visibility impairment due only to total PM_{10} emissions. By removing the contribution of SO_2 and NO_X emissions to visibility impairment, it is very evident that total PM_{10} emissions cause extremely minor visibility impairment. Therefore, the control of total PM_{10} emissions will have an imperceptible effect on visibility conditions. These two points are discussed in the following paragraphs.

To assess the contribution of visibility impairment due to just total PM_{10} emissions, the visibility impacts for the baseline and PM_{10} control scenarios were considered. The peak modeled baseline dV values at the Brigantine Class I area were determined for each day modeled. For the three year period, 2001 thru 2003, a total of 1096 24-hour periods were modeled. For the three year period, 24-hour dV impacts of 0.1 dV or greater due to all VIP were identified. These 0.1 dV periods were then reanalyzed to determine the dV impact due just to total PM_{10} emissions. For the baseline scenario, the peak dV impacts due to total PM_{10} emissions were 0.07 dV for 2001 and 2002 and 0.03 dV for 2003.

There were four PM_{10} control scenarios that were considered for Unit No. 3. The control scenarios included 32%, 35%, 66%, and 89% control efficiencies. For each PM_{10} control scenario, all 24-hour periods with a dV impact of 0.1 dV or greater due to VIP emissions and controlled PM_{10} emissions were determined. The periods were then reanalyzed to provide the dV impact due to just total PM_{10} emissions. For the 32% PM_{10} control scenario, the peak total PM_{10} dV impact was 0.038 dV and occurred in 2001. The 35% PM_{10} control scenario resulted in a peak total PM_{10} dV impact of 0.040 dV. The 66% and 89% control scenarios produced peak total PM_{10} dV impacts of 0.020 dV and 0.006 dV respectively. The baseline and control scenarios total PM_{10} dV impacts are summarized in Table 4-6. The spreadsheet calculations used to total PM_{10} impacts are included in Attachment D.

Table 4-6
PM_{10} Only Visibility Impacts

Emission Source and Pollutant	Peak Modeled Deciview Impacts (dV)				
	Base Case	32% Control	35% Control	66% Control	89% Control
Unit No. 3 PM_{10} Emissions	0.07	0.04	0.04	0.02	0.01

Note: A 1.0 deciview value is considered the lowest range of a perceptible change in visibility and 0.5 deciviews are representative of one half of the detectable change. The values shown in this table range between 14 and 100 times lower than the 1.0 deciview value. The values shown in this table correspond to visibility modeling results for 2001, which is the worst case visibility modeling year.

5. SUMMARY OF MCKEE RUN BART PROPOSAL

Based on the information developed in the Impacts Analysis, McKee Run proposes that BART for PM_{10} from Boiler 3 is current combustion control methods. The following factors support this determination.

1. None of the control technologies analyzed would result in any significant, or even perceptible, improvement in visibility in a Class I area. If the highest efficiency PM_{10} control technology was implemented (Switch to Natural Gas with 89% control) the maximum 98th percentile visibility improvement that would result would be only 0.08 dV. The maximum visibility improvement that would result on the highest impact day would be only 0.10 dV. The human eye cannot perceive a change in visibility impairment unless it is at least 1 to 2 dV. McKee Run does not believe that controls are justified under BART if no perceptible visibility improvement will result from their implementation.
2. Based on U.S. EPA's Appendix Y guidance, which DNREC directed facilities to follow, Boiler 3 does not significantly cause nor contribute to visibility impairment in any Class I area. The pre-control visibility modeling analysis shows that the 98th percentile visibility impact for Boiler 3 is 0.46 dV in the Brigantine Wildlife Refuge and 0.27 dV in the Shenandoah National Park. These impacts are less than the 0.5 dV level at which U.S. EPA suggests that a source should be considered to contribute to visibility impairment. A source that does not contribute to visibility impairment is not required to install BART controls under the Regional Haze rules.
3. The total annualized costs (which are actually the annual operating costs) to implement the fuel switching options are $19.0 million for natural gas, $57.0 million for No. 2 fuel oil, $38 million for No. 4 fuel oil, and $9.5 million for 0.5% S No. 6 fuel oil. The cost effectiveness of these technologies are $64,986 (natural gas), $264,137 (No. 2 fuel oil), $326,821 (No. 4 fuel oil), and $89,197 (0.5% S No. 6 fuel oil) per ton of PM_{10} removed, and $2.4 million (natural gas), $1.0 billion (No. 2 fuel

oil), $7.3 million (No. 4 fuel oil), and $2.2 million (0.5% S No. 6 fuel oil) per deciview of visibility improvement. McKee Run does not believe that these costs of compliance are at all reasonable given that they would result in almost no visibility improvement in either of the Class I areas.

4. As a result of compliance with Delaware's Multi-Pollutant regulation Boiler 3 will have a PM_{10} reduction of 32% and thus, a visibility improvement associated with the 0.5% sulfur in residual fuel requirement. The facility will be required to comply with this requirement beginning January 1, 2009, prior to the requirement to install BART controls. Therefore, the consideration of BART controls for Boiler 3 should be compared above and beyond the control level expected from compliance with the fuel sulfur specifications of Delaware's Multi-Pollutant regulation. Provided below in Table 5-1 is a summary of the emissions and economic impact for each of the control technologies considered in the BART analysis compared with the fuel switching option to 0.5% sulfur in No. 6 fuel oil.

The results of the BART Analysis are provided in full detail, following the procedures outlined in the previous sections of this proposal. Table 5-2 outlines the following information for the Boiler 3 BART eligible source:

- Identify VIPs for the source;
- Identify control technologies available for each VIP;
- Identify technically feasible control technologies for each source/VIP scenario;
- Evaluate control effectiveness of each technically feasible control technology;
- Calculate cost effectiveness for each control technology;
- Determine energy, non-air quality environmental impacts, and remaining useful life of source;
- Evaluate visibility impacts of control technology; and
- Identify BART control.

Table 5-1
Summary of Economic Impact for PM_{10} Controls at Boiler 3 Compared to 0.5% Sulfur Fuel

Control Technology	*Baseline Emission Rate (tons/yr)*	*Emissions Performance Level Above 0.5% Sulfur Fuel (32%)*	*Emissions Reductions Above 0.5% Sulfur Fuel (106.7) (tons/yr)*	*Incremental Costs of Compliance Compared to 0.5% Sulfur Fuel (Total Annualized Cost: $9,513,798)*
Switch from 1% S No. 6 Fuel Oil to Natural Gas	328.2	57%	186.1	Incremental Cost: $51,113/incremental ton (No. 6 FO 1% S to Natural Gas vs. No. 6 FO 1% S to No. 6 FO 0.5% S)
Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 2 Fuel Oil	328.2	34%	109.4	Incremental Cost: $434,621/incremental ton (No. 6 FO 1% to No. 2 FO vs. No. 6 1% S to No. 6 FO 0.5% S)
Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 4 Fuel Oil	328.2	3%	9.7	Incremental Cost: $2,918,484/incremental ton (No. 6 FO 1% to No. 4 FO vs. No. 6 FO 1% to No. 6 FO 0.5%)

McKee Run has included Table 5-3 that presents visibility impacts on the Brigantine Wilderness Refuge Class I area comparing the pre-control and post-control scenarios. McKee Run used the 98th Percentile deciview values for the pre-control and post-control scenarios for the Boiler 3 BART eligible source as outlined in 40 CFR Part 51, Appendix Y. The purpose of this table is to highlight the visibility impacts for the Boiler 3 BART-eligible source during the baseline or pre-control period and to compare these values with the visibility impacts for the proposed post-control scenario.

Table 5-2
Summary of BART Analysis

VIP	*Step 1 – Identify Control Technologies*	*Step 2 – Identify Technically Feasible Control Technologies*	*Step 3 – Evaluate Control Effectiveness for Technically Feasible Control Technologies*	*Step 4.1 – Calculate Cost Effectiveness for Control Technologies*	*Steps 4.2 and 4.3 – Determine Energy, Other Non-Air Quality Environmental Impacts, and Remaining Useful Life*	*Step 5 – Evaluate Visibility Impacts of Control Technologies*	*Identify BART Control*
Boiler 3 (Emission Unit 3)							
PM_{10}							
	Switch from 1% S No. 6 Fuel Oil to Natural Gas	Yes	89%	Total Annualized Cost: $19,027,596 Average Cost Effectiveness: $64,986/ton Cost Effectiveness per dV: $243,943,538/dV Incremental Cost: Not calculated due to the high annual cost of the fuel switching option to No. 2 FO.	N/A	Highest Average 98th Percentile Impact Improvement of only 0.08 dV in Brigantine.	Fuel switching is not a cost effective BART control option for PM_{10}. BART not justified as visibility improvement of only 0.08 dV occurs.
	Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 2 Fuel Oil	Yes	66%	Total Annualized Cost: $57,082,788 Average Cost Effectiveness: $264,137/ton Cost Effectiveness per dV: $1,001,452,421/dV Incremental Cost: $190,906/incremental ton (No. 6 FO to No. 2 FO vs. No. 6 FO to No. 4 FO)	N/A	Highest Average 98th Percentile Impact Improvement of only 0.06 dV in Brigantine.	Fuel switching is not a cost effective BART control option for PM_{10}. BART not justified as visibility improvement of only 0.06 dV occurs.

Table 5-2
Summary of BART Analysis

VIP	*Step 1 – Identify Control Technologies*	*Step 2 – Identify Technically Feasible Control Technologies*	*Step 3 – Evaluate Control Effectiveness for Technically Feasible Control Technologies*	*Step 4.1 – Calculate Cost Effectiveness for Control Technologies*	*Steps 4.2 and 4.3 – Determine Energy, Other Non-Air Quality Environmental Impacts, and Remaining Useful Life*	*Step 5 – Evaluate Visibility Impacts of Control Technologies*	*Identify BART Control*
	Use Add-On Control of a Wet ESP	Yes – However, not analyzed since fuel switching options alone resulted in greater control of PM_{10}.	43%	N/A	Disposal and handling of collected slurry from wet ESP.	N/A	Not analyzed since fuel switching options alone resulted in greater control of PM_{10}.
	Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 4 Fuel Oil	Yes	35%	Total Annualized Cost: $38,055,192 Average Cost Effectiveness: $326,821/ton Cost Effectiveness per dV: $731,830,615/dV Incremental Cost: $2,918,484/incremental ton (No. 6 FO to No. 4 FO vs. No. 6 FO 1% to No. 6 FO 0.5%)	N/A	Highest Average 98th Percentile Impact Improvement of only 0.05 dV in Brigantine.	Fuel switching is not a cost effective BART control option for PM_{10}. BART not justified as visibility improvement of only 0.05 dV occurs.
	Switch from 1% S No. 6 Fuel Oil to 0.5% S No. 6 Fuel Oil	Yes	32%	Total Annualized Cost: $9,513,798 Average Cost Effectiveness: $89,197/ton Cost Effectiveness per dV: $221,251,116/dV	N/A	Highest Average 98th Percentile Impact Improvement of only 0.04 dV in Brigantine.	Fuel switching is not a cost effective BART control option for PM_{10}. BART not justified as visibility improvement of only 0.04 dV occurs. However, this improvement will occur as a result of Delaware's Multi-Pollutant regulation.

Table 5-2
Summary of BART Analysis

VIP	*Step 1 – Identify Control Technologies*	*Step 2 – Identify Technically Feasible Control Technologies*	*Step 3 – Evaluate Control Effectiveness for Technically Feasible Control Technologies*	*Step 4.1 – Calculate Cost Effectiveness for Control Technologies*	*Steps 4.2 and 4.3 – Determine Energy, Other Non-Air Quality Environmental Impacts, and Remaining Useful Life*	*Step 5 – Evaluate Visibility Impacts of Control Technologies*	*Identify BART Control*
	Use Add-On Control of Dry ESP	Yes – However, not analyzed since fuel switching options alone resulted in greater control of PM_{10}.	N/A	N/A	High energy demand due to multiple field ESP.	N/A	Not analyzed since fuel switching options alone resulted in greater control of PM_{10}.
	Use Add-On Control of Baghouse	No	N/A	N/A	N/A	N/A	Not analyzed due to technical difficulty expressed by control technology vendors.

Table 5-3
Comparison of Annual 98th Percentile Daily Visibility Impacts in Class I Area(s) - Pre Control vs. Post Control Scenarios
City of Dover McKee Run Generating Station
Dover, DE

Source Name	Control Efficiency	Pollutant	2001			2002			2003		
			98th Percentile Pre Control	98th Percentile Post Control	Visibility Improvement	98th Percentile Pre Control	98th Percentile Post Control	Visibility Improvement	98th Percentile Pre Control	98th Percentile Post Control	Visibility Improvement
Brigantine Wildlife Refuge											
Unit No. 3	89%	PM_{10}	0.518	0.464	0.054	0.388	0.310	0.078	0.473	0.397	0.076
	66%	PM_{10}	0.518	0.479	0.039	0.388	0.336	0.052	0.473	0.416	0.057
	32%	PM_{10}	0.518	0.490	0.028	0.388	0.352	0.036	0.473	0.430	0.043
	35%	PM_{10}	0.518	0.483	0.035	0.388	0.341	0.047	0.473	0.421	0.052

ATTACHMENT A –
AIR QUALITY MODELING PROTOCOL – BART SIGNIFICANCE LEVEL MODELING

April 4, 2007

John Sipple
State of Delaware Department of Natural Resources and Environmental Control
Division of Air & Waste Management
156 South State Street
Dover, DE 19901

Re: McKee Run Generating Station - BART Modeling Protocol Letter

Dear Mr. Sipple:

The McKee Run Generating (McKee Run) Station is subject to the Best Available Retrofit Technology (BART) provisions that are part of the Regional Haze Rule listed at 40 CFR Part 51.308. Under the Regional Haze rules, a visibility modeling analysis is performed for facilities that have BART eligible sources to determine if the sources at the facility cause or contribute to visibility impairment at nearby Class I areas. If the source potentially causes or contributes to visibility impairment, then a control technology evaluation for the BART eligible source must be conducted. If visibility modeling demonstrates that a source does not contribute to or cause visibility impairment, the control technology evaluation is typically not required.

The McKee Run Station is submitting this letter to the Delaware Department of Natural Resources and Environmental Control (DNREC) to outline the steps that will be taken to conduct the visibility modeling analyses for the BART eligible unit at the McKee Run Generating Station in Dover, DE. Specifically, the McKee Run Station proposes to incorporate the visibility modeling approach developed by the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) Regional Planning Organization (RPO). VISTAS established visibility modeling procedures (VISTAS Modeling Protocol – 2005) for conducting visibility modeling for BART eligible sources. These procedures were designed for sources that are located in the southeastern United States; however the procedures have been approved for use by non-VISTAS states.

An important component to the VISTAS modeling procedures involves the use of processed meteorological data files. VISTAS processed meteorological data for the CALPUFF air dispersion model can be used for sources located throughout the southeast included sources located in Delaware. VISTAS developed refined CALMET meteorological data that can be used for performing the visibility modeling for the McKee Run Station and all Class I areas within 300 km of the facility.

The McKee Run Station proposes to utilize the VISTAS refined CALMET data, along with modeling recommendations from VISTAS to perform a visibility modeling analysis of the BART eligible sources at the facility. This letter describes the facility background information, the inventory of visibility impairing pollutant (VIP) emission rates, and

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visibility modeling procedures that the McKee Run Station will use for the source-specific visibility modeling analysis.

Location of the Facility and Nearby Class I Areas

The McKee Run Station is located in the city of Dover, in Kent County, DE. A USGS 1:24,000 scale topographical map is shown in Figure 1, with the McKee Run location highlighted. The geographical coordinates for the approximate center of the facility are:

- Universal Transverse Mercator (UTM) Easting: 452,863 meters
- Universal Transverse Mercator (UTM) Northing: 4,336,147 meters
- UTM Zone : 18
- North American Datum (NAD): 1927
- Longitude (degrees, minutes, seconds): 39° 10' 31.0"
- Latitude (degrees, minutes, seconds): 75° 32' 45.0"

Kent County is located in the Southern Delaware Intrastate Air Quality Control Region (AQCR). The area is in attainment for all criteria pollutants except ozone (O_3) for which Kent County is a moderate non-attainment area. The elevation at the facility is 7.0 meters (m), (23 feet) above mean sea level (amsl).

The McKee Run Station proposes to evaluate visibility impacts at Class I areas within 300 km of the facility. As shown in Figure 2, there are two Class I areas located within 300 km of the McKee Run Station. These Class I areas are:

- Brigantine Wildlife Refuge, approximately 96 km to the east-northeast, managed by the U.S. Fish and Wildlife Service,
- Shenandoah National Park, approximately 230 km to the west-southwest, managed by the National Park Service.

Emissions Inventory

According to the guidance contained in the Regional Haze Regulations, an emissions unit is considered to be BART eligible if the following three criteria are met:

- If the emission unit was in existence on August 7, 1977 but not in operation before August 7, 1962,
- If the facility falls within one of the 26 listed source categories summarized in the guidance, and;
- If the potential emissions are at least 250 tons per year (tpy) of at least one visibility impairing pollutant across all BART eligible units at the facility.

The No. 3 Boiler (Unit No. 3) is the only emissions unit at the McKee Run Station that meets the BART eligibility installation date criteria listed above. Unit No. 3 is a 110 megawatt (MW) boiler that fires No. 6 residual fuel oil and natural gas. Unit No. 3

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approximate quadrangle location

0 0.5 1
kilometers

N

Based on USGS 1:24,000 topographical map for Dover, Deleware, 1993.

McKee Run
Generating Station
Dover, Delaware

Figure 1
Facility Location Map

E:\Client Files\City of Dover\USGS\McKee Run Facility Location Map.wor

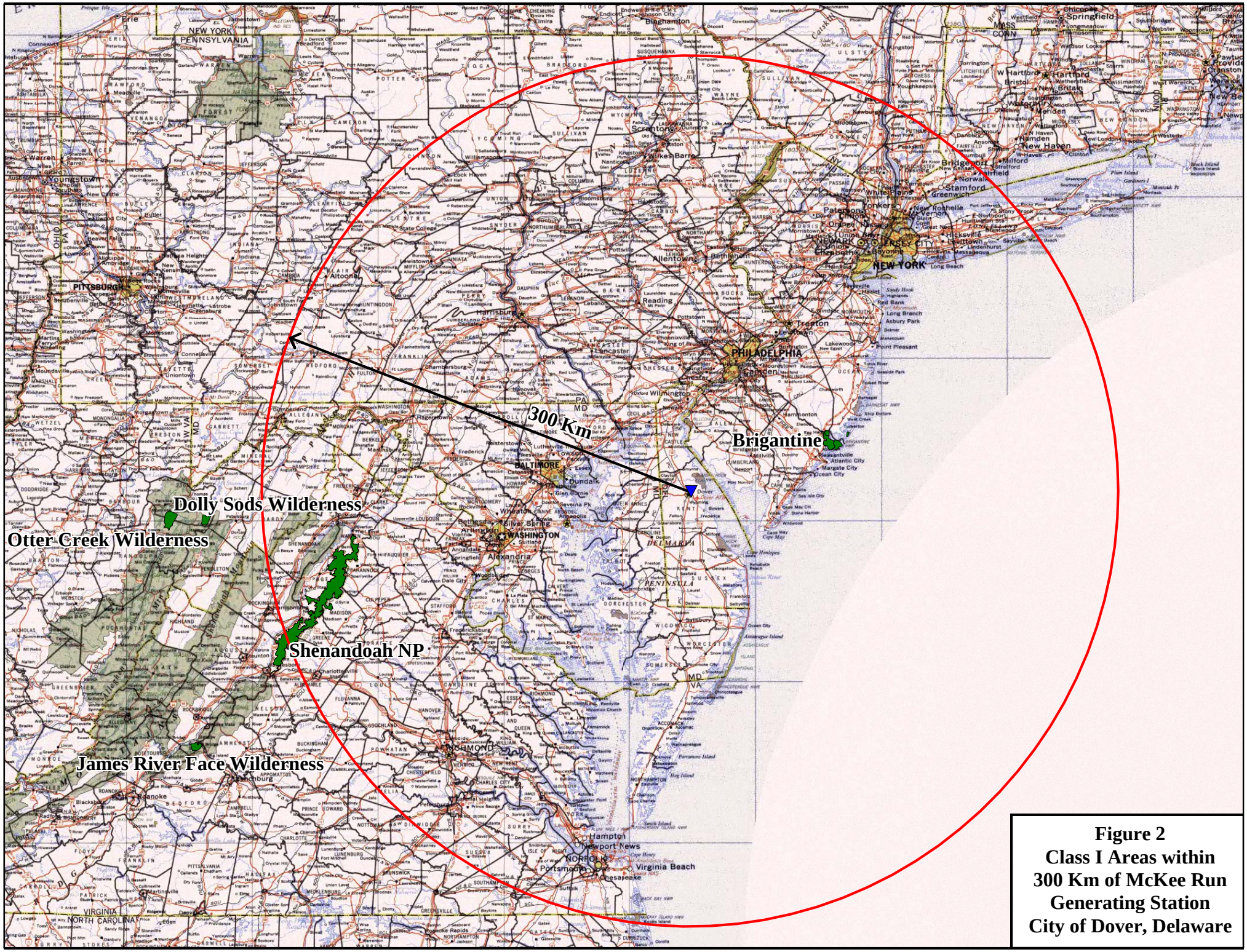

Figure 2
Class I Areas within 300 Km of McKee Run Generating Station City of Dover, Delaware

typically operates as a peaking unit, although it is permitted to operate 8,760 hours per year. The potential emissions and annual actual emissions of oxides of nitrogen, sulfur dioxide, and particulate matter of 10 microns or less (PM_{10}) are shown in Table 1.

Visibility Modeling Emission Rates

The Regional Haze Regulations provides guidance to the states that the highest 24-hour average emission rate of visibility impairing pollutants must be used in the visibility modeling analysis. Visibility impairing pollutants are defined as SO_2, NO_X, condensable and filterable PM_{10}, (including PM_{10} sub-species), ammonia (NH_3), and volatile organic compounds (VOC). Although, NH_3 and VOC are visibility impairing pollutants, these pollutants are not typically included as part of the emission inventory used to model visibility impacts and thus the McKee Run Station has not included them in the emission inventory.

The McKee Run Station calculated the highest 24-hour average emission rates of SO_2, NO_X, and PM_{10} for Unit No. 3. These emission rates are shown in Table 2 and reflect peak operating conditions for Unit No. 3.

It is important to note that DNREC has indicated that the requirements of the Clean Air Interstate Rule (CAIR) and the state Multi-Pollutant Regulation 1146 will apply to Unit No. 3. DNREC will consider the application of these two regulations to reflect BART level of controls for NO_X and SO_2 as part of the Regional Haze SIP. Therefore, although the visibility modeling analysis will consider all three visibility impairing pollutants to determine the baseline visibility impacts, only PM_{10} will be evaluated for the potential application of BART.

Stack Characteristics

The McKee Run Station will use exhaust gas flow rate and temperature data that are representative of normal operation for Unit No. 3. The Unit No. 3 source location coordinates will be transformed to a Lambert Conformal projection based on the origin and projection parameters that VISTAS defined for their CALMET meteorological domain.

Due to the extended distance between the McKee Run Station and the Class I areas, building downwash will not be included in the visibility modeling analysis. Excluding building downwash from the analysis is a valid approach since the effects of building downwash are inconsequential at large modeled distances. As shown in Figure 2, the closest Class I area is almost 100 km away. In addition, the VISTAS visibility modeling procedures contain a recommendation to omit building downwash effects for sources that are located more than 50 km from a Class I area.

Visibility Modeling Approach and Technical Information

This section contains information on the technical approach that will be followed in the visibility modeling analysis and outlines the configurations for CALMET and CALPUFF that will be used to model the BART eligible source at the McKee Run Station. The technical approach follows the guidance established in the VISTAS modeling protocol.

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Table 1
McKee Run Station VIP Emission Rates
BART Applicability
Unit No. 3

VIP Emission Rates Unit No. 3			
	NO_X	SO_2	PM_{10}
	tpy	tpy	tpy
PTE [a]	1378.2	5409.6	354.6
Annual Actual [b]	210.31	530.20	31.41

Notes:
[a] Potential to emit based on maximum allowed permit emission and operation rates.
[b] The annual actuals reflected in this table are from the calendar year 2005 annual emission inventory.

Table 2
McKee Run Station Highest 24-Hour Emission Rate
Modeling Baseline Rate
Unit No. 3

Max Emission Rates at Max Load, ~101.5 MW Baseline Emission Rates for Modeling					
NO_X [a]	NO_X	SO_2	SO_2	PM_{10} [b]	PM_{10}
lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr
0.50	5430.25	0.85	923.63	0.087	94.57

Notes:

[a] Maximum allowed by permit limit 0.50 lb/MMBtu.

[b] PM-10 value determined using AP-42 filterable and condensable for No. 6 fuel oil with 0.9% sulfur content. Sulfur content % was determined from 2005 fuel data.

As part of the visibility modeling analysis, the McKee Run Station proposes to use the refined, 4-km CALMET meteorological data provided by VISTAS. The 4-km CALMET meteorological data represent the combination of Mesoscale Model 5 (MM5) data and National weather service (NWS) surface observations, upper air data, precipitation data, and buoy (ocean-based measurement) data. The Domain 5 CALMET data will be used to predict visibility impacts at the Brigantine Wildlife Refuge and the Shenandoah National Park. The geographical extent of the Domain 5 data is shown in Figure 3 and provides sufficient buffer around each Class I area. The Domain 5 CALMET data will be obtained via one of the state agencies (e.g., Virginia Department of Environmental Quality, Alabama Department of Environmental Management) in the VISTAS region.

The 4-km CALMET data reflect the following processing steps used by VISTAS:

- Modeling period: 3 years (2001-2003),
- Meteorological inputs: MM5 data provide initial guess fields in CALMET,
- CALMET grid resolution: 4-km,
- CALMET vertical layers: 10 layers. Cell face heights (meters): 0, 20, 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000,
- CALMET mode: No-Observations mode including option to read overwater data directly from MM5 data,
- Diagnostic options: IWAQM default values, except as follows: diagnostic terrain blocking and slope flow algorithms used for 2003 simulations (using 36-km MM5 data), but no diagnostic terrain adjustments in 2001 and 2002 simulation (using 12-km MM5 data),
- Land use defining water: JWAT1 = 55, JWAT2 = 55 (large bodies of water), and
- Geophysical data for regional runs: SRTM-GTOPO30 30-arcsec terrain data, Composite Theme Grid (CTG) USGS 200m land use dataset.

CALPUFF Configuration

The CALPUFF air dispersion model will be used to determine the visibility impacts at the two Class I areas. The CALPUFF air dispersion model will be used as recommended by VISTAS and as outlined below:

- Version 5.6393 of the CALPUFF air dispersion model will be used,
- Building downwash will not be considered,
- CALPUFF domains will be set to an area that provides an adequate buffer around all modeled Class I areas. The domains will be sized so to ensure at least a 50 km buffer surrounding each Class I area,
- Modeled Species: SO_2, NO_X, and PM_{10} from the Unit No. 3 with PM_{10} subspecies being developed per U.S. EPA and National Park Service Guidance,

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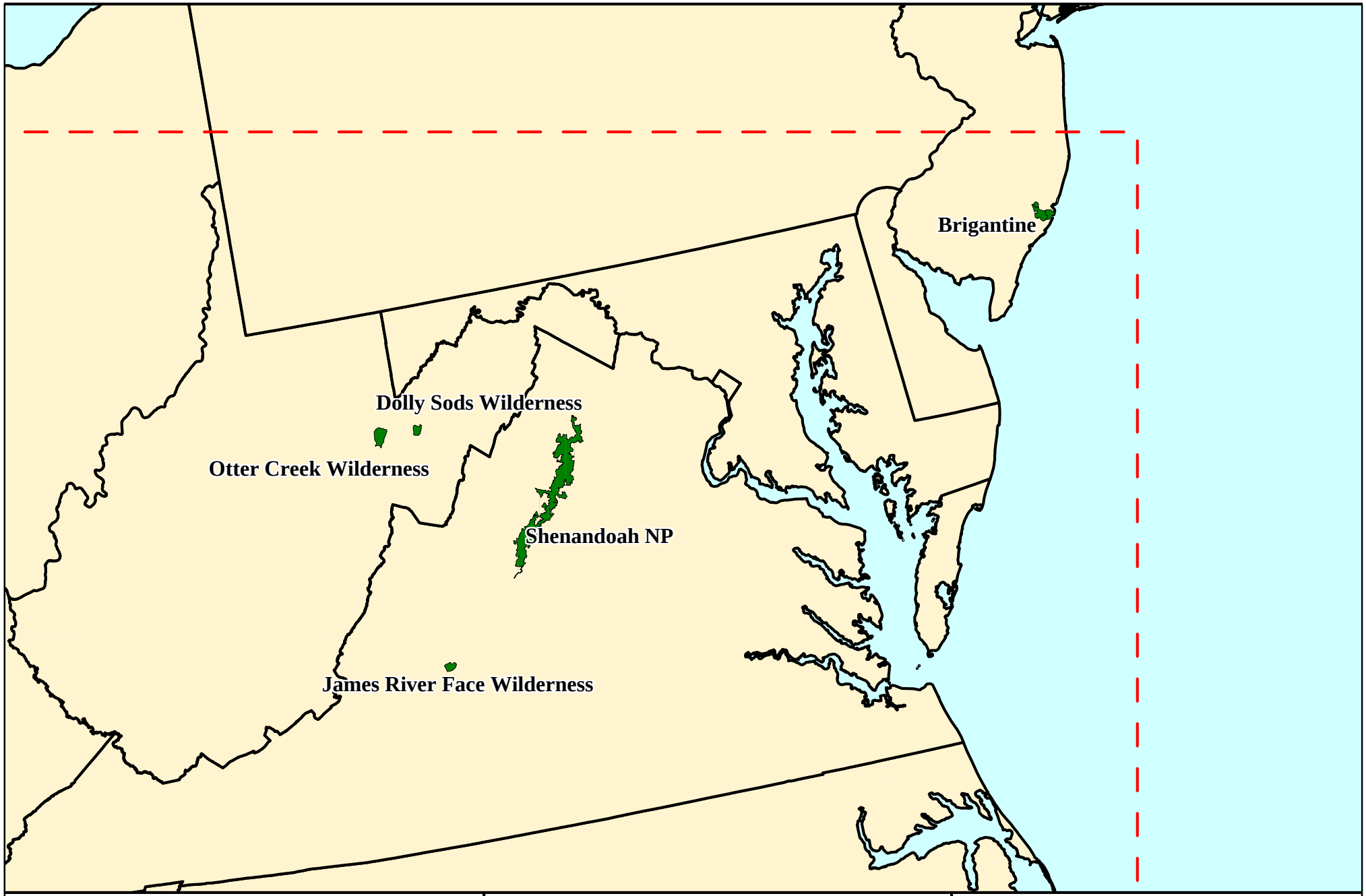

0 100 200
kilometers

CALMET Domain Boudary

Figure 3
Northest Extent of the VISTAS 4-km CALMET Domain

- The McKee Run Station will use receptor grids developed by the National Park Service for the Brigantine Wildlife Refuge and the Shenandoah National Park,
- The Pasquill-Gifford (PG) dispersion option will be used,
- Observed non-urban ozone data for the 2001-2003 CASTnet and AIRS monitoring networks will be used as necessary, and
- A background ammonia concentration of 0.5 parts per billion (ppb) will be used for all months.

CALPOST and POSTUTIL Configuration

The concentration output information from CALPUFF will be post-processed by CALPOST and POSTUTIL to estimate visibility impacts at each Class I area. The following CALPOST and POSTUTIL configurations, as outlined in the VISTAS common modeling protocol, will be used:

- Visibility Method 6 with Class I area specific monthly relative humidity values will be used,
- Natural background light extinction values will be calculated using data from U.S. EPA's "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program", (U.S. EPA 2003) guidance document. Average background concentrations of sulfates, nitrates, organic secondary aerosol, elemental carbon, soil, and coarse filterable particulate will be taken from Table 2-1, while f[RH] factors will be taken from Table A-3 of the U.S. EPA 2003 document for each Class I area. A Rayleigh scattering efficiency of 10 Mm-1 will be used for all Class I areas, and
- The McKee Run Station will not use the Ammonia Limiting Method (MNITRATE=1) to reparation nitrate formation in POSTUTIL.

<u>Presentation of Visibility Modeling Results</u>

The visibility modeling results will be submitted as part of the McKee Run Station's BART proposal analysis. The BART proposal analysis will include an assessment of the impact on visibility due to the current emissions from the BART eligible source. The BART proposal analysis will also include the visibility improvement related to the application of PM_{10} control technologies. As stated previously, DNREC considers the CAIR and Multi-Pollutant Regulation 1146 to be equivalent to BART for Unit No. 3 and thus no visibility improvement is needed to be quantified for SO_2 and NO_X. The McKee Run Station will use the eighth highest (98th percentile) visibility impact for assessing the change in visibility levels due to PM_{10} controls. An electronic copy of all visibility modeling files will be submitted as part of the BART proposal analysis.

Please contact me at (610) 933-5246 extension 23 or Mr. Ken Beard of the McKee Run Station at 302-672-6336 if you have any questions or require additional information concerning this proposed BART visibility modeling protocol.

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Sincerely,

All 4 Inc.

Cara Fox

cc: Ali Mirzakhalili, DNREC
Dean Blaha, City of Dover McKee Run Generating Station
Kenneth Beard, City of Dover McKee Run Generating Station

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ATTACHMENT B –
CONTROL COST SPREADSHEETS

Table B-1
City of Dover
BART Evaluation Annual Costs
Boiler 3
Fuel Switch to Natural Gas

	Current Scenario	**Future Scenario**	**Difference**	**Removal Efficiency (%)**	**Cost Effectiveness ($/ton removed)**
Natural Gas Usage (Mscf/yr)	--	9,327,253			
Fuel Oil Usage (gal/yr)	63,425,320	--			
Natural Gas Unit Cost ($/Mscf)	--	$10.20			
Fuel Oil Unit Cost ($/gal)	$1.20	--			
Annual Cost ($/yr)	$76,110,384	$95,137,980	$19,027,596		
PM_{10} Emissions (tons/yr)	328	35.4	293	89%	$64,986

Table B-2
City of Dover
BART Evaluation Annual Costs
Boiler 3
Fuel Switch to 0.3% S No. 2 Fuel Oil

	Current Scenario	**Future Scenario**	**Difference**	**Removal Efficiency (%)**	**Cost Effectiveness ($/ton removed)**
Fuel Oil Usage (gal/yr)	63,425,320	67,955,700	4,530,380		
Fuel Oil Unit Cost ($/gal)	$1.20	$1.96	$0.76		
Annual Cost ($/yr)	$76,110,384	$133,193,172	$57,082,788		
PM_{10} Emissions (tons/yr)	328	112	216	66%	$264,137

Table B-3
City of Dover
BART Evaluation Annual Costs
Boiler 3
Fuel Switch to 0.3% S No. 4 Oil

	Current Scenario	**Future Scenario**	**Difference**	**Removal Efficiency (%)**	**Cost Effectiveness ($/ton removed)**
Fuel Oil Usage (gal/yr)	63,425,320	65,612,400	2,187,080		
Fuel Oil Unit Cost ($/gal)	$1.20	$1.74	$0.54		
Annual Cost ($/yr)	$76,110,384	$114,165,576	$38,055,192		
PM_{10} Emissions (tons/yr)	328	212	116	35%	$326,821

Table B-4
City of Dover
BART Evaluation Annual Costs
Boiler 3
Fuel Switch to 0.5% S No. 6 Fuel Oil

	Current Scenario	**Future Scenario**	**Difference**	**Removal Efficiency (%)**	**Cost Effectiveness ($/ton removed)**
Fuel Oil Usage (gal/yr)	63,425,320	63,425,320	0		
Fuel Oil Unit Cost ($/gal)	$1.20	$1.35	$0.15		
Annual Cost ($/yr)	$76,110,384	$85,624,182	$9,513,798		
PM_{10} Emissions (tons/yr)	328	222	107	32%	$89,197

ATTACHMENT C –
SUMMARY OF BART SIGNIFICANCE LEVEL MODELING RESULTS

ATTACHMENT D –
Analysis of Total PM_{10} Visibility Impacts

Table 1
Top 10 Deciview Values Due to Particulate Emissions
PM_{10} Base Case
City of Dover McKee Run Generating Station

YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2001	0.07	0.84	4.45	0.94	5.56	11.79	0.573
	0.04	0.59	3.12	0.70	3.91	8.32	0.460
	0.03	0.98	5.21	1.01	6.52	13.72	0.248
	0.03	0.39	2.07	0.54	2.59	5.59	0.602
	0.03	0.62	3.26	0.67	4.09	8.64	0.369
	0.03	0.56	2.95	0.81	3.69	8.01	0.393
	0.03	0.21	1.11	0.26	1.39	2.97	0.962
	0.03	0.32	1.70	0.34	2.12	4.48	0.621
	0.03	0.26	1.39	0.34	1.74	3.73	0.737
	0.03	0.66	3.49	0.68	4.37	9.20	0.290
YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2002	0.07	0.81	4.31	0.83	5.40	11.35	0.580
	0.04	0.85	4.52	0.86	5.65	11.88	0.374
	0.04	0.60	3.17	0.77	3.97	8.51	0.493
	0.03	0.56	2.98	0.67	3.72	7.93	0.417
	0.03	0.87	4.63	1.09	5.80	12.39	0.241
	0.03	0.73	3.88	0.81	4.85	10.27	0.264
	0.03	0.58	3.06	0.81	3.83	8.28	0.319
	0.02	0.55	2.93	0.65	3.67	7.80	0.309
	0.02	0.41	2.16	0.46	2.70	5.73	0.388
	0.02	0.29	1.54	0.34	1.92	4.09	0.533
YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2003	0.03	0.15	0.79	0.14	0.99	2.07	1.571
	0.03	0.47	2.47	0.65	3.09	6.68	0.473
	0.03	0.35	1.87	0.45	2.34	5.01	0.604
	0.03	0.47	2.51	0.66	3.14	6.78	0.439
	0.03	0.41	2.18	0.48	2.73	5.80	0.478
	0.02	0.24	1.28	0.28	1.60	3.40	0.671
	0.02	0.39	2.06	0.48	2.58	5.51	0.391
	0.02	0.93	4.94	0.73	6.18	12.78	0.168
	0.02	0.20	1.03	0.21	1.29	2.73	0.698
	0.02	0.29	1.55	0.36	1.93	4.13	0.461

[a] Deciview from PM_{10} emission only. No other VIP considered.

[b] The percentages of particulate species are relative to the deciview value from all VIP.

[c] Deciview from all VIP (i.e. NO_x, SO_2, PM_{10}, H_2SO_4).

Table 2
Top 10 Deciview Values Due to Particulate Emissions
PM_{10} 32% Control
City of Dover McKee Run Generating Station

YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2001	0.038	0.18	2.99	0.63	4.00	7.80	0.482
	0.021	0.12	2.01	0.45	2.69	5.27	0.404
	0.019	0.22	3.62	0.70	4.85	9.39	0.201
	0.019	0.08	1.27	0.33	1.70	3.38	0.553
	0.018	0.13	2.09	0.42	2.79	5.43	0.326
	0.018	0.12	1.91	0.53	2.55	5.11	0.343
	0.016	0.04	0.66	0.15	0.88	1.73	0.918
	0.015	0.06	1.03	0.21	1.38	2.68	0.577
	0.015	0.05	0.82	0.20	1.10	2.17	0.703
	0.015	0.14	2.25	0.44	3.01	5.84	0.253
YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2002	0.037	0.18	2.87	0.55	3.84	7.44	0.493
	0.025	0.19	3.03	0.58	4.05	7.85	0.315
	0.022	0.12	1.90	0.45	2.54	5.01	0.439
	0.018	0.12	1.92	0.43	2.57	5.04	0.365
	0.017	0.19	3.10	0.73	4.15	8.17	0.204
	0.015	0.16	2.60	0.54	3.47	6.77	0.223
	0.015	0.12	1.99	0.52	2.66	5.29	0.277
	0.013	0.12	1.87	0.41	2.50	4.90	0.273
	0.012	0.08	1.34	0.29	1.79	3.50	0.352
	0.012	0.06	0.92	0.20	1.23	2.41	0.504
YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2003	0.018	0.03	0.46	0.08	0.61	1.18	1.528
	0.018	0.09	1.55	0.41	2.07	4.12	0.426
	0.017	0.07	1.14	0.27	1.53	3.01	0.559
	0.017	0.10	1.56	0.41	2.09	4.16	0.399
	0.015	0.08	1.34	0.29	1.79	3.50	0.441
	0.013	0.05	0.76	0.17	1.01	1.99	0.640
	0.012	0.08	1.28	0.30	1.71	3.37	0.356
	0.012	0.21	3.37	0.50	4.50	8.58	0.139
	0.011	0.04	0.61	0.12	0.82	1.59	0.668
	0.011	0.06	0.93	0.21	1.25	2.45	0.430

[a] Deciview from PM_{10} emission only. No other VIP considered.

[b] The percentages of particulate species are relative to the deciview value from all VIP.

[c] Deciview from all VIP (i.e. NO_x, SO_2, PM_{10}, H_2SO_4).

Table 3
Top 10 Deciview Values Due to Particulate Emissions
PM_{10} 35% Control
City of Dover McKee Run Generating Station

YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2001	0.040	0.56	3.03	0.64	4.58	8.81	0.456
	0.023	0.37	2.01	0.45	3.04	5.87	0.386
	0.020	0.69	3.71	0.72	5.62	10.74	0.188
	0.020	0.23	1.25	0.33	1.89	3.70	0.538
	0.019	0.38	2.07	0.42	3.14	6.01	0.313
	0.019	0.35	1.91	0.53	2.89	5.68	0.327
	0.017	0.12	0.64	0.15	0.97	1.88	0.904
	0.016	0.19	1.01	0.20	1.53	2.93	0.563
	0.016	0.15	0.80	0.19	1.21	2.35	0.694
	0.016	0.42	2.25	0.44	3.40	6.51	0.243
YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2002	0.039	0.53	2.89	0.56	4.37	8.35	0.468
	0.026	0.57	3.06	0.58	4.64	8.85	0.298
	0.023	0.35	1.88	0.44	2.84	5.51	0.424
	0.020	0.36	1.92	0.43	2.91	5.62	0.349
	0.018	0.58	3.13	0.73	4.73	9.17	0.193
	0.016	0.49	2.63	0.55	3.99	7.66	0.210
	0.016	0.37	2.00	0.53	3.03	5.93	0.264
	0.014	0.35	1.86	0.41	2.82	5.44	0.262
	0.013	0.25	1.32	0.29	2.00	3.86	0.341
	0.013	0.16	0.89	0.20	1.35	2.60	0.496
YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2003	0.019	0.08	0.44	0.08	0.67	1.27	1.515
	0.018	0.21	1.12	0.27	1.69	3.29	0.545
	0.018	0.28	1.54	0.40	2.33	4.55	0.387
	0.017	0.26	1.43	0.38	2.17	4.24	0.412
	0.016	0.24	1.31	0.29	1.98	3.82	0.430
	0.014	0.14	0.73	0.16	1.11	2.14	0.631
	0.013	0.23	1.26	0.29	1.91	3.69	0.345
	0.013	0.63	3.43	0.51	5.18	9.75	0.130
	0.011	0.11	0.59	0.12	0.90	1.72	0.658
	0.011	0.17	0.91	0.21	1.38	2.67	0.421

[a] Deciview from PM_{10} emission only. No other VIP considered.

[b] The percentages of particulate species are relative to the deciview value from all VIP.

[c] Deciview from all VIP (i.e. NO_x, SO_2, PM_{10}, H_2SO_4).

Table 4
Top 10 Deciview Values Due to Particulate Emissions
PM_{10} 66% Control
City of Dover McKee Run Generating Station

YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2001	0.020	2.40	0.39	0.76	0.97	4.52	0.437
	0.011	1.57	0.25	0.52	0.63	2.97	0.376
	0.010	0.97	0.16	0.36	0.39	1.88	0.530
	0.010	2.97	0.48	0.89	1.20	5.54	0.178
	0.009	1.49	0.24	0.58	0.60	2.91	0.319
	0.009	1.63	0.26	0.49	0.65	3.03	0.305
	0.008	0.49	0.08	0.17	0.20	0.94	0.897
	0.008	0.78	0.13	0.23	0.31	1.45	0.555
	0.008	0.61	0.10	0.21	0.25	1.17	0.687
	0.008	1.76	0.28	0.53	0.71	3.28	0.235
YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2002	0.019	2.29	0.37	0.67	0.92	4.25	0.450
	0.013	2.43	0.39	0.71	0.98	4.51	0.286
	0.012	1.47	0.24	0.50	0.59	2.80	0.413
	0.010	1.50	0.24	0.49	0.60	2.83	0.340
	0.009	2.48	0.40	0.84	1.00	4.72	0.185
	0.008	2.08	0.33	0.65	0.84	3.90	0.203
	0.008	1.56	0.25	0.58	0.63	3.02	0.257
	0.007	1.45	0.23	0.47	0.59	2.74	0.256
	0.006	1.03	0.16	0.32	0.41	1.92	0.335
	0.006	0.69	0.11	0.22	0.28	1.30	0.490
YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2003	0.009	0.34	0.05	0.09	0.14	0.62	1.507
	0.009	0.87	0.14	0.30	0.35	1.66	0.537
	0.009	1.20	0.19	0.44	0.48	2.31	0.379
	0.009	1.11	0.18	0.42	0.45	2.16	0.404
	0.008	1.02	0.16	0.32	0.41	1.91	0.423
	0.007	0.57	0.09	0.18	0.23	1.07	0.625
	0.006	0.97	0.16	0.33	0.39	1.85	0.340
	0.006	2.73	0.44	0.65	1.10	4.92	0.124
	0.006	0.46	0.07	0.14	0.18	0.85	0.653
	0.006	1.18	0.19	0.41	0.47	2.25	0.246

[a] Deciview from PM_{10} emission only. No other VIP considered.

[b] The percentages of particulate species are relative to the deciview value from all VIP.

[c] Deciview from all VIP (i.e. NO_x, SO_2, PM_{10}, H_2SO_4).

Table 5
Top 10 Deciview Values Due to Particulate Emissions
PM_{10} 89% Control
City of Dover McKee Run Generating Station

YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2001	0.006	0.00	0.00	0.00	1.61	1.61	0.375
	0.003	0.00	0.00	0.00	1.01	1.01	0.337
	0.003	0.00	0.00	0.00	2.08	2.08	0.146
	0.003	0.00	0.00	0.00	0.59	0.59	0.496
	0.003	0.00	0.00	0.00	1.03	1.03	0.275
	0.003	0.00	0.00	0.00	0.96	0.96	0.284
	0.003	0.00	0.00	0.00	0.29	0.29	0.866
	0.002	0.00	0.00	0.00	0.47	0.47	0.524
	0.002	0.00	0.00	0.00	0.37	0.37	0.664
	0.002	0.00	0.00	0.00	1.13	1.13	0.210
YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2002	0.006	0.00	0.00	0.00	1.51	1.51	0.391
	0.004	0.00	0.00	0.00	1.63	1.63	0.245
	0.003	0.00	0.00	0.00	0.92	0.92	0.378
	0.003	0.00	0.00	0.00	0.96	0.96	0.304
	0.003	0.00	0.00	0.00	1.65	1.65	0.159
	0.002	0.00	0.00	0.00	1.39	1.39	0.174
	0.002	0.00	0.00	0.00	1.01	1.01	0.227
	0.002	0.00	0.00	0.00	0.93	0.93	0.231
	0.002	0.00	0.00	0.00	0.64	0.64	0.310
	0.002	0.00	0.00	0.00	0.41	0.41	0.470
YEAR	Unit No. 3 PM_{10} Only Delta Deciview [a]	Percentage of Particulate Species [b]					Unit No. 3 Total Delta Deciview [c]
		%_OC	%_EC	%_PMC	%_PMF	% Total PM	
2003	0.003	0.00	0.00	0.00	0.20	0.20	1.478
	0.003	0.00	0.00	0.00	0.53	0.53	0.506
	0.003	0.00	0.00	0.00	0.74	0.74	0.351
	0.003	0.00	0.00	0.00	0.69	0.69	0.374
	0.002	0.00	0.00	0.00	0.62	0.62	0.397
	0.002	0.00	0.00	0.00	0.34	0.34	0.603
	0.002	0.00	0.00	0.00	1.86	1.86	0.105
	0.002	0.00	0.00	0.00	0.60	0.60	0.315
	0.002	0.00	0.00	0.00	0.27	0.27	0.632
	0.002	0.00	0.00	0.00	0.73	0.73	0.228

[a] Deciview from PM_{10} emission only. No other VIP considered.

[b] The percentages of particulate species are relative to the deciview value from all VIP.

[c] Deciview from all VIP (i.e. NO_x, SO_2, PM_{10}, H_2SO_4).

Table 6
Comparison of Control Options for PM10
Change in Deciview Values [a]
City of Dover McKee Run Generating Station

Scenario	Base Case	32% Control	35% Control	66% Control	89% Control
Unit No. 3 PM_{10} Only Delta Deciview [b]	0.07	0.04	0.04	0.02	0.01

[a] A 0.5 deciview value is considered the lowest range of a perceptible change in visibility.
[b] 2001 is the worst-case year.

July 1, 2008

Mr. John Sipple
State of Delaware
Department of Natural Resources and Environmental Control
156 South State Street
Dover, DE 19901

Re: City of Dover McKee Run Generating Station Best Available Retrofit Technology (BART) Analysis and Proposal Addendum

Dear Mr. Sipple:

As requested in your June 4, 2008 electronic mail correspondence, The City of Dover McKee Run Generating Station (McKee Run) is submitting an addendum to the Best Available Retrofit Technology (BART) Analysis and Proposal originally submitted in June 2007. The addendum is being submitted to address the suggestions and comments of the Federal Land Managers (FLM) that were received by the Delaware Department of Natural Resource and Environmental Conservation (DNREC) after FLM review of the draft Visibility State Implementation Plan (SIP).

As outlined in the June 4, 2008 electronic mail correspondence, McKee Run will address the following two items:

> ***Comment 1:*** *A wet electrostatic precipitator (ESP) is considered as a BART alternative, but cost analysis of the alternative is not performed. It is stated at the bottom of page 3-8 that the wet ESP alternative will not be analyzed since it offers a similar or lesser level of PM_{10} control than those already identified in the fuel switching options, but when all fuel switching alternatives are later deemed to be too expensive for BART, the wet ESP is never analyzed separately. The cost of a wet ESP should be analyzed as a BART alternative.*
>
> ***Comment 2:*** *Section 3.2.2 discusses that Boiler 3 will be required to reduce the sulfur content of the fuel oil to comply with Delaware's Multi-Point regulation for SO_2 and that this action is considered a control option for PM_{10}. Section 5, item 4 states that since Boiler 3 will be required under Delaware's Multi-Point regulation for SO_2 to meet the 0.5% sulfur in residual fuel requirement, "Therefore, the consideration of BART controls for Boiler 3 should be compared above and beyond the control level expected from compliance with the fuel sulfur specification of Delaware's Multi-Pollutant regulations. It should be noted that a BART determination is required to be performed using a 'pre-control' baseline, rather than a baseline assumption that includes a yet-to-be-installed improved sulfur content fuel employed for purposes of another regulatory program.*

Response to Comment 1: Attached to this letter are three amended tables; Table 3-2, Table 5-2, and Table B-5. These three tables have been amended to include the capital and annualized costs for the use of a wet ESP to control PM_{10} emissions. As demonstrated in the tables the installation of a wet ESP is not a cost effective BART control option for PM_{10}.

Response to Comment 2: Attached to this letter is an amended Section 5 of the June 2007 BART Analysis and Proposal. Section 5 has been revised to clarify item 4 in relation to Delaware's Multi-Pollutant regulation. Item 4. and Table 5-1 were included for discussion purposes only to highlight that future regulation would have an impact on visibility independently of the BART requirements. Delaware's Multi-Pollutant regulation will require McKee Run to reduce sulfur content in the fuel beginning in 2009 prior to the 2013 BART requirements. The BART analysis performed in the June 2007 submittal utilized the 'pre-control' baseline rates at McKee Run **without** taking into account the future requirements under Delaware's Multi-Pollutant regulation. Table 5-2 of the originally submitted June 2007 BART Analysis and Proposal summarizes the analysis performed per U.S. EPA's Appendix Y Guidance utilizing McKee Run's 'pre-control' baseline.

If you have any questions regarding this submittal, please do not hesitate to contact me at (302) 672-6304, or Ken Beard at (302) 672-6336.

Sincerely,

Vince Scire

Vince Scire

cc: Ken Beard (McKee Run)
Cara Fox (All4 Inc.)

Attachments Comment 1) – Amended Table 3-2, Table 5-2, and New Table B-5

Amended Table 3-2 (July 2008)
Summary of Economic Impact Analysis for PM_{10} Controls at Boiler 3

Control Technology	*Projected Emission Rate (tons/yr)*	*Emissions Performance Level*	*Expected Emissions Reductions (tons/yr)*	*Costs of Compliance*
Switch from 1% S No. 6 Fuel Oil to Natural Gas	328.2	89%	292.8	Total Annualized Cost: $19,027,596 Average Cost Effectiveness: $64,986/ton Cost Effectiveness per dV: $243,943,538/dV Incremental Cost: Not calculated due to the high annual cost of the fuel switching option to No. 2 FO.
Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 2 Fuel Oil	328.2	66%	216.1	Total Annualized Cost: $57,082,788 Average Cost Effectiveness: $264,137/ton Cost Effectiveness per dV: $1,001,452,421/dV Incremental Cost: $190,906/incremental ton (No. 6 FO to No. 2 FO vs. No. 6 FO to No. 4 FO)
Use Add-On Control of a Wet ESP	328.2	43%	141.1	Total Annualized Cost: $1,915,511 Average Cost Effectiveness: $13,573/ton Cost Effectiveness per dV: $47,887,775/dV Incremental Cost: Lowest annualized cost therefore no incremental cost analysis conducted.
Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 4 Fuel Oil	328.2	35%	116.4	Total Annualized Cost: $38,055,192 Average Cost Effectiveness: $326,821/ton Cost Effectiveness per dV: $731,830,615/dV Incremental Cost: $2,918,484/incremental ton (No. 6 FO to No. 4 FO vs. No. 6 FO 1% to No. 6 FO 0.5%)
Switch from 1% S No. 6 Fuel Oil to 0.5% S No. 6 Fuel Oil	328.2	32%	106.7	Total Annualized Cost: $9,513,798 Average Cost Effectiveness: $89,197/ton Cost Effectiveness per dV: $221,251,116/dV

Amended Table 5-2 (July 2008)

Summary of BART Analysis

VIP	*Step 1 – Identify Control Technologies*	*Step 2 – Identify Technically Feasible Control Technologies*	*Step 3 – Evaluate Control Effectiveness for Technically Feasible Control Technologies*	*Step 4.1 – Calculate Cost Effectiveness for Control Technologies*	*Steps 4.2 and 4.3 – Determine Energy, Other Non-Air Quality Environmental Impacts, and Remaining Useful Life*	*Step 5 – Evaluate Visibility Impacts of Control Technologies*	*Identify BART Control*
Boiler 3 (Emission Unit 3)							
PM_{10}							
	Switch from 1% S No. 6 Fuel Oil to Natural Gas	Yes	89%	Total Annualized Cost: $19,027,596 Average Cost Effectiveness: $64,986/ton Cost Effectiveness per dV: $243,943,538/dV Incremental Cost: Not calculated due to the high annual cost of the fuel switching option to No. 2 FO.	N/A	Highest Average 98th Percentile Impact Improvement of only 0.08 dV in Brigantine.	Fuel switching is not a cost effective BART control option for PM_{10}. BART not justified as visibility improvement of only 0.08 dV occurs.
	Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 2 Fuel Oil	Yes	66%	Total Annualized Cost: $57,082,788 Average Cost Effectiveness: $264,137/ton Cost Effectiveness per dV: $1,001,452,421/dV Incremental Cost: $190,906/incremental ton (No. 6 FO to No. 2 FO vs. No. 6 FO to No. 4 FO)	N/A	Highest Average 98th Percentile Impact Improvement of only 0.06 dV in Brigantine.	Fuel switching is not a cost effective BART control option for PM_{10}. BART not justified as visibility improvement of only 0.06 dV occurs.

Amended Table 5-2 (July 2008)

Summary of BART Analysis

VIP	*Step 1 – Identify Control Technologies*	*Step 2 – Identify Technically Feasible Control Technologies*	*Step 3 – Evaluate Control Effectiveness for Technically Feasible Control Technologies*	*Step 4.1 – Calculate Cost Effectiveness for Control Technologies*	*Steps 4.2 and 4.3 – Determine Energy, Other Non-Air Quality Environmental Impacts, and Remaining Useful Life*	*Step 5 – Evaluate Visibility Impacts of Control Technologies*	*Identify BART Control*
	Use Add-On Control of a Wet ESP	Yes	43%	Total Annualized Cost: $1,915,511 Average Cost Effectiveness: $13,573/ton Cost Effectiveness per dV: $47,887,775/dV Incremental Cost: Lowest annualized cost therefore no incremental cost analysis conducted.	1) Energy demand due to ESP and 2) Disposal and handling of collected slurry from wet ESP.	Highest Average 98th Percentile Impact Improvement of only 0.04 dV in Brigantine.	The use of add-on control of a wet ESP is not a cost effective BART control option for PM_{10}. BART not justified as visibility improvement of only 0.04 dV occurs.
	Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 4 Fuel Oil	Yes	35%	Total Annualized Cost: $38,055,192 Average Cost Effectiveness: $326,821/ton Cost Effectiveness per dV: $731,830,615/dV Incremental Cost: $2,918,484/incremental ton (No. 6 FO to No. 4 FO vs. No. 6 FO 1% to No. 6 FO 0.5%)	N/A	Highest Average 98th Percentile Impact Improvement of only 0.05 dV in Brigantine.	Fuel switching is not a cost effective BART control option for PM_{10}. BART not justified as visibility improvement of only 0.05 dV occurs.

Amended Table 5-2 (July 2008)

Summary of BART Analysis

VIP	*Step 1 – Identify Control Technologies*	*Step 2 – Identify Technically Feasible Control Technologies*	*Step 3 – Evaluate Control Effectiveness for Technically Feasible Control Technologies*	*Step 4.1 – Calculate Cost Effectiveness for Control Technologies*	*Steps 4.2 and 4.3 – Determine Energy, Other Non-Air Quality Environmental Impacts, and Remaining Useful Life*	*Step 5 – Evaluate Visibility Impacts of Control Technologies*	*Identify BART Control*
	Switch from 1% S No. 6 Fuel Oil to 0.5% S No. 6 Fuel Oil	Yes	32%	Total Annualized Cost: $9,513,798 Average Cost Effectiveness: $89,197/ton Cost Effectiveness per dV: $221,251,116/dV	N/A	Highest Average 98th Percentile Impact Improvement of only 0.04 dV in Brigantine.	Fuel switching is not a cost effective BART control option for PM_{10}. BART not justified as visibility improvement of only 0.04 dV occurs. However, this improvement will occur as a result of Delaware's Multi-Pollutant regulation.
	Use Add-On Control of Dry ESP	Yes – However, not analyzed since fuel switching options alone resulted in greater control of PM_{10}.	N/A	N/A	High energy demand due to multiple field ESP.	N/A	Not analyzed since fuel switching options alone resulted in greater control of PM_{10}.
	Use Add-On Control of Baghouse	No	N/A	N/A	N/A	N/A	Not analyzed due to technical difficulty expressed by control technology vendors.

Comment 1) Table B-5
City of Dover - McKee Run Generating Station
CAPITAL AND ANNUALIZED COSTS FOR WESP
Boiler No. 3

CAPITAL COSTS

COST ITEM		COST ($)
Direct Costs		
Purchased Equipment Costs		
[a] ***Purchased Equipment Costs Subtotal***	A	***$3,100,000***
Freight	0.075 A	$232,500
Total Purchased Equipment Cost	B	***$3,332,500***
Direct Installation Costs		
[a] ***Direct Installation Cost***	C	***$1,000,000***
Total Direct Cost	D	***$4,332,500***
Indirect Costs		
[b] Engineering	0.10 D	$433,250
[b] Construction Management	0.03 D	$129,975
[b] Contingencies	0.25 (D+Eng)	$1,191,438
Total Indirect Cost		***$1,754,663***
Total Capital Investment (TCI)		***$6,087,163***

ANNUALIZED COSTS

COST ITEM	COST FACTOR	RATE	COST ($)
Direct Annual Costs			
Operating Labor			
[c] Operator, two employees	2 hours/shift	$44.00 per hour	$173,448
Supervisor	15% of operator labor		$26,017
Maintenance			
Maintenance Labor and Material	5% of sum of direct installation costs, engineering, contingencies, and owner's cost		$131,234
Utilities			
[a], [c] Fresh Water usage	69 MMgal/yr	$500.00 per MMgal[b]	$34,295
[a], [c] Wastewater disposal	69 MMgal/yr	$3.00 per Mgal[d]	$205,772
[a], [c] Electricity	420 KWh	$0.11 per kWh[e]	$354,141
Demand Charge	420 KW	$9.60 max kW per month [e]	$48,384
Total Direct Annual Costs			***$973,293***
Indirect Annual Costs			
Spare Parts	60% of Maintenance Labor & Materials		$78,741
Administrative charges	2% of TCI		$121,743
Property taxes	1% of TCI		$60,872
Insurance	1% of TCI		$60,872
Capital recovery	0.102 x TCI		$619,991
	Life of the control:	20 years at 8.0% interest	
Total Indirect Annual Costs			***$942,218***
Total Annual Costs [d]			***$1,915,511***
Cost Effectiveness ($/ton)[f]			
PM_{10} Control Efficiency	***43% PM_{10} removal***		
Potential PM_{10} Emissions	***328.2 tpy***	***Total Annual Costs/Controlled PM_{10} Emissions:***	
Controlled PM_{10} Emissions	***141.1 tons of PM_{10} removed annually***		***$13,573***

[a] Estimated based on data obtained from Southern Environmental Inc. June 2008.
[b] Cost information estimated using the U.S. EPA Air Pollution Control Cost Manual (6th Edition) published in January 2002 by the OAQPS.
[c] Based on 8,760 hours of operation per year 90% uptime.
[d] Cost specific to McKee Run. McKee Run currently spends $3.00/gallon to dispose of wastewater from the facility.
[e] Cost specific to McKee Run. McKee Run has both a kWh use charge and a demand charge associated with electric usage. Specifically 10.695 cents per kWh and approximately $9.60 demand charge.
[f] Emissions from Table 3-2.

Attachment Comment 2) – Amended Section 5.

5. SUMMARY OF MCKEE RUN BART PROPOSAL

Based on the information developed in the Impacts Analysis and the other technical and cost analyses, McKee Run proposes that BART for PM_{10} from Boiler 3 is current combustion control methods. A summary of the factors that support this determination is contained in the following paragraphs.

1. None of the control technologies analyzed would result in any significant, or even perceptible, improvement in visibility in a Class I area. If the highest efficiency PM_{10} control technology was implemented (Switch to Natural Gas with 89% control) the maximum 98th percentile visibility improvement that would result would be only 0.08 dV. The maximum visibility improvement that would result on the highest impact day would be only 0.10 dV. The human eye cannot perceive a change in visibility impairment unless it is at least 1 to 2 dV. McKee Run does not believe that controls are justified under BART if no perceptible visibility improvement will result from their implementation.
2. Based on U.S. EPA's Appendix Y guidance, which DNREC directed facilities to follow; Boiler 3 does not significantly cause nor contribute to visibility impairment in any Class I area. The pre-control visibility modeling analysis shows that the 98th percentile visibility impact for Boiler 3 is 0.46 dV in the Brigantine Wildlife Refuge and 0.27 dV in the Shenandoah National Park. These impacts are less than the 0.5 dV level at which U.S. EPA suggests that a source should be considered to contribute to visibility impairment. A source that does not contribute to visibility impairment is not required to install BART controls under the Regional Haze rules.
3. The total annualized costs (which are actually the annual operating costs) to implement the fuel switching options are $19.0 million for natural gas, $57.0 million for No. 2 fuel oil, $38 million for No. 4 fuel oil, and $9.5 million for 0.5% S No. 6 fuel oil. The cost effectiveness of these technologies are $64,986 (natural gas), $264,137 (No. 2 fuel oil), $326,821 (No. 4 fuel oil), and $89,197 (0.5% S No. 6 fuel oil) per ton of PM_{10} removed, and $2.4 million (natural gas), $1.0

billion (No. 2 fuel oil), $7.3 million (No. 4 fuel oil), and $2.2 million (0.5% S No. 6 fuel oil) per deciview of visibility improvement. McKee Run does not believe that these costs of compliance are at all reasonable given that they would result in almost no visibility improvement in either of the Class I areas.

4. *In addition to the above points regarding the BART analysis another item to note is that in 2009 the facility will be required to comply with Delaware's Multi-Pollutant regulation at Boiler 3.* As a result of compliance with Delaware's Multi-Pollutant regulation Boiler 3 will have a PM_{10} reduction of 32% and thus, a visibility improvement associated with the 0.5% sulfur in residual fuel requirement. The facility will be required to comply with this requirement beginning January 1, 2009, prior to the requirement to install BART controls. *For comparison purposes provided below in* ~~Therefore, the consideration of BART controls for Boiler 3 should be compared above and beyond the control level expected from compliance with the fuel sulfur specifications of Delaware's Multi-Pollutant regulation. Provided below in~~ Table 5-1 is a summary of the emissions and economic impact for each of the control technologies considered in the BART analysis compared with the fuel switching option to 0.5% sulfur in No. 6 fuel oil *to meet Delaware's Multi-Pollutant regulation.*

Table 5-1 (July 2008)
Summary of Economic Impact for PM_{10} Controls at Boiler 3 Compared to 0.5% Sulfur Fuel

Control Technology	*Baseline Emission Rate (tons/yr)*	*Emissions Performance Level Above 0.5% Sulfur Fuel (32%)*	*Emissions Reductions Above 0.5% Sulfur Fuel (106.7) (tons/yr)*	*Incremental Costs of Compliance Compared to 0.5% Sulfur Fuel (Total Annualized Cost: $9,513,798)*
Switch from 1% S No. 6 Fuel Oil to Natural Gas	328.2	57%	186.1	Incremental Cost: $51,113/incremental ton (No. 6 FO 1% S to Natural Gas vs. No. 6 FO 1% S to No. 6 FO 0.5% S)
Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 2 Fuel Oil	328.2	34%	109.4	Incremental Cost: $434,621/incremental ton (No. 6 FO 1% to No. 2 FO vs. No. 6 1% S to No. 6 FO 0.5% S)
Use Add-On Control of a Wet ESP	328.2	43%	34.40	Incremental Cost: Lowest annualized cost therefore no incremental cost analysis conducted.
Switch from 1% S No. 6 Fuel Oil to 0.3% S No. 4 Fuel Oil	328.2	3%	9.7	Incremental Cost: $2,918,484/incremental ton (No. 6 FO 1% to No. 4 FO vs. No. 6 FO 1% to No. 6 FO 0.5%)

** Please note that Table 5-1 is for comparison purposes only, to compare the effects of Delaware's Multi-Pollutant regulation on the BART analysis. The complete BART analysis and results are summarized in Table 5-2 per U.S. EPA Appendix Y Guidance.*

The results of the BART Analysis are provided in full detail, following the procedures outlined in the previous sections of this proposal. Table 5-2 outlines the following information for the Boiler 3 BART eligible source:

- Identify VIPs for the source;
- Identify control technologies available for each VIP;
- Identify technically feasible control technologies for each source/VIP scenario;
- Evaluate control effectiveness of each technically feasible control technology;

- Calculate cost effectiveness for each control technology;
- Determine energy, non-air quality environmental impacts, and remaining useful life of source;
- Evaluate visibility impacts of control technology; and
- Identify BART control.

McKee Run has included Table 5-3 that presents visibility impacts on the Brigantine Wilderness Refuge Class I area comparing the pre-control and post-control scenarios. McKee Run used the 98th Percentile deciview values for the pre-control and post-control scenarios for the Boiler 3 BART eligible source as outlined in 40 CFR Part 51, Appendix Y. The purpose of this table is to highlight the visibility impacts for the Boiler 3 BART-eligible source during the baseline or pre-control period and to compare these values with the visibility impacts for the proposed post-control scenario.

ADDENDUM
BEST AVAILABLE RETROFIT TECHNOLOGY DETERMINATION
INDIAN RIVER GENERATING STATION UNIT 3
MILLSBORO, DELAWARE

Submitted by:

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June 20, 2008

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Table 5-5a-b Cost Effectiveness for Visibility Improvement for Alternative Control Technologies

List of Acronyms and Abbreviations

BART	Best Available Retrofit Technology
dv	deciview
DNREC	Delaware Natural Resources & Environmental Control
ESP	electrostatic precipitator
FLM	Federal Land Managers
Indian River	Indian River Operations, LLC
MPR	Multi-Pollutant Regulation
NP	National Park
NWA	National Wilderness Area

1.0 Introduction

On January 1, 2007, the Delaware Natural Resources & Environmental Control (DNREC) sent a letter to Indian River Operations, LLC (Indian River) regarding the applicability of the Regional Haze Guidelines for Unit 3 at the Indian River Generating Station in Millsboro, Delaware (Facility). This unit was considered by DNREC as "BART-Eligible" and was required to perform analysis for Best Available Retrofit Technology (BART) Determinations (70 FR 39104). A report was submitted in August 2007 that provided the BART determination for Unit 3 for PM10.

DNREC received comments on their draft Visibility State Implementation Plan from the Federal Land Managers (FLM). The FLM suggested using the 1st highest results for the BART analysis as opposed to the 8th highest values for visibility. This addendum addresses their comment and presents the BART determination using the 1st highest results. Section 5.7 and 5.8 of the August 2007 report is the only section that are updated due to the FLM comment. Therefore, this addendum only includes the necessary changes to Section 5.7 and Section 5.8.

5.0 BART Analysis and Determination

5.7 Summary

Tables 5-4a and 5-4b summarize the BART analysis for the Unit 3 for particulates. As shown in these tables, the changes in visibility impact for both alternative control technologies are minimal over the baseline for both emission scenarios.

Tables 5-5a and 5-5b show the cost effectiveness of the two alternative control technology options in terms of improvement in visibility over baseline. The cost for even marginal change in visibility is substantial for both options.

Table 5-4a
Change in Delta Deciview from Baseline Scenario (ESP)
Emission Scenario 1: PM10 Emissions Only

Class I Area	Parameter	Baseline	Pulse Jet Fabric Filter	Wet ESP after FGD
Brigantine NWA	**1st Highest Delta Deciview**	0.173	0.01	0.007
	Difference from Baseline	-	**0.163**	**0.166**
Shenandoah NP	**1st Highest Delta Deciview**	0.04	0.003	0.001
	Difference from Baseline	-	**0.037**	**0.039**

Table 5-4b
Change in Delta Deciview from Baseline Scenario (ESP)
Emission Scenario 2: PM10/SO2/NOx Emissions

Class I Area	Parameter	Baseline	Pulse Jet Fabric Filter	Wet ESP after FGD
Brigantine NWA	**1st Highest Delta Deciview**	0.466	0.404	0.367
	Difference from Baseline	-	**0.062**	**0.099**
Shenandoah NP	**1st Highest Delta Deciview**	0.273	0.237	0.227
	Difference from Baseline	-	**0.036**	**0.046**

Table 5-5a
Cost Effectiveness for Visibility Improvement for Alternative Control Technologies
Brigantine NWA

Control Technology	Emission Rate (lb/ MMBtu)	Visibility Impact (dv)	Expected Change in Visibility Impact from Baseline	Capital Cost $	Direct Cost $	Indirect Cost $	Total Annualized Cost $	Average Cost Effectiveness ($ per change in dv)
Baseline (existing Cold side ESP): Emission Scenario 1	0.3	0.173	-	-	-	-	-	-
Pulse Jet Fabric Filter: Emission Scenario 1	0.015	0.01	0.163	$43,419,200	$20,330,504	$15,621,995	$35,952,499	**$220,567,479**
Wet ESP after FGD: Emission Scenario 1	0.01	0.007	0.166	$88,270,292	$39,882,776	$31,759,177	$71,641,952	**$431,578,024**
Baseline (existing Cold side ESP): Emission Scenario 2	0.3	0.466	-	-	-	-	-	-
Pulse Jet Fabric Filter: Emission Scenario 2	0.015	0.404	0.062	$43,419,200	$20,330,504	$15,621,995	$35,952,499	**$579,879,016**
Wet ESP after FGD: Emission Scenario 2	0.01	0.367	0.099	$88,270,292	$39,882,776	$31,759,177	$71,641,952	**$723,656,081**

Table 5-5b
Cost Effectiveness for Visibility Improvement for Alternative Control Technologies
Shenandoah NP

Control Technology	Emission Rate (lb/ MMBtu)	Visibility Impact (dv)	Expected Change in Visibility Impact from Baseline	Capital Cost $	Direct Cost $	Indirect Cost $	Total Annualized Cost $	Average Cost Effectiveness ($ per change in dv)
Baseline (existing Cold side ESP): Emission Scenario 1	0.3	0.04	-	-	-	-	-	-
Pulse Jet Fabric Filter: Emission Scenario 1	0.015	0.003	0.037	$43,419,200	$20,330,504	$15,621,995	$35,952,499	**$971,689,162**
Wet ESP after FGD: Emission Scenario 1	0.01	0.001	0.039	$88,270,292	$39,882,776	$31,759,177	$71,641,952	**$1,836,973,128**
Baseline (existing Cold side ESP): Emission Scenario 2	0.3	0.273	-	-	-	-	-	-
Pulse Jet Fabric Filter: Emission Scenario 2	0.015	0.237	0.036	$43,419,200	$20,330,504	$15,621,995	$35,952,499	**$998,680,528**
Wet ESP after FGD: Emission Scenario 2	0.01	0.227	0.046	$88,270,292	$39,882,776	$31,759,177	$71,641,952	**$1,557,433,739**

5.8 Unit 3 PM BART Determination

There are no changes to the conclusions of the BART determination for Unit 3 due to the FLM comments. The above revised tables refer to the 1st highest visibility values as opposed to the 8th highest values that were reported in the August 2007 BART determination.

Due to insignificant predicted improvement in visibility and very high cost of the alternative control technologies, the existing ESP with emission limit of 0.3 lbs/MMBtu is considered BART for Unit 3 for particulate matter. However, NRG may voluntarily consider implementation of the wet ESP in future as part of multi-pollutant control in future in order to comply with the MPR and other future regulations. In such case, the visibility impact will be reduced from existing conditions.

BEST AVAILABLE RETROFIT TECHNOLOGY DETERMINATION
INDIAN RIVER GENERATING STATION UNIT 3
MILLSBORO, DELAWARE

Submitted by:

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Attachment 2 Model Input Output Files (CD)
Attachment 3 Cost Determination for Alternative Control Technologies

List of Acronyms and Abbreviations

AIRS	Aerometric Information Retrieval System
BART	Best Available Retrofit Technology
CAIR	Clean Air Implementation Rule
CALPUFF	California Puff Model
CENRAP	Central Regional Air Partnership
dv	deciview
DNREC	Delaware Natural Resources & Environmental Control
EC	elemental carbon
EGU	electric generating unit
ESP	electrostatic precipitator
F	Fahrenheit
FWS	Fish and Wildlife Service
Fps	feet per second
Indian River	Indian River Operations, LLC
IWAQM	Interagency Workgroup on Air Quality Models
km	kilometers
lb/MMBtu	pound per million British thermal units
lbs/hr	pounds per hour
LCC	Lambert Conformal Conic
MPR	Multi-Pollutant Regulation
MANE-VU	Mid-Atlantic Northeast Visibility Union
NAAQS	National Ambient Air Quality Standards
NESCAUM	Northeast States for Coordinated Air Use Management
NOx	nitrogen oxide
NPS	National Park Service
NP	National Park
NWA	National Wilderness Area
PJFF	Pulse jet fabric filter
PM	particulate matter
PM10	particulate matter with aerodynamic size of 10 micron or lower
PMF	fine particulate matter
PMC	coarse particulate matter
RPO	Regional Planning Organization
SCR	Selective Catalytic Reduction
SNCR	Selective non-catalytic reduction
SO_2	sulfur dioxide
tpy	tons per year
USEPA	U.S. Environmental Protection Agency

1.0 Introduction

On January 1, 2007, the Delaware Natural Resources & Environmental Control (DNREC) sent a letter to Indian River Operations, LLC (Indian River) regarding the applicability of the Regional Haze Guidelines for Unit 3 at the Indian River Generating Station in Millsboro, Delaware (Facility). This unit was considered by DNREC as "BART-Eligible" and was required to perform analysis for Best Available Retrofit Technology (BART) Determinations (70 FR 39104). In that letter, DNREC listed two options for complying with the BART:

(i) Consider a permitted emission cap limiting the combined emission from the "BART-Eligible" unit to less than 250 tons per year (tpy) of each visibility impairing pollutant; or

(ii) Perform a BART Determination for the visibility impairing pollutants.

The Facility chose not to consider a permitted emission cap and therefore performed the BART determination.

Because the Unit 3 is an electric generating unit (EGU), participating in DNREC's Multi-Pollutant Regulation (MPR), BART requirements for sulfur dioxide (SO_2) and nitrogen oxides (NOx) will be met through this cap and trade program. In Delaware, MPR integrates the emission limitations of the federal Clean Air Implementation Rule (CAIR). The BART determination is therefore required only for particulate matter with aerodynamic size of 10 micron or less (PM10).

This report provides the BART determination for Unit 3 for PM10.

2.0 Background Information

2.1 Description of Site

The Indian River facility is located on Power Plant Road, in Millsboro, Delaware on the Indian River Bay. Figure 2-1 shows the site within the state of Delaware and nearby natural features. The site contains four coal-fired boilers, one combustion turbine, one oil fired heater, material and ash handling operations, fuel oil tanks, and other miscellaneous emission sources. Initial start up of the facility was in 1957 with Unit 1. Total estimated output from the facility is approximately 767 MW. Figure 2-2 is a site plan showing all four units including Unit 3.

The terrain surrounding the facility is mostly flat with terrain heights reaching 20 feet within 5 kilometers (km) from the property boundary line. The vegetation is mostly grassland. Land use in the surrounding area is mostly rural and coastal. The Indian River Bay draining to the Atlantic Ocean is located due east of the facility. Sussex County is in attainment with the National Ambient Air Quality Standards (NAAQS) for all BART regulated pollutants. The nearest Class I area is the Brigantine National Wilderness Area (Brigantine NWA) under the Fish and Wildlife Service (FWS) and is approximately 127 kilometers (km) northeast of the facility. Also, the Shenandoah National Park (Shenandoah NP) under the National Park Service (NPS) is within 300 km due southeast of the facility.

Unit 3 was determined by DNREC to be “BART-Eligible”. The other three units at this facility are not covered by BART program.

2.2 Existing Controls

The existing Unit 3 currently has several elements in place to control emissions. For NOx controls, the Unit 3 boiler is equipped with low-NO_X burners, over fire air, and selective non-catalytic reduction (SNCR) operating during ozone season only. For control of PM/PM_{10} emissions, cold side electrostatic precipitators (ESP) are installed on the backend of the unit.

2.3 Compliance with CAIR/MPR

DNREC agrees to EPA’s position that for EGUs covered under CAIR program, compliance with CAIR will constitute compliance with BART for SO_2 and NOx. In Delaware, CAIR program is integrated with the MPR. In addition to the requirements set forth by EPA’s federal CAIR program, Delaware has promulgated Regulation 1146 for the control of SO_2 and NOx. The facilities compliance with the MPR is as follows.

For CAIR, the facility will minimize SO_2 and NOx emissions, and for any emissions beyond its CAIR allocation, the facility will surrender allowances as required by the rule. Within the MPR,

Delaware has established annual emissions caps for SO_2 and NOx and the facility will operate within the requirements of the rule or any amendments or orders provided by DNREC. For Unit 3, the facility has installed SNCR technology, low NOx burner Technology, and over fire air to reduce NOx emissions. To achieve the limits provided in the regulation, the facility plans to operate the SNCR system on an annual basis beginning in 2008 until Selective Catalytic Reduction (SCR) Technology (or other technologies as feasible) can be installed, anticipated to be available by January 1, 2012. For SO_2, the facility will continue to utilize low sulfur content coal in the range of 0.8% to 1.6% sulfur content until Flue Gas Desulfurization (FGD) Technology (or other technologies as feasible) can be installed, anticipated to be available by January 1, 2012. After the installation of these technologies, the unit will achieve emission rates equal to or less than 0.125 lbs/MMBtu for NOx and 0.26 lbs/MMBtu for SO_2, as required under MPR.

2.4 Elements of BART Analysis

On July 6, 2005, the U.S. Environmental Protection Agency (USEPA) published final amendments to its 1999 Regional Haze Rule in the Federal Register, including Appendix Y, the final guidance for Best Available Retrofit Technology determinations (70 FR 39104-39172). The BART program applies to facilities in one of the 26 source categories that have units installed between August 7, 1962 and August 7, 1977, with the potential to emit more than 250 tpy of a visibility impairing pollutants (SO_2, NOx and PM10). The units meeting these criteria are ”BART-Eligible” units.

The next step is to determine whether these “BART-Eligible” units either “cause” or “contribute” to visibility impairment to Class I area within 300 km. USEPA defined “cause” as an impact of 1.0 deciview (dv) and ‘contribute” as an impact of 0.5 dv or more, compared to natural background.

If the units are determined to either “cause” or “contribute” to visibility impairment in a Class I area, an engineering review is required to determine if installation of new control requirements is appropriate. This engineering review takes into consideration five factors such as: i) cost; ii) energy and non-environmental impacts; iii) existing controls at the units; iv) remaining useful life of the units; and v) visibility improvement reasonably expected from the control technology.

Delaware is part of the Mid-Atlantic/Northeast Visibility Union (MANE-VU) regional Planning organization. In a recent teleconference (July 30, 2007), DENREC informed NRG that it supported MANE-VU’s recommendation that “BART-eligible” units would not be exempted from BART determination based on results of visibility analysis. Though it does not necessarily mean that controls will be required, the BART-eligible units have to complete the “Five Factor” BART analysis mentioned above.

2.5 Class I Areas Considered

As shown in Figure 2-3, there are two Class I areas within a 300 km radius from the Indian River facility. They are: i) Brigantine NWA under the FWS (Brigantine NWA); and the Shenandoah National Park (Shenandoah NP) under the National Park Service (NPS). The Brigantine NWA is approximately127 km due northeast and the Shenandoah NP is approximately 258 km due southeast of the facility.

3.0 Technical Approach and Methodology

DNREC has determined that Unit 3 is a "BART-Eligible" source. The next step is to determine whether the Unit 3 emissions either "caused" or "contributed" visibility impairment in the two Class I areas identified in Section 2.5.

Air dispersion modeling using USEPA approved procedure was performed to determine the visibility impact of the Unit 3 emissions. The air modeling was performed generally in conformance with the following guideline documents:

- Interagency Workgroup on Air Quality Models (IWAQM) Phase 2 Summary report in Modeling Long Range Transport Impacts (USEPA, 1998), commonly referred to as IWAQM Phase 2 Report.
- Federal Land Manager's Air Quality Related Values Workgroup, Phase I Report (12/00), commonly referred to as the FLAG Document.
- BART Resource Guide Prepared by Northeast States for Coordinated Air Use Management (NESCAUM) for the Mid-Atlantic Northeast Visibility Union (MANE-VU) Regional Planning Organization (RPO), dated August 23, 2006.
- CALPUFF User's Guide January 2000.

The rest of this section describes the methodology of the modeling and input data for the model.

3.1 Long Range Transport Model

The California Puff Model (CALPUFF) was promulgated by the USEPA on April 15, 2003 as a preferred dispersion model to assess long-range transport applications (i.e. transport distances exceeding 50 km to approximately 300 km). Up to this distance, a non-steady-state modeling approach which considers spatial and time variations in meteorological conditions, such as CALPUFF, is appropriate. For this modeling demonstration, CALPUFF Version 5.711a was used, consistent with the approved BART version.

In July 2007, USEPA released version 5.8 of the CALPUFF model and also updated the CALMET and CALPOST programs. In the July 30, 2007 teleconference, DENREC confirmed that CALPUFF version 5.711a still could be used for this analysis since revised meteorological data set for the new version of the CALPUFF model has not be developed yet by NESCAUM.

CALPUFF is a multi-layer, multi-species, non-steady state puff dispersion model which can simulate the time and space varying meteorological conditions on pollutant transport,

transformation, and removal. CALPUFF uses three dimensional meteorological fields developed by the meteorological processing program CALMET.

CALPUFF contain algorithms for near source effects such as building downwash, traditional plume rise, partial plume penetration, sub-grid scale terrain interactions, as well as long range effects such as pollutant removal (dry and wet deposition), chemical transformation, vertical wind shear, over-water transport, and coastal interaction effects.

The post processor CALPOST version 5.51 was used in this analysis to process the CALPUFF data and derive the maximum incremental visibility impact due to Unit 3 operations as a change in deciviews (dv) at the Class I areas.

3.2 Computational Grid

The CALMET data was received from NESCAUM for use in this analysis. The CALMET field that was generated NESCAUM covers multiple states in the Mid-Atlantic and northeast United States. The computational grid is generally a subset of the meteorological grid, and the CALPUFF computational grid system utilized for this modeling demonstration extended at least 50 kilometers in all directions beyond the Indian River Generating Station along with any portions of the two Class I areas. The additional buffer distance of at least 50 km is allowed for the consideration of puff trajectory recirculation. Figure 3-1 shows the meteorological and modeling domains. Due to the size of the modeling domain used for this analysis, a Lambert Conformal Conic (LCC) coordinate system was used. The LCC projection was used because it accounted for the curvature of the Earth's surface.

3.3 Source Parameters

The source parameters include stack parameters and emission rates. The BART determination was limited to Unit 3 and the stack parameters are shown in Table 3-1.

Table 3-1
Stack Parameters for Unit 3

UTM Northing (km)	Base Elevation (ft)	Stack Height (ft)	Stack Temperature (°F)
4336.8312	3.31	385	300

The BART determination was limited to PM10 only per DNREC. However, SO_2 and NOx are known to be precursors of secondary particulates (e.g. sulfates and nitrates) formed in the atmosphere during long-range transport and therefore were included in the modeling.

As mentioned in Section 2.3, the Unit 3 will be complying with DNREC's MPR by January 1, 2012. The permitted emission limits for SO_2 and NOx at this time (Phase II of MPR) will be 0.26 lb/MMBtu and 0.125 lb/MMBtu, respectively. These emission limits were used to estimate the maximum hourly emission rates as shown in Table 3-2.

Currently, Unit 3 is equipped with cold-side ESP, which is state of the art control technology for these types of boilers. The permitted limit for PM for Unit 3 as per the existing Title V operating permit is 0.3 lb/MMBtu (2-hour average). This emission limit was used for estimating maximum hourly PM10 emission rate as shown in Table 3-2.

Typically, the 24-hour averaged emission rates are lower than maximum hourly emission rates. However, to be conservative, the maximum hourly emission rates were considered to be same as maximum 24 hour emission rates and were used in the modeling.

Table 3-2
Maximum 24-hour Average Emission Rates for the Unit 3

Pollutant	Emission Limit (Lbs/MMBtu)	Unit 3 Nominal Heat Input Rate (MMBtu/hr)	Maximum Hourly Emission Rate (Lbs/hr)/(Grams/Sec)	Maximum 24-Hour Average Emission Rate (Lbs/hr)/Grams/Sec)
SO2	0.26	1,904	495/62.37	495/62.37
NOx	0.125	1,904	238/29.99	238/29.99
PM10	0.30	1,904	571/71.94	571/71.94

The particulate matter is required to be segregated into coarse and fine particulate as well as elemental carbon, since each of these have different light extinction coefficients. Fine particulates are of aerodynamic size 2.5 micron or lower and coarse particulate are of aerodynamic size greater than 2.5 microns. The fine and coarse particulate matter are further segregated to condensable (both organic and inorganic). The exit temperature of gases from Unit 3 stack is approximately 300 Fahrenheit (F). Also, there are no selective catalytic reduction (SCR) or FGDs in place. Thus, very little if any of the emissions are expected to be condensable, either organic or inorganic. All particulate matter was therefore considered as filterable. The PM was segregated to PM fines (PMF in CALPUFF) and PM coarse (PMC in CALPUFF) using AP-42 speciation for dry bottom pulverized coal boilers using bituminous coal and ESP controls. Elemental carbon (EC in CALPUFF) was considered as 1% of total PM as per USEPA guidelines.

3.4 Building Downwash Analysis

Both Class I areas were greater than 50 km from the Unit 3 stack. At this distance, the effect of building downwash is negligible. Therefore, building downwash analysis was not performed.

3.5 Meteorological Data

The meteorological data utilized in this analysis was the 2002 MANE-VU-developed CALMET dataset obtained from the Northeast States for Coordinated Air Use Management (NESCAUM). This data was provided on an external hard drive, and was utilized in this source-specific BART analysis. The dataset includes surface level observation from meteorological stations.

3.6 Receptor Layout

The NPS has predetermined locations of receptors in each Class I Area. These were used for the modeling. The receptor layout for the Brigantine NWA and the Shenandoah NP are shown in Figures 3-2 and 3-3, respectively.

3.7 Background Concentrations of Ammonia and Ozone

CALPUFF/CALPOST requires background concentration for ammonia and ozone to use the chemical transformation algorithms. Annual average ozone concentration was obtained from EPA's CAST-Net site for Shenandoah NPS for 2002. Attachment 1 shows a copy of the report obtained from the site. For Brigantine NWA, the annual average ozone concentration was obtained from EPA's Aerometric Information Retrieval System (AIRS) database for 2002. Attachment 1 shows a copy of the report obtained from this database. Since there was multiple ozone monitoring stations in Brigantine NWA, the highest ozone concentration was selected.

There were no known sites for ammonia background concentrations at these two Class I areas. Therefore, a default value of 0.5 ppb was selected. The background concentrations used in the modeling are shown in Table 3-3.

Table 3-3
Background Concentrations of Ozone and Ammonia used in Visibility Impact Modeling

Pollutant	Brigantine NWA	Shenandoah NPS
Ozone	57.5 ppb	50 ppb
Ammonia	0.5 ppb	0.5 ppb

The ammonia limiting method was not used as per NESCAUM BART Resource Guide.

3.8 Background Light Extinction Coefficient

For visibility impact analysis, the natural background concentration for several species is required. This includes ammonium sulfate, ammonium nitrate, organic carbon, elemental carbon, soil and coarse particulate. The monthly natural background concentration coefficients were taken from Table 6-3 of the Central Regional Air Partnership (CENRAP) protocol and were

based on the average natural concentration for the eastern United States. These are shown in Table 3-4.

Table 3-4
Background Concentration of Species in Eastern United States for Visibility Impact Modeling

Parameter	BKSO4	BKNO3	BKPMC	BKSOC	BKSSOIL	BKSEC
Concentration ($\mu g/m^3$)	0.23	0.10	3.00	1.40	0.50	0.02

3.9 Relative Humidity Method

Relative humidity is required at the Class I area to estimate the visibility impacts. Two methods are currently used in CALPUFF for incorporating relative humidity:

- Method 2, which requires hourly relative humidity data to be used in CALMET.
- Method 6, which requires monthly averaged relative humidity data.

Per the NESCAUM BART Resource Guide, Method 6 was used in the analysis with the monthly average humidity based on the centroid of the area. The relative humidity was capped at 98% for generating the factors used for particle growth in CALPUFF. These factors are listed in Table 3-5 for reference.

Table 3-5
Monthly Relative Humidity Factors Use in Visibility Impact Modeling

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Brigantine	2.9	2.6	2.7	2.6	2.9	3.0	3.2	3.4	3.4	3.2	2.8	2.9
Shenandoah	2.9	2.6	2.7	2.4	2.9	3.1	3.2	3.5	3.5	3.0	2.7	2.9

3.10 Rayleigh Scattering Coefficient

CALPOST uses a default Rayleigh scattering coefficient of 10 Mm^{-1}. This default value was used in this analysis.

3.11 CALPUFF Model Settings

All USEPA default settings were used in the CALPUFF model and the CALPOST post processor.

4.0 Results of Analysis

This section contains the results of the BART regional haze analysis. All modeling input and output files are included in electronic form on CD-ROM in Attachment 2 of this report.

4.1 Visibility Impact Analysis for Baseline Condition

Perceived visibility in deciview is derived from the light extinction coefficient. The visibility change related to background is calculated using the modeled and established natural visibility conditions. For the BART screening analysis, daily visibility is expressed as a change in deciview compared to natural visibility conditions.

Sources with modeled 98th percentile (8th highest in one year) impacts below the 0.5 dv threshold are considered not to "cause' or "contribute" to visibility impairment and no further controls are necessary. Sources with impacts at, or above, 0.5 dv can either perform refined CALPUFF modeling to show their visibility impact is in fact below the 0.5 dv threshold or continue with the BART process and perform a five factor BART analysis.

As mentioned earlier, the facility will comply with the BART controls for SO2 and NOx by complying with the MPR. This BART analysis is therefore for PM10 only. However, since SO2 and NOx also would contribute to visibility degradation, the analysis was performed for two emission scenarios:

- Emission Scenario 1: Visibility impact was determined considering PM10 emissions only; and
- Emission Scenario 2: Visibility impact was determined considering SO2, NOx, and PM10 emissions.

For both emission scenarios, a baseline impact was determined considering the current PM10 control device (i.e. cold side ESP) and MPR assigned emission rates for SO2 and NOx. The results of the analysis are presented in Tables 4-1a and 4.1b. For Scenario 1, the 8th highest 24-hour impact at Brigantine NWA and Shenandoah NP were 0.098 delta deciview and 0.007 delta deciview, respectively. For emission scenario 2, the 8th highest 24-hour impact at Brigantine NWA and Shenandoah NP were 0.098 delta deciview and 0.007 delta deciview, respectively. In both emission scenarios and for both Class I areas, the maximum impacts were well below the 0.5 delta deciview threshold for contributing to the visibility impairment.

Therefore, Unit 3 emissions neither "cause" nor "contribute" to a perceptible regional haze impact at the two Class I areas considered in the analysis.

Table 4-1a: Baseline Visibility Impact Analysis Results at the Class I Areas: Method 6 Annual Average Conditions as Background Emission Scenario 1: PM10 Emissions Only

Class I Area	Rank (highest to lowest)	Julian Day	Receptor Location		Delta Deciview
			x	y	
Brigantine NWA	1	257	1916.898	185.879	0.173
	2	147	1906.799	185.211	0.16
	3	6	1918.281	189.085	0.128
	4	51	1904.279	186.473	0.118
	5	23	1906.799	185.211	0.117
	6	313	1904.506	185.58	0.113
	7	223	1904.506	185.58	0.103
	8	**38**	**1916.898**	**185.879**	**0.098**
Shenandoah NP	1	85	1602.75	-6.918	0.04
	2	84	1608.439	43.221	0.021
	3	233	1592.264	-20.383	0.017
	4	239	1574.426	-56.014	0.016
	5	282	1611.47	28.794	0.011
	6	283	1611.739	34.5	0.01
	7	172	1606.656	44.73	0.008
	8	**240**	**1607.078**	**14.693**	**0.007**

Table 4-1b: Baseline Visibility Impact Analysis Results at the Class I Areas: Method 6 Annual Average Conditions as Background Emission Scenario 2: SO2/NOx/PM10 Emissions

Class I Area	Rank (highest to lowest)	Julian Day	Receptor Location		Delta Deciview
			x	y	
Brigantine NWA	1	344	1906.799	185.211	0.466
	2	215	1916.209	185.704	0.401
	3	174	1916.898	185.879	0.388
	4	71	1918.281	189.085	0.382
	5	173	1918.281	189.085	0.358
	6	223	1904.506	185.58	0.33
	7	126	1916.898	185.879	0.322
	8	**6**	**1918.281**	**189.085**	**0.316**
Shenandoah NP	1	85	1602.75	-6.918	0.273
	2	239	1574.426	-56.014	0.17
	3	84	1606.422	10.79	0.153
	4	233	1574.426	-56.014	0.135
	5	283	1610.98	38.106	0.094
	6	282	1611.47	28.794	0.059
	7	206	1574.426	-56.014	0.056
	8	**285**	**1606.142**	**5.084**	**0.055**

5.0 BART Analysis and Determination

DENREC requires a five factor analysis for BART determination for all "BART Eligible" sources irrespective of the results of the visibility analysis as per recommendations of MANE-VU. The procedure is described in 40 CFR Part 51 regional Haze regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule (USEPA). The Rule identification of the BART considering following five statutory factors:

- Cost;
- Energy and non-environmental impacts;
- Existing controls in place;
- Remaining useful life of source; and
- Visibility improvement reasonably expected from the technology

The analysis for Unit 3 PM control is described in following sections.

5.1 Identifying Alternative Control Technologies

As mentioned earlier, SO2 and NOx controls will be in place for Unit 3 in compliance with the MPR, which qualifies as compliance with BART. The alternative control technology assessment was therefore limited to particulates.

The Unit 3 is equipped with cold-side ESP, which is the state of art control technology for particulate matter control for this type of boilers. The ESP is maintained as required by the manufacturer and is operating effectively. The performance of ESP depends on many operating variables including coal type. At this time, the ESP is considered to be operating effectively and therefore any further modification to the ESP is not expected to result in significant improvement in particulate control. Thus, alternative technologies were assessed based on either a stand alone (i.e. replacement of the ESP) or adding a secondary particulate control after the existing ESP.

Potentially stand alone applicable particulate control technologies for coal fired boilers in lieu of cold side ESP are:

- Multiclones; and
- Fabric filters;

Multiclones:

Multiple-cyclone separators, also known as multiclones, consist of a number of small diameter cyclones, operating in parallel and having a common gas inlet and outlet. Multiclones operate on the same principle as cyclones, creating a main downward vortex and an ascending inner vortex. The centrifugal force of the vortex generated in individual cyclones result in separation of the particulates from the flue gas which then fall down to a centralized hopper. The cleaner gas passes through an outlet common plenum to the outlet duct.

Multiclones are more efficient that single cyclones because they are longer and smaller in diameter. The longer length provides longer residence time while the smaller diameter creates greater centrifugal force. These two factors result in better separation of dust particulates. The pressure drop of multiclone collectors is higher than that of single-cyclone separators. At pressures near one atmosphere and 2 to 5 in. water gauge pressure differential, this technology can effectively remove particles larger than 20 microns in size; particles less than 10 microns are usually unaffected and not removed.

Multiclones were the first type of particulate control used for coal fired boilers. However, the overall particulate collection efficiency is less than what is required to meet current emission standards. These are sometimes used now as primary collector upstream of a final collector such as an ESP or a fabric filter.

Multiclone as a stand alone particulate control is considered to be infeasible in maintaining the desired emission standards for Unit 3 and therefore not considered further in the analysis.

Pulse jet fabric filter baghouse:

Pulse jet fabric filter (PJFF) baghouses have been used for collection of particulate from coal fired boilers. Fabric filters are media filters that the flue gas passes through to remove the particulate. Cloth filter media is typically sewn into cylindrical tubes called bags. Each fabric filter may have thousands of these filter bags. The filter unit is typically divided into compartments, which allows online maintenance or bag replacement. The quantity of compartments is determined by maximum economic compartment size, total gas volume rate, air-to-cloth (A/C) ratio, and cleaning system design. Extra compartments for maintenance or off-line cleaning increase the reliability at the expense of capital cost and real estate utilization. Each compartment includes at least one hopper for temporary storage of the collected fly ash.

Fabric bags vary in composition, length, and cross-section (diameter or shape). Bag selection characteristics vary with cleaning technology, emissions limits, flue gas and ash characteristics,

desired bag life, capital cost, A/C ratio, and pressure differential. Fabric bags are typically guaranteed for 3 years but frequently last 5 years or more.

In pulse jet fabric filters, the flue gas typically enters the compartment hopper and passes from the outside of the bag to the inside, depositing particulate on the outside of the bag. To prevent the collapse of the bag, a metal cage is installed on the inside of the bag. The flue gas passes up through the center of the bag into the outlet plenum. The bags and cages are suspended from a tube sheet.

Cleaning is performed by initiating a downward pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag. This releases the dust cake from the bag surface. The dust then falls into the hopper. This cleaning may occur with the compartment online or off line. Care must be taken during design to ensure that the upward velocity between the bags is minimized so that particulate is not re-entrained during the cleaning process. The PJFF cleans bags in sequential, usually staggered, rows. During online cleaning, part of the dust cake from the row being cleaned may be captured by the adjacent rows. Despite this apparent shortcoming, PJFF have successfully implemented online cleaning on many large units.

The PJFF bags are typically made of felted materials that do not rely as heavily on the dust cakes filtering capability as woven fiberglass bags. This allows the PJFF bags to be cleaned more vigorously. The felted materials also allow the PJFF to operate at a much higher cloth velocity, which significantly reduces the size of the unit and the space required for installation.

PJFF is considered technically feasible technology for Unit 3 particulate control and therefore considered in the analysis. A review of USEPA's RACT/BACT/LAER Control (RBLC) clearinghouse showed that fabric filters have been used for coal fired boilers with outlet emission of as low as 0.015 lbs/MMBtu. The emission rate was confirmed by several vendors contacted for this application. Therefore, outlet emission of 0.015 lbs/MMBtu (filterable) was considered for the visibility impact analysis for the control technology. This emission limit is lower than the presumptive PM10 emission limits considered by MANE-VU for CAIR EGUs, which is 0.02-0.04 lbs/MMBtu.

Wet ESP:

Wet ESPs are commonly used for acid and organic mist collection. Although there are few applications in the utility industry, there are hundreds of industrial applications. Wet ESP as a stand alone particulate control (such as replacement of existing dry ESP) has not been considered for utility industry because: i) there is no inherent advantage of wet ESP over dry ESP if acid mists are not present; and ii) wet ESPs operate at far lower temperature range than dry ESP and

therefore the flue gas has to be cooled down to 120-150 F range for its use, which makes it uneconomical compared to a dry ESP.

However, wet ESPs have been proposed and used downstream of wet flue gas desulfurization (FGD) systems. Wet FGDs scrub SO2 but also generate some particulate in the form of acid mists due to near dew point temperatures at the scrubber outlet. The wet ESP is used to remove the additional acid mists from the gas stream.

Wet ESPs have been also used as an integral part of multi-pollutant control systems. One such system is the Electro-Catalytic oxidation (ECO) developed by Powerspan Inc. The ECO system is an integrated air pollution control technology that achieves major reductions in the primary air pollutants of concern from coal-fired power plants, specifically 99% reduction of sulfur dioxide (SO2) emissions, 90% of nitrogen oxide (NOx) emissions, 80-90% of mercury (Hg) emissions, and 95% of fine particulate matter (PM2.5) emissions. The system also provides high removal of other metals and acid gases such as sulfuric acid (SO3/H2SO4), hydrochloric acid (HCl), and hydrofluoric acid (HF). The ECO system produces a valuable, ammonium sulfate fertilizer co-product, reducing operating costs and minimizing landfill disposal of waste.

The ECO process treats power plant flue gas in three steps to achieve multi-pollutant removal:

1. ECO Reactor: oxidizes pollutants;
2. Absorber Vessel: removes SO2, NO2, and oxidized mercury; and
3. Wet Electrostatic Precipitator (ESP): removes acid aerosols, air toxics, and fine particulates

After exiting the absorber vessel, the flue gas enters a wet ESP. Aerosols generated in the ECO reactor and ammonia scrubbing process steps, along with air toxics and fine particulate matter, are captured in the wet ESP and returned to the lower loop of the scrubber. In commercial operation the ECO system is installed downstream of a power plant's existing electrostatic precipitator or fabric filter.

Wet ESPs differ from dry ESPs in that liquid flows down the collecting plate, removing collected material from its surface as opposed to mechanically rapping or employing sonic horns to remove the material from the plate as is done in dry ESPs. The liquid layer created on the collection plate of wet ESPs prevents particle re-entrainment, improving its collection characteristics over dry ESPs. The improved collection permits higher gas velocities, limiting the equipment size required.

Wet ESPs have been used successfully in industrial applications to collect acid aerosols for over 50 years, particularly in metallurgical plants and in sulfuric acid manufacturing. Wet ESPs have shown to be efficient collectors of PM2.5 and hazardous air pollutants such as mercury.

NRG is committed to multi-pollutant control to meet the requirements of MPR. Though the exact technology for multi-pollutant control has not been selected at this time, there is strong possibility of using a wet scrubbing process for reducing SO2 emissions. In that case, use of wet ESP as the final air pollution control device is feasible on Unit 3. A wet ESP is therefore considered in this analysis.

Discussion with vendors (Powerspan) indicated that particulate emission level of 0.01 lbs/MMBtu can be achieved for IR Unit 3 and therefore this was considered as the basis for BART analysis. This emission limit is lower than the presumptive PM emission limits considered by MANE-VU for CAIR EGUs, which is 0.02-0.04 lbs/MMBtu.

Thus, the two control technologies selected for BART analysis are:

- A Pulse Jet Fabric Filter baghouse with outlet PM emission of 0.015 lbs/MMBtu; and
- A wet ESP as part of multi-pollutant control with outlet PM emission of 0.010 lbs/MMBtu

5.2 Estimating Cost of Compliance and Cost Effectiveness

The next step in the BART analysis is to estimate the cost of compliance for the technically feasible technologies. Both capital and annual operating costs were estimated based on discussion with vendors and available published data. Brief description of the methodology is as follows and the cost determination can be found in Attachment 3.

The total installed capital cost includes direct costs and indirect costs. Direct costs are from purchased equipment cost and equipment construction cost at site. For the PJFF option, site construction costs also include demolition of the existing ESP and rerouting of ducting to the proposed PJFF. Though demolition of existing ESP is not needed for the Wet ESP option, significant rerouting of ducting is required to make available the necessary equipment footprint. Indirect costs include engineering/supervision fees, general construction and field expenses, construction fee, start-up costs, performance test costs, and contingencies. The estimate for indirect costs was obtained from USEPA OAQPS Control Cost Manual.

Annual operational costs were estimated for both options. The direct costs for operation included: i) maintenance costs; general facility operation costs, contingencies, engineering costs, environmental compliance costs, and cost of utility. For estimation of utility cost, a pressure drop of 6 inch water gage (wg) for the PJFF and 1 inch wg for wet ESP were considered. Indirect operating costs were overhead, property taxes, G&A, and insurance charges.

The estimated cost for the two alternative technology options and cost effectiveness are shown in Table 5-1.

Table 5-1
Cost Effectiveness for Alternative Control Technologies

Control Technology	Emission Rate (lb/ MMBtu)	Emissions (ton/yr)	Expected Emissions reductions (tons/year)	Capital Cost $	Direct Cost $	Indirect Cost $	Total Annualized Cost $	Average Cost Effectiveness ($ per ton of pollutant removed)	Incremental Cost Effectiveness ($ per ton of pollutant removed)
Baseline (existing Cold side ESP)	0.3	2501.86	-	-	-	-	-	-	-
Pulse Jet Fabric Filter	0.015	125.09	2376.76	$43,419,200	$20,330,504	$15,621,995	$35,952,499	$15,127	-
Wet ESP after FGD	0.01	83.40	2418.46	$88,270,292	$39,882,776	$31,759,177	$71,641,952	$29,623	$855,911

5.3 Determining Energy and Non-environmental Impacts

There is no significant energy or non-environmental impacts for either the PJFF or the wet ESP. The higher pressure drop in the PJFF will result in some increase in power requirement. The PJFF will generate dry ash in the hopper which will be transported to the landfill on the site as is currently done with the ash from existing ESP.

The Wet ESP consumes electric power similar to dry ESP and thus there will be no significant change in power demand. The additional condensable acid mist generated by wet FGD up stream is effectively captured in the Wet ESP. The small quantity of wastewater stream from the wet ESP would be connected to the plant's existing discharge system and thus will have no significant water quality impact.

5.4 Existing Controls

As mentioned earlier, the existing control at Unit 3 for particulate matter is a cold side ESP, which is state of art for coal fired boiler of the type in Unit 3.

5.5 Remaining Useful Life of the Unit

Since the remaining useful life for Unit 3 is expected to be greater than the life of the control options, no further consideration of this parameter is needed in the analysis.

5.6 Visibility Improvement Reasonably Expected

Results (Section 4) showed that the impact of Unit 3 emissions after implementation of MPR does not "cause" or "contribute" to any perceived visibility impairment in the two Class I areas within 300 km from the facility. Similar modeling was performed for the two alternative control technology options. This section presents the results of the visibility impact modeling for the two control technology options.

Both emission scenarios 1 and 2 were modeled. For reference, the two emission scenarios were:

- Emission Scenario 1: Visibility impact was determined considering PM10 emissions only; and
- Emission Scenario 2: Visibility impact was determined considering SO2, NOx, and PM10 emissions.

Table 5-2 shows the source parameters used in the modeling. The fabric filter was considered to operate in the same temperature range as the cold side ESP. Since a wet FGD system is considered upstream of the wet ESP, the temperature of flue gas was considered to be 134 F (329 K) as per discussion with a vendor. The source parameters from the existing ESP (baseline) are also shown in Table 5-2 for reference. The source parameters were same for the baseline and fabric filter emission scenarios.

Table 5-2
Source Parameters for Alternative Control Technologies

Alternative Control Technology	PM 10 Emission Rate	Stack Height	Base Elevation	Stack Diameter	Exit Velocity	Exit Temp.
	(lb/MMBtu)	(m)	(m)	(m)	(m/s)	(K)
Baseline (ESP)	0.30	117.348	1.01	4.115	23.5	422.039
Pulse Jet Fabric Filter	0.015	117.348	1.01	4.115	23.5	422.039
Wet ESP after FGD	0.01	117.348	1.01	4.115	19.8	329.817

Table 5-3a, 5-3b, 5-3c, and 5-3d show the results of CALPUFF modeling at the Brigantine NWA and the Shenandoah NP for emission scenario 1 and 2. The 98th percentile (8th highest) values for both emission scenarios are shown in these tables.

Table 5-3a: Visibility Impact Analysis Results at the Class I Areas: Method 6
Annual Average Conditions as Background
Emission Scenario 1: PM10 Emissions Only

Alternative Technology Option 1: Pulse Jet Fabric Filter

Class I Area	Rank (highest to lowest)	Julian Day	Receptor Location		Delta Deciview
			x	y	
Brigantine NWA	1	257	1916.898	185.879	0.01
	2	147	1906.799	185.211	0.009
	3	6	1918.281	189.085	0.007
	4	23	1906.799	185.211	0.007
	5	51	1904.279	186.473	0.007
	6	313	1905.195	185.755	0.007
	7	38	1916.898	185.879	0.006
	8	**151**	**1916.898**	**185.879**	**0.006**
Shenandoah NP	1	85	1602.75	-6.918	0.003
	2	84	1608.439	43.221	0.002
	3	233	1583.156	-33.544	0.001
	4	239	1574.426	-56.014	0.001
	5	240	1604.636	12.3	0.001
	6	282	1611.47	28.794	0.001
	7	283	1611.739	34.5	0.001
	8	**1**	**1570.525**	**-58.686**	**0.000**

Table 5-3b: Visibility Impact Analysis Results at the Class I Areas: Method 6
Annual Average Conditions as Background
Emission Scenario 1: PM10 Emissions Only

Alternative Technology Option 2: Wet ESP after FGD

Class I Area	Rank (highest to lowest)	Julian Day	Receptor Location		Delta Deciview
			x	y	
Brigantine NWA	1	6	1916.898	185.879	0.007
	2	147	1906.346	186.997	0.006
	3	257	1916.898	185.879	0.006
	4	88	1916.898	185.879	0.005
	5	23	1906.799	185.211	0.004
	6	38	1916.209	185.704	0.004
	7	51	1904.279	186.473	0.004
	8	**313**	**1904.506**	**185.58**	**0.004**
Shenandoah NP	1	84	1610.98	38.106	0.001
	2	85	1602.75	-6.918	0.001
	3	233	1574.426	-56.014	0.001
	4	239	1574.426	-56.014	0.001
	5	1	1570.525	-58.686	0.000
	6	2	1570.525	-58.686	0.000
	7	3	1570.525	-58.686	0.000
	8	**4**	**1570.525**	**-58.686**	**0.000**

Table 5-3c: Visibility Impact Analysis Results at the Class I Areas: Method 6
Annual Average Conditions as Background
Emission Scenario 1: PM10/SO2/NOx Emissions

Alternative Technology Option 1: Pulse Jet Fabric Filter

Class I Area	Rank (highest to lowest)	Julian Day	Receptor Location		Delta Deciview
			x	y	
Brigantine NWA	1	344	1906.799	185.211	0.404
	2	71	1918.281	189.085	0.346
	3	174	1916.898	185.879	0.319
	4	215	1916.209	185.704	0.315
	5	173	1918.281	189.085	0.289
	6	126	1916.898	185.879	0.259
	7	216	1918.281	189.085	0.25
	8	**222**	**1904.279**	**186.473**	**0.244**
Shenandoah NP	1	85	1602.75	-6.918	0.237
	2	239	1574.426	-56.014	0.155
	3	84	1606.422	10.79	0.136
	4	233	1574.426	-56.014	0.12
	5	283	1610.98	38.106	0.084
	6	206	1574.426	-56.014	0.053
	7	285	1606.142	5.084	0.051
	8	**252**	**1606.656**	**44.73**	**0.049**

Table 5-3d: Visibility Impact Analysis Results at the Class I Areas: Method 6
Annual Average Conditions as Background
Emission Scenario 1: PM10/SO2/NOx Emissions

Alternative Technology Option 2: Wet ESP after FGD

Class I Area	Rank (highest to lowest)	Julian Day	Receptor Location		Delta Deciview
			x	y	
Brigantine NWA	1	71	1917.82	188.017	0.367
	2	215	1904.506	185.58	0.361
	3	173	1918.281	189.085	0.345
	4	6	1918.281	189.085	0.344
	5	174	1916.898	185.879	0.33
	6	214	1918.281	189.085	0.328
	7	126	1916.898	185.879	0.3
	8	**216**	**1918.281**	**189.085**	**0.252**
Shenandoah NP	1	85	1611.47	28.794	0.227
	2	239	1574.426	-56.014	0.149
	3	233	1574.426	-56.014	0.141
	4	84	1606.142	5.084	0.139
	5	283	1611.739	34.5	0.07
	6	206	1574.426	-56.014	0.051
	7	251	1606.656	44.73	0.047
	8	**252**	**1606.656**	**44.73**	**0.046**

5.7 Summary

Tables 5-4a and 5-4b summarize the BART analysis for the Unit 3 for particulates. As shown in these tables, the changes in visibility impact for both alternative control technologies are minimal over the baseline for both emission scenarios. The changes are less than 0.1 dv, which is considered the threshold for a significant impact as per DENREC. On the other hand, as shown in Table 5-1, the cost effectiveness of the two alternative technologies are substantial, in the order of $15,126/ton and $29,622/ton of particulate removed for the PJFF (option 1) and wet ESP (Option 2), respectively. The incremental cost effectiveness of the wet ESP option over the PJFF option is approximately $855,900/ton of particulate removed.

Tables 5-5a and 5-5b show the cost effectiveness of the two alternative control technology options in terms of improvement in visibility over baseline. The cost for even marginal change in visibility of 1 dv is substantial for both options.

Table 5-4a
Change in Delta Deciview from Baseline Scenario (ESP)
Emission Scenario 1: PM10 Emissions Only

Class I Area	Parameter	Baseline	Pulse Jet Fabric Filter	Wet ESP after FGD
Brigantine NWA	**8th Highest Delta Deciview**	0.098	0.006	0.004
	Difference from Baseline	-	**0.092**	**0.094**
Shenandoah NP	**8th Highest Delta Deciview**	0.007	0.000	0.000
	Difference from Baseline	-	**0.007**	**0.007**

Table 5-4b
Change in Delta Deciview from Baseline Scenario (ESP)
Emission Scenario 2: PM10/SO2/NOx Emissions

Class I Area	Parameter	Baseline	Pulse Jet Fabric Filter	Wet ESP after FGD
Brigantine NWA	**8th Highest Delta Deciview**	0.316	0.244	0.252
	Difference from Baseline	-	**0.072**	**0.064**
Shenandoah NP	**8th Highest Delta Deciview**	0.055	0.049	0.046
	Difference from Baseline	-	**0.006**	**0.009**

Table 5-5a
Cost Effectiveness for Visibility Improvement for Alternative Control Technologies
Brigantine NWA

Control Technology	Emission Rate (lb/ MMBtu)	Visibility Impact (dv)	Expected Change in Visibility Impact from Baseline	Capital Cost $	Direct Cost $	Indirect Cost $	Total Annualized Cost $	Average Cost Effectiveness ($ per change in dv)
Baseline (existing Cold side ESP): Emission Scenario 1	0.3	0.098	-	-	-	-	-	-
Pulse Jet Fabric Filter: Emission Scenario 1	0.015	0.006	0.092	$43,419,200	$20,330,504	$15,621,995	$35,952,499	**$390,788,030**
Wet ESP after FGD: Emission Scenario 1	0.01	0.004	0.094	$88,270,292	$39,882,776	$31,759,177	$71,641,952	**$762,148,429**
Baseline (existing Cold side ESP): Emission Scenario 2	0.3	0.316	-	-	-	-	-	-
Pulse Jet Fabric Filter: Emission Scenario 2	0.015	0.244	0.072	$43,419,200	$20,330,504	$15,621,995	$35,952,499	**$499,340,261**
Wet ESP after FGD: Emission Scenario 2	0.01	0.252	0.064	$88,270,292	$39,882,776	$31,759,177	$71,641,952	**$1,119,405,505**

Table 5-5b
Cost Effectiveness for Visibility Improvement for Alternative Control Technologies
Shenandoah NP

Control Technology	Emission Rate (lb/ MMBtu)	Visibility Impact (dv)	Expected Change in Visibility Impact from Baseline	Capital Cost $	Direct Cost $	Indirect Cost $	Total Annualized Cost $	Average Cost Effectiveness ($ per change in dv)
Baseline (existing Cold side ESP): Emission Scenario 1	0.3	0.007	-	-	-	-	-	-
Pulse Jet Fabric Filter: Emission Scenario 1	0.015	0	0.007	$43,419,200	$20,330,504	$15,621,995	$35,952,499	**$5,136,071,253**
Wet ESP after FGD: Emission Scenario 1	0.01	0	0.007	$88,270,292	$39,882,776	$31,759,177	$71,641,952	**$10,234,564,614**
Baseline (existing Cold side ESP): Emission Scenario 2	0.3	0.055	-	-	-	-	-	-
Pulse Jet Fabric Filter: Emission Scenario 2	0.015	0.049	0.006	$43,419,200	$20,330,504	$15,621,995	$35,952,499	**$5,992,083,128**
Wet ESP after FGD: Emission Scenario 2	0.01	0.046	0.009	$88,270,292	$39,882,776	$31,759,177	$71,641,952	**$7,960,216,922**

5.8 Unit 3 PM BART Determination

Due to insignificant predicted improvement in visibility and very high cost of the alternative control technologies, the existing ESP with emission limit of 0.3 lbs/MMBtu is considered BART for Unit 3 for particulate matter. However, NRG may voluntarily consider implementation of the wet ESP in future as part of multi-pollutant control in future in order to comply with the MPR and other future regulations. In such case, the visibility impact will be reduced from existing conditions.

Figures

Attachment 1

Background Ozone Concentration in Class I Areas

Clean Air Markets - Data and Maps - Microsoft Internet Explorer

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Air Quality and Deposition

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Annual Concentration Quick Report

You specified: **Year(s)**: 2002

DOWNLOAD results using the buttons below.
SORT results by clicking on a column name (once=ascending, twice=descending).

New Quick Report | Download All Data | Report Definitions | View Column Codes

Filter Data (Expand this toolbar to filter your results.)

(86 records in 1 page of 86 records)

Site ID (SITE_ID)	Site Name (SITE_NAME)	Sample Collection Start Date/Time (DATEON)	Sample Collection End Date/Time (DATEOFF)	Year (YEAR)	Ozone Concentration (OZONE_CONC)	(
ROM406	Rocky Mtn NP	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	50.114275052884615384615384615384615384615384475	1
SAL133	Salamonie Reservoir	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	31.631940833653846153846153846153846154	1
SEK402	Sequoia NP - Lookout Pt	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	52.035791596695804195804195804195804195575	1
SHN418	Shenandoah NP - Big Meadows	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	44.949587713831585081585081585081585081585	1
SND152	Sand Mountain	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	34.022011519711538461538461538461538461538461	1
SPD111	Speedwell	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	30.768534351153846153846153846153846153846153	1
STK138	Stockton	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	33.514439614580419580419580419580419580419580	1
SUM156	Sumatra	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	25.180351604615384615384615384615384615384615	1
THR422	Theodore	01/01/2002	12/31/2002	2002	32.932245903269230769230769230769230769230769	1

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Done Internet

Start Inbox - Microsoft ... Clean Air Market... 9:03 AM

340010005	Brigantine Wildlife Refuge, Nacote Creek; NJ

Ozone Monitoring Data 2002; Values in ppb

Monitor Id	Year	Except Data Flag	Interval	Unit	Exceed Std Pri	Method Cnt	Obs Cnt	Max1 Value	Max2 Value	Arith Mean
3400100054420101	2002	1	1	007	1	1	8617	.127	.107	.0569
3400100054420101	2002	2	1	007	1	1	8708	.127	.107	.0575
3400100054420101	2002	3	1	007	1	1	8708	.127	.107	.0575
3400100054420101	2002	4	1	007	1	1	8617	.127	.107	.0569
3400100054420101	2002	5	1	007	1	1	8617	.127	.107	.0569
3400100054420101	2002	6	1	007	1	1	8708	.127	.107	.0575
3400100054420101	2002	7	1	007	1	1	8617	.127	.107	.0569
3400100054420101	2002	1	W	007	9		8633	.101	.099	.0505
3400100054420101	2002	2	W	007	11		8728	.101	.099	.0511
3400100054420101	2002	3	W	007	11		8728	.101	.099	.0511

Source: USEPA AIRS Database

Attachment 2

Model Input Output Files (CD)

Attachment 3

Cost Determination for Alternative Control Technologies

Prepared for:
Conectiv Delmarva Generation
Wilmington, Delaware

Revised Source-Specific Best Available Retrofit Technology (BART) Determination: Edge Moor Units 4 & 5

Prepared for:
Conectiv Delmarva Generation
Wilmington, Delaware

ENSR Corporation
July 2008
Document No.: 01855-056-0400

ENSR | AECOM

Revised Source-Specific Best Available Retrofit Technology (BART) Determination: Edge Moor Units 4 & 5

Prepared By: Olga Kostrova

Reviewed By: Robert J. Paine

Reviewed by: Ian B.Thomson

ENSR Corporation
July 2008
Document No.: 01855-056-0400

ENSR | AECOM

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Executive Summary

Conectiv Delmarva Generation, Inc, (Conectiv) an affiliate of Conectiv Energy, operates the Edge Moor Power Plant ("Edge Moor"), a coal and oil-fired electric generating station located in Wilmington, Delaware. Edge Moor has been identified by DNREC as a source that is eligible for consideration of BART controls for PM_{10} (CAIR serves as BART for SO_2 and NO_x). This document, an update to a BART report submitted in June 2007, summarizes the procedures by which a modeling analysis and a BART engineering review have been conducted for the Edge Moor Units 4 and 5.

The Regional Haze Rule requires Best Available Retrofit Technology (BART) for any BART-eligible source that ''emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility" in any mandatory Class I federal area. The Environmental Protection Agency (EPA) has determined that implementation of the Clean Air Interstate Rule (CAIR) by electric generating unit (EGU) sources satisfies applicable BART requirements for SO_2 and NO_x emissions from those sources (see Appendix A for specific EPA BART references in this regard). The Delaware Department of Natural Resources and Environmental Control (DNREC) has indicated that the federal CAIR program is employed in Delaware as part of a Federal Implementation Plan (FIP) process under which EGU sources will meet the State's CAIR emission reduction requirements. As such, CAIR satisfies BART for SO_2 and NO_x for EGU sources in the State of Delaware. In addition, Delaware has promulgated a Multi-Pollutant Regulation for Electrical Generating Units that effectively serves the same purpose as CAIR, and which satisfies BART for SO_2 and NO_x for EGU sources in the State of Delaware. Accordingly, this report focuses solely on performing BART modeling analyses and engineering reviews for primary particulate matter (PM_{10}) emissions from Edge Moor Units 4 and 5.

The document entitled "Source-Specific Best Available Retrofit Technology (BART) Modeling and Engineering Review: Edge Moor Units 4 & 5" was submitted to DNREC in June 2007. The modeling analysis documented in that report was conducted in accordance with our understanding of the agreed-upon approach following a conference call with the DNREC in which the proposed procedures were discussed and approved for use. The results of the analysis indicated that the PM_{10} emissions from the existing facility will have imperceptible impacts on regional haze at the two Class I areas within 300 km of the plant. The results indicated that PM_{10} impacts would be at or below the MANE-VU 0.1 delta-deciview threshold for a level of visibility change not worth additional consideration. The report also documented substantial emission controls to be installed at Edge Moor in accordance with the Multi-Pollutant Regulation (MPR).

In April 2008, DNREC requested additional documentation on certain aspects of a more formal BART determination analysis for control options for Edge Moor beyond the MPR steps, even though the remaining visibility incremental improvement potentially possible is a small fraction of what is perceptible. This report provides the additional documentation requested.

Edge Moor Unit 4 is a dry-bottom, pulverized coal (primary fuel), tangentially-fired boiler equipped with an electrostatic precipitator (ESP) for the control of filterable particulates. Edge Moor Unit 5 is a residual oil-fired (primary fuel) boiler with a multiple cyclone (multiclone) for the control of filterable particulates.

Possible alternative BART PM_{10} control technologies that have been preliminarily considered as being potentially feasible for further reducing PM emissions from Edge Moor Units 4 and 5 are as follows.

<u>Control Option 1</u>. This option involves adding dry sorbent injection (DSI) to Unit 4 to control SO_2 emissions, which also would reduce inorganic condensable PM_{10} by about 50%. PM_{10} emissions from Unit 5 would be reduced by about 9% by capping sulfur content of fuel oil at 0.5%. This control option will be implemented as a result of Delaware's Multi-Pollutant Regulation.

<u>Control Option 2</u>. This option is the same as Control Option 1 with the addition of fabric filter PM controls on Unit 4. The physical ability of accommodating a fabric filter baghouse at the Edge Moor Site near Unit 4 would

be particularly challenging, given the small amount of space available at this facility which directly abuts the Delaware River. PM_{10} emissions from Unit 4, should a fabric filter baghouse be feasible, would be reduced by about 40%.

The BART analysis for PM_{10} was conducted in accordance with the procedures contained in the Final BART Guidelines published by the EPA on July 6, 2005. Consistent with the BART Guidelines, the five steps for a case-by-case BART analysis were followed.

- Step 1– Identify all available control technologies for the unit including improvements to existing control equipment or installation of new add-on control equipment.
- 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.
- 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.
- 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.
- 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 modeling procedures used in this analysis are the same as those used in 2007, and are consistent with those outlined in the updated final VISTAS common BART modeling protocol (Revision 3.2, dated August 31, 2006), available at http://www.vistassesarm.org/documents/BARTModelingProtocol_rev3.2_31Aug06.pdf. This report references relevant portions of the common VISTAS report. Also, recent initiatives have been made by VISTAS to incorporate the new IMPROVE equation with CALPUFF results. Because of the inherent benefits of the new IMPROVE equation, ENSR has used that equation in its BART modeling.

As a result of this additional analysis, ENSR and Conectiv recommend that Control Option 1 (DSI on Unit 4 and 0.5% sulfur oil for Unit 5) as the Best Available Retrofit Technology alternative for the Edge Moor Generating Station. The controls associated with this selected BART option will be implemented as a result of Delaware's Multi-Pollutant Regulation. The MPR controls also involve emission reductions from non-BART Unit 3, which will provide beneficial visibility improvements that are in addition to those from the Edge Moor BART-eligible units. BART Control Option 2 with a fabric filter on Unit 4 was rejected due to the very small incremental improvement in visibility at high cost. As mentioned above, the other candidate BART control options are infeasible, and were therefore not further considered.

1.0 Introduction

The Edge Moor Power Plant, operated by Conectiv, has been identified by DNREC as a source that is eligible for consideration of BART controls for PM_{10} (CAIR serves as BART for SO_2 and NO_x). This document summarizes the procedures by which a modeling analysis and a BART engineering review have been conducted for the Edge Moor Units 4 and 5.

The Regional Haze Rule requires a BART assessment for any BART-eligible source that ‘‘emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility” in any mandatory Class I federal area. Delaware has promulgated a Multi-Pollutant Regulation for Electrical Generating Units that effectively serves the same purpose as CAIR, and which satisfies BART for SO_2 and NO_x for EGU sources in the State of Delaware. Accordingly, this report focuses solely on performing BART modeling analyses and engineering reviews for primary particulate matter (PM_{10}) emissions from Edge Moor Units 4 and 5.

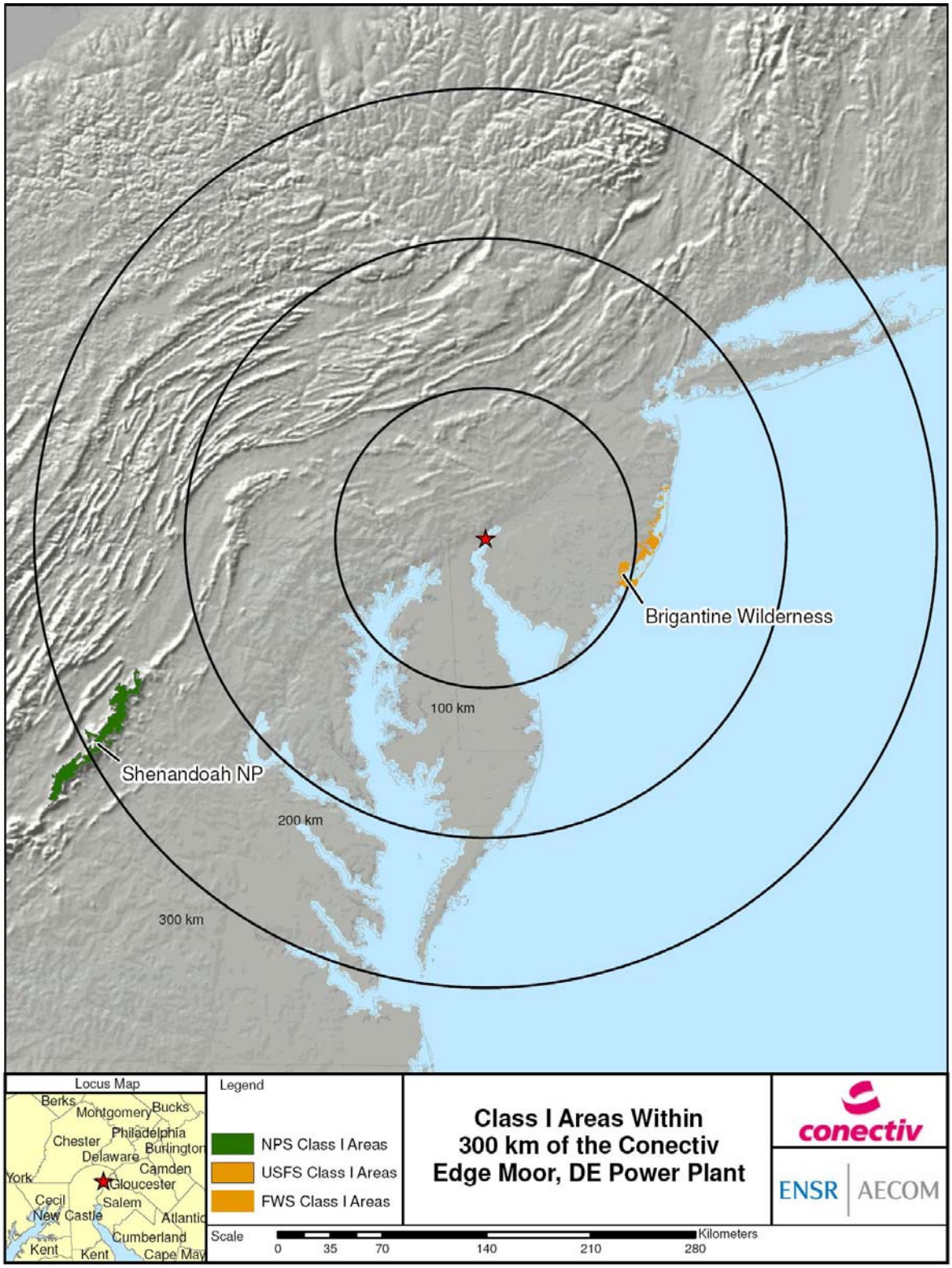
1.1 Location of Source vs. Relevant Class I Areas

Figure 1-1 shows the location of the Edge Moor Power Plant relative to nearby Class I areas. There are two Class I areas within 300 km of the plant: (1) Brigantine Wilderness and (2) Shenandoah National Park. The nearest point of the Brigantine Wilderness is approximately 92 kilometers east of the Edge Moor Power Plant, while the nearest point of the Shenandoah National Park is approximately 248 kilometers southwest of the Edge Moor Power Plant. The BART modeling analysis has been conducted for both of these Class I areas in accordance with the referenced VISTAS common BART modeling protocol and the procedures described in the referenced source-specific BART modeling protocol.

1.2 Organization of Report Document

Section 2 describes the input data that has been used for the modeling including the modeling domain, terrain and land use, and meteorological data. Section 3 of this report describes the source emissions that have been used as input to the BART modeling demonstration. An engineering review of the effects of anticipated visibility-affecting emission reductions is provided in Section 4. Section 5 discusses the CALPUFF modeling results. BART recommendations and conclusions are provided in Section 6. References are provided in Section 7. Appendix B describes the implementation of the new IMPROVE equation in the VISTAS states, as approved by the Federal Land Managers.

Figure 1-1 Location of Class I Areas in Relation to Edge Moor Power Plant



2.0 Inputs to CALPUFF Model

2.1 Meteorological Database

Although MANE-VU has processed a single year of data for use in BART assessments, a better (3-year) database is available for Delaware (including the Edge Moor Power Station), which lies within the VISTAS modeling domain. VISTAS has developed five sub-regional 4-km CALMET meteorological databases for three years (2001-2003). The sub-regional modeling domains are strategically designed to cover all potential BART-eligible sources within VISTAS states and all PSD Class I areas within 300 km of those sources. The extents of the 4-km sub-regional domains are shown in Figure 4-4 of the VISTAS common BART modeling protocol. The BART modeling for Edge Moor has been done using the easternmost 4-km subdomain that encompasses all of Delaware, as shown in Figure 4-4 of the VISTAS BART protocol (subdomain #5).

Three years of MM5 data (2001-2003) were used by VISTAS to generate the 4-km sub-regional meteorological datasets. See Sections 4.3.2 and 4.4.2 in the VISTAS common BART modeling protocol for more detail on these issues.

USGS 90-meter Digital Elevation Model (DEM) files were used by VISTAS to generate the terrain data at 4-km resolution for input to the 4-km sub-regional CALMET run. Likewise, USGS 90-meter Composite Theme Grid (CTG) files were used by VISTAS to generate the land use data at 4-km resolution for input to the 4-km sub-regional CALMET run.

2.2 Model Selection and Features

As noted in the VISTAS protocol, VISTAS used the BART-specific versions of CALMET and CALPUFF that have been posted at http://www.src.com/calpuff/download/download.htm#VISTAS_VERSION. These versions contain enhancements funded by the Minerals Management Service (MMS) and VISTAS. They are maintained on TRC's Atmospheric Studies Group CALPUFF website for public access.

The major features of the CALPUFF modeling system, including those of CALMET and the post processors (CALPOST and POSTUTIL) are referenced in Section 3 of the VISTAS protocol.

2.3 Modeling Domain and Receptors

All of the modeling for the Edge Moor Power Plant used the 4-km subdomain #5. A smaller computational grid within the VISTAS subdomain #5 was designed to minimize computation time and output file size. The Edge Moor computational grid domain covers distances of 452 km W-E and 352 km N-S and is shown in Figure 2-1. This domain includes two Class I areas with a 50-km buffer, plus a nearly 100-km buffer around the source (up to the limit of the VISTAS sub-domain northern boundary).

The receptors used for each of the Class I areas are based on the National Park Service database of Class I receptors, as recommended by VISTAS.

2.4 Technical Options Used in the Modeling

CALMET modeling for the VISTAS-provided 4-km subdomains had already been conducted by the VISTAS contractor, and this modeling was reviewed and approved by the Federal Land Managers.

For CALPUFF model options, the Edge Moor Power Plant followed the VISTAS common BART modeling protocol, which states that we should use IWAQM (EPA, 1998) guidance. The VISTAS protocol also notes that building downwash effects are not required to be included, and we followed this guidance for this application as well. The Edge Moor Power Plant is several tens of kilometers from the nearest Class I area,

and therefore building downwash effects can be expected to have little effect on the results of the CALPUFF modeling.

2.5 Air Quality Database (Background Ozone and Ammonia)

Hourly measurements of ozone from all non-urban monitors, as generated by VISTAS and available on the VISTAS CALPUFF page on the TRC web site (http://www.src.com/calpuff/download/sample_files.htm), have been used as input to CALPUFF. Currently, VISTAS advises sources to use a background ammonia concentration of 0.5 ppb, which has been used for this analysis. However, since there are no NO_x emissions being considered in this application, the results are not sensitive to the ammonia concentration used.

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

There are two Class I areas (Brigantine Wilderness Area and Shenandoah National Park) that were modeled for Edge Moor. For these Class I areas, natural background conditions have been established in order to determine a change in natural conditions related to a source's emissions. For the modeling described in this document, ENSR used the natural background light extinction of 7.44 deciviews for Brigantine W and 7.41 deciviews for Shenandoah NP, modified as noted below with site-specific considerations, and corresponding to the annual average (EPA 2003, Appendix B), consistent with the July 19, 2006 EPA guidance to Region 4 on this issue ("Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations", Joseph W. Paise/ EPA OAQPS to Kay Prince/Branch Chief).

The input to CALPOST is computed by converting the deciviews to extinction using the equation:

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

For example, for Brigantine, 7.44 deciviews is equivalent to an extinction of 11.04 inverse megameters (Mm^{-1}). This extinction does not include the default 10 Mm^{-1} for Rayleigh scattering. The remaining extinction of 11.04 Mm^{-1} is due to naturally occurring particles, and should be held constant for the entire year's simulation. Therefore, the data provided to CALPOST for Brigantine is the total natural background extinction minus 10 (expressed in Mm^{-1}), or 11.04 Mm^{-1}. This is most easily input as a fine soil concentration of 11.04 $\mu g/m^3$ in CALPOST, since the extinction efficiency of soil (PM-fine) is 1.0 and there is no f(RH) component. The concentration entries for all other particle constituents were set to zero, and the fine soil concentrations were kept the same for each month of the year. The monthly values for f(RH) that CALPOST used were taken from "Guidance for Tracking Progress Under the Regional Haze Rule" (EPA, 2003) Appendix A, Table A-3.

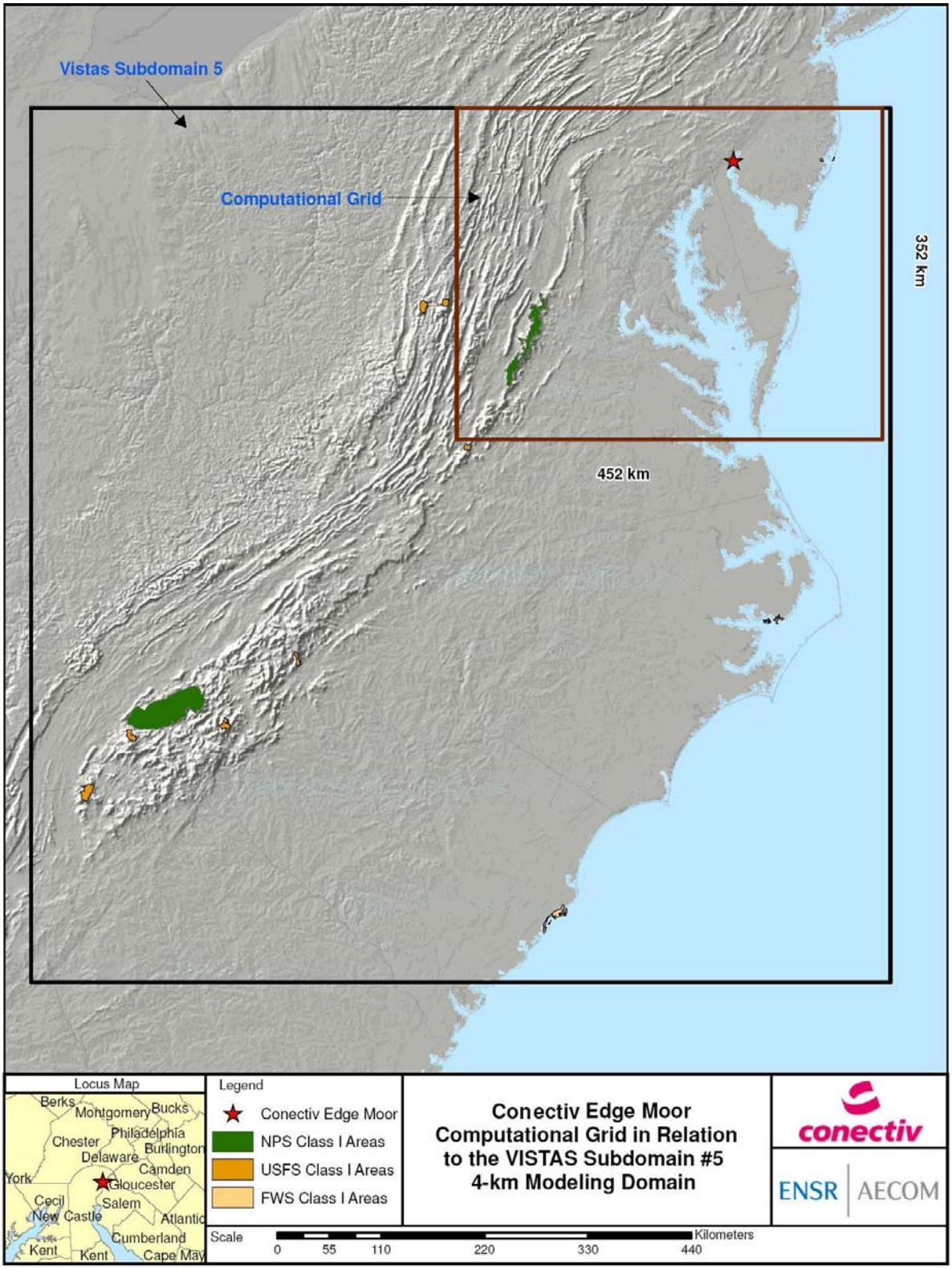
2.7 Light Extinction and Haze Impact Calculations

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

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

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

Figure 2-1 Edge Moor CALPUFF Computational Grid in Relation to the VISTAS Subdomain #5



Dr. Ivar Tombach, consultant to VISTAS, has provided a spreadsheet calculation system (see Appendix B) that incorporates the revised IMPROVE equation for determining light extinction from particulate concentration estimates. The VISTAS BART modeling protocol indicates that the unrevised IMPROVE algorithm does not incorporate the effects of naturally occurring sea salt on background visibility. The Brigantine Wilderness is significantly affected by this omission because it is off the coastline of New Jersey and surrounded by salt water. Therefore, we incorporated this effect into the present CALPUFF framework by using the guidance provided by Dr. Tombach, as presented in Appendix B. Table 2-1 lists sea salt concentrations and Rayleigh coefficients that were used in Dr. Tombach's new IMPROVE equation.

Table 2-1 Sea Salt Concentrations and Rayleigh Scattering Coefficients

	Brigantine W	**Shenandoah NP**
Sea Salt Concentration (µg/m3)	0.22	0.02
Raleigh Scattering Coefficient (Mm-1)	12	10

The assessment of visibility impacts at the Class I areas used CALPOST Method 6. Each hour's source-caused extinction was calculated by first using the hygroscopic components of the source-caused concentrations, due to ammonium sulfate and nitrate (not relevant for EGUs in CAIR states except for H_2SO_4 emissions), and monthly Class I area-specific f(RH) values. The contribution to the total source-caused extinction from ammonium sulfate and nitrate was then added to the other, non-hygroscopic components of the particulate concentration (from coarse and fine soil, secondary organic aerosols, and elemental carbon) to yield the total hourly source-caused extinction.

The EPA BART rule's recommended significance threshold for contribution to visibility impairment is 0.5 delta deciviews. For reference purposes, ENSR compared the PM_{10} visibility impacts to both the EPA-recommended 0.5 delta deciview threshold and the very low "significance" threshold of 0.1 delta deciviews for MANE-VU (98th percentile impacts), especially for the non-sulfate portion of the PM_{10} emissions which will not be affected by CAIR emission reductions.

3.0 Source Description and Baseline Emissions Data

The baseline emissions data used to assess the visibility impacts at the selected Class I areas are discussed in this section. As noted earlier, implementation of CAIR by EGUs satisfies BART requirements for SO_2 and NO_x. Therefore, as requested by DNREC, this report focuses only on PM_{10} control options. Because the various components of PM_{10} emissions have different visibility extinction efficiencies, the PM_{10} emissions are divided, or "speciated," into several components. The EPA guidance on BART modeling encourages the use of source-specific emissions and speciation factors. Otherwise, values from EPA's AP-42 reference document can be used as the default. PM_{10} was speciated in a manner that is consistent with EPA and National Park Service guidance.

Edge Moor Unit 4 is a nominal 175 MW dry-bottom, pulverized coal (primary fuel), tangentially-fired boiler equipped with an electrostatic precipitator (ESP) for the control of filterable particulates. Edge Moor Unit 5 is a nominal 445 MW residual oil-fired (primary fuel) boiler with a multiple cyclone (multiclone) for the control of filterable particulates. An aerial view of Edge Moor Units 4 and 5 is shown in Figure 3-1.

The PM_{10} emissions and speciation approach used for the baseline modeling are described in the bullets below.

- Total PM_{10} is comprised of filterable and condensable emissions.
- Total filterable PM for Unit 4 is determined from the relationship "0.08A lb/ton" (where A is the ash content in % wt.) based on AP-42, Table 1.1-4. The filterable PM is subdivided by size category consistent with the default approach from the AP-42 Document, Table 1.1-6. For coal-fired utility boilers equipped with an ESP, 67% of the filterable PM emissions are filterable PM_{10} and 29% of the filterable PM emissions are fine filterable PM_{10} emissions (less than 2.5 microns in size). For coal-fired utility boilers, elemental carbon is expected to be 3.7% of fine 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.
- Total filterable PM for Unit 5 is determined from the relationship "0.83(1.12S+0.37) lb/Mgal" (where S is the sulfur content in % wt.) based on AP-42, Table 1.3-4. The filterable is subdivided by size category consistent with the default approach from the AP-42 Document, Table 1.3-4. For uncontrolled oil-fired utility boilers, 71% of the filterable PM emissions are filterable PM_{10} and 52% of the filterable PM emissions are fine filterable PM_{10} emissions (less than 2.5 microns in size). For oil-fired utility boilers, elemental carbon is expected to be 7.4% of fine PM_{10}, based on the best estimate for electric utility petroleum 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 PM_{10} consists of inorganic and organic compounds. The inorganic portion is assumed to consist of H_2SO_4; the organic portion is modeled as secondary organic aerosols.
- For Unit 4, H_2SO_4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Coal Fired Power Plants", Keith Harrison, Larry Monroe and J. Edward Cichanowicz (Southern Company Services and Southern Research Institute, Revision 3, October 2005). This procedure is consistent with the method used by Conectiv for the data provided to DNREC as part of the Company's Toxic Release Inventory (TRI) reports. Before control, H_2SO_4 is determined by the relationship 0.008 x %S/100 x 10^6/HHV x HIR x 98.06/32.07. H_2SO_4 control is 49% for an air pre-heater and 49% for a cold-side ESP.

- For Unit 5 (oil-fired), H_2SO_4 emissions are based on the AP-42 Document, Table 1.3-2, where total condensable PM_{10} is 1.5 lb/Mgal. The inorganic portion of PM_{10} is 85% of the total condensable PM_{10}, while the organic portion is 15% of the total condensable PM_{10}.

In practice, CALPUFF allows for the user to input certain components of PM_{10} as separate species and separate sizes, which will result in more accurate wet and dry deposition velocity results and also more accurate effects on light scattering from the different PM_{10} species. As noted above, the particle size distribution information is provided in the AP-42 Document, Tables 1.1-6 and Table 1.3-4, and has been used for the BART modeling analysis.

A summary of the modeling stack parameters used in the BART CALPUFF modeling is presented in Table 3-1. A summary of the modeling emission parameters, as determined by the source emission factors mentioned above, is presented in Table 3-2.

Table 3-1 Modeling Exhaust Stack Parameters

	Units	Unit 4	Unit 5
UTM-X, Zone 18, NAD83	Meters	456891.942	4398832.728
UTM-Y, Zone 18, NAD83	Meters	456891.693	4398788.334
Stack Height	Meters	67.06	83.82
Base Elevation	Meters	3.96	3.96
Stack Diameter	Meters	4.11	6.40
Gas Exit Velocity	m/s	25.91	22.86
Stack Gas Exit Temperature	Deg K	407.59	413.15

Figure 3-1 Aerial View of the Edge Moor Plant

Table 3-2 Baseline Emission Rates

Facility	Unit	Description	Nominal Maximum Heat Input	Higher Heating Value	Higher Heating Value	Ash Content	Fuel Sulfur Content	Maximum Filterable PM Emissions			Filterable PM10					Condensible PM10			Total PM10
											total	coarse	Fine						
													fine total	fine soil	EC	total	SO4	organic	
			MMBtu/hr (a)	Btu/gal (b)	Btu/lb (b)	% wt. (c)	% wt. (c)	lb/MMBtu	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Edge Moor Power Plant	4	Unit 4, Coal, 175 MW, PC Tangential ,Dry Bottom, ESP	1,793	N.A.	12,567	9.12	0.75	0.0290 (d)	52.05	AP-42	35.13 (e)	19.52	15.61 (e)	15.04	0.58 (f)	22.42	6.28 (g)	16.14 (h)	57.55
Edge Moor Power Plant	5	Unit 5, #6 Oil, 445 MW, Multiple Cyclone	4,551	152,655	N.A.	0.00	0.62	0.0579 (i)	263.38	AP-42	187.22 (j)	50.77	136.45 (j)	126.35	10.10 (k)	44.72 (l)	38.01 (l)	6.71 (l)	231.94

(a) Nominal maximum heat input is based on information received from Conectiv on April 5, 2007.
(b) Higher heating values are based on the average values for calendar years 2001 through 2006.
(c) Ash and sulfur contents are based on the values cited in the latest complete emission statement submitted to DNREC in 2004.
(d) Total filterable PM is determined from the relationship "0.08A lb/ton" (where A is the ash content in % wt.) based on AP-42, Table 1.1-4.
(e) Total filterable PM10 is 67% of filterable PM and fine filterable PM10 is 29% of filterable PM based on AP-42, Table 1.1-6.
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Coal Fired Power Plants," Keith Harrison, Larry Monroe and J. Edward Cichanowicz, Southern Company Services and Southern Research Institute, Revision 3, October 2005. Before control, H2SO4 is determined from the relationship "0.008(%S/100)(10^6/HHV)(HIR)(98.06/32.07)" (where S is the sulfur content in % wt., HHV, the higher heating value in Btu/lb, and HIR, the heat input rate in MMBtu/hr). H2SO4 control is 0.49 for an air preheater and 0.49 for a cold- side ESP.
(h) Condensable organic PM10 is determined from the relationship, "0.20(0.1S-0.03 lb/MMBtu)" (where S is the sulfur content in % wt.) based on AP-42, Table 1.1-5.
(i) Total filterable PM is determined from the relationship "0.83(1.12S+0.37) lb/Mgal" (where S is the sulfur content in % wt.) based on AP-42, Table 1.3-4.
(j) Total filterable PM10 and fine filterable PM10 is 71% of filterable PM fine PM10 is 52% of filterable PM based on AP-42, Table 1.3-4.
(k) Elemental carbon is 7.4% of fine PM based on the best estimate for electric utility petroleum 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.
(l) Total condensable PM10 is 1.5 lb/Mgal based on AP-42, Table 1.3-2. Inorganic and inorganic fractions are 85% and 15% of total condensable PM10, respectively.

4.0 Evaluation of Air Pollution Control Technologies

The DNREC has promulgated Regulation 1146, the Electric Generating Unit Multi-Pollutant Regulation, effective December 11, 2006. This regulation establishes SO_2 and NO_x emission limits for coal and residual oil-fired EGUs with a nameplate capacity rating of 25 MW or greater. According to this regulation, NO_x emissions from coal and residual oil fired EGUs must not exceed 0.15 lb/MMBtu from May 1, 2009 through December 31, 2011, and 0.125 lb/MMBtu on or after January 1, 2012, on a 24-hour rolling average basis. For coal-fired EGUs, SO_2 emissions must not exceed 0.37 lb/MMBtu from May 1, 2009 through December 31, 2011, and 0.26 lb/MMBtu on or after January 1, 2012, also on a 24-hour rolling average basis. For residual oil-fired units, EGUs must not receive residual oil with a sulfur content in excess of 0.5% by weight on or after January 1, 2009.

Edge Moor Unit 4 is a nominal 175 MW dry-bottom, pulverized coal (primary fuel), tangentially-fired boiler equipped with low-NO_x coal burners (LNB) and overfire air (OFA) for the control of NO_x emissions and an electrostatic precipitator (ESP) for the control of filterable particulate emissions. Unit 4 is currently permitted to burn coal with a sulfur content of 1.0% wt. To comply with DNREC's Multi-Pollutant Regulation, Unit 4 will be retrofitted with a dry-sorbent injection system using a sodium-based sorbent to further reduce SO_2 emissions. For NO_x control, Unit 4 will be undertake the addition/enhancement/optimization of low-NO_x burner (LNB), overfire air (OFA), and an enhanced selective non-catalytic reduction system (SNCR).

Edge Moor Unit 5 is a nominal 445 MW residual oil-fired (primary fuel) boiler with oil LNB and OFA for the control of NO_x emissions and a multiclone for the control of filterable particulates. Unit 5 is also currently permitted to burn oil with a sulfur content of 1.0% wt. To comply with DNREC's Multi-Pollutant Regulation, Unit 5 will receive residual oil for use at the facility with a maximum sulfur content of no more than 0.5% by weight to reduce SO_2 emissions. NO_x additions/enhancements/optimizations will be employed will also include the use of a flue gas recirculation system, boosted over air system, and an enhanced SNCR system to further control NO_x emissions.

Edge Moor Unit 3 (a coal-fired unit) is not a BART-eligible unit because it was placed into service before August 7, 1962. However, the Delaware Multi-Pollutant Regulation (and CAIR) will result in emission reductions at this unit as well. Since the baseline period (2000-2004), Conectiv has installed enhanced LNBs and has also installed supplemental OFA on this unit. Conectiv also plans on improving the SNCR system at this unit by making it operational year-round, and installing multi-level lances for injection, to assist the unit comply with the provisions of the Multi-Pollutant Regulation. These controls will extend the EGU-related emission reductions at Edge Moor to the only non-BART unit at the plant.

The remainder of this section discusses the BART determination factors related to PM_{10} controls and evaluates the effectiveness of existing and proposed air pollution control technologies in reducing direct PM_{10} emissions. In addition, the MPR controls that affect SO_2 and NO_x emissions are described for supplemental information.

4.1 Particulate Controls

Currently, Edge Moor Unit 4 is equipped with an ESP to control particulate emissions. By 2009, the unit will also be equipped with dry sorbent injection to control SO_2 emissions. The dry sorbent injection system will provide the added benefit of controlling sulfates, a principal constituent of condensable PM_{10}. Edge Moor Unit 5 is equipped with a multiple cyclone separator to control particulate emissions. By 20009, the unit will fire residual fuel oil with a lower sulfur content of 0.5% wt. This will also result in a reduction in the emissions of sulfates and hence condensable PM_{10}.

The PM control technologies that were identified as available for retrofit to the Edge Moor Units 4 and 5 include the following:

- Fabric Filter Baghouse
- Electrostatic Precipitator (ESP)
- Wet ESP
- Compact Hybrid Particulate Collector
- GE MAX-9 Hybrid
- Multiple Cyclone Separator
- Alternative Fuels

These control technologies are reviewed below in the context of their effectiveness in further reducing PM emissions from Edge Moor Units 4 and 5.

4.1.1 Fabric Filter Baghouse

In a fabric filter, flue gas passes through a tightly woven or felted fabric, causing particles in the gas to be collected on the fabric by sieving, electrostatic attraction, and other mechanisms. Fabric filters may be in the form of sheets, cartridges or, most commonly, bags. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. Fabric filters are frequently referred to as baghouses because the fabric is usually configured in cylindrical bags. Groups of bags are placed in isolable compartments to allow cleaning of the bags or replacement of some of the bags without shutting down the entire fabric filter.

Pulse-jet fabric filtration (PJFF) is the preferred cleaning method for coal-fired boilers because it can treat high dust loadings, operate at constant pressure drop, and occupy less space than other types of fabric filters. Practical application of pulse-jet fabric filters requires the use of a large fabric area in order to avoid an unacceptable pressure drop across the fabric. The total fabric area is determined by the maximum economic compartment size, total gas volume rate, air-to-cloth (A/C) ratio, and cleaning method. The air-to-cloth ratio, in turn, depends on the particulate loading and particle characteristics. A high particulate loading will require the use of a larger baghouse in order to avoid forming too heavy a dust cake, which would result in an excessive pressure drop across the unit.

In pulse-jet fabric filters, the flue gas typically enters the compartment hopper and passes from the outside of the bag to the inside, depositing particulate on the outside of the bag. To prevent the collapse of the bag, a metal cage is installed on the inside of the bag. The flue gas passes up through the center of the bag into the outlet plenum. The filter unit is typically divided into compartments, which allows online maintenance or bag replacement. The number of compartments is determined by maximum economic compartment size, total volumetric flow rate, air-to-cloth (A/C) ratio, and cleaning system design. Extra compartments for maintenance or offline cleaning increase the reliability at the expense of capital cost and real estate utilization.

Cleaning is performed by initiating a downward pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag. This releases the dust cake from the bag surface, which then falls into the hopper. This cleaning may occur with the compartment online or offline. Care must be taken during design to ensure that the upward velocity between the bags is minimized so that particulate is not re-entrained during the cleaning process. The PJFF cleans bags in sequential, usually staggered, rows. During online cleaning, part of the dust cake from the row being cleaned may be captured by the adjacent rows. Despite this apparent shortcoming, PJFF have successfully implemented online cleaning on many large units.

Fabric filter baghouses are now the most common PM control device being applied to new large-scale, coal-fired boilers in the country. These devices in general provide highest collection efficiencies for both coarse and fine particulates and are relatively insensitive to fluctuations in gas stream conditions. In addition, the efficiency and pressure drop are relatively unaffected by large changes in inlet dust loadings for continuously cleaned filters. Despite physical site constraints, the BART analysis therefore focuses on the effectiveness and economic impacts associated with the retrofit of a fabric filter on Edge Moor Unit 4.

Because of the sticky and hygroscopic nature of residual oil fly ash, fabric filters have almost never been applied to oil-fired units, unless the bags are first pre-conditioned by means of dry sorbent injection upstream of the baghouse for SO_2 control. A fabric filter baghouse, therefore, is not considered technically feasible for application to Unit 5.

4.1.2 Electrostatic Precipitator

Unit 4 is equipped with an ESP to control filterable particulate matter discharged from the boiler. The ESP uses electrical forces to move particles entrained within the exhaust stream onto collector plates. The entrained particles are given an electrical charge when they pass through the corona, a region where gaseous ions flow. Electrodes in the center of the gas stream are maintained at high voltage and generate the electrical field that forces the particles to the collector plates. The collector plates are periodically knocked or "rapped" by various mechanical means to dislodge the particulate, which slides downward into a hopper where they are collected. The collection hopper is evacuated periodically, as it becomes full. The particulate is removed through a rotary valve into an ash-handling system, such as a pneumatic conveyor, and is then disposed of.

The voltage applied to the electrodes causes the gas between the electrodes to break down electrically, an action known as a “corona.” The electrodes are usually given a negative polarity because a negative corona supports a higher voltage than does a positive corona before sparking occurs. The ions generated in the corona follow electric field lines from the wires to the collecting plates. Therefore, each wire establishes a charging zone through which the particles must pass. As larger particles absorb many times more ions than small particles, the electrical forces are much stronger on larger particles.

Certain design features and particle characteristics affect the control efficiency of an ESP. The rapping that dislodges the accumulated layer also releases some of the particles back into the gas stream. These re-entrained particles are then collected again in later sections, but the particles re-entrained in the last section are not collected and escape the unit. Further, part of the gas may flow around the charging zones through the clearances required for non-electrified internal components at the top of the ESP. This is called “sneakage” and places an upper limit on the collection efficiency. On Unit 4, the ESP has been designed to maintain the gas flow through at a relatively low velocity to minimize particle re-entrainment and to prevent gas flow around the charging zone to minimize sneakage.

Another major factor in the ESP’s performance is the resistivity of the particles discharged from the boiler. Because the particles form a continuous layer on the ESP plates, all of the ion current must pass through the layer to reach the ground plates, creating an electric field in the layer. At high resistivities, this current can become strong enough to cause local electrical breakdown known as “back corona.” At low resistivities, the particles are held on the plates so loosely that particle re-entrainment becomes much more severe. On Unit 4, ESP performance has been optimized for the relatively constant particle properties associated with the coal commonly fired in the boiler. It should also be noted that sodium based sorbent injection technology, planned for use by Conectiv for compliance with Delaware’s Multi-pollutant Regulation is commonly used by ESP operators to reduce fly ash resistivity to improve the capture efficiency of particulate matter in such control devices.

ESPs are the most widely applied particulate control device to existing coal-fired utility boilers in the country. Based on performance tests conducted in December 1989, the Unit 4 ESP was demonstrated to limit filterable particulate emissions to 0.018 lb/MMBtu. These performance levels are much better than the MACT standard of 0.07 lb/MMBtu. As stated in the preamble to the BART Guidelines, “...unless there are new technologies

subsequent to the MACT standards which would lead to cost effective increases in the level of control, States may rely on the MACT standards for purposes of BART". Because no new technologies have become available since issuance of the MACT standard, the existing ESPs may be considered representative of BART. Furthermore, the performance levels are comparable to those specified for ESPs being applied to new coal-fired utility boilers around the country. Because of the particle size distribution of the PM emission from the existing unit, another ESP in series with the existing control device would provide little to no additional PM reduction and hence is not considered technically feasible for Unit 4. However, as part of implementation of the Multi-pollutant effort, Conectiv has also received permission from DNREC to improve the anodes in the Unit 4 existing precipitator design to a "pipe and spike" electrode to further enhance collection performance, and to replace 24 sonic horns to improve collection plate ash removal performance.

Although ESPs have also been applied to oil-fired utility boilers, they have experienced problems in dislodging the particles on the collection plates because of the sticky and hygroscopic nature of the fly ash. Further, the fine particulates exiting the existing multiclone may be more easily re-entrained in the flue gas or may flow around the charging zone resulting in sneakage. Because of these potential problems and severe site constraints, an ESP is not considered technically feasible for application to Unit 5.

4.1.3 Wet ESP

A wet ESP collects particles based on the same theory as a dry ESP, where negatively charged particles are collected on positively charged surfaces. In a wet ESP, however, the collecting surfaces are wet instead of dry and are flushed with water to remove the particulate. Typically, a wet ESP is installed downstream of an existing wet FGD system where the flue gas is already saturated to minimize water consumption. The particulate collection efficiency is enhanced by preventing re-entrainment after contact with the wet walls, compared with re-entrainment due to rapping on a dry ESP. Due this feature, wet ESPs are well suited for the removal of fine particulate or acid mist from the gas stream.

Several major hurdles exist with the use of a wet ESP. First, the flue gas must be saturated with moisture prior to entering the wet ESP to allow the unit to work correctly. This requires that a quenching system be installed to add water to the flue gas to reduce the flue gas temperature to the saturation point or the wet ESP may be installed downstream of an existing wet FGD system. Without the presence of a wet FGD system, the wet ESP adds additional cost, increases water demand on the plant, and generates a visible moisture plume at the stack outlet. The removed particulate would also be contained in a wastewater stream that is generated by the wet ESP. In addition to this issue, the capital cost of a wet ESP is high as compared to other technologies due to the higher cost of the alloy materials required. A higher grade of material is required to withstand the highly corrosive conditions presented by the wet and acidic flue gas stream.

Because the flue gas must be saturated before entering a wet ESP, these devices are usually applied to combustion installations equipped with either a Venturi scrubber for PM control or a wet FGD system for acid gas control. Consequently, wet ESPs have seen extremely limited application to large-scale, coal-fired utility boilers and, therefore, are not considered technically feasible for application to Unit 4. Likewise, wet ESPs have almost never been applied to oil-fired boilers and, therefore, are not considered technically feasible for Unit 5.

4.1.4 Compact Hybrid Particulate Collector

Another control technology used for particulate control is a high A/C ratio fabric filter installed after an existing particulate control device (typically a cold side ESP). Commonly referred to as a Compact Hybrid Particulate Collector (COHPACTM), this technology was developed and trademarked by the Electric Power Research Institute (EPRI). The COHPAC filter typically operates at A/C ratios ranging from 6 to 8 ft/min, compared to a conventional fabric filter that typically operate at A/C ratios of about 4 ft/min. For a COHPAC system, the majority of the particulate is collected in the upstream particulate control device. Therefore, the performance requirements of a high A/C ratio fabric filter is reduced, allowing installation of this technology in a smaller footprint area, with less steel and filtration media to substantially lower both capital and operating costs compared to conventional fabric filters .

COHPAC collectors are designed to operate at filtration rates higher than normal pulse jet air-to-cloth ratios. These higher filtration rates provide many advantages over normal ratios, including lower capital cost, reduced real estate requirements, shorter system installation times, and associated outage times. While the type of pulse-jet cleaning technology is not the most critical factor to success, a pulse cleaning system must have the inherent capability to effectively clean long filter bags, while utilizing on-line filter cleaning and still be able to maintain reasonable pressure drops and deliver acceptable bag life.

To date, the COHPAC technology has limited experience on combustion type applications, having been applied to only four coal-fired boilers and two refuse fired combustors over the past ten years. Consequently, the COHPAC technology is not considered commercially available for application to Edge Moor Unit 4.

4.1.5 GE MAX-9 Hybrid

The Max-9 is a new technology for removing particulate matter from process gas streams. Basically, this technology is an electrostatic precipitator, but with fabric filter elements instead of collecting plates. When the dust particles are charged, they are attracted to the grounded metal cage inside the filter element, just as they would be attracted to the collecting plates in an ordinary ESP. Because the dust particles are all charged to the same polarity, they repel each other while trapped on the filter. This results in a very porous, permeable "dust cake." Accordingly, the pressure drop across the Max-9 is very low compared with that across a conventional baghouse – approximately 70% less than the typical high-efficiency baghouse.

Process gas enters the Max-9 from a hopper inlet duct. The gas then flows upward through the filters and out through the top of the filters. The area above the tube sheet is a clean gas plenum. Compressed air pulses are used to clean the filters. Compressed air pulses are used to clean the filters. A brief, intense blast of air is fired through the purge air manifold; holes in the blowpipes located above the filters direct the cleaning air pulse down through the filters. The cleaning sequence is controlled by timers, which trigger solenoids. The high voltage system operates at very low current densities and at a steady state. There is no danger of fire caused by sparking, and the transformer/rectifier requires no voltage control.

To date, the GE Max-9 has not been applied to any large-scale, coal-fired boilers and, therefore, is not considered commercially available for application to Edge Moor Unit 4.

4.1.6 Multiple Cyclone Separator

Multiple cyclone separators, also known as “multiclones”, consist of a number of small-diameter cyclones, operating in parallel and having a common gas inlet and outlet. Multiclones operate on the same principle as cyclones, creating a main downward vortex and an ascending inner vortex. Multiclones are more efficient than single cyclones because they are longer and smaller in diameter. The longer length provides longer residence time, while the smaller diameter creates greater centrifugal force. These two factors result in better separation of dust particles. The pressure drop of multiclone collectors is higher than that of single-cyclone separators.

Cyclone collectors are centrifugal collectors that rely on the particle density and velocity to separate the fly ash from the flue gas. The particulate-laden flue gas enters the top or the side of the cyclone. Vanes impart a rotational velocity to the flue gas, driving the fly ash to the edge of the cylinder. The flue gas then exits the center of the cyclone out the top, leaving the fly ash to fall out the bottom. At pressures near one atmosphere and 2 to 5 inches water gauge pressure differential, multiclones have been demonstrated to be capable of achieving a 40% to 60% reduction in filterable particulate emissions.

Unit 5 is equipped with a multiple cyclone separator to control filterable particulate matter discharged from the boiler. Based on performance tests conducted in December 1989, the Unit 5 multiclone was demonstrated to limit filterable particulate emissions to 0.020 to 0.024 lb/MMBtu. These performance levels are comparable to those specified for particulate control devices applied to new residual oil-fired boilers. Consequently, the existing multiclone is considered BART for PM emissions from Unit 5.

4.1.7 Alternative Fuels

The only other means of reducing PM emissions from Unit 5 is converting from No. 6 residual fuel oil to "cleaner" fuels, such as No. 2 distillate fuel oil or natural gas. The advantages and disadvantages of converting to these alternative fuels is summarized below:

- No. 2 Distillate Fuel Oil. Converting to No. 2 distillate fuel oil with a lower sulfur content, say 0.3% wt., could reduce PM_{10} emissions by up to 68% relative to baseline conditions, although it is very likely that the boiler would not be able to achieve full generating load capacity burning this type of fuel. The economic implications of converting to No. 2 fuel oil would also be difficult to determine because of the ever increasing price of this commodity. Further, this conversion would require the installation of new fuel oil storage tanks and handling system for the No. 2 fuel oil with the associated high capital expenditure. Because of physical site constraints, however, the space for the required storage tanks and handling system would be problematic.
- Natural Gas. Converting to pipeline quality natural gas could reduce PM_{10} emissions by up to 85% relative to baseline conditions. Again, concerns would remain about the unit being able to accommodate this fuel and being able to reach full generating load capability. As with No. 2 oil, the economic implications of converting to natural gas would be difficult to determine because of the variability in prices in the future. Most importantly, however, Conectiv would not be unable to obtain a non-interruptible supply of natural gas from suppliers at the site due to existing supply infrastructure constraints.

Given these considerations, the conversion of Unit 5 from No. 6 residual fuel oil to either No. 2 distillate fuel oil or natural gas is not considered technically feasible as a means of further reducing PM emissions from that unit.

4.2 Sulfur Dioxide Controls

To comply with the DNREC's Multi-Pollutant Regulation, Unit 4 will be retrofitted with a dry-sorbent injection system using a sodium-based sorbent to reduce SO_2 emissions. Likewise, Unit 5 will be converted to firing residual fuel oil with a lower sulfur content of no more than 0.5% wt in compliance with the s Multi-Pollutant Regulation.

4.2.1 Dry Sorbent Injection and Fuel Oil Sulfur Content

To comply with the Multi-Pollutant Regulation, dry sorbent injection (DSI) will be installed to control SO_2 emissions from Unit 4. DSI requires less capital equipment, less physical space, and less modification to existing ductwork than do spray dryer absorbers or wet scrubbers. However, reagent costs are much higher and, depending on the absorbent and amount of sorbent injected, control efficiency is lower than for a spray dryer absorber. Lime, soda ash, and sodium based sorbents (such as Trona, or sodium sesquicarbonate) are possible reagents. Lime and soda ash are the least reactive reagents, resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected.

The sorbent particles need to be ground extremely fine (milled) to maximize the surface area of the particles. The finer the particles, the faster and more complete the reaction for a given injection rate. The neutralization reaction between the SO_2 (mild acid) and the sorbent (strong base) takes place on the surface area of the sorbent particles. After finely ground sorbent is pulverized, it is blown into the hot flue gas stream using a high pressure blower. The sorbent reacts with the acid gases in the flue gas stream, and the reacted particles are removed with the ash in the particulate control device.

The chemical reaction of the acid components of the flue gas with the alkaline reagent takes place in the ductwork ahead of the particulate collection device and continues in the device itself. The main chemical reaction is as follows:

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

Plant operating conditions will ultimately affect the performance of the sodium sesquicarbonate in acid gas removal. The most important variables for high removal efficiency are injection temperature, SO_2 concentration, retention time, and fine particle size (~10 microns).

As designed, DSI will be capable of limiting SO_2 emissions from Unit 4 to the standards established in the Multi-Pollutant Regulation, that is, 0.37 lb/MMBtu by May 1, 2009 and 0.26 lb/MMBtu by January 1, 2012. In addition, DSI will remove an equivalent percentage of the SO_3 and sulfates in the gas stream, thus reducing the inorganic condensable PM_{10} from Unit 4 by 50% over baseline conditions. Similar reductions in visibility-affecting emissions from Unit 3, which is not a BART-eligible source, will also occur due to Trona injection for that unit.

4.2.2 Low Sulfur Fuel Oil

To comply with the Multi-Pollutant Regulation, the maximum sulfur content of the residual fuel oil fired in Unit 5 will be reduced to 0.5%, resulting in almost a 20% reduction in SO_2 emissions over baseline conditions. In addition, lower sulfur fuel oil should remove an equivalent percentage of the SO_3 and sulfates in the gas stream.

4.3 Nitrogen Oxides Controls

Currently, Edge Moor Unit 4 consists of a tangentially-fired boiler equipped with low-NO_x coal burners (LNB) and overfire air (OFA) for the control of NO_x emissions. To comply with DNREC's Multi-Pollutant Regulation, Unit 4 will enhance and optimize the LNB and OFA, and install selective non-catalytic reduction (SNCR). Likewise, Edge Moor Unit 5 is equipped with LNB and OFA for the control of NO_x emissions. To comply with Multi-Pollutant Regulation, Unit 5 will enhance and optimize the LNB and OFA, and install a new boosted overfire air system, enhanced SNCR system, and flue gas recirculation (FGR) system.

4.3.1 Selective Non-Catalytic Reduction

To comply with the Multi-Pollutant Regulation, selective non-catalytic reduction (SNCR) will be installed to control NO_x emissions from both Units 4 and 5. SNCR has been applied to a number of different types of combustion sources, including utility and industrial boilers fired with natural gas, oil, and coal. The SNCR process is based on a gas-phase homogeneous reaction, within a specified temperature range, between NO_x in the flue gas and injected ammonia to produce gaseous nitrogen and water vapor. The SNCR process converts NO_X to nitrogen and water by the following general reactions:

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

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

In an SNCR system, NO_x reduction does not take place in the presence of a catalyst, but rather is driven by the thermal decomposition of ammonia or urea and the subsequent reduction of NO_x. Consequently, the SNCR process operates at higher temperatures than the SCR process. Critical to the successful reduction of NO_x with SNCR is the temperature of the flue gas at the point where the reagent is injected. For the ammonia injection process, the necessary temperature range is 1,700 to 1,900 °F. The factors affecting SNCR performance are gas mixing, residence time at temperature, and ammonia slip.

Theoretically, one mole of ammonia will react with one mole of NO_x, forming elemental nitrogen and water. In reality, not all the injected reagent will react, due to imperfect mixing, uneven temperature distribution, and insufficient residence time. These physical limitations may be compensated for by injecting excess ammonia and essentially achieving low NO_x emissions at the expense of ammonia slip. Thus, for a given boiler

configuration, there is a limit on the degree of NO_x reduction that can be achieved with SNCR while maintaining acceptable levels of ammonia slip.

In combination with enhanced staged combustion techniques, the SNCR will be capable of limiting NO_x emissions from Units 4 and 5 to the standards established in the Multi-Pollutant Regulation, that is, 0.15 lb/MMBtu by May 1, 2009 and 0.125 lb/MMBtu by January 1, 2012. By minimizing ammonia slip, the SNCR will not result in an appreciable change in PM_{10} emissions. This is in contrast with selective catalytic reduction (SCR), which would remove more NO_x emissions, but would increase the primary emissions of H_2SO_4 by causing increased oxidation of the SO_2 emissions. During warm-weather months when NO_x emissions create very low amounts of particulate (ammonium nitrate) due to the chemistry equilibrium between ammonium nitrate and gaseous nitric acid, the operation of SCR equipment can actually lead to no visibility improvement or, in certain cases, even increased visibility impairment due to the increased H_2SO_4 emissions that result.

4.3.2 Staged Combustion

A number of techniques have been employed to reduce the formation of NO_x by reducing peak flame temperature and/or starving the hottest parts of the flame for oxygen. By staging the combustion process, a longer, cooler flame results, which forms less NO_x. Staged combustion techniques include low-NO_x burners (LNB), over-fire air (OFA), and flue gas recirculation (FGR). To further reduce NO_x emissions, Unit 5 will be retrofitted with enhanced LNB and supplemental OFA, and will also be retrofitted with FGR.

4.4 Technical Feasibility of PM Control Options

Fabric filters and ESPs have been applied to large-scale, coal-fired utility boilers for many years. These devices have been demonstrated to achieve high PM collection efficiencies with minimal problems, maintenance, or downtime. Because of the particle size distribution of the PM emission from the existing unit, however, another ESP in series with the existing control device would provided little to no additional PM control and hence is not considered further in this analysis. The COHPAC Collector, on the other hand, has very limited experience on utility boiler applications, having been applied to only four coal-fired boilers and two refuse-fired combustors over the past ten years. Likewise, the Max-9 Hybrid has yet to be demonstrated on combustion installations comparable to the size of Edge Moor Unit 4. Despite physical site constraints, the BART analysis therefore focuses on the effectiveness and economic impacts associated with the retrofit of a fabric filter on Edge Moor Unit 4.

To date, ESPs and cyclones are the only PM control devices that have been applied to large-scale, residual oil-fired utility boilers. Because of severe physical site constraints, however, the retrofit of an ESP downstream of the existing multiclone is not considered technically feasible and hence is not considered further in this analysis. Because of the sticky and hygroscopic nature of residual oil fly ash, fabric filters have never been applied to oil-fired units, unless the bags are first pre-conditioned by means of dry sorbent injection upstream of the baghouse for SO_2 control. Likewise, the COHPAC Collector and Max-9Hybrid have never been applied to oil-fired boilers. The use of lower sulfur No. 4 or No. 2 fuel oils to further reduce PM emissions is not considered technically feasible, because there is insufficient space onsite for the required fuel oil storage tanks and handling system. Likewise, the use of natural gas to further reduce PM emissions is not technically feasible because a non-interruptible supply of natural gas is not available to the site. Therefore, there are no control technologies considered technically feasible to further reduce PM emissions from Unit 5.

4.5 Effectiveness of Feasible PM Control Options

As previously addressed, the SO_2 control technologies to be implemented in response to the MPR will also have effects on the PM emissions from Units 4 and 5. These control technologies, therefore constitute BART Control Option 1. The retrofit of a fabric filter on Unit 4 then will further reduce PM emissions from Unit 4. Based on recent permit approvals for new installations, the manufacturers of these control devices will guarantee filterable PM emissions on the order of 0.015 lb/MMBtu. The retrofit of a fabric filter on Unit 4 then constitutes BART Control Options 2. Tables 4-1 and 4-2 provide the PM emission rates and speciation used as input to CALPUFF for BART Control Options 1 and 2, respectively.

4.6 Impacts of Technically Feasible Options

To determine the cost effectiveness of the PM control options, the capital and annual operating costs for the technically feasible PM_{10} control technologies were estimated using CUECOST3, as revised on February 9, 2000. Because these costs are order of magnitude estimates, they are accurate only to about ±30%. The capital costs were annualized over a 30-year period and then added to the annual operating costs to obtain the total annual costs for each technology. Table 4-4 shows the costs of the BART Control Options applied to Edge Moor Units 4 and 5.

Table 4-3: Cost Effectiveness of BART Control Options

Control Option	Capital Cost ($)	Annual Fixed Charges ($/yr)	Annual O&M Costs ($/yr)	Total Annual Costs ($/yr)
1	$0	$0	$0	$0
2	$23,843,834	$2,789,729	$1,541,721	$4,331,450

This BART analysis does not identify any substantive energy impacts associated with the alternative PM control technologies considered for Edge Moor Units 4 and 5. Likewise, there are no significant non-air quality environmental impacts associated with these control technologies.

4.7 Conclusions

The EPA established procedures for determining BART in its Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations updated on July 24, 2005. The BART Guidelines recommend the following five steps for a case-by-case BART determination:

- Step 1– Identify all available control technologies for the unit including improvements to existing control equipment or installation of new add-on control equipment.
- 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.
- 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.
- 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.
- Step 5- Determine the visibility impairment associated with baseline emissions and the visibility improvements provided by the control technologies considered in the engineering analysis.

To minimize filterable PM_{10} emissions from Edge Moor Power Plant, Units 4 and 5 are equipped with an ESP and multiclone, respectively. These particulate collection devices have been shown to achieve performance levels comparable to those being specified as BACT for new coal- and oil-fired boilers. The existing control devices, therefore, are considered representative of BART for filterable PM_{10}. In selecting the SO_2 and NO_x control technologies designed to comply with CAIR and the Multi-Pollutant Regulations, Conectiv essentially completed the first four steps in the case-by-case BART determination established by the EPA. The selected SO_2 control systems are also effective in reducing primary sulfate emissions, a constituent of condensable PM_{10}.

The fifth step in the case-by-case BART determination is satisfied in the visibility analysis documented in the next section of this report.

Table 4-1 Emissions for BART Control Option 1

Facility	Unit	Description	Nominal Maximum Heat Input	Higher Heating Value	Higher Heating Value	Ash Content	Fuel Sulfur Content	Maximum Filterable PM Emissions			Filterable PM10					Condensible PM10			Total PM10
											total	coarse	Fine						
													fine total	fine soil	EC	total	SO4	organic	
			MMBtu/hr (a)	Btu/gal (b)	Btu/lb (b)	% wt. (c)	% wt. (c)	lb/MMBtu	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Edge Moor Power Plant	4	Unit 4, Coal, 175 MW, PC Tangential ,Dry Bottom, DSI, ESP	1,793	N.A.	12,567	9.12	0.75	0.0290 (d)	52.05	AP-42	35.13 (e)	19.52	15.61 (e)	15.04	0.58 (f)	19.28	3.14 (g)	16.14 (h)	54.41
Edge Moor Power Plant	5	Unit 5, #6 Oil, 445 MW, Multiple Cyclone	4,551	150,000	N.A.	0.00	0.50	0.0515 (i)	234.19	AP-42	166.48 (j)	45.15	121.33 (j)	112.35	8.98 (k)	45.51 (l)	38.68 (l)	6.83 (l)	211.99

(a) Nominal maximum heat input is based on information received from Conectiv on April 5, 2007.
(b) Higher heating values are based on the average values for calendar years 2001 through 2006.
(c) Ash content is based on the values cited in the latest complete emission statement submitted to DNREC in 2004 and sulfur content reflect maximum allowable under the Multi-Pollutant Regulations.
(d) Total filterable PM is determined from the relationship "0.08A lb/ton" (where A is the ash content in % wt.) based on AP-42, Table 1.1-4.
(e) Total filterable PM10 is 67% of filterable PM and fine filterable PM10 is 29% of filterable PM based on AP-42, Table 1.1-6.
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Coal Fired Power Plants," Keith Harrison, Larry Monroe and J. Edward Cichanowicz, Southern Company Services and Southern Research Institute, Revision 3, October 2005. Before control, H2SO4 is determined from the relationship "0.008(%S/100)(10^6/HHV)(HIR)(98.06/32.07)" (where S is the sulfur content in % wt., HHV, the higher heating value in Btu/lb, and HIR, the heat input rate in MMBtu/hr). H2SO4 control is 0.49 for an air preheater, 0.49 for a cold- side ESP, and 0.50 for DSI.
(h) Condensable organic PM10 is determined from the relationship, "0.20(0.1S-0.03 lb/MMBtu)" (where S is the sulfur content in % wt.) based on AP-42, Table 1.1-5.
(i) Total filterable PM is determined from the relationship "0.83(1.12S+0.37) lb/Mgal" (where S is the sulfur content in % wt.) based on AP-42, Table 1.3-4.
(j) Total filterable PM10 and fine filterable PM10 is 71% of filterable PM fine PM10 is 52% of filterable PM based on AP-42, Table 1.3-4.
(k) Elemental carbon is 7.4% of fine PM based on the best estimate for electric utility petroleum 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.
(l) Total condensable PM10 is 1.5 lb/Mgal based on AP-42, Table 1.3-2. Inorganic and inorganic fractions are 85% and 15% of total condensable PM10, respectively.

Table 4-2 Emissions for BART Control Option 2

Facility	Unit	Description	Nominal Maximum Heat Input	Higher Heating Value	Higher Heating Value	Ash Content	Fuel Sulfur Content	Maximum Filterable PM Emissions			Filterable PM10					Condensible PM10			Total PM10
											total	coarse	Fine						
													fine total	fine soil	EC	total	SO4	organic	
			MMBtu/hr (a)	Btu/gal (b)	Btu/lb (b)	% wt. (c)	% wt. (c)	lb/MMBtu	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Edge Moor Power Plant	4	Unit 4, Coal, 175 MW, PC Tangential ,Dry Bottom, DSI, ESP, FF	1,793	N.A.	12,567	9.12	0.75	0.0150 (d)	26.90	AP-42	18.15 (e)	10.09	8.07 (e)	7.77	0.30 (f)	16.45	0.31 (g)	16.14 (h)	34.61
Edge Moor Power Plant	5	Unit 5, #6 Oil, 445 MW, Multiple Cyclone	4,551	150,000	N.A.	0.00	0.50	0.0515 (i)	234.19	AP-42	166.48 (j)	45.15	121.33 (j)	112.35	8.98 (k)	45.51 (l)	38.68 (l)	6.83 (l)	211.99

(a) Nominal maximum heat input is based on information received from Conectiv on April 5, 2007.
(b) Higher heating values are based on the average values for calendar years 2001 through 2006.
(c) Ash content is based on the values cited in the latest complete emission statement submitted to DNREC in 2004 and sulfur content is based on maximum allowable under the Multi-Pollutant Regulations.
(d) Total filterable PM is determined from the relationship "0.08A lb/ton" (where A is the ash content in % wt.) based on AP-42, Table 1.1-4.
(e) Total filterable PM10 is 67% of filterable PM and fine filterable PM10 is 29% of filterable PM based on AP-42, Table 1.1-6.
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Coal Fired Power Plants," Keith Harrison, Larry Monroe and J. Edward Cichanowicz, Southern Company Services and Southern Research Institute, Revision 3, October 2005. Before control, H2SO4 is determined from the relationship "0.008(%S/100)(10^6/HHV)(HIR)(98.06/32.07)" (where S is the sulfur content in % wt., HHV, the higher heating value in Btu/lb, and HIR, the heat input rate in MMBtu/hr). H2SO4 control is 49% for an air preheater, 49% for a cold- side ESP, 0.50 for DSI, and 0.10 for FF.
(h) Condensable organic PM10 is determined from the relationship, "0.20(0.1S-0.03 lb/MMBtu)" (where S is the sulfur content in % wt.) based on AP-42, Table 1.1-5.
(i) Total filterable PM is determined from the relationship "0.83(1.12S+0.37) lb/Mgal" (where S is the sulfur content in % wt.) based on AP-42, Table 1.3-4.
(j) Total filterable PM10 and fine filterable PM10 is 71% of filterable PM fine PM10 is 52% of filterable PM based on AP-42, Table 1.3-4.
(k) Elemental carbon is 7.4% of fine PM based on the best estimate for electric utility petroleum 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.
(l) Total condensable PM10 is 1.5 lb/Mgal based on AP-42, Table 1.3-2. Inorganic and inorganic fractions are 85% and 15% of total condensable PM10, respectively.

5.0 CALPUFF Modeling Results

5.1 Baseline CALPUFF Modeling Results

CALPUFF modeling results of the baseline emissions at two 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 2-2.

The results of the visibility analysis for the baseline emissions demonstrate that visibility impacts from Edge Moor Units 4 and 5 are clearly imperceptible, being well below the BART perceptibility threshold value of 0.5 delta-dv for all Class I areas. The baseline visibility impacts are slightly above the MANE-VU "significance" threshold of 0.1 delta-dv when sulfates are included in the analysis. The analysis determined that more than half of the PM_{10}-caused visibility impacts can be attributed to inorganic condensable PM emissions, which result from the conversion of a small fraction of SO_2 in the gas stream into SO_3 and H_2SO_4. Consequently, it is anticipated that the implementation of CAIR and the Delaware Multi-Pollutant Regulation will not only result in a significant reduction in SO_2 and NO_x emissions from Units 4 and 5, but also the emissions of sulfates and other inorganic condensable PM emissions (Control Option Case 1). This implementation of the additional SO_2 control systems, therefore, will result in further improvements in the visibility impacts associated with Edge Moor Units 4 and 5.

The results in Table 5-1 indicate that the 8th highest day's impacts for each year and each Class I area are well below 0.5 delta-dv, and are comparable to the low MANE-VU contribution threshold of 0.1 delta-dv.

5.2 CALPUFF Modeling Results for Feasible Control Options

Two feasible BART control options were modeled for each meteorological year (2001-2003) and for two Class I areas to determine the effects of controlling PM_{10} emissions from Units 4 and 5. Emission rates that were used in modeling the BART control options are listed in Tables 4-1 and 4-2. These control scenarios are more fully discussed in Section 4.

The results of the BART control options modeling are presented in Table 5-1. Results for each feasible candidate BART control case are discussed in more detail below.

Control Option 1: This control option would result in 50% reduction of inorganic condensable PM_{10} emissions due to SO_2 emission controls with DSI. Modeling results for direct PM_{10} emissions show that the visibility may improve by about 0.01 delta-dv (relative to the baseline case) at Shenandoah National Park and Brigantine Wilderness. The improvement in visibility is minor, but additional visibility benefits would be obtained from the SO_2 and NO_x emission MPR reductions that are accommodated into the CAIR implementation. As discussed below, ENSR and Conectiv conclude that this control option is the Best Available Retrofit Technology alternative for the Edge Moor Generating Station based on the expected incremental visibility improvement, the cost of compliance, energy impacts, and other non-air quality environmental impacts

Control Option 2: This option involves adding fabric filter to Unit 4 to control PM_{10} emissions. This option would reduce total PM_{10} emissions by about 40%, but would result in a very minor visibility improvement at high cost. The incremental visibility improvement at Brigantine Wilderness is only 0.02 delta-dv and 0.01 delta-dv at Shenandoah National Park.

Table 5-1 Summary of Results – Edge Moor BART Modeling

Class I Area	Case	2001				2002				2003			
		Days > than		MAX dv ΔB_{ext}	8th Highest dv ΔB_{ext}	Days > than		MAX dv ΔB_{ext}	8th Highest dv ΔB_{ext}	Days > than		MAX dv ΔB_{ext}	8th Highest dv ΔB_{ext}
		0.1 dv ΔB_{ext}	0.5 dv ΔB_{ext}			0.1 dv ΔB_{ext}	0.5 dv ΔB_{ext}			0.1 dv ΔB_{ext}	0.5 dv ΔB_{ext}		
Brigantine W	Baseline	13	0	0.20	0.13	6	0	0.15	0.10	8	0	0.16	0.10
	BART Case 1	12	0	0.19	0.12	6	0	0.14	0.09	7	0	0.15	0.09
	BART Case 2	10	0	0.18	0.11	6	0	0.13	0.08	6	0	0.14	0.09
Shenandoah NP	Baseline	0	0	0.05	0.02	0	0	0.06	0.03	1	0	0.12	0.04
	BART Case 1	0	0	0.04	0.02	0	0	0.06	0.03	1	0	0.11	0.04
	BART Case 2	0	0	0.04	0.02	0	0	0.05	0.02	1	0	0.10	0.04

5.3 Cost of BART Control Options

Table 5-2 Cost of BART Control Options

	Baseline	BART Option 1	BART Option 2
Capital Costs	n/a	n/a	$23,843,834
Fixed Capital Costs	n/a	n/a	$2,789,729
Annual O&M Costs	n/a	n/a	$1,541,721
Total Annual Costs	n/a	n/a	$4,331,450
Incremental Direct PM_{10} Emissions Removed (tons) relative to previous control option	n/a	38.31(1)	78.67(1)
Incremental PM_{10} Emissions Removal Cost ($/ton)	n/a	n/a	$55,060
8th Highest Ave over 3-Years in Brigantine (dv)	0.110	0.100	0.093
8th Highest Ave over 3-Years in Shenandoah (dv)	0.030	0.030	0.027
Incremental Visibility Improvement Cost in Brigantine ($/dv)	n/a	n/a	$8,259,037
Incremental Visibility Improvement Cost in Shenandoah ($/dv)	n/a	n/a	$16,518,074

(1) Unit 4 2001-2006 average utilization factor is 91%, and Unit 5 2001-2006 average utilization factor is 30%.

6.0 Conclusions and BART Recommendations

Edge Moor has been identified by DNREC as a source that is eligible for consideration of BART controls for PM_{10} (CAIR serves as BART for SO_2 and NO_x). A BART modeling and engineering analysis has been completed in accordance with an approved BART modeling protocol, and in conjunction with a conference call with the DNREC in which the proposed procedures were discussed and approved for use. Additional BART determination analyses have been performed to respond to DNREC comments received earlier this year.

The results of the modeling study using peak daily baseline PM_{10} emissions demonstrate that visibility impacts from Edge Moor Units 4 and 5 are clearly imperceptible, being well below the EPA-prescribed BART threshold value of 0.5 delta-dv (8th highest or 98th percentile day in each of the three modeled years) for both Class I areas. In addition, the visibility impacts are comparable to the lower MANE-VU "significance" threshold of 0.1 delta-dv (8th highest or 98th percentile day in each of the three modeled years).

The DNREC has indicated that an engineering review and Class I modeling of anticipated emission reductions from the BART-eligible sources should be provided even if the baseline modeling results show very low visibility impacts. ENSR conducted engineering review and Class I modeling of available PM_{10} control options for Units 4 and 5. The modeling results for two feasible options indicate that the visibility improvements for the proposed PM_{10} alternative control technologies are very minor relative to the baseline.

ENSR and Conectiv recommend that Control Option 1 (DSI on Unit 4 and 0.5% sulfur oil for Unit 5) as the Best Available Retrofit Technology alternative for the Edge Moor Generating Station. The controls associated with this option will be implemented as a result of Delaware's Multi-Pollutant Regulation. The emission reductions from non-BART Unit 3 will also provide beneficial visibility improvements that are in addition to those from the Edge Moor BART-eligible units.

Control Option 2 with a fabric filter on Unit 4 was rejected as BART due to the very small incremental improvement in visibility at high cost. A summary of the BART analysis is presented in Table 6-1.

Table 6-1 Summary of BART Analysis

	Step 1	*Step 2*	*Step 3*	*Step 4a*	*Step 4b*	*Step 5*	
	Identify Control Technologies	**Feasible Control Technology?**	**Evaluate Control Effectiveness for Potentially Technically Feasible Control Technologies**	**Calculated Cost Effectiveness for Control Technologies**	**Determine Energy, Other Non-Air Quality Environmental Impacts, and Remaining Useful Life**	**Evaluate Visibility Impacts of Control Technologies**	**Identify BART Control**
Control Option 1	**Unit 4:** Dry-sorbent injection (reduces inorganic condensable PM_{10})	Yes	50% reduction of inorganic condensable PM_{10}	Cost is not calculated since this control option will be implemented as a result of Delaware's Multi-Pollutant Regulation.	No significant non-air quality or energy impacts	8th Highest impact improvement of 0.01 delta-dv in Brigantine and Shenandoah for PM_{10} emission reductions relative to baseline emissions.	This set of emission controls will occur as a result of Delaware's Multi-Pollutant Regulation.
	Unit 5: Sulfur content capped at 0.5%		8.6% reduction of total PM_{10}				
Control Option 2	**Unit 4:** Dry-sorbent injection and fabric filter	Yes	40% reduction of total PM_{10}	Capital cost of $23,843,834; annual operating cost of $4,331,450	No significant non-air quality or energy impacts	8th Highest impact improvement of 0.02 delta-dv in Brigantine and 0.01 delta-dv in Shenandoah relative to Control Option 1.	BART not justified due to visibility improvement of only 0.02 delta-dv at high cost.
	Unit 5: Sulfur content capped at 0.5%		8.6% reduction of total PM_{10}				

7.0 References

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

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Appendix A

Relevant Excerpts from EPA's "Additional Regional Haze Questions"

(available at **http://www.tceq.state.tx.us/assets/public/implementation/air/sip/bart/EPA_QA-Haze.pdf**)

Q. If the unit is already controlled (e.g., under MACT or BACT) and it is the best, the latest control technology, does the source still need to conduct a full blown BART analysis and control technology evaluation including the installed control device? Or, can the source just describe the control device on their BART-eligible source unit and make the case that it qualifies as BART, without having to evaluate other technologies?

A. f the unit has "best, latest…", then the source can just describe the control device on their BART-eligible source unit and make the case that it qualifies as BART, without having to evaluate other technologies. The streamlining of BART analyses in this situation is addressed in Section IV.C of the BART Guidelines, "How does a BART review relate to [MACT] Standards under CAA section 112, or to other emission limitations required under the CAA?

Q. How does the CAIR substitute for BART?

A. States subject to and participating in the CAIR cap and trade program for SO_2 and NO_x may treat the CAIR requirements for EGUs as a substitute for the application of BART controls for these pollutants. States do not need to require BART-eligible EGUs subject to the CAIR to install, maintain, and operate BART per 40 CFR 51.308(e)(4).

Q. If a CAIR facility is found to be exempt from BART for SO_2 and NO_x, and the State does exemption modeling on PM_{10} and concludes there is no impact on a Class I area, can the State totally exempt the utility from BART?

A. States subject to and participating in the CAIR cap and trade program for SO_2 and NO_x are allowed to treat the CAIR requirements for EGUs as a substitute for the application of BART controls per 40 CFR 51.308(e)(4). This does not mean EGUs are exempt for SO_2 and NO_x, only that CAIR satisfies the BART requirement for those pollutants. The remaining visibility pollutants to consider for determining BART-eligible sources are PM, and, using judgment, VOCs, and ammonia. For PM, the July 6, 2005, final BART rule at 70 FR 39160 notes PM_{10} may be used an indicator for PM in this step of the determination and thus, PM_{10} can be used for the exemption modeling.

Appendix B

Re-Calculating CALPOST Visibility Outputs with the New IMPROVE Algorithm

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Recalculating CALPOST Visibility Outputs with the New IMPROVE Algorithm

15 August 2006

Introduction

CALPOST processes outputs from CALPUFF modeling of a source's emissions to calculate the incremental visibility impairments caused by the modeled source. Those increments are presented in two tables, both labeled "Ranked Daily Visibility Change", in the CALPOST output (.LST) file. The table of interest to us has the subtitle "Modeled Extinction by Species" and lists the dates and locations of such incremental impacts in light extinction (b_{ext}) in ranked order, starting with the one that represents the largest percentage change in light extinction.[1]

Visibility effects are calculated in CALPOST from CALPUFF-modeled particulate matter component concentrations using effectively the "traditional" IMPROVE algorithm. CALPOST allows for choice of the humidity scattering enhancement function (f(RH)) to be used with the IMPROVE algorithm; for modeling in connection with the US EPA's Regional Haze Regulations (RHR), the appropriate form of f(RH) is the one described and tabulated in the EPA's 2003 guidance for tracking progress under the RHR.

Recently, the IMPROVE Steering Committee developed a new algorithm for estimating light extinction from particulate matter component concentrations. This algorithm (the "new IMPROVE algorithm") provides a better correspondence between the measured visibility and that calculated from particulate matter component concentrations. The new algorithm differs in several substantive ways from the traditional one:

- The extinction efficiencies of sulfates, nitrates, and organics have been changed and are now functions of their concentrations. The extinction efficiencies of

[1] The other table in the CALPOST output file, with the subtitle "% of Modeled Extinction by Species", provides equivalent results in terms of changes in the haze index, in deciviews. The two tables represent the same results, with identical ranking of events, while just using different (but mathematically related) metrics.

sulfate and nitrate are no longer identical, although the new hygroscopic scattering enhancement factors applied to them are the same.

- The concentration of particulate organic matter (POM; variously also labeled OCM or OMC, and sometimes just called "organics") is now taken to be 1.8 times that of the measured organic carbon (OC) concentration. (Confusingly, CALPOST labels the organics concentration as OC.)

- The contribution of fine sea salt to light extinction has been added, and is accompanied by its own hygroscopic scattering enhancement factor, $f_{ss}(RH)$.

- The light scattering by air itself (Rayleigh scattering) now varies with site elevation and mean temperature. It is to be rounded off to the nearest one Mm^{-1} when used with the new algorithm.

- The light absorption by NO_2 gas has been added.

The new IMPROVE algorithm is represented by the following formula:[2]

$$\begin{aligned} b_{ext} = \; & 2.2 \bullet f_S(RH) \bullet [\text{small sulfate}] + 4.8 \bullet f_L(RH) \bullet [\text{large sulfate}] \\ & + 2.4 \bullet f_S(RH) \bullet [\text{small nitrate}] + 5.1 \bullet f_L(RH) \bullet [\text{large nitrate}] \\ & + 2.8 \bullet [\text{small organics}] + 6.1 \bullet [\text{large organics}] \\ & + 10 \bullet [\text{elemental carbon}] \\ & + 1 \bullet [\text{fine soil}] \\ & + 1.7 \bullet f_{SS}(RH) \bullet [\text{sea salt}] \\ & + 0.6 \bullet [\text{coarse matter}] \\ & + \text{Rayleigh scattering (site specific)} \\ & + 0.33 \bullet [NO_2(\text{ppb})] \end{aligned} \qquad \text{(Eq. 1)}$$

The concentrations of "large" and "small" sulfate particles are calculated as follows:

$$[\text{large sulfate}] = \{[\text{total sulfate}]/20\} \bullet [\text{total sulfate}] \text{ if } [\text{total sulfate}] < 20\ \mu g^3$$

$$[\text{large sulfate}] = [\text{total sulfate}] \text{ if } [\text{total sulfate}] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. 2)}$$

$$[\text{small sulfate}] = [\text{total sulfate}] - [\text{large sulfate}].$$

Identical formulas, with changes in component names, are used for nitrate and organics. In effect, these formulas conclude that low concentrations of these components are mainly in the form of "small" particles with their own extinction efficiency and $f_S(RH)$, while high concentrations (approaching 20 $\mu g/m^3$) are mainly in the form of "large" particles with a different extinction efficiency and $f_L(RH)$. The scaling factor [total sulfate]/20 sets the fraction of total sulfate that is small.

[2] Square brackets denote concentrations.

The sea salt concentration is taken to be 1.7•[Cl^-] or, if chloride ion measurements are not available, the chlorine concentration can be used in its place. Site specific Rayleigh scattering values have been calculated for all IMPROVE sites.[3] Nitrogen dioxide concentrations are not measured at IMPROVE sites and the concentrations are sufficiently low that the NO_2 term is very small and can typically be ignored in rural areas.

In order for CALPOST to calculate CALPUFF-modeled source impacts on visibility using the new IMPROVE algorithm, CALPOST would have to be extensively reprogrammed. As an alternative, such a calculation could be done "off line" by adding another layer of post processing after CALPOST. To this end, I have developed a processor, in the form of an Excel workbook, that takes the CALPOST "Ranked Daily Visibility Change: Modeled Extinction by Species" output table based on default annual average natural conditions concentrations and creates an equivalent table of results based on the new algorithm.

The following describes the science behind the processor (which we'll call the CALPOST-IMPROVE Processor) and provides instructions for using it.

Concepts

In addition to the mechanical changes imposed by all the new terms in the new IMPROVE formula, applying the new algorithm also requires some conceptual changes. The biggest of these is that the extinction efficiencies of sulfates, nitrates, and organics now depend on the concentrations of those species. The practical implication of this is that extinction is no longer linearly additive. You cannot take a background level of extinction and add to it CALPOST's calculation of extinction caused by the particulate matter coming from a source, because when the two aerosols mix in the atmosphere their combined mass concentration results in increases in the extinction efficiencies of both the background and the source contribution. This means that combining background particulate matter with the particulate matter from a source gives an extinction result that is greater than the sum of the two separated extinctions.

With the nonlinear behavior resulting from applying the new IMPROVE algorithm, the extinction impact of the source (i.e., the increase in extinction resulting from introducing source emissions into the atmosphere) is the sum of three parts:

> (Part A) The source impact calculated by the new IMPROVE algorithm using the CALPOST outputs for a plume in isolation;
>
> (Part B) An increase in that source impact because the extinction efficiency increases when the source's aerosol combines with the background aerosol; and correspondingly,

[3] *Revised IMPROVE Algorithm for estimating Light Extinction from Particle Speciation Data.* Report to IMPROVE Steering Committee, November 2005.

(Part C) An increase in the extinction of the background aerosol because of that same mixing.

The total new extinction is the sum of the above three components plus the original background extinction. The original background extinction is just that calculated by the new IMPROVE algorithm from background concentrations of the various components, without any consideration of the effects of the plume.

For example, assume that the sulfate concentration attributed to a source is $[S_S]$ and the sulfate in the natural background is $[S_N]$, for a total ambient sulfate concentration of $[S_T]$. According to Equations 1 and 2, the total extinction due to sulfate for this combination is

$$b_{ext}(sulfate) = 2.2 \bullet f_S(RH) \bullet [small\ sulfate] + 4.8 \bullet f_L(RH) \bullet [large\ sulfate], \qquad \text{(Eq. 3)}$$

where

$$[large\ sulfate_T] = \{[S_T]/20\} \bullet [S_T] \text{ if } [S_T] < 20\ \mu g^3$$

$$[large\ sulfate_T] = [S_T] \text{ if } [S_T] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. 4)}$$

$$[small\ sulfate_T] = [S_T] - [large\ sulfate_T],$$

and the subscript T denotes total sulfate

For the portion of the extinction due directly to the source emissions (Parts A and B, above), we have, however

$$[large\ sulfate_S] = \{[S_T]/20\} \bullet [S_S] \text{ if } [S_T] < 20\ \mu g^3$$

$$[large\ sulfate_S] = [S_S] \text{ if } [S_T] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. 5)}$$

$$[small\ sulfate_S] = [S_S] - [large\ sulfate_S],$$

because we are now partitioning $[S_S]$ into large and small sulfate, where the size of the fraction depends on the concentration of all of the sulfate, $[S_T]$.

Similarly, for the portion of the extinction due to the background (the original background S_N plus the enhancement described under Part C, above), we have

$$[large\ sulfate_N] = \{[S_T]/20\} \bullet [S_N] \text{ if } [S_T] < 20\ \mu g^3$$

$$[large\ sulfate_N] = [S_N] \text{ if } [S_T] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. 6)}$$

$$[small\ sulfate_N] = [S_N] - [large\ sulfate_N],$$

As a check, we see that adding the corresponding formulas in Equations 5 and 6 gives the results in Equations 4.

Finally, for the original background, where there is no source impact, the corresponding formulas are

$$[\text{large sulfate}_N] = \{[S_N]/20\}\bullet[S_N] \text{ if } [S_N] < 20\ \mu g^3$$

$$[\text{large sulfate}_N] = [S_N] \text{ if } [S_N] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. 7)}$$

$$[\text{small sulfate}_N] = [S_N] - [\text{large sulfate}_N],$$

As usual, the fractional change in extinction is then calculated as

$$(b_{ext,T} - b_{ext,N})/b_{ext,N}, \qquad \text{(Eq. 8)}$$

which can also be expressed in deciviews.

These formulas are used in the CALPOST-IMPROVE Processor. Similar formulas apply for nitrates and organics. There is no nonlinearity in the remaining terms in Equation 1.

Description of Processor

The CALPOST-IMPROVE Processor is a Microsoft Excel workbook that consists of four worksheets:

1. Input/Output – The output table from CALPOST is imported to here and user entries are made for the Rayleigh scattering coefficient and, if desired, for a sea salt concentration at the Class I area of interest. A revised table, with extinction based on the new IMPROVE algorithm is then presented on the same page. This is the only page on which user input takes place, and the results of the calculations appear on this page.

2. Calculations -- The calculations themselves are all done on this worksheet. There is no user input to this page. The variables are explained on the worksheet itself, so the user can find intermediate values if so inclined. Since NO_2 concentrations are not measured at IMPROVE sites and the NO_2 absorption in rural areas is expected to be small, NO_2 has been omitted from these calculations.

3. F(RH) – This worksheet tabulates the traditional IMPROVE f(RH) against RH, and then also lists values for the three new humidity growth functions, $f_S(RH)$, $f_L(RH)$, and $f_{SS}(RH)$. It serves as a lookup table for the "Calculations" worksheet .

4. Rayleigh & Sea Salt – This page tabulates the IMPROVE-recommended Rayleigh scattering coefficients for all VISTAS Class I areas and for Class I areas in adjacent states. It also lists the average sea salt concentrations for the same

locations, based on chloride or chlorine measurements by IMPROVE monitors between 2000 and 2004. This sheet just provides information for the user; it is not linked to the rest of the workbook. The user can obtain Rayleigh and sea salt numbers for the Class I area of interest from this table and then manually enter them in the designated spaces in worksheet 1.

Instructions for Using the CALPOST-IMPROVE Processor

Step 1. Begin by opening the output (.LST) file from CALPOST in a text editor or word processing program.[4] In the second half of the file, locate the table "Ranked Daily Visibility Change" with the subheading "Modeled Extinction by Species".[5]

Step 2. Copy this table and paste it onto a new page. Save it as a text (.txt) file, not as a formatted (e.g., MS Word .doc or .rtf) file. The final table should contain only the column headings and the data. Delete all other captions, any additional data summaries at the end, and blank lines before or after the table. The processor can handle a maximum of 22 lines of data (i.e., the highest rank in the last, unlabeled, column should be 22) plus a row of column captions. Delete any data that exceed this limit. The result should look like the example in Figure 1.

Step 3. Open the CALPOST-IMPROVE Processor with Microsoft Excel. Save the open file under a new name so that the original empty processor will remain available for future use. The front worksheet, labeled "Input/Output" looks like Figure 2. There is a large empty box, surrounded by double lines, into which the table created above will be imported, as described below.[6] Two smaller boxes provide for user input of the Rayleigh scattering coefficient and, optionally, sea salt concentration for the Class I area, as described below. Results of the new IMPROVE algorithm calculations appear in blue in the lower half of the worksheet and some additional results, that are also useful for quality control, appear in green to the right of the large box. At the moment, many results cells will display nonsensical numbers and error messages, such as shown in Figure 2.

Step 4. Select the upper left cell (A7) in the large box. On the Excel menu bar, go to *Data>Get External Data* and click on *Import Text File.* (If the large box is not empty, click on *Edit Text Import* instead.) Select the file that contains the table created in Step 2 and click on the *Get Data* button. Go through the Text Import Wizard steps, checking that all values appear correctly in separate columns. (The label "COORDINATES (km)" will be split over two columns; this is OK.) When everything appears in order, click *Finish.*

---

[4] The background concentrations that were entered into CALPOST must be the EPA-prescribed default annual average natural conditions concentrations for the East. The processor will not give correct answers if other concentrations were used in CALPOST.

[5] For future reference, this may also be a good time to locate the table with the same title but with the subtitle "% of Modeled Extinction by Species", which appears later in the output file.

[6] If the workbook has already been used, the boxes may not be empty. This does not matter.

```
YEAR DAY HR  RECEPTOR    COORDINATES (km)  TYPE BEXT(Model) BEXT(BKG)
BEXT(Total) %CHANGE  F(RH)  bxSO4  bxNO3   bxOC   bxEC  bxPMC  bxPMF
2002 175  0  1027       1479.069    24.683   D      5.495      21.650      27.145
25.38   3.500  5.401  0.045  0.042  0.002  0.001  0.004    1
2002 172  0  1021       1479.244    23.778   D      4.923      21.650      26.573
22.74   3.500  4.475  0.404  0.038  0.001  0.001  0.004    2
2002 284  0  1045       1484.348    27.580   D      3.150      21.470      24.620
14.67   3.300  2.684  0.428  0.033  0.001  0.001  0.003    3
2002 353  0  1026       1482.762    24.457   D      2.594      21.290      23.884
12.18   3.100  2.017  0.557  0.018  0.001  0.000  0.002    4
2002 283  0  1026       1482.762    24.457   D      2.502      21.470      23.972
11.65   3.300  2.269  0.201  0.028  0.001  0.001  0.003    5
2002 195  0  1045       1484.348    27.580   D      2.011      21.830      23.841
9.21   3.700  1.963  0.031  0.015  0.001  0.000  0.001    6
2002  20  0  1117       1486.636    34.592   D      1.872      21.200      23.072
8.83   3.000  1.542  0.320  0.009  0.000  0.000  0.001    7
2002 173  0  1128       1479.259    35.042   D      1.649      21.650      23.299
7.62   3.500  1.625  0.012  0.010  0.000  0.000  0.001    8
2002 234  0  1021       1479.244    23.778   D      1.524      22.190      23.714
6.87   4.100  1.482  0.029  0.011  0.000  0.000  0.001    9
2002 298  0  1021       1479.244    23.778   D      1.459      21.470      22.929
6.80   3.300  1.284  0.160  0.014  0.001  0.000  0.001   10
2002 299  0  1021       1479.244    23.778   D      1.436      21.470      22.906
6.69   3.300  1.281  0.140  0.013  0.000  0.000  0.001   11
2002 275  0  1026       1482.762    24.457   D      1.270      21.470      22.740
5.92   3.300  1.202  0.058  0.009  0.000  0.000  0.001   12
2002 263  0  1045       1484.348    27.580   D      1.237      22.100      23.337
5.60   4.000  1.223  0.008  0.005  0.000  0.000  0.001   13
2002 252  0  1026       1482.762    24.457   D      1.189      22.100      23.289
5.38   4.000  1.166  0.013  0.009  0.000  0.000  0.001   14
2002 285  0  1021       1479.244    23.778   D      0.992      21.470      22.462
4.62   3.300  0.813  0.179  0.001  0.000  0.000  0.000   15
2002 161  0  1026       1482.762    24.457   D      0.873      21.650      22.523
4.03   3.500  0.842  0.020  0.009  0.000  0.000  0.001   16
2002 150  0  1026       1482.762    24.457   D      0.857      21.380      22.237
4.01   3.200  0.822  0.026  0.007  0.000  0.000  0.001   17
2002 340  0  1140       1481.017    37.258   D      0.817      21.290      22.107
3.84   3.100  0.663  0.153  0.001  0.000  0.000  0.000   18
2002 151  0  1117       1486.636    34.592   D      0.745      21.380      22.125
3.49   3.200  0.704  0.033  0.007  0.000  0.000  0.001   19
2002 160  0  1021       1479.244    23.778   D      0.735      21.650      22.385
3.40   3.500  0.710  0.014  0.010  0.000  0.000  0.001   20
2002 346  0  1021       1479.244    23.778   D      0.703      21.290      21.993
3.30   3.100  0.620  0.080  0.002  0.000  0.000  0.000   21
2002 247  0  1021       1479.244    23.778   D      0.661      22.100      22.761
2.99   4.000  0.654  0.004  0.002  0.000  0.000  0.000   22
```

Figure 1. Example of CALPOST Output Table, in Proper Format for Importing into the CALPOST-IMPROVE Processor.

Step 5.[7] The "Import Data" window will appear, with cell A7 indicated as the location at which data will be entered. Click on the *Properties* button. In the window that appears, select "Overwrite existing cells with new data, clear unused cells" and uncheck "Adjust column width", then click on *OK*. Now click on the *OK* button in the "Import Data" window.

Step 6. Assuming that your Excel application is set up to automatically recalculate whenever any entries are changed, you should now have filled the cells in the large box

[7] If the processor already had data in it and *Edit Text Import* was clicked in Step 4, then the "Import Data" window will not appear and Step 5 can be skipped.

CALPOST Recalculation with New IMPROVE Algorithm

---------- INPUT from CALPOST (based on old IMPROVE algorithm) ----------

1. At cell A7, import "Ranked Daily Visibility Change" (bext) table, including column headings, from CALPOST (22 days, max)

2. Check calculated values below against CALPOST's "Ranked Daily Visibility Change" (dv) table

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)	TYPE	BEXT(Model)	BEXT(BKG)	BEXT(Total)	%CHANGE	F(RH)	bxSO4	bxNO3	bxOC	bxEC	bxPMC	bxPMF	Rank	dv(total)	dv(bkg)	Δdv
																		#NUM!	#NUM!	#NUM!
																		#NUM!	#NUM!	#NUM!
																		#NUM!	#NUM!	#NUM!
																		#NUM!	#NUM!	#NUM!
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																		#NUM!	#NUM!	#NUM!
																		#NUM!	#NUM!	#NUM!

3. Enter value of site-specific Rayleigh scattering coefficient, from "Rayleigh & Sea Salt" worksheet

4. (Optional) Insert annual average sea salt concentration, from "Rayleigh & Sea Salt" worksheet. Leave blank if not used.

---------- OUTPUT (based on new IMPROVE algorithm) ----------

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)	TYPE	BEXT(Source)	BEXT(BKG)	BEXT(Total)	%CHANGE	RH(%)	bsSO4	bsNO3	bsOC	bsEC	bsPMC	bsPMF	New Rank	dv(total)	dv(bkg)	Δdv
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A

Figure 2. Example of Appearance of Input/Output Worksheet before Data Entry.

on the first worksheet, numbers should have appeared in the green columns to the right, and some numbers will have appeared in the output table in blue on the lower half of the worksheet. If the data import worked properly, none of the imported data should have spilled out of the large box. Check that all the column captions in bold outside the large box are now duplicated on the first line in the box. (There won't be a caption for Rank.)

Step 7. As a further check on whether everything is correct so far, the dv information in the three columns to the right of the large box should be the same as that in the second CALPOST table "Ranked Daily Visibility Change: % of Modeled Extinction by Species", which was mentioned in Footnote 1.

Step 8. Fill in the small box after red instruction 3 with the Rayleigh scattering coefficient for the Class I area of interest. Also, if you wish, fill in the other small box, the one after red instruction 4, with the annual average sea salt concentration. (The sea salt box may be left blank, but the Rayleigh scattering coefficient box must be filled in.) To help with filling in these two boxes, the fourth worksheet, "Rayleigh & Sea Salt", provides IMPROVE-calculated values of the Rayleigh coefficients for Class I areas in the VISTAS region and in adjacent states. Also, average sea salt concentrations for 2000-2004, calculated in accordance with the new IMPROVE procedures, can be found there. At this point the "Input/Output" worksheet should look something like Figure 3, with all columns filled with meaningful data.

Step 9. The new IMPROVE algorithm output table at the bottom of the page can be compared with the original CALPOST table at the top of the page. All of the columns in both tables show exactly the same variables, except that the F(RH) column in the top table is replaced by just the RH in the lower table (since the new procedure has three different f(RH) functions). Although the events are in the same order in both tables, note that their rankings may have changed, as in New Ranks 12 vs. 13 and 19 vs. 20 in Figure 3.

For those who are interested in more detail, values of the three f(RH) functions appear in columns L through N on the second, "Calculations" spreadsheet. The extinction impact of the source, including enhancement of the extinction efficiencies for sulfates, nitrates, and organics due to the Part B that was described above, appears in columns U through AA. Extinction due to the annual average natural background appears in Columns AH through AL; natural background extinctions for those components that are enhanced by greater total mass concentrations (Part C) appear in columns AS through AV.

CALPOST Recalculation with New IMPROVE Algorithm

---------- INPUT from CALPOST (based on old IMPROVE algorithm) ----------

1. At cell A7, import "Ranked Daily Visibility Change" (bext) table, including column headings, from CALPOST (22 days, max)

2. Check calculated values below against CALPOST's "Ranked Daily Visibility Change" (dv) table

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)		TYPE	BEXT(Model)	BEXT(BKG)	BEXT(Total)	%CHANGE	F(RH)	bxSO4	bxNO3	bxOC	bxEC	bxPMC	bxPMF	Rank	dv(total)	dv(bkg)	Δdv
YEAR	DAY	HR	RECEPTOR	COORDINA	TES (km)	TYPE	BEXT(Model)	BEXT(BKG)	BEXT(Total)	%CHANGE	F(RH)	bxSO4	bxNO3	bxOC	bxEC	bxPMC	bxPMF		dv(total)	dv(bkg)	Δdv
2002	175	0	1027	1479.069	24.683	D	5.495	21.65	27.145	25.38	3.5	5.401	0.045	0.042	0.002	0.001	0.004	1	9.99	7.72	2.26
2002	172	0	1021	1479.244	23.778	D	4.923	21.65	26.573	22.74	3.5	4.475	0.404	0.038	0.001	0.001	0.004	2	9.77	7.72	2.05
2002	284	0	1045	1484.348	27.58	D	3.15	21.47	24.62	14.67	3.3	2.684	0.428	0.033	0.001	0.001	0.003	3	9.01	7.64	1.37
2002	353	0	1026	1482.762	24.457	D	2.594	21.29	23.884	12.18	3.1	2.017	0.557	0.018	0.001	0	0.002	4	8.71	7.56	1.15
2002	283	0	1026	1482.762	24.457	D	2.502	21.47	23.972	11.65	3.3	2.269	0.201	0.028	0.001	0.001	0.003	5	8.74	7.64	1.10
2002	195	0	1045	1484.348	27.58	D	2.011	21.83	23.841	9.21	3.7	1.963	0.031	0.015	0.001	0	0.001	6	8.69	7.81	0.88
2002	20	0	1117	1486.636	34.592	D	1.872	21.2	23.072	8.83	3	1.542	0.32	0.009	0	0	0.001	7	8.36	7.51	0.85
2002	173	0	1128	1479.259	35.042	D	1.649	21.65	23.299	7.62	3.5	1.625	0.012	0.01	0	0	0.001	8	8.46	7.72	0.73
2002	234	0	1021	1479.244	23.778	D	1.524	22.19	23.714	6.87	4.1	1.482	0.029	0.011	0	0	0.001	9	8.63	7.97	0.66
2002	298	0	1021	1479.244	23.778	D	1.459	21.47	22.929	6.8	3.3	1.284	0.16	0.014	0.001	0	0.001	10	8.30	7.64	0.66
2002	299	0	1021	1479.244	23.778	D	1.436	21.47	22.906	6.69	3.3	1.281	0.14	0.013	0	0	0.001	11	8.29	7.64	0.65
2002	275	0	1026	1482.762	24.457	D	1.27	21.47	22.74	5.92	3.3	1.202	0.058	0.009	0	0	0.001	12	8.22	7.64	0.57
2002	263	0	1045	1484.348	27.58	D	1.237	22.1	23.337	5.6	4	1.223	0.008	0.005	0	0	0.001	13	8.47	7.93	0.54
2002	252	0	1026	1482.762	24.457	D	1.189	22.1	23.289	5.38	4	1.166	0.013	0.009	0	0	0.001	14	8.45	7.93	0.52
2002	285	0	1021	1479.244	23.778	D	0.992	21.47	22.462	4.62	3.3	0.813	0.179	0.001	0	0	0	15	8.09	7.64	0.45
2002	161	0	1026	1482.762	24.457	D	0.873	21.65	22.523	4.03	3.5	0.842	0.02	0.009	0	0	0.001	16	8.12	7.72	0.40
2002	150	0	1026	1482.762	24.457	D	0.857	21.38	22.237	4.01	3.2	0.822	0.026	0.007	0	0	0.001	17	7.99	7.60	0.39
2002	340	0	1140	1481.017	37.258	D	0.817	21.29	22.107	3.84	3.1	0.663	0.153	0.001	0	0	0	18	7.93	7.56	0.38
2002	151	0	1117	1486.636	34.592	D	0.745	21.38	22.125	3.49	3.2	0.704	0.033	0.007	0	0	0.001	19	7.94	7.60	0.34
2002	160	0	1021	1479.244	23.778	D	0.735	21.65	22.385	3.4	3.5	0.71	0.014	0.01	0	0	0.001	20	8.06	7.72	0.33
2002	346	0	1021	1479.244	23.778	D	0.703	21.29	21.993	3.3	3.1	0.62	0.08	0.002	0	0	0	21	7.88	7.56	0.32
2002	247	0	1021	1479.244	23.778	D	0.661	22.1	22.761	2.99	4	0.654	0.004	0.002	0	0	0	22	8.22	7.93	0.29

3. Enter value of site-specific Rayleigh scattering coefficient, from "Rayleigh & Sea Salt" worksheet 11

4. (Optional) Insert annual average sea salt concentration, from "Rayleigh & Sea Salt" worksheet. Leave blank if not used. 0.02

---------- OUTPUT (based on new IMPROVE algorithm) ----------

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)		TYPE	BEXT(Source)	BEXT(BKG)	BEXT(Total)	%CHANGE	RH(%)	bsSO4	bsNO3	bsOC	bsEC	bsPMC	bsPMF	New Rank	dv(total)	dv(bkg)	Δdv
2002	175	0	1027	1479.069	24.683	D	4.441	22.04	26.521	20.32	86	4.363	0.039	0.033	0.002	0.001	0.004	1	9.75	7.90	1.85
2002	172	0	1021	1479.244	23.778	D	3.989	22.04	26.063	18.24	86	3.604	0.349	0.029	0.001	0.001	0.004	2	9.58	7.90	1.68
2002	284	0	1045	1484.348	27.58	D	2.464	21.78	24.264	11.40	84	2.076	0.357	0.026	0.001	0.001	0.003	3	8.86	7.78	1.08
2002	353	0	1026	1482.762	24.457	D	2.000	21.57	23.586	9.35	82	1.528	0.455	0.014	0.001	0	0.002	4	8.58	7.69	0.89
2002	283	0	1026	1482.762	24.457	D	1.947	21.78	23.744	9.02	84	1.753	0.167	0.022	0.001	0.001	0.003	5	8.65	7.78	0.86
2002	195	0	1045	1484.348	27.58	D	1.609	22.21	23.837	7.30	87	1.569	0.027	0.012	0.001	0	0.001	6	8.69	7.98	0.70
2002	20	0	1117	1486.636	34.592	D	1.427	21.48	22.916	6.70	81	1.16	0.26	0.007	0	0	0.001	7	8.29	7.64	0.65
2002	173	0	1128	1479.259	35.042	D	1.316	22.04	23.370	6.02	86	1.297	0.01	0.008	0	0	0.001	8	8.49	7.90	0.58
2002	234	0	1021	1479.244	23.778	D	1.249	22.64	23.896	5.56	89	1.213	0.026	0.009	0	0	0.001	9	8.71	8.17	0.54
2002	298	0	1021	1479.244	23.778	D	1.134	21.78	22.924	5.25	84	0.988	0.133	0.011	0.001	0	0.001	10	8.30	7.78	0.51
2002	299	0	1021	1479.244	23.778	D	1.114	21.78	22.903	5.16	84	0.986	0.117	0.01	0	0	0.001	11	8.29	7.78	0.50
2002	275	0	1026	1482.762	24.457	D	0.981	21.78	22.770	4.54	84	0.925	0.048	0.007	0	0	0.001	13	8.23	7.78	0.44
2002	263	0	1045	1484.348	27.58	D	1.038	22.64	23.684	4.62	89	1.026	0.007	0.004	0	0	0.001	12	8.62	8.17	0.45
2002	252	0	1026	1482.762	24.457	D	0.998	22.64	23.643	4.44	89	0.978	0.012	0.007	0	0	0.001	14	8.60	8.17	0.43
2002	285	0	1021	1479.244	23.778	D	0.775	21.78	22.561	3.58	84	0.625	0.149	8E-04	0	0	0	15	8.14	7.78	0.35
2002	161	0	1026	1482.762	24.457	D	0.696	22.04	22.744	3.18	86	0.67	0.017	0.007	0	0	0.001	16	8.22	7.90	0.31
2002	150	0	1026	1482.762	24.457	D	0.651	21.67	22.322	3.03	83	0.623	0.021	0.005	0	0	0.001	17	8.03	7.73	0.30
2002	340	0	1140	1481.017	37.258	D	0.625	21.57	22.200	2.92	82	0.5	0.125	8E-04	0	0	0	18	7.98	7.69	0.29
2002	151	0	1117	1486.636	34.592	D	0.567	21.67	22.237	2.64	83	0.533	0.027	0.005	0	0	0.001	20	7.99	7.73	0.26
2002	160	0	1021	1479.244	23.778	D	0.586	22.04	22.634	2.68	86	0.565	0.012	0.008	0	0	0.001	19	8.17	7.90	0.26
2002	346	0	1021	1479.244	23.778	D	0.534	21.57	22.109	2.50	82	0.467	0.065	0.002	0	0	0	21	7.93	7.69	0.25
2002	247	0	1021	1479.244	23.778	D	0.553	22.64	23.195	2.46	89	0.548	0.004	0.002	0	0	0	22	8.41	8.17	0.24

Figure 3. Example of Appearance of Finished Input/Output Worksheet.

Appendix
Details of Calculation Approach

As an example of the calculation steps, assume that the sulfate concentration resulting from emissions from a source is $[S_E]$ and the sulfate in the undisturbed natural background is $[S_N]$, for a total ambient sulfate concentration of $[S_T]$. According to Equations 1 and 2 in the main body of this document, the total extinction due to sulfate for this combination is

$$b_{ext}(sulfate) = 2.2 \cdot f_S(RH) \cdot [small\ sulfate] + 4.8 \cdot f_L(RH) \cdot [large\ sulfate], \qquad \text{(Eq. A-1)}$$

where

$$[large\ sulfate_T] = \{[S_T]/20\} \cdot [S_T] \text{ if } [S_T] < 20\ \mu g^3$$

$$[large\ sulfate_T] = [S_T] \text{ if } [S_T] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. A-2)}$$

$$[small\ sulfate_T] = [S_T] - [large\ sulfate_T],$$

and the subscript T denotes total sulfate

For the original background, where there is no source impact, the corresponding formulas for the terms in Equations A-2 are

$$[large\ sulfate_N] = \{[S_N]/20\} \cdot [S_N] \text{ if } [S_N] < 20\ \mu g^3$$

$$[large\ sulfate_N] = [S_N] \text{ if } [S_N] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. A-3)}$$

$$[small\ sulfate_N] = [S_N] - [large\ sulfate_N],$$

where the subscript N denotes natural sulfate.

Similar calculations need to be carried out for nitrates. Contributions of the other particulate components are linear and can just be calculated according to Equation 1.

If the impact due to NO_2 is also to be considered, then the source impact due to this component is, according to Equation 1,

$$b_{ext}(NO_2) = 0.33 \cdot [NO_2], \qquad \text{(Eq. A-4)}$$

where $[NO_2]$ is in ppb. It is reasonable to assume that the ambient NO_2 concentrations under natural conditions would be so small as to cause negligible light absorption, so the corresponding term is not needed in the natural conditions calculation.

The contributions due to the various components are summed together as in Equation 1 to obtain the total extinction $b_{ext,T}$ and the natural background extinction $b_{ext,N}$. The

fractional change in extinction is then calculated as the difference, normalized by the natural background extinction

$$(b_{ext,T} - b_{ext,N})/b_{ext,N}, \qquad \text{(Eq. A-5)}$$

a result that can also be expressed in deciviews.

These formulas are used in the CALPOST-IMPROVE Processor. Similar formulas apply for nitrates and organics. There is no nonlinearity in the remaining terms in Equation 1.

U.S. Locations

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WI, Milwaukee
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Prepared for:
Conectiv Delmarva Generation
Wilmington, Delaware

Source-Specific Best Available Retrofit Technology (BART) Modeling and Engineering Review: Edge Moor Units 4 & 5

ENSR Corporation
June 2007
Document No.: 01855-056-0300

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Source-Specific Best Available Retrofit Technology (BART) Modeling and Engineering Review: Edge Moor Units 4 & 5

Olga Kostrova

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Robert J. Paine

Reviewed By: Robert J. Paine

ENSR Corporation
June 2007
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1.0 Executive Summary

Conectiv Delmarva Generation, Inc, (Conectiv) an affiliate of Conectiv Energy, operates the Edge Moor Power Plant ("Edge Moor"), a coal and oil-fired electric generating station located in Wilmington, Delaware. Edge Moor has been identified by DNREC as a source that is eligible for consideration of BART controls for PM_{10} (CAIR serves as BART for SO_2 and NO_x). This document summarizes the procedures by which a modeling analysis and a BART engineering review have been conducted for the Edge Moor Units 4 and 5.

The Regional Haze Rule requires Best Available Retrofit Technology (BART) for any BART-eligible source that ''emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility" in any mandatory Class I federal area. The Environmental Protection Agency (EPA) has determined that implementation of the Clean Air Interstate Rule (CAIR) by electric generating unit (EGU) sources satisfies applicable BART requirements for SO_2 and NO_x emissions from those sources (see Appendix A for specific EPA BART references in this regard). The Delaware Department of Natural Resources and Environmental Control (DNREC) has indicated that the federal CAIR program is employed in Delaware as part of a Federal Implementation Plan (FIP) process under which EGU sources will meet the State's CAIR emission reduction requirements. As such, CAIR satisfies BART for SO_2 and NO_x for EGU sources in the State of Delaware. Accordingly, this report focuses solely on performing BART modeling analyses and engineering reviews for primary particulate matter (PM_{10}) emissions from Edge Moor Units 4 and 5.

The document entitled "Source-Specific Best Available Retrofit Technology (BART) Exemption and Determination Modeling Protocol: Edge Moor Units 4 and 5" was submitted to DNREC in May 2007. The modeling exercise was conducted in general accordance with the protocol following a conference call with the DNREC in which the proposed procedures were discussed and approved for use.

Even though Delaware is located within the Mid-Atlantic/Northeast Visibility Union (MANE-VU), the VISTAS modeling domain covers the entire state as well. ENSR modeled Edge Moor using the VISTAS meteorological data rather than the MANE-VU meteorological data for three reasons. First, VISTAS meteorological data covers three years (2001-2003), whereas MANE-VU meteorological data covers only one year (2002). Second, VISTAS meteorological data has a finer grid resolution of 4 km than MANE-VU's coarse grid resolution of 12 km. Third, the MANE-VU CALMET database was created in "No-Obs" mode (without a Step 2 procedure using surface and upper air station data), using MM5 data as the only source of meteorological observations. In contrast, VISTAS CALMET was run using surface and upper air station data. Therefore, the VISTAS data tests a data period three times as long as the MANE-VU data and has technical advantages in the way it was prepared. Pennsylvania, another nearby MANE-VU state with a number of BART-eligible sources, recommends the use of the VISTAS meteorological data due to these technical considerations.

The modeling procedures are consistent with those outlined in the updated final VISTAS common BART modeling protocol (Revision 3.2, dated August 31, 2006), available at http://www.vistassesarm.org/documents/BARTModelingProtocol_rev3.2_31Aug06.pdf. This report references relevant portions of the common VISTAS report. Also, recent initiatives have been made by VISTAS to incorporate the new IMPROVE equation with CALPUFF results. Because of the inherent benefits of the new IMPROVE equation, ENSR has used that equation in its BART modeling. More discussion on this is provided in Section 4-4.

For the BART modeling analysis, ENSR compared the 98th percentile 24-hour average modeled change in light extinction from natural conditions with the threshold value of 0.5 deciviews (dv) recommended in the BART rule. It should be noted that the BART rule mentions a perception threshold of 1.0 dv, and allows a single facility to contribute up to half of this threshold and still be determined to have no perceptible impact on regional haze. We also note that in the draft MANE-VU report entitled, "Five-Factor Analysis of BART-Eligible Sources" (February 2007), MANE-VU indicates that a much lower visibility threshold, 0.1 delta-dv, can be used as a threshold for insignificant impacts (such that a formal BART determination is not warranted because the

possible reductions in visibility impacts are very small). The MANE-VU report indicates on page 14 that "…this value is below the 0.5 dv impact recommended by EPA for exemption modeling and we can be fairly certain that facilities below the 0.1 dv level have very small individual impacts on visibility at Class I areas." Mr. Gary Kleiman of NESCAUM has also verified (2006) this MANE-VU policy. For purposes of this analysis, ENSR has taken this more conservative approach because Delaware is a MANE-VU state. The 98th percentile results for total PM_{10} impacts on visibility as well as the sulfate portion (from H_2SO_4 emissions) versus the remainder of the PM_{10} are reported. The sulfate portion is specifically broken out because CAIR-related emission reductions in SO_2 also reduce the H_2SO_4 emissions, so that component of particulate emissions is already subject to CAIR-related controls.

The results of the modeling study demonstrate that visibility impacts due to primary PM_{10} emissions from Edge Moor Units 4 and 5 are clearly imperceptible, being well below the BART threshold value of 0.5 delta-dv (8th highest or 98th percentile day in each of the three modeled years 2001, 2002 and 2003), for all Class I areas. In addition, the visibility impacts are below the MANE-VU threshold of 0.1 delta-dv (8th highest or 98th percentile day in each of the three modeled years 2001, 2002 and 2003) at Shenandoah National Park. The visibility impacts for Brigantine Wilderness are just above the MANE-VU threshold of 0.1 delta-dv (a maximum value of 0.13 delta-dv, 8th highest or 98th percentile day in each of the three modeled years 2001, 2002 and 2003) when sulfates are included in the modeling. It should be noted that nearly all of the visibility impacts can be attributed to inorganic condensable PM emissions, which are modeled as sulfuric acid (H_2SO_4) emissions that result from the conversion of a small fraction (typically 1 percent or less) of the SO_2 in the coal-fired boiler flue gas stream into SO_3 and H_2SO_4. Conectiv anticipates that the implementation of CAIR and the Delaware Multi-Pollutant Regulation will also significantly reduce emissions of sulfates / inorganic condensable PM emissions since these emissions are directly proportional to SO_2 emissions. The modeling shows that the visibility impacts from non-sulfate PM_{10} are below 0.1 delta-dv for both Class I areas (a maximum value of 0.06 delta-dv, 8th highest or 98th percentile day in each of the three modeled years 2001, 2002 and 2003), and that additional BART analyses for primary particulate would likely yield no meaningful visibility improvements.

The DNREC has indicated that an engineering review of anticipated emission reductions from the BART-eligible sources should be provided even if the baseline modeling results show very low visibility impacts. Based on the discussion provided in Section 6 of this report, the anticipated reductions of SO_2 emissions from Units 4 and 5 due to the implementation of CAIR and Delaware's Multi-Pollutant Regulations are expected to result in significant reductions of primary sulfate emissions, which will likely reduce the PM_{10} visibility impacts from these units to levels of 0.1 delta-dv or lower. The emission reductions from non-BART Unit 3 will also provide beneficial visibility improvements that are in addition to those from the Edge Moor BART-eligible units.

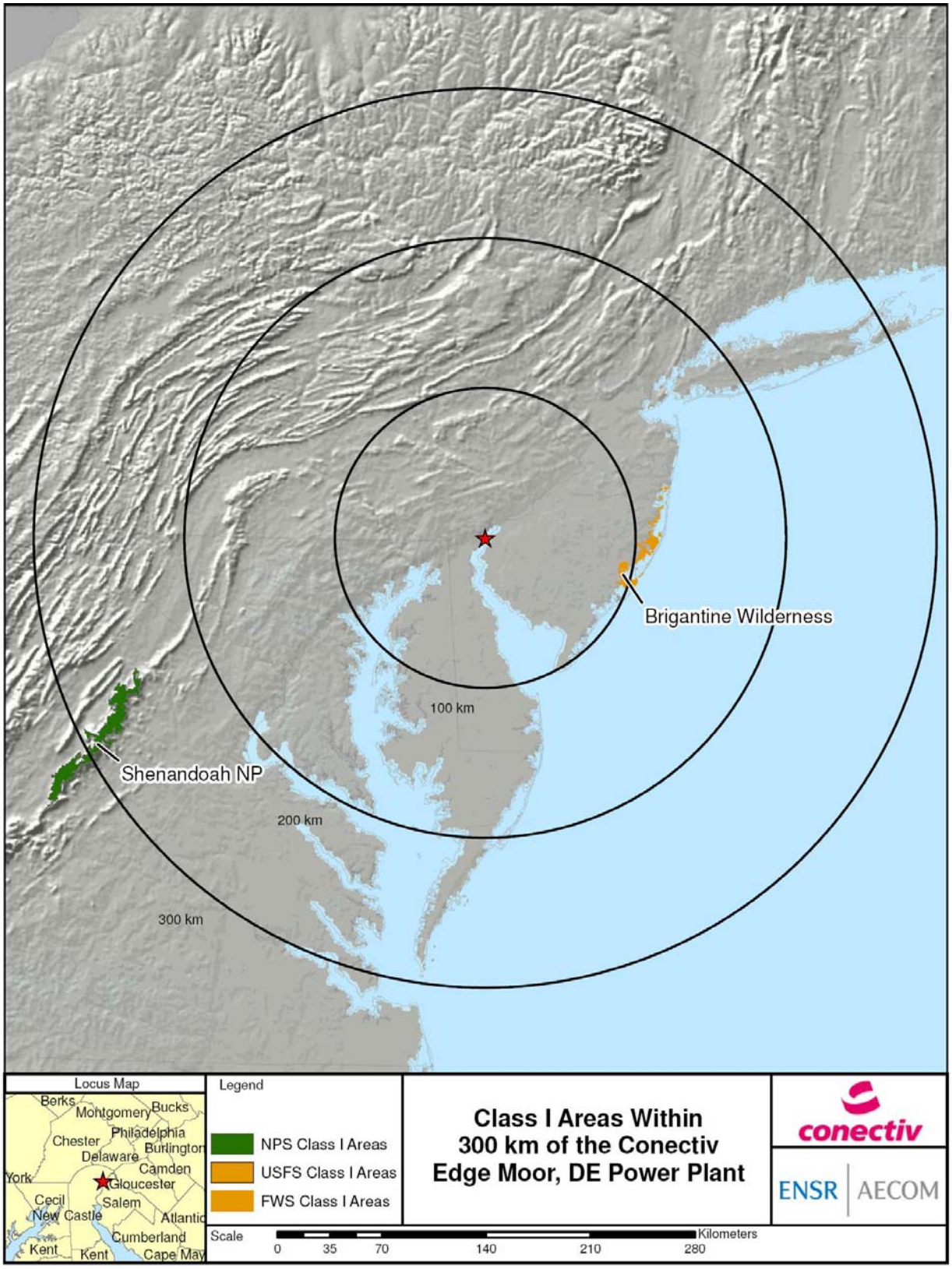
1.1 Location of Source vs. Relevant Class I Areas

Figure 1-1 shows the location of the Edge Moor Power Plant relative to nearby Class I areas. There are two Class I areas within 300 km of the plant: (1) Brigantine Wilderness and (2) Shenandoah National Park. The nearest point of the Brigantine Wilderness is approximately 92 kilometers east of the Edge Moor Power Plant, while the nearest point of the Shenandoah National Park is approximately 248 kilometers southwest of the Edge Moor Power Plant. The BART modeling analysis has been conducted for both of these Class I areas in accordance with the referenced VISTAS common BART modeling protocol and the procedures described in the referenced source-specific BART modeling protocol.

1.2 Organization of Report Document

Section 2 of this report describes the source emissions that have been used as input to the BART modeling demonstration. Section 3 describes the input data that has been used for the modeling including the modeling domain, terrain and land use, and meteorological data. Section 4 describes the CALPUFF modeling and the air quality modeling procedures, and Section 5 discusses the CALPUFF modeling results. An engineering review of the effects of anticipated SO_2 and NO_x emission reductions is provided in Section 6. References are provided in Section 7. Appendix B describes the implementation of the new IMPROVE equation in the VISTAS states, as approved by the Federal Land Managers.

Figure 1-1 Location of Class I Areas in Relation to Edge Moor Power Plant



2.0 Source Description and Emissions Data

The emissions data used to assess the visibility impacts at the selected Class I areas are discussed in this section. As noted earlier, implementation of CAIR by EGUs satisfies BART requirements for SO_2 and NO_x. Therefore, this report focuses only on PM_{10}. Because the various components of PM_{10} emissions have different visibility extinction efficiencies, the PM_{10} emissions are divided, or "speciated," into several components. The EPA guidance on BART modeling encourages the use of source-specific emissions and speciation factors. Otherwise, values from EPA's AP-42 reference document can be used as the default. PM_{10} was speciated in a manner that is consistent with EPA and National Park Service guidance.

Edge Moor Unit 4 is a nominal 175 MW dry-bottom, pulverized coal (primary fuel), tangentially-fired boiler equipped with an electrostatic precipitator (ESP) for the control of filterable particulates. Edge Moor Unit 5 is a nominal 445 MW residual oil-fired (primary fuel) boiler with a multiple cyclone (multiclone) for the control of filterable particulates.

The PM_{10} emissions and speciation approach used for the baseline modeling are described in the bullets below.

- Total PM_{10} is comprised of filterable and condensable emissions.
- Baseline filterable PM_{10} emissions (units of lb/hr) were based on the source-specific emission factors (units of lb/MMBtu) derived from stack emission tests conducted in December 1989 and the maximum daily heat input recorded by the continuous emission monitoring system (CEMS) during the period from 2001 through 2006.
- Filterable PM for Unit 4 is subdivided by size category consistent with the default approach from the AP-42 Document, Table 1.1-6. For coal-fired utility boilers equipped with an ESP, 67% of the filterable PM emissions are filterable PM_{10} and 29% of the filterable PM emissions are fine filterable PM_{10} emissions (less than 2.5 microns in size). For coal-fired utility boilers, elemental carbon is expected to be 3.7% of fine 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.
- Filterable PM for Unit 5 is subdivided by size category consistent with the default approach from the AP-42 Document, Table 1.3-4. For uncontrolled oil-fired utility boilers, 71% of the filterable PM emissions are filterable PM_{10} and 52% of the filterable PM emissions are fine filterable PM_{10} emissions (less than 2.5 microns in size). For oil-fired utility boilers, elemental carbon is expected to be 7.4% of fine PM_{10}, based on the best estimate for electric utility petroleum 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 PM_{10} consists of inorganic and organic compounds. The inorganic portion is assumed to consist of H_2SO_4; the organic portion is modeled as secondary organic aerosols.
- For Unit 4, H_2SO_4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Coal Fired Power Plants", Keith Harrison, Larry Monroe and J. Edward Cichanowicz (Southern Company Services and Southern Research Institute, Revision 3, October 2005). This procedure is consistent with the method used by Conectiv for the data provided to DNREC as part of the Company's Toxic Release Inventory (TRI) reports. Before control, H_2SO_4 is determined by the relationship 0.008 x %S/100 x 10^6/HHV x HIR x 98.06/32.07. H_2SO_4 control is 49% for an air pre-heater and 49% for a cold-side ESP.

- For Unit 5 (oil-fired), H_2SO_4 emissions are based on the AP-42 Document, Table 1.3-2, where total condensable PM_{10} is 1.5 lb/Mgal. The inorganic portion of PM_{10} is 85% of the total condensable PM_{10}, while the organic portion is 15% of the total condensable PM_{10}.

In practice, CALPUFF allows for the user to input certain components of PM_{10} as separate species and separate sizes, which will result in more accurate wet and dry deposition velocity results and also more accurate effects on light scattering from the different PM_{10} species. As noted above, the particle size distribution information is provided in the AP-42 Document, Tables 1.1-6 and Table 1.3-4, and has been used for the BART modeling analysis.

A summary of the modeling stack parameters used in the BART CALPUFF modeling is presented in Table 2-1. A summary of the modeling emission parameters, as determined by the source emission factors mentioned above, is presented in Table 2-2.

Table 2-1 Modeling Exhaust Stack Parameters

	Units	Unit 4	Unit 5
UTM-X, Zone 18, NAD83	Meters	456891.942	4398832.728
UTM-Y, Zone 18, NAD83	Meters	456891.693	4398788.334
Stack Height	Meters	67.06	83.82
Base Elevation	Meters	3.96	3.96
Stack Diameter	Meters	4.11	6.40
Gas Exit Velocity	m/s	25.91	22.86
Stack Gas Exit Temperature	Deg K	407.59	413.15

Table 2-2 Baseline Emission Rates

Estimated Maximum PM10 Emissions and Speciated PM10 Emissions
Conectiv Edge Moor BART Eligible Units

Facility	Unit	Description	Nominal Maximum Heat Input	Higher Heating Value	Higher Heating Value	Ash Content	Fuel Sulfur Content	Maximum Filterable PM Emissions			Filterable PM10					Condensible PM10			Total PM10
											total	coarse	Fine						
													fine total	fine soil	EC	total	SO4	organic	
			MMBtu/hr (a)	Btu/gal (b)	Btu/lb (b)	% wt. (c)	% wt. (c)	lb/MMBtu	lb/hr	Basis	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Edge Moor Power Plant	4	Unit 4, Coal, Nominal 175 MW, PC Tangential ,Dry Bottom, ESP	1,793	N.A.	12,567	9.12	0.75	0.0290 (d)	52.05	AP-42	35.13 (e)	19.52	15.61 (e)	15.04	0.58 (f)	22.42	6.28 (g)	16.14 (h)	57.55
Edge Moor Power Plant	5	Unit 5, #6 Oil, Nominal 445 MW, Multiple Cyclone	4,551	152,655	N.A.	0	0.62	0.0579 (i)	263.38	AP-42	187.22 (j)	50.77	136.45 (j)	126.35	10.10 (k)	44.72 (l)	38.01 (l)	6.71 (l)	231.94

(a) Nominal maximum heat input is based on information received from Conectiv on April 5, 2007.
(b) Higher heating values are based on the average values for calendar years 2001 through 2006.
(c) Ash and sulfur contents are based on the values cited in the latest complete emission statement submitted to DNREC in 2004.
(d) Total filterable PM is determined from the relationship "0.08A lb/ton" (where A is the ash content in % wt.) based on AP-42, Table 1.1-4.
(e) Total filterable PM10 is 67% of filterable PM and fine filterable PM10 is 29% of filterable PM based on AP-42, Table 1.1-6.
(f) Elemental carbon is 3.7% of fine PM based on the best estimate for electric utility coal combustion in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", William Battye and Kathy Boyer, EPA Contract No. 68-D-98-046, January 2002.
(g) H2SO4 emissions are based on "Estimating Total Sulfuric Acid Emissions from Coal Fired Power Plants," Keith Harrison, Larry Monroe and J. Edward Cichanowicz, Southern Company Services and Southern Research Institute, Revision 3, October 2005. Before control, H2SO4 is determined from the relationship "0.008(%S/100)(10^6/HHV)(HIR)(98.06/32.07)" (where S is the sulfur content in % wt., HHV, the higher heating value in Btu/lb, and HIR, the heat input rate in MMBtu/hr). H2SO4 control is 49% for an air preheater and 49% for a cold- side ESP.
(h) Condensable organic PM10 is determined from the relationship, "0.20(0.1S-0.03 lb/MMBtu)" (where S is the sulfur content in % wt.) based on AP-42, Table 1.1-5.
(i) Total filterable PM is determined from the relationship "0.83(1.12S+0.37) lb/Mgal" (where S is the sulfur content in % wt.) based on AP-42, Table 1.3-4.
(j) Total filterable PM10 and fine filterable PM10 is 71% of filterable PM fine PM10 is 52% of filterable PM based on AP-42, Table 1.3-4.
(k) Elemental carbon is 7.4% of fine PM based on the best estimate for electric utility petroleum 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.
(l) Total condensable PM10 is 1.5 lb/Mgal based on AP-42, Table 1.3-2. Inorganic and inorganic fractions are 85% and 15% of total condensable PM10, respectively.

3.0 Input Data to the CALPUFF Model

3.1 General Modeling Procedures

Although MANE-VU has processed a single year of data for use in BART assessments, a better (3-year) database is available for Delaware (including the Edge Moor Power Station), which lies within the VISTAS modeling domain. VISTAS has developed five sub-regional 4-km CALMET meteorological databases for three years (2001-2003). The sub-regional modeling domains are strategically designed to cover all potential BART-eligible sources within VISTAS states and all PSD Class I areas within 300 km of those sources. The extents of the 4-km sub-regional domains are shown in Figure 4-4 of the VISTAS common BART modeling protocol. The BART modeling for Edge Moor has been done using the easternmost 4-km subdomain that encompasses all of Delaware, as shown in Figure 4-4 of the VISTAS BART protocol (subdomain #5).

USGS 90-meter Digital Elevation Model (DEM) files were used by VISTAS to generate the terrain data at 4-km resolution for input to the 4-km sub-regional CALMET run. Likewise, USGS 90-meter Composite Theme Grid (CTG) files were used by VISTAS to generate the land use data at 4-km resolution for input to the 4-km sub-regional CALMET run.

Three years of MM5 data (2001-2003) were used by VISTAS to generate the 4-km sub-regional meteorological datasets. See Sections 4.3.2 and 4.4.2 in the VISTAS common BART modeling protocol for more detail on these issues.

All of the modeling for the Edge Moor Power Plant used the 4-km subdomain #5. A smaller computational grid within the VISTAS subdomain #5 was designed to minimize computation time and output file size. The Edge Moor computational grid domain covers distances of 452 km W-E and 352 km N-S and is shown in Figure 3-1. This domain includes two Class I areas with a 50-km buffer, plus a nearly 100-km buffer around the source (up to the limit of the VISTAS sub-domain northern boundary).

3.2 Air Quality Database (Background Ozone and Ammonia)

Hourly measurements of ozone from all non-urban monitors, as generated by VISTAS and available on the VISTAS CALPUFF page on the TRC web site (http://www.src.com/calpuff/download/sample_files.htm), have been used as input to CALPUFF. Currently, VISTAS advises sources to use a background ammonia concentration of 0.5 ppb, which has been used for this analysis. However, since there are no NO_x emissions being considered in this application, the results are not sensitive to the ammonia concentration used.

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

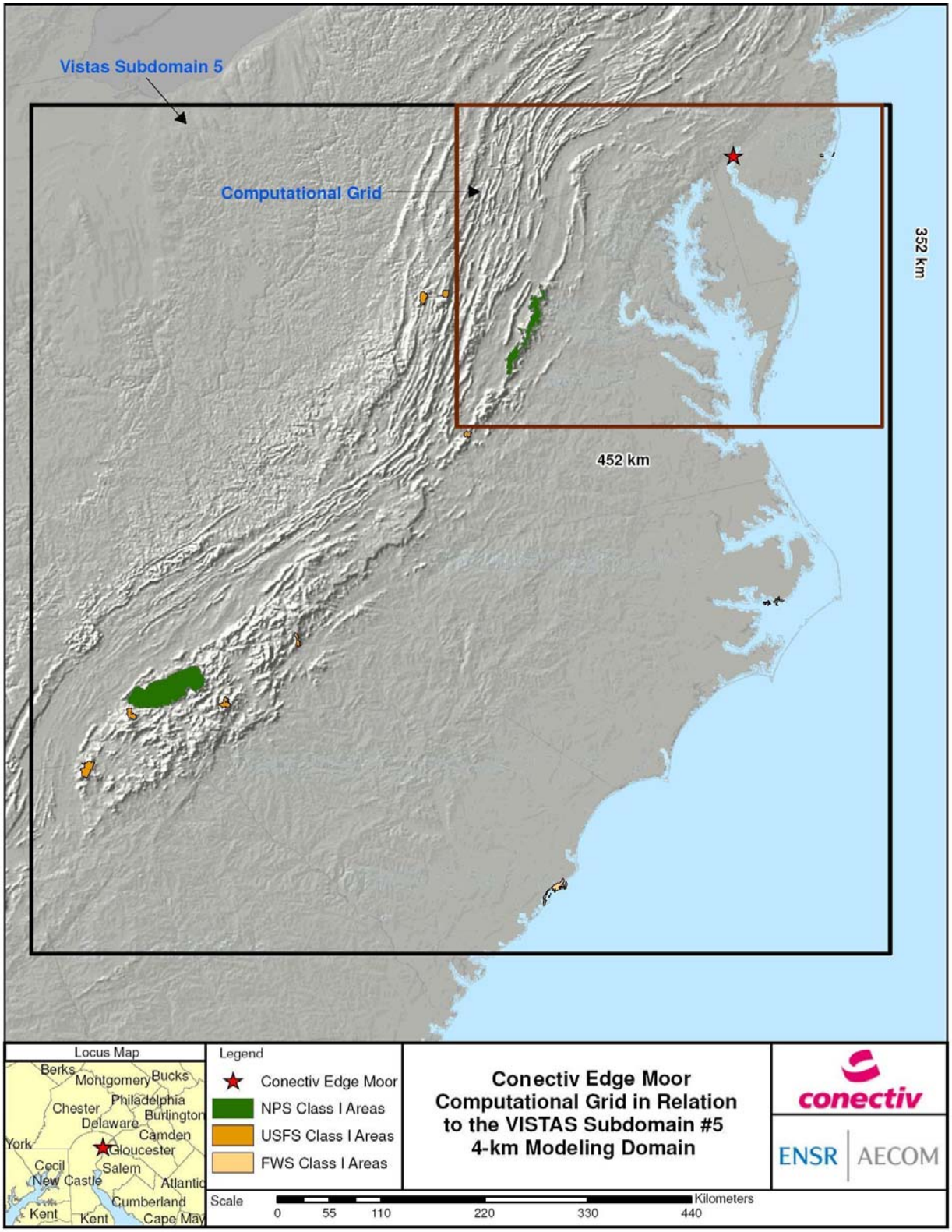
There are two Class I areas (Brigantine Wilderness Area and Shenandoah National Park) that were modeled for Edge Moor. For these Class I areas, natural background conditions have been established in order to determine a change in natural conditions related to a source's emissions. For the modeling described in this document, ENSR used the natural background light extinction of 7.44 deciviews for Brigantine W and 7.41 deciviews for Shenandoah NP, modified as noted below with site-specific considerations, and corresponding to the annual average (EPA 2003, Appendix B), consistent with the July 19, 2006 EPA guidance to Region 4 on this issue ("Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations", Joseph W. Paise/ EPA OAQPS to Kay Prince/Branch Chief).

The input to CALPOST is computed by converting the deciviews to extinction using the equation:

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

For example, for Brigantine, 7.44 deciviews is equivalent to an extinction of 11.04 inverse megameters (Mm^{-1}). This extinction does not include the default 10 Mm^{-1} for Rayleigh scattering. The remaining extinction of 11.04 Mm^{-1} is due to naturally occurring particles, and should be held constant for the entire year's simulation. Therefore, the data provided to CALPOST for Brigantine is the total natural background extinction minus 10 (expressed in Mm^{-1}), or 11.04 Mm^{-1}. This is most easily input as a fine soil concentration of 11.04 $\mu g/m^3$ in CALPOST, since the extinction efficiency of soil (PM-fine) is 1.0 and there is no f(RH) component. The concentration entries for all other particle constituents were set to zero, and the fine soil concentrations were kept the same for each month of the year. The monthly values for f(RH) that CALPOST used were taken from "Guidance for Tracking Progress Under the Regional Haze Rule" (EPA, 2003) Appendix A, Table A-3.

Figure 3-1 Edge Moor CALPUFF Computational Grid in Relation to the VISTAS Subdomain #5



4.0 Air Quality Modeling Procedures

This section provides a summary of the modeling procedures outlined in the VISTAS protocol that have been used for the refined CALPUFF analysis conducted for the Edge Moor Power Plant.

4.1 Model Selection and Features

As noted in the VISTAS protocol, VISTAS used the BART-specific versions of CALMET and CALPUFF that have been posted at http://www.src.com/calpuff/download/download.htm#VISTAS_VERSION. These versions contain enhancements funded by the Minerals Management Service (MMS) and VISTAS. They are maintained on TRC's Atmospheric Studies Group CALPUFF website for public access.

The major features of the CALPUFF modeling system, including those of CALMET and the post processors (CALPOST and POSTUTIL) are referenced in Section 3 of the VISTAS protocol.

4.2 Modeling Domain and Receptors

The BART modeling runs for the baseline emissions used the subdomain 4-km CALMET data run in observation mode with surface stations, upper air stations, and precipitation data stations, which were supplied by VISTAS, as discussed above. This domain includes all Class I areas within 300 km of the source, plus a 50-km buffer around each source. The receptors used for each of the Class I areas are based on the National Park Service database of Class I receptors, as recommended by VISTAS.

4.3 Technical Options Used in the Modeling

CALMET modeling for the VISTAS-provided 4-km subdomains had already been conducted by the VISTAS contractor, and this modeling was reviewed and approved by the Federal Land Managers.

For CALPUFF model options, the Edge Moor Power Plant followed the VISTAS common BART modeling protocol, which states that we should use IWAQM (EPA, 1998) guidance. The VISTAS protocol also notes that building downwash effects are not required to be included, and we followed this guidance for this application as well. The Edge Moor Power Plant is several tens of kilometers from the nearest Class I area, and therefore building downwash effects can be expected to have little effect on the results of the CALPUFF modeling.

4.4 Light Extinction and Haze Impact Calculations

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

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

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

Dr. Ivar Tombach, consultant to VISTAS, has provided a spreadsheet calculation system (see Appendix B) that incorporates the revised IMPROVE equation for determining light extinction from particulate concentration estimates. The VISTAS BART modeling protocol indicates that the unrevised IMPROVE algorithm does not incorporate the effects of naturally occurring sea salt on background visibility. The Brigantine Wilderness is significantly affected by this omission because it is off the coastline of New Jersey and surrounded by salt water. Therefore, we incorporated this effect into the present CALPUFF framework by using the guidance provided by Dr. Tombach, as presented in Appendix B. Table 4-1 lists sea salt concentrations and Rayleigh coefficients that were used in Dr. Tombach's new IMPROVE equation.

Table 4-1 Sea Salt Concentrations and Rayleigh Scattering Coefficients

	Brigantine W	**Shenandoah NP**
Sea Salt Concentration (µg/m3)	0.22	0.02
Raleigh Scattering Coefficient (Mm-1)	12	10

The assessment of visibility impacts at the Class I areas used CALPOST Method 6. Each hour's source-caused extinction was calculated by first using the hygroscopic components of the source-caused concentrations, due to ammonium sulfate and nitrate (not relevant for EGUs in CAIR states except for H_2SO_4 emissions), and monthly Class I area-specific f(RH) values. The contribution to the total source-caused extinction from ammonium sulfate and nitrate was then added to the other, non-hygroscopic components of the particulate concentration (from coarse and fine soil, secondary organic aerosols, and elemental carbon) to yield the total hourly source-caused extinction.

The EPA BART rule's recommended significance threshold for contribution to visibility impairment is 0.5 delta deciviews. As noted above, ENSR compared the PM_{10} visibility impacts to both the EPA-recommended 0.5 delta deciview threshold and the very conservative threshold of 0.1 delta deciviews for MANE-VU (98th percentile impacts), especially for the non-sulfate portion of the PM_{10} emissions. As an added check and in accordance with the EPA BART rule, the 22nd highest prediction over the three years modeled has been compared to these thresholds.

5.0 Modeling Results for Baseline PM_{10} Emissions

The BART modeling results for Units 4 and 5 at Edge Moor are provided in Table 5-1. The table lists regional haze impacts with sulfates and without sulfates modeled (sulfates result from conversion of SO_2, a pollutant for which BART is already satisfied due to regulation under CAIR). The table indicates that the 8th highest day's impacts for each year and each Class I area, even including measured sulfates, are well below 0.5 delta-dv. However, in comparing the visibility results with the very conservative MANE-VU contribution threshold of 0.1 delta-dv, Table 5-1 indicates that with sulfates included, impacts at Shenandoah National Park are below 0.1 delta-dv, but impacts at Brigantine Wilderness are slightly above that threshold, with the maximum 8th highest impact being 0.13 delta-dv.

However, in light of the fact that Delaware is a CAIR state, it is also important to list the non-sulfate portion of the visibility impact from the Edge Moor Power Plant, since regional CAIR controls on SO_2 will also effectively control regional emissions of sulfates (H_2SO_4). As discussed earlier, sulfates are a large contributor to visibility impacts. Table 5-1 indicates that the highest 98th percentile (8th highest) impact for the non-sulfate particulate emissions from Edge Moor Units 4 and 5 at Brigantine W is only 0.06 delta-dv. Therefore, when SO_2 controls are taken into account (see discussion in Section 6), it is very likely that Edge Moor's PM_{10} emissions will be below the MANE-VU 0.1 threshold. An engineering review of anticipated emission reductions and their effects on visibility impacts is provided in Section 6.

Based upon the modeling results, Conectiv notes that:

1) SO_2 and NO_x controls are required by, and will result from, CAIR. Future reductions in SO_2 emissions to comply with CAIR will likewise reduce the formation of sulfates (H_2SO_4) that result from inorganic condensable PM_{10} emissions.

2) Total PM_{10} impacts (even including sulfates) are well below the EPA-specified 0.5 delta-deciview regional haze contribution threshold, with the 98th percentile impact equal to only 0.13 delta-dv.

3) At least half of these impacts are due to sulfuric acid mist emissions, which the regional implementation of CAIR will effectively address.

4) After taking CAIR into account, the remaining visibility impact (from filterable and organic condensable PM_{10}) is well below MANE-VU's very conservative 0.10 delta-deciview threshold, a threshold that MANE-VU considers to be so low that a BART determination analysis is not required when that threshold is not exceeded by the modeled visibility impact.

Table 5-1 Summary of Results – Edge Moor BART Modeling

Class I Area	2001				2002				2003			
	Days > than		MAX dv Δ B_{ext}	8th Highest dv Δ B_{ext}	Days > than		MAX dv Δ B_{ext}	8th Highest dv Δ B_{ext}	Days > than		MAX dv Δ B_{ext}	8th Highest dv Δ B_{ext}
	0.1 dv Δ B_{ext}	0.5 dv Δ B_{ext}			0.1 dv Δ B_{ext}	0.5 dv Δ B_{ext}			0.1 dv Δ B_{ext}	0.5 dv Δ B_{ext}		
MVISBK=6, Annual Average Background, 4-km CALMET, New IMPROVE, Sulfates Included												
Brigantine Wilderness	17	0	0.22	0.13	8	0	0.17	0.11	9	0	0.14	0.11
Shenandoah National Park	0	0	0.05	0.02	0	0	0.05	0.04	1	0	0.11	0.05
MVISBK=6, Annual Average Background, 4-km CALMET, New IMPROVE, Without Sulfates												
Brigantine Wilderness	0	0	0.10	0.06	0	0	0.08	0.05	0	0	0.07	0.05
Shenandoah National Park	0	0	0.03	0.01	0	0	0.02	0.01	0	0	0.05	0.02

6.0 Evaluation of Air Pollution Control Technologies

EPA has determined that implementation of CAIR by EGU sources satisfies applicable BART requirements for SO_2 and NO_x emissions from those sources. The DNREC has indicated that the federal CAIR program is employed in Delaware as part of a Federal Implementation Plan (FIP) and, as such, CAIR satisfies BART for SO_2 and NO_x for EGU sources in the State of Delaware. Furthermore, the DNREC has promulgated Regulation 1146, the Electric Generating Unit Multi-Pollutant Regulation, effective December 11, 2006. This regulation establishes SO_2 and NO_x emission limits for coal and residual oil-fired EGUs with a nameplate capacity rating of 25 MW or greater. According to this regulation, NO_x emissions from coal and residual oil fired EGUs must not exceed 0.15 lb/MMBtu from May 1, 2009 through December 31, 2011, and 0.125 lb/MMBtu on or after January 1, 2012, on a 24-hour rolling average basis. For coal-fired EGUs, SO_2 emissions must not exceed 0.37 lb/MMBtu from May 1, 2009 through December 31, 2011, and 0.26 lb/MMBtu on or after January 1, 2012, also on a 24-hour rolling average basis. For residual oil-fired units, EGUs must not receive residual oil with a sulfur content in excess of 0.5% by weight on or after January 1, 2009.

Edge Moor Unit 4 is a nominal 175 MW dry-bottom, pulverized coal (primary fuel), tangentially-fired boiler equipped with low-NO_x coal burners (LNB) and overfire air (OFA) for the control of NO_x emissions and an electrostatic precipitator (ESP) for the control of filterable particulate emissions. Unit 4 is currently permitted to burn coal with a sulfur content of 1.0% wt. To comply with DNREC's Multi-Pollutant Regulation, Unit 4 is anticipated to be retrofitted with a dry-sorbent injection system using a sodium-based sorbent to further reduce SO_2 emissions. For NO_x control, Unit 4 will be undertake the addition/enhancement/optimization of low-NO_x burner (LNB), overfire air (OFA), and will implement a new selective non-catalytic reduction system (SNCR).

Edge Moor Unit 5 is a nominal 445 MW residual oil-fired (primary fuel) boiler with oil LNB and OFA for the control of NO_x emissions and a multiclone for the control of filterable particulates. Unit 5 is also currently permitted to burn oil with a sulfur content of 1.0% wt. To comply with DNREC's Multi-Pollutant Regulation, Unit 5 is anticipated to receive residual oil for use at the facility with a maximum sulfur content of no more than 0.5% by weight to reduce SO_2 emissions. NO_x additions/enhancements/optimizations anticipated to be employed will also include the addition of a new SNCR system to further control NO_x emissions.

Edge Moor Unit 3 (a coal-fired unit) is not a BART-eligible unit because it was placed into service before August 7, 1962. However, the Delaware Multi-Pollutant Regulation (and CAIR) will result in emission reductions at this unit as well. Since the baseline period (2000-2004), Conectiv has installed enhanced LNBs and supplemental OFA on this unit. Conectiv also plans on improving the urea injection components associated with the SNCR NOx control system as part of the Multi-Pollutant Regulation. These controls will extend the CAIR-related emission reductions at Edge Moor to the only non-BART unit at the plant.

The remainder of this section discusses the BART determination factors related to PM_{10} controls and evaluates the effectiveness of existing and proposed air pollution control technologies in reducing not only direct PM_{10} emissions, but also precursors to PM_{10} emissions, from Edge Moor Units 4 and 5.

Electrostatic Precipitator

Unit 4 is equipped with an American Air Filter, cold side ESP to control filterable particulate matter discharged from the boiler. The ESP uses electrical forces to move particles entrained within the exhaust stream onto collector plates. The entrained particles are given an electrical charge when they pass through the corona, a region where gaseous ions flow. Electrodes in the center of the gas stream are maintained at high voltage and generate the electrical field that forces the particles to the collector plates. The collector plates are periodically knocked or "rapped" by various mechanical means to dislodge the particulate, which slides downward into a

hopper where they are collected. The collection hopper is evacuated periodically, as it becomes full. The particulate is removed through a rotary valve into an ash-handling system, such as a pneumatic conveyor, and is then disposed of.

The voltage applied to the electrodes causes the gas between the electrodes to break down electrically, an action known as a "corona." The electrodes are usually given a negative polarity because a negative corona supports a higher voltage than does a positive corona before sparking occurs. The ions generated in the corona follow electric field lines from the wires to the collecting plates. Therefore, each wire establishes a charging zone through which the particles must pass. As larger particles absorb many times more ions than small particles, the electrical forces are much stronger on larger particles.

Certain design features and particle characteristics affect the control efficiency of an ESP. The rapping that dislodges the accumulated layer also releases some of the particles back into the gas stream. These re-entrained particles are then collected again in later sections, but the particles re-entrained in the last section are not collected and escape the unit. Further, part of the gas may flow around the charging zones through the clearances required for non-electrified internal components at the top of the ESP. This is called "sneakage" and places an upper limit on the collection efficiency. On Unit 4, the ESP has been designed to maintain the gas flow through at a relatively low velocity to minimize particle re-entrainment and to prevent gas flow around the charging zone to minimize sneakage.

Another major factor in the ESP's performance is the resistivity of the particles discharged from the boiler. Because the particles form a continuous layer on the ESP plates, all of the ion current must pass through the layer to reach the ground plates, creating an electric field in the layer. At high resistivities, this current can become strong enough to cause local electrical breakdown known as "back corona." At low resistivities, the particles are held on the plates so loosely that particle re-entrainment becomes much more severe. On Unit 4, ESP performance has been optimized for the relatively constant particle properties associated with the coal commonly fired in the boiler. It should also be noted that sodium based sorbent injection technology, anticipated for use by Conectiv for compliance with Delaware's Multi-pollutant Regulation is commonly used by ESP operators to reduce fly ash resistivity to improve the capture efficiency of particulate matter in such control devices,

ESPs are the most widely applied particulate control device to coal-fired utility boilers in the country. Based on performance tests conducted in December 1989, the Unit 4 ESP was demonstrated to limit filterable particulate emissions to 0.015 to 0.018 lb/MMBtu. These performance levels are much better than the MACT standard of 0.07 lb/MMBtu. As stated in the preamble to the BART Guidelines, "...unless there are new technologies subsequent to the MACT standards which would lead to cost effective increases in the level of control, States may rely on the MACT standards for purposes of BART". Because no new technologies have become available since issuance of the MACT standard, the existing ESPs may be considered representative of BART. Furthermore, the performance levels are comparable to those specified for ESPs and baghouses being applied to new coal-fired utility boilers around the country. Consequently, the existing ESP is considered BART for PM_{10} emissions from Unit 4.

Multiple Cyclone Separator

Unit 5 is equipped with a multiple cyclone separator to control filterable particulate matter discharged from the boiler. Multiple cyclone separators, also known as "multiclones", consist of a number of small-diameter cyclones, operating in parallel and having a common gas inlet and outlet. Multiclones operate on the same principle as cyclones, creating a main downward vortex and an ascending inner vortex. Multiclones are more efficient than single cyclones because they are longer and smaller in diameter. The longer length provides longer residence time, while the smaller diameter creates greater centrifugal force. These two factors result in better separation of dust particles. The pressure drop of multiclone collectors is higher than that of single-cyclone separators.

Cyclone collectors are centrifugal collectors that rely on the particle density and velocity to separate the fly ash from the flue gas. The particulate-laden flue gas enters the top or the side of the cyclone. Vanes impart a rotational velocity to the flue gas, driving the fly ash to the edge of the cylinder. The flue gas then exits the center of the cyclone out the top, leaving the fly ash to fall out the bottom. At pressures near one atmosphere and 2 to 5 inches water gauge pressure differential, multiclones have been demonstrated to be capable of achieving a 40% to 60% reduction in filterable particulate emissions.

Multiclones are a common particulate control device applied to residual oil-fired utility boilers. Based on performance tests conducted in December 1989, the Unit 5 multiclone was demonstrated to limit filterable particulate emissions to 0.020 to 0.024 lb/MMBtu. These performance levels are comparable to those specified for particulate control devices applied to new oil-fired boilers. Consequently, the existing multiclone is considered BART for PM_{10} emissions from Unit 5.

Dry Sorbent Injection and Fuel Oil Sulfur Content

To comply with the Multi-Pollutant Regulation, it is anticipated that dry sorbent injection (DSI) will be installed to control SO_2 emissions from Unit 4. DSI requires less capital equipment, less physical space, and less modification to existing ductwork than do spray dryer absorbers or wet scrubbers. However, reagent costs are much higher and, depending on the absorbent and amount of sorbent injected, control efficiency is lower than for a spray dryer absorber. Lime, soda ash, and sodium based sorbents (such as Trona, or sodium sesquicarbonate) are possible reagents. Lime and soda ash are the least reactive reagents, resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected.

The sorbent particles need to be ground extremely fine (milled) to maximize the surface area of the particles. The finer the particles, the faster and more complete the reaction for a given injection rate. The neutralization reaction between the SO_2 (mild acid) and the sorbent (strong base) takes place on the surface area of the sorbent particles. After finely ground sorbent is pulverized, it is blown into the hot flue gas stream using a high pressure blower. The sorbent reacts with the acid gases in the flue gas stream, and the reacted particles are removed with the ash in the particulate control device.

The chemical reaction of the acid components of the flue gas with the alkaline reagent takes place in the ductwork ahead of the particulate collection device and continues in the device itself. The main chemical reaction is as follows:

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

Plant operating conditions will ultimately affect the performance of the sodium sesquicarbonate in acid gas removal. The most important variables for high removal efficiency are injection temperature, SO_2 concentration, retention time, and fine particle size (~10 microns).

As designed, DSI will be capable of limiting SO_2 emissions from Unit 4 to the standards established in the Multi-Pollutant Regulation, that is, 0.37 lb/MMBtu by May 1, 2009 and 0.26 lb/MMBtu by January 1, 2012. In addition, DSI will remove an equivalent percentage of the SO_3 and sulfates in the gas stream, thus reducing the inorganic condensable PM_{10} from Unit 4 by a factor of about 4 (over peak, actual baseline emissions of greater than 1.0 lb/MMBtu of SO_2) by 2012. Similar reductions in visibility-affecting emissions from Unit 3, which is not a BART-eligible source, will also occur due to DSI injection for that unit.

The reduction in the fuel oil sulfur content for Unit 5 emissions will result in a reduction of directly-emitted sulfates of at least 30% relative to baseline conditions. Together, the reductions of primary sulfate emissions due to the SO_2 emission reduction measures taken for Units 4 and 5 would be expected to result in a revised 98th percentile visibility prediction of 0.1 delta-dv or lower for BART-eligible Units 4 and 5.

Selective Non-Catalytic Reduction

To comply with the Multi-Pollutant Regulation, it is presently anticipated that new selective non-catalytic reduction (SNCR) control systems will be installed to further control NO_x emissions from both Units 4 and 5. SNCR has been applied to a number of different types of combustion sources, including utility and industrial boilers fired with natural gas, oil, and coal. The SNCR process is based on a gas-phase homogeneous reaction, within a specified temperature range, between NO_x in the flue gas and injected ammonia to produce gaseous nitrogen and water vapor. The SNCR process converts NO_X to nitrogen and water by the following general reactions:

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

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

In an SNCR system, NO_x reduction does not take place in the presence of a catalyst, but rather is driven by the thermal decomposition of ammonia or urea and the subsequent reduction of NO_x. Consequently, the SNCR process operates at higher temperatures than the SCR process. Critical to the successful reduction of NO_x with SNCR is the temperature of the flue gas at the point where the reagent is injected. For the ammonia injection process, the necessary temperature range is 1,700 to 1,900 °F. The factors affecting SNCR performance are gas mixing, residence time at temperature, and ammonia slip.

Theoretically, one mole of ammonia will react with one mole of NO_x, forming elemental nitrogen and water. In reality, not all the injected reagent will react, due to imperfect mixing, uneven temperature distribution, and insufficient residence time. These physical limitations may be compensated for by injecting excess ammonia and essentially achieving low NO_x emissions at the expense of ammonia slip. Thus, for a given boiler configuration, there is a limit on the degree of NO_x reduction that can be achieved with SNCR while maintaining acceptable levels of ammonia slip.

In combination with enhanced staged combustion techniques, the SNCR will be capable of limiting NO_x emissions from Units 4 and 5 to the standards established in the Multi-Pollutant Regulation, that is, 0.15 lb/MMBtu by May 1, 2009 and 0.125 lb/MMBtu by January 1, 2012. By minimizing ammonia slip, the SNCR will not result in an appreciable change in PM_{10} emissions. This is in contrast with selective catalytic reduction (SCR), which would remove more NO_x emissions but would increase the primary emissions of H_2SO_4 by causing increased oxidation of the SO_2 emissions. During warm-weather months when NO_x emissions create very low amounts of particulate (ammonium nitrate) due to the chemistry equilibrium between ammonium nitrate and gaseous nitric acid, the operation of SCR equipment can actually lead to no visibility improvement or, in certain cases, even increased visibility impairment due to the increased H_2SO_4 emissions that result.

Staged Combustion

A number of techniques have been employed to reduce the formation of NO_x by reducing peak flame temperature and/or starving the hottest parts of the flame for oxygen. By staging the combustion process, a longer, cooler flame results, which forms less NO_x. Staged combustion techniques include low-NO_x burners (LNB), flue gas recirculation, over-fire air (OFA), and burners out of service. To further reduce NO_x emissions, Unit 4 will be retrofitted as needed with enhanced LNB and supplemental OFA. Similarly, Unit 5 will be retrofitted/enhanced with these technologies (as well as potentially flue gas recirculation) as necessary, to further reduce NOx emissions.

Conclusions on Engineering Analysis

EPA established procedures for determining BART in its Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations updated on July 24, 2005. The BART Guidelines recommend the following five steps for a case-by-case BART determination:

- Step 1– Identify all available control technologies for the unit including improvements to existing control equipment or installation of new add-on control equipment.
- 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.
- 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.
- 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.
- Step 5- Determine the visibility impairment associated with baseline emissions and the visibility improvements provided by the control technologies considered in the engineering analysis.

To minimize filterable PM_{10} emissions from Edge Moor Power Plant, Units 4 and 5 are equipped with an ESP and multiclone, respectively. These particulate collection devices have been shown to achieve performance levels comparable to those being specified as BACT for new coal- and oil-fired boilers. The existing control devices, therefore, are considered representative of BART for filterable PM_{10}. In selecting the SO_2 control technologies designed to comply with CAIR and the Multi-Pollutant Regulations, Conectiv essentially completed the first four steps in the case-by-case BART determination established by the EPA. The selected SO_2 control systems are also effective in reducing primary sulfate emissions, a constituent of condensable PM_{10}.

The fifth step in the case-by-case BART determination is satisfied in the visibility analysis documented in this report and estimates of the reductions of sulfate-caused impacts discussed in this section. The results of the visibility analysis demonstrate that visibility impacts due to primary PM_{10} emissions from Edge Moor Units 4 and 5 are clearly imperceptible, being well below the BART perceptibility threshold value of 0.5 delta-dv for all Class I areas. Furthermore, the baseline visibility impacts are below the MANE-VU threshold of 0.1 delta-dv at Shenandoah National Park. The baseline visibility impacts for Brigantine Wilderness Area are just above the MANE-VU threshold of 0.1 delta-dv when sulfates are included in the analysis. The analysis determined that more than half of the PM_{10}-caused visibility impacts can be attributed to inorganic condensable PM emissions, which result from the conversion of a small fraction of SO_2 in the gas stream into SO_3 and H_2SO_4 Consequently, it is anticipated that the implementation of CAIR and the Delaware Multi-Pollutant Regulation will not only result in a significant reduction in SO_2 emissions from Units 4 and 5 (in addition to other non-Delaware and Delaware EGU sources), but also the emissions of sulfates and other inorganic condensable PM emissions. This implementation of the additional SO_2 control systems, therefore, will result in further improvements in the visibility impacts associated with Edge Moor Units 4 and 5, such that the total PM_{10} visibility impacts are at or below the MANE-VU insignificance threshold of 0.1 delta-dv.

7.0 Conclusions

Edge Moor has been identified by DNREC as a source that is eligible for consideration of BART controls for PM_{10} (CAIR serves as BART for SO_2 and NO_x). A BART modeling and engineering analysis has been completed in accordance with an approved BART modeling protocol, and in conjunction with a conference call with the DNREC in which the proposed procedures were discussed and approved for use.

The results of the modeling study using peak daily baseline PM_{10} emissions demonstrate that visibility impacts due to primary PM_{10} emissions from Edge Moor Units 4 and 5 are clearly imperceptible, being well below the EPA-prescribed BART threshold value of 0.5 delta-dv (8th highest or 98th percentile day in each of the three modeled years 2001, 2002 and 2003), for both Class I areas. In addition, the visibility impacts are below the MANE-VU threshold of 0.1 delta-dv (8th highest or 98th percentile day in each of the three modeled years 2001, 2002 and 2003) at Shenandoah National Park. The visibility impacts for Brigantine Wilderness are just above the MANE-VU threshold of 0.1 delta-dv (a maximum value of 0.13 delta-dv, 8th highest or 98th percentile day in each of the three modeled years 2001, 2002 and 2003) when sulfates are included in the modeling. Conectiv anticipates that the implementation of CAIR and the Delaware Multi-Pollutant Regulation will also significantly reduce emissions of sulfates / inorganic condensable PM emissions since these emissions are directly proportional to SO_2 emissions. The modeling shows that the visibility impacts from non-sulfate PM_{10} are below 0.1 delta-dv for both Class I areas (a maximum value of 0.06 delta-dv, 8th highest or 98th percentile day in each of the three modeled years 2001, 2002 and 2003), and that additional BART analyses for primary particulate would likely yield no meaningful visibility improvements.

The DNREC has indicated that an engineering review of anticipated emission reductions from the BART-eligible sources should be provided even if the baseline modeling results show very low visibility impacts. The discussion provided in Section 6 of this report reviews the existing PM_{10} emissions control equipment and concludes that this equipment is BART. The engineering analysis also indicates that anticipated reductions of SO_2 emissions from Units 4 and 5 due to the implementation of CAIR and Multi-Pollutant Regulations are expected to result in significant reductions of primary sulfate emissions, which will likely reduce the PM_{10} visibility impacts from these units to levels of 0.1 delta-dv or lower. The emission reductions from non-BART Unit 3 will also provide beneficial visibility improvements that are in addition to those from the Edge Moor BART-eligible units.

8.0 References

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Appendix A

Relevant Excerpts from EPA's "Additional Regional Haze Questions"

(available at http://www.tceq.state.tx.us/assets/public/implementation/air/sip/bart/EPA_QA-Haze.pdf)

Q. If the unit is already controlled (e.g., under MACT or BACT) and it is the best, the latest control technology, does the source still need to conduct a full blown BART analysis and control technology evaluation including the installed control device? Or, can the source just describe the control device on their BART-eligible source unit and make the case that it qualifies as BART, without having to evaluate other technologies?

A. If the unit has "best, latest…", then the source can just describe the control device on their BART-eligible source unit and make the case that it qualifies as BART, without having to evaluate other technologies. The streamlining of BART analyses in this situation is addressed in Section IV.C of the BART Guidelines, "How does a BART review relate to [MACT] Standards under CAA section 112, or to other emission limitations required under the CAA?

Q. How does the CAIR substitute for BART?

A. States subject to and participating in the CAIR cap and trade program for SO_2 and NO_x may treat the CAIR requirements for EGUs as a substitute for the application of BART controls for these pollutants. States do not need to require BART-eligible EGUs subject to the CAIR to install, maintain, and operate BART per 40 CFR 51.308(e)(4).

Q. If a CAIR facility is found to be exempt from BART for SO_2 and NO_x, and the State does exemption modeling on PM_{10} and concludes there is no impact on a Class I area, can the State totally exempt the utility from BART?

A. States subject to and participating in the CAIR cap and trade program for SO_2 and NO_x are allowed to treat the CAIR requirements for EGUs as a substitute for the application of BART controls per 40 CFR 51.308(e)(4). This does not mean EGUs are exempt for SO_2 and NO_x, only that CAIR satisfies the BART requirement for those pollutants. The remaining visibility pollutants to consider for determining BART-eligible sources are PM, and, using judgment, VOCs, and ammonia. For PM, the July 6, 2005, final BART rule at 70 FR 39160 notes PM_{10} may be used an indicator for PM in this step of the determination and thus, PM_{10} can be used for the exemption modeling.

Appendix B

Re-Calculating CALPOST Visibility Outputs with the New IMPROVE Algorithm

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Recalculating CALPOST Visibility Outputs with the New IMPROVE Algorithm

15 August 2006

Introduction

CALPOST processes outputs from CALPUFF modeling of a source's emissions to calculate the incremental visibility impairments caused by the modeled source. Those increments are presented in two tables, both labeled "Ranked Daily Visibility Change", in the CALPOST output (.LST) file. The table of interest to us has the subtitle "Modeled Extinction by Species" and lists the dates and locations of such incremental impacts in light extinction (b_{ext}) in ranked order, starting with the one that represents the largest percentage change in light extinction.[1]

Visibility effects are calculated in CALPOST from CALPUFF-modeled particulate matter component concentrations using effectively the "traditional" IMPROVE algorithm. CALPOST allows for choice of the humidity scattering enhancement function (f(RH)) to be used with the IMPROVE algorithm; for modeling in connection with the US EPA's Regional Haze Regulations (RHR), the appropriate form of f(RH) is the one described and tabulated in the EPA's 2003 guidance for tracking progress under the RHR.

Recently, the IMPROVE Steering Committee developed a new algorithm for estimating light extinction from particulate matter component concentrations. This algorithm (the "new IMPROVE algorithm") provides a better correspondence between the measured visibility and that calculated from particulate matter component concentrations. The new algorithm differs in several substantive ways from the traditional one:

- The extinction efficiencies of sulfates, nitrates, and organics have been changed and are now functions of their concentrations. The extinction efficiencies of

[1] The other table in the CALPOST output file, with the subtitle "% of Modeled Extinction by Species", provides equivalent results in terms of changes in the haze index, in deciviews. The two tables represent the same results, with identical ranking of events, while just using different (but mathematically related) metrics.

sulfate and nitrate are no longer identical, although the new hygroscopic scattering enhancement factors applied to them are the same.

- The concentration of particulate organic matter (POM; variously also labeled OCM or OMC, and sometimes just called "organics") is now taken to be 1.8 times that of the measured organic carbon (OC) concentration. (Confusingly, CALPOST labels the organics concentration as OC.)

- The contribution of fine sea salt to light extinction has been added, and is accompanied by its own hygroscopic scattering enhancement factor, $f_{ss}(RH)$.

- The light scattering by air itself (Rayleigh scattering) now varies with site elevation and mean temperature. It is to be rounded off to the nearest one Mm^{-1} when used with the new algorithm.

- The light absorption by NO_2 gas has been added.

The new IMPROVE algorithm is represented by the following formula:[2]

$$\begin{aligned} b_{ext} = \; & 2.2 \bullet f_S(RH) \bullet [\text{small sulfate}] + 4.8 \bullet f_L(RH) \bullet [\text{large sulfate}] \\ & + 2.4 \bullet f_S(RH) \bullet [\text{small nitrate}] + 5.1 \bullet f_L(RH) \bullet [\text{large nitrate}] \\ & + 2.8 \bullet [\text{small organics}] + 6.1 \bullet [\text{large organics}] \\ & + 10 \bullet [\text{elemental carbon}] \\ & + 1 \bullet [\text{fine soil}] \\ & + 1.7 \bullet f_{SS}(RH) \bullet [\text{sea salt}] \\ & + 0.6 \bullet [\text{coarse matter}] \\ & + \text{Rayleigh scattering (site specific)} \\ & + 0.33 \bullet [NO_2(\text{ppb})] \end{aligned} \qquad \text{(Eq. 1)}$$

The concentrations of "large" and "small" sulfate particles are calculated as follows:

$$[\text{large sulfate}] = \{[\text{total sulfate}]/20\} \bullet [\text{total sulfate}] \text{ if } [\text{total sulfate}] < 20\ \mu g^3$$

$$[\text{large sulfate}] = [\text{total sulfate}] \text{ if } [\text{total sulfate}] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. 2)}$$

$$[\text{small sulfate}] = [\text{total sulfate}] - [\text{large sulfate}].$$

Identical formulas, with changes in component names, are used for nitrate and organics. In effect, these formulas conclude that low concentrations of these components are mainly in the form of "small" particles with their own extinction efficiency and $f_S(RH)$, while high concentrations (approaching 20 $\mu g/m^3$) are mainly in the form of "large" particles with a different extinction efficiency and $f_L(RH)$. The scaling factor [total sulfate]/20 sets the fraction of total sulfate that is small.

[2] Square brackets denote concentrations.

The sea salt concentration is taken to be 1.7•[Cl^-] or, if chloride ion measurements are not available, the chlorine concentration can be used in its place. Site specific Rayleigh scattering values have been calculated for all IMPROVE sites.[3] Nitrogen dioxide concentrations are not measured at IMPROVE sites and the concentrations are sufficiently low that the NO_2 term is very small and can typically be ignored in rural areas.

In order for CALPOST to calculate CALPUFF-modeled source impacts on visibility using the new IMPROVE algorithm, CALPOST would have to be extensively reprogrammed. As an alternative, such a calculation could be done "off line" by adding another layer of post processing after CALPOST. To this end, I have developed a processor, in the form of an Excel workbook, that takes the CALPOST "Ranked Daily Visibility Change: Modeled Extinction by Species" output table based on default annual average natural conditions concentrations and creates an equivalent table of results based on the new algorithm.

The following describes the science behind the processor (which we'll call the CALPOST-IMPROVE Processor) and provides instructions for using it.

Concepts

In addition to the mechanical changes imposed by all the new terms in the new IMPROVE formula, applying the new algorithm also requires some conceptual changes. The biggest of these is that the extinction efficiencies of sulfates, nitrates, and organics now depend on the concentrations of those species. The practical implication of this is that extinction is no longer linearly additive. You cannot take a background level of extinction and add to it CALPOST's calculation of extinction caused by the particulate matter coming from a source, because when the two aerosols mix in the atmosphere their combined mass concentration results in increases in the extinction efficiencies of both the background and the source contribution. This means that combining background particulate matter with the particulate matter from a source gives an extinction result that is greater than the sum of the two separated extinctions.

With the nonlinear behavior resulting from applying the new IMPROVE algorithm, the extinction impact of the source (i.e., the increase in extinction resulting from introducing source emissions into the atmosphere) is the sum of three parts:

> (Part A) The source impact calculated by the new IMPROVE algorithm using the CALPOST outputs for a plume in isolation;
>
> (Part B) An increase in that source impact because the extinction efficiency increases when the source's aerosol combines with the background aerosol; and correspondingly,

[3] *Revised IMPROVE Algorithm for estimating Light Extinction from Particle Speciation Data.* Report to IMPROVE Steering Committee, November 2005.

(Part C) An increase in the extinction of the background aerosol because of that same mixing.

The total new extinction is the sum of the above three components plus the original background extinction. The original background extinction is just that calculated by the new IMPROVE algorithm from background concentrations of the various components, without any consideration of the effects of the plume.

For example, assume that the sulfate concentration attributed to a source is $[S_S]$ and the sulfate in the natural background is $[S_N]$, for a total ambient sulfate concentration of $[S_T]$. According to Equations 1 and 2, the total extinction due to sulfate for this combination is

$$b_{ext}(sulfate) = 2.2 \bullet f_S(RH) \bullet [small\ sulfate] + 4.8 \bullet f_L(RH) \bullet [large\ sulfate], \qquad \text{(Eq. 3)}$$

where

$$[large\ sulfate_T] = \{[S_T]/20\} \bullet [S_T] \text{ if } [S_T] < 20\ \mu g^3$$

$$[large\ sulfate_T] = [S_T] \text{ if } [S_T] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. 4)}$$

$$[small\ sulfate_T] = [S_T] - [large\ sulfate_T],$$

and the subscript T denotes total sulfate

For the portion of the extinction due directly to the source emissions (Parts A and B, above), we have, however

$$[large\ sulfate_S] = \{[S_T]/20\} \bullet [S_S] \text{ if } [S_T] < 20\ \mu g^3$$

$$[large\ sulfate_S] = [S_S] \text{ if } [S_T] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. 5)}$$

$$[small\ sulfate_S] = [S_S] - [large\ sulfate_S],$$

because we are now partitioning $[S_S]$ into large and small sulfate, where the size of the fraction depends on the concentration of all of the sulfate, $[S_T]$.

Similarly, for the portion of the extinction due to the background (the original background S_N plus the enhancement described under Part C, above), we have

$$[large\ sulfate_N] = \{[S_T]/20\} \bullet [S_N] \text{ if } [S_T] < 20\ \mu g^3$$

$$[large\ sulfate_N] = [S_N] \text{ if } [S_T] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. 6)}$$

$$[small\ sulfate_N] = [S_N] - [large\ sulfate_N],$$

As a check, we see that adding the corresponding formulas in Equations 5 and 6 gives the results in Equations 4.

Finally, for the original background, where there is no source impact, the corresponding formulas are

$$[large\ sulfate_N] = \{[S_N]/20\}\bullet[S_N] \text{ if } [S_N] < 20\ \mu g^3$$

$$[large\ sulfate_N] = [S_N] \text{ if } [S_N] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. 7)}$$

$$[small\ sulfate_N] = [S_N] - [large\ sulfate_N],$$

As usual, the fractional change in extinction is then calculated as

$$(b_{ext,T} - b_{ext,N})/b_{ext,N}, \qquad \text{(Eq. 8)}$$

which can also be expressed in deciviews.

These formulas are used in the CALPOST-IMPROVE Processor. Similar formulas apply for nitrates and organics. There is no nonlinearity in the remaining terms in Equation 1.

Description of Processor

The CALPOST-IMPROVE Processor is a Microsoft Excel workbook that consists of four worksheets:

1. Input/Output – The output table from CALPOST is imported to here and user entries are made for the Rayleigh scattering coefficient and, if desired, for a sea salt concentration at the Class I area of interest. A revised table, with extinction based on the new IMPROVE algorithm is then presented on the same page. This is the only page on which user input takes place, and the results of the calculations appear on this page.

2. Calculations -- The calculations themselves are all done on this worksheet. There is no user input to this page. The variables are explained on the worksheet itself, so the user can find intermediate values if so inclined. Since NO_2 concentrations are not measured at IMPROVE sites and the NO_2 absorption in rural areas is expected to be small, NO_2 has been omitted from these calculations.

3. F(RH) – This worksheet tabulates the traditional IMPROVE f(RH) against RH, and then also lists values for the three new humidity growth functions, $f_S(RH)$, $f_L(RH)$, and $f_{SS}(RH)$. It serves as a lookup table for the "Calculations" worksheet .

4. Rayleigh & Sea Salt – This page tabulates the IMPROVE-recommended Rayleigh scattering coefficients for all VISTAS Class I areas and for Class I areas in adjacent states. It also lists the average sea salt concentrations for the same

locations, based on chloride or chlorine measurements by IMPROVE monitors between 2000 and 2004. This sheet just provides information for the user; it is not linked to the rest of the workbook. The user can obtain Rayleigh and sea salt numbers for the Class I area of interest from this table and then manually enter them in the designated spaces in worksheet 1.

Instructions for Using the CALPOST-IMPROVE Processor

Step 1. Begin by opening the output (.LST) file from CALPOST in a text editor or word processing program.[4] In the second half of the file, locate the table "Ranked Daily Visibility Change" with the subheading "Modeled Extinction by Species".[5]

Step 2. Copy this table and paste it onto a new page. Save it as a text (.txt) file, not as a formatted (e.g., MS Word .doc or .rtf) file. The final table should contain only the column headings and the data. Delete all other captions, any additional data summaries at the end, and blank lines before or after the table. The processor can handle a maximum of 22 lines of data (i.e., the highest rank in the last, unlabeled, column should be 22) plus a row of column captions. Delete any data that exceed this limit. The result should look like the example in Figure 1.

Step 3. Open the CALPOST-IMPROVE Processor with Microsoft Excel. Save the open file under a new name so that the original empty processor will remain available for future use. The front worksheet, labeled "Input/Output" looks like Figure 2. There is a large empty box, surrounded by double lines, into which the table created above will be imported, as described below.[6] Two smaller boxes provide for user input of the Rayleigh scattering coefficient and, optionally, sea salt concentration for the Class I area, as described below. Results of the new IMPROVE algorithm calculations appear in blue in the lower half of the worksheet and some additional results, that are also useful for quality control, appear in green to the right of the large box. At the moment, many results cells will display nonsensical numbers and error messages, such as shown in Figure 2.

Step 4. Select the upper left cell (A7) in the large box. On the Excel menu bar, go to *Data>Get External Data* and click on *Import Text File.* (If the large box is not empty, click on *Edit Text Import* instead.) Select the file that contains the table created in Step 2 and click on the *Get Data* button. Go through the Text Import Wizard steps, checking that all values appear correctly in separate columns. (The label "COORDINATES (km)" will be split over two columns; this is OK.) When everything appears in order, click *Finish.*

---

[4] The background concentrations that were entered into CALPOST must be the EPA-prescribed default annual average natural conditions concentrations for the East. The processor will not give correct answers if other concentrations were used in CALPOST.

[5] For future reference, this may also be a good time to locate the table with the same title but with the subtitle "% of Modeled Extinction by Species", which appears later in the output file.

[6] If the workbook has already been used, the boxes may not be empty. This does not matter.

```
YEAR DAY HR  RECEPTOR    COORDINATES (km)  TYPE BEXT(Model) BEXT(BKG)
BEXT(Total) %CHANGE  F(RH)  bxSO4  bxNO3   bxOC   bxEC  bxPMC  bxPMF
2002 175  0  1027       1479.069    24.683   D      5.495      21.650      27.145
25.38   3.500  5.401  0.045  0.042  0.002  0.001  0.004    1
2002 172  0  1021       1479.244    23.778   D      4.923      21.650      26.573
22.74   3.500  4.475  0.404  0.038  0.001  0.001  0.004    2
2002 284  0  1045       1484.348    27.580   D      3.150      21.470      24.620
14.67   3.300  2.684  0.428  0.033  0.001  0.001  0.003    3
2002 353  0  1026       1482.762    24.457   D      2.594      21.290      23.884
12.18   3.100  2.017  0.557  0.018  0.001  0.000  0.002    4
2002 283  0  1026       1482.762    24.457   D      2.502      21.470      23.972
11.65   3.300  2.269  0.201  0.028  0.001  0.001  0.003    5
2002 195  0  1045       1484.348    27.580   D      2.011      21.830      23.841
9.21   3.700  1.963  0.031  0.015  0.001  0.000  0.001    6
2002  20  0  1117       1486.636    34.592   D      1.872      21.200      23.072
8.83   3.000  1.542  0.320  0.009  0.000  0.000  0.001    7
2002 173  0  1128       1479.259    35.042   D      1.649      21.650      23.299
7.62   3.500  1.625  0.012  0.010  0.000  0.000  0.001    8
2002 234  0  1021       1479.244    23.778   D      1.524      22.190      23.714
6.87   4.100  1.482  0.029  0.011  0.000  0.000  0.001    9
2002 298  0  1021       1479.244    23.778   D      1.459      21.470      22.929
6.80   3.300  1.284  0.160  0.014  0.001  0.000  0.001   10
2002 299  0  1021       1479.244    23.778   D      1.436      21.470      22.906
6.69   3.300  1.281  0.140  0.013  0.000  0.000  0.001   11
2002 275  0  1026       1482.762    24.457   D      1.270      21.470      22.740
5.92   3.300  1.202  0.058  0.009  0.000  0.000  0.001   12
2002 263  0  1045       1484.348    27.580   D      1.237      22.100      23.337
5.60   4.000  1.223  0.008  0.005  0.000  0.000  0.001   13
2002 252  0  1026       1482.762    24.457   D      1.189      22.100      23.289
5.38   4.000  1.166  0.013  0.009  0.000  0.000  0.001   14
2002 285  0  1021       1479.244    23.778   D      0.992      21.470      22.462
4.62   3.300  0.813  0.179  0.001  0.000  0.000  0.000   15
2002 161  0  1026       1482.762    24.457   D      0.873      21.650      22.523
4.03   3.500  0.842  0.020  0.009  0.000  0.000  0.001   16
2002 150  0  1026       1482.762    24.457   D      0.857      21.380      22.237
4.01   3.200  0.822  0.026  0.007  0.000  0.000  0.001   17
2002 340  0  1140       1481.017    37.258   D      0.817      21.290      22.107
3.84   3.100  0.663  0.153  0.001  0.000  0.000  0.000   18
2002 151  0  1117       1486.636    34.592   D      0.745      21.380      22.125
3.49   3.200  0.704  0.033  0.007  0.000  0.000  0.001   19
2002 160  0  1021       1479.244    23.778   D      0.735      21.650      22.385
3.40   3.500  0.710  0.014  0.010  0.000  0.000  0.001   20
2002 346  0  1021       1479.244    23.778   D      0.703      21.290      21.993
3.30   3.100  0.620  0.080  0.002  0.000  0.000  0.000   21
2002 247  0  1021       1479.244    23.778   D      0.661      22.100      22.761
2.99   4.000  0.654  0.004  0.002  0.000  0.000  0.000   22
```

Figure 1. Example of CALPOST Output Table, in Proper Format for Importing into the CALPOST-IMPROVE Processor.

Step 5.[7] The "Import Data" window will appear, with cell A7 indicated as the location at which data will be entered. Click on the *Properties* button. In the window that appears, select "Overwrite existing cells with new data, clear unused cells" and uncheck "Adjust column width", then click on *OK*. Now click on the *OK* button in the "Import Data" window.

Step 6. Assuming that your Excel application is set up to automatically recalculate whenever any entries are changed, you should now have filled the cells in the large box

[7] If the processor already had data in it and *Edit Text Import* was clicked in Step 4, then the "Import Data" window will not appear and Step 5 can be skipped.

CALPOST Recalculation with New IMPROVE Algorithm

---------- INPUT from CALPOST (based on old IMPROVE algorithm) ----------

1. At cell A7, import "Ranked Daily Visibility Change" (bext) table, including column headings, from CALPOST (22 days, max)

2. Check calculated values below against CALPOST's "Ranked Daily Visibility Change" (dv) table

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)		TYPE	BEXT(Model)	BEXT(BKG)	BEXT(Total)	%CHANGE	F(RH)	bxSO4	bxNO3	bxOC	bxEC	bxPMC	bxPMF	Rank	dv(total)	dv(bkg)	Δdv
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!
																			#NUM!	#NUM!	#NUM!

3. Enter value of site-specific Rayleigh scattering coefficient, from "Rayleigh & Sea Salt" worksheet

4. (Optional) Insert annual average sea salt concentration, from "Rayleigh & Sea Salt" worksheet. Leave blank if not used.

---------- OUTPUT (based on new IMPROVE algorithm) ----------

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)		TYPE	BEXT(Source)	BEXT(BKG)	BEXT(Total)	%CHANGE	RH(%)	bsSO4	bsNO3	bsOC	bsEC	bsPMC	bsPMF	New Rank	dv(total)	dv(bkg)	Δdv
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	#N/A	#N/A	#N/A	#N/A

Figure 2. Example of Appearance of Input/Output Worksheet before Data Entry.

on the first worksheet, numbers should have appeared in the green columns to the right, and some numbers will have appeared in the output table in blue on the lower half of the worksheet. If the data import worked properly, none of the imported data should have spilled out of the large box. Check that all the column captions in bold outside the large box are now duplicated on the first line in the box. (There won't be a caption for Rank.)

Step 7. As a further check on whether everything is correct so far, the dv information in the three columns to the right of the large box should be the same as that in the second CALPOST table "Ranked Daily Visibility Change: % of Modeled Extinction by Species", which was mentioned in Footnote 1.

Step 8. Fill in the small box after red instruction 3 with the Rayleigh scattering coefficient for the Class I area of interest. Also, if you wish, fill in the other small box, the one after red instruction 4, with the annual average sea salt concentration. (The sea salt box may be left blank, but the Rayleigh scattering coefficient box must be filled in.) To help with filling in these two boxes, the fourth worksheet, "Rayleigh & Sea Salt", provides IMPROVE-calculated values of the Rayleigh coefficients for Class I areas in the VISTAS region and in adjacent states. Also, average sea salt concentrations for 2000-2004, calculated in accordance with the new IMPROVE procedures, can be found there. At this point the "Input/Output" worksheet should look something like Figure 3, with all columns filled with meaningful data.

Step 9. The new IMPROVE algorithm output table at the bottom of the page can be compared with the original CALPOST table at the top of the page. All of the columns in both tables show exactly the same variables, except that the F(RH) column in the top table is replaced by just the RH in the lower table (since the new procedure has three different f(RH) functions). Although the events are in the same order in both tables, note that their rankings may have changed, as in New Ranks 12 vs. 13 and 19 vs. 20 in Figure 3.

For those who are interested in more detail, values of the three f(RH) functions appear in columns L through N on the second, "Calculations" spreadsheet. The extinction impact of the source, including enhancement of the extinction efficiencies for sulfates, nitrates, and organics due to the Part B that was described above, appears in columns U through AA. Extinction due to the annual average natural background appears in Columns AH through AL; natural background extinctions for those components that are enhanced by greater total mass concentrations (Part C) appear in columns AS through AV.

CALPOST Recalculation with New IMPROVE Algorithm

---------- INPUT from CALPOST (based on old IMPROVE algorithm) ----------

1. At cell A7, import "Ranked Daily Visibility Change" (bext) table, including column headings, from CALPOST (22 days, max)

2. Check calculated values below against CALPOST's "Ranked Daily Visibility Change" (dv) table

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)		TYPE	BEXT(Model)	BEXT(BKG)	BEXT(Total)	%CHANGE	F(RH)	bxSO4	bxNO3	bxOC	bxEC	bxPMC	bxPMF	Rank	dv(total)	dv(bkg)	Δdv
YEAR	DAY	HR	RECEPTOR	COORDINA	TES (km)	TYPE	BEXT(Model)	BEXT(BKG)	BEXT(Total)	%CHANGE	F(RH)	bxSO4	bxNO3	bxOC	bxEC	bxPMC	bxPMF		dv(total)	dv(bkg)	Δdv
2002	175	0	1027	1479.069	24.683	D	5.495	21.65	27.145	25.38	3.5	5.401	0.045	0.042	0.002	0.001	0.004	1	9.99	7.72	2.26
2002	172	0	1021	1479.244	23.778	D	4.923	21.65	26.573	22.74	3.5	4.475	0.404	0.038	0.001	0.001	0.004	2	9.77	7.72	2.05
2002	284	0	1045	1484.348	27.58	D	3.15	21.47	24.62	14.67	3.3	2.684	0.428	0.033	0.001	0.001	0.003	3	9.01	7.64	1.37
2002	353	0	1026	1482.762	24.457	D	2.594	21.29	23.884	12.18	3.1	2.017	0.557	0.018	0.001	0	0.002	4	8.71	7.56	1.15
2002	283	0	1026	1482.762	24.457	D	2.502	21.47	23.972	11.65	3.3	2.269	0.201	0.028	0.001	0.001	0.003	5	8.74	7.64	1.10
2002	195	0	1045	1484.348	27.58	D	2.011	21.83	23.841	9.21	3.7	1.963	0.031	0.015	0.001	0	0.001	6	8.69	7.81	0.88
2002	20	0	1117	1486.636	34.592	D	1.872	21.2	23.072	8.83	3	1.542	0.32	0.009	0	0	0.001	7	8.36	7.51	0.85
2002	173	0	1128	1479.259	35.042	D	1.649	21.65	23.299	7.62	3.5	1.625	0.012	0.01	0	0	0.001	8	8.46	7.72	0.73
2002	234	0	1021	1479.244	23.778	D	1.524	22.19	23.714	6.87	4.1	1.482	0.029	0.011	0	0	0.001	9	8.63	7.97	0.66
2002	298	0	1021	1479.244	23.778	D	1.459	21.47	22.929	6.8	3.3	1.284	0.16	0.014	0.001	0	0.001	10	8.30	7.64	0.66
2002	299	0	1021	1479.244	23.778	D	1.436	21.47	22.906	6.69	3.3	1.281	0.14	0.013	0	0	0.001	11	8.29	7.64	0.65
2002	275	0	1026	1482.762	24.457	D	1.27	21.47	22.74	5.92	3.3	1.202	0.058	0.009	0	0	0.001	12	8.22	7.64	0.57
2002	263	0	1045	1484.348	27.58	D	1.237	22.1	23.337	5.6	4	1.223	0.008	0.005	0	0	0.001	13	8.47	7.93	0.54
2002	252	0	1026	1482.762	24.457	D	1.189	22.1	23.289	5.38	4	1.166	0.013	0.009	0	0	0.001	14	8.45	7.93	0.52
2002	285	0	1021	1479.244	23.778	D	0.992	21.47	22.462	4.62	3.3	0.813	0.179	0.001	0	0	0	15	8.09	7.64	0.45
2002	161	0	1026	1482.762	24.457	D	0.873	21.65	22.523	4.03	3.5	0.842	0.02	0.009	0	0	0.001	16	8.12	7.72	0.40
2002	150	0	1026	1482.762	24.457	D	0.857	21.38	22.237	4.01	3.2	0.822	0.026	0.007	0	0	0.001	17	7.99	7.60	0.39
2002	340	0	1140	1481.017	37.258	D	0.817	21.29	22.107	3.84	3.1	0.663	0.153	0.001	0	0	0	18	7.93	7.56	0.38
2002	151	0	1117	1486.636	34.592	D	0.745	21.38	22.125	3.49	3.2	0.704	0.033	0.007	0	0	0.001	19	7.94	7.60	0.34
2002	160	0	1021	1479.244	23.778	D	0.735	21.65	22.385	3.4	3.5	0.71	0.014	0.01	0	0	0.001	20	8.06	7.72	0.33
2002	346	0	1021	1479.244	23.778	D	0.703	21.29	21.993	3.3	3.1	0.62	0.08	0.002	0	0	0	21	7.88	7.56	0.32
2002	247	0	1021	1479.244	23.778	D	0.661	22.1	22.761	2.99	4	0.654	0.004	0.002	0	0	0	22	8.22	7.93	0.29

3. Enter value of site-specific Rayleigh scattering coefficient, from "Rayleigh & Sea Salt" worksheet: 11

4. (Optional) Insert annual average sea salt concentration, from "Rayleigh & Sea Salt" worksheet. Leave blank if not used.: 0.02

---------- OUTPUT (based on new IMPROVE algorithm) ----------

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)		TYPE	BEXT(Source)	BEXT(BKG)	BEXT(Total)	%CHANGE	RH(%)	bsSO4	bsNO3	bsOC	bsEC	bsPMC	bsPMF	New Rank	dv(total)	dv(bkg)	Δdv
2002	175	0	1027	1479.069	24.683	D	4.441	22.04	26.521	20.32	86	4.363	0.039	0.033	0.002	0.001	0.004	1	9.75	7.90	1.85
2002	172	0	1021	1479.244	23.778	D	3.989	22.04	26.063	18.24	86	3.604	0.349	0.029	0.001	0.001	0.004	2	9.58	7.90	1.68
2002	284	0	1045	1484.348	27.58	D	2.464	21.78	24.264	11.40	84	2.076	0.357	0.026	0.001	0.001	0.003	3	8.86	7.78	1.08
2002	353	0	1026	1482.762	24.457	D	2.000	21.57	23.586	9.35	82	1.528	0.455	0.014	0.001	0	0.002	4	8.58	7.69	0.89
2002	283	0	1026	1482.762	24.457	D	1.947	21.78	23.744	9.02	84	1.753	0.167	0.022	0.001	0.001	0.003	5	8.65	7.78	0.86
2002	195	0	1045	1484.348	27.58	D	1.609	22.21	23.837	7.30	87	1.569	0.027	0.012	0.001	0	0.001	6	8.69	7.98	0.70
2002	20	0	1117	1486.636	34.592	D	1.427	21.48	22.916	6.70	81	1.16	0.26	0.007	0	0	0.001	7	8.29	7.64	0.65
2002	173	0	1128	1479.259	35.042	D	1.316	22.04	23.370	6.02	86	1.297	0.01	0.008	0	0	0.001	8	8.49	7.90	0.58
2002	234	0	1021	1479.244	23.778	D	1.249	22.64	23.896	5.56	89	1.213	0.026	0.009	0	0	0.001	9	8.71	8.17	0.54
2002	298	0	1021	1479.244	23.778	D	1.134	21.78	22.924	5.25	84	0.988	0.133	0.011	0.001	0	0.001	10	8.30	7.78	0.51
2002	299	0	1021	1479.244	23.778	D	1.114	21.78	22.903	5.16	84	0.986	0.117	0.01	0	0	0.001	11	8.29	7.78	0.50
2002	275	0	1026	1482.762	24.457	D	0.981	21.78	22.770	4.54	84	0.925	0.048	0.007	0	0	0.001	13	8.23	7.78	0.44
2002	263	0	1045	1484.348	27.58	D	1.038	22.64	23.684	4.62	89	1.026	0.007	0.004	0	0	0.001	12	8.62	8.17	0.45
2002	252	0	1026	1482.762	24.457	D	0.998	22.64	23.643	4.44	89	0.978	0.012	0.007	0	0	0.001	14	8.60	8.17	0.43
2002	285	0	1021	1479.244	23.778	D	0.775	21.78	22.561	3.58	84	0.625	0.149	8E-04	0	0	0	15	8.14	7.78	0.35
2002	161	0	1026	1482.762	24.457	D	0.696	22.04	22.744	3.18	86	0.67	0.017	0.007	0	0	0.001	16	8.22	7.90	0.31
2002	150	0	1026	1482.762	24.457	D	0.651	21.67	22.322	3.03	83	0.623	0.021	0.005	0	0	0.001	17	8.03	7.73	0.30
2002	340	0	1140	1481.017	37.258	D	0.625	21.57	22.200	2.92	82	0.5	0.125	8E-04	0	0	0	18	7.98	7.69	0.29
2002	151	0	1117	1486.636	34.592	D	0.567	21.67	22.237	2.64	83	0.533	0.027	0.005	0	0	0.001	20	7.99	7.73	0.26
2002	160	0	1021	1479.244	23.778	D	0.586	22.04	22.634	2.68	86	0.565	0.012	0.008	0	0	0.001	19	8.17	7.90	0.26
2002	346	0	1021	1479.244	23.778	D	0.534	21.57	22.109	2.50	82	0.467	0.065	0.002	0	0	0	21	7.93	7.69	0.25
2002	247	0	1021	1479.244	23.778	D	0.553	22.64	23.195	2.46	89	0.548	0.004	0.002	0	0	0	22	8.41	8.17	0.24

Figure 3. Example of Appearance of Finished Input/Output Worksheet.

Appendix
Details of Calculation Approach

As an example of the calculation steps, assume that the sulfate concentration resulting from emissions from a source is $[S_E]$ and the sulfate in the undisturbed natural background is $[S_N]$, for a total ambient sulfate concentration of $[S_T]$. According to Equations 1 and 2 in the main body of this document, the total extinction due to sulfate for this combination is

$$b_{ext}(sulfate) = 2.2 \cdot f_S(RH) \cdot [small\ sulfate] + 4.8 \cdot f_L(RH) \cdot [large\ sulfate], \qquad \text{(Eq. A-1)}$$

where

$$[large\ sulfate_T] = \{[S_T]/20\} \cdot [S_T] \text{ if } [S_T] < 20\ \mu g^3$$

$$[large\ sulfate_T] = [S_T] \text{ if } [S_T] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. A-2)}$$

$$[small\ sulfate_T] = [S_T] - [large\ sulfate_T],$$

and the subscript T denotes total sulfate

For the original background, where there is no source impact, the corresponding formulas for the terms in Equations A-2 are

$$[large\ sulfate_N] = \{[S_N]/20\} \cdot [S_N] \text{ if } [S_N] < 20\ \mu g^3$$

$$[large\ sulfate_N] = [S_N] \text{ if } [S_N] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. A-3)}$$

$$[small\ sulfate_N] = [S_N] - [large\ sulfate_N],$$

where the subscript N denotes natural sulfate.

Similar calculations need to be carried out for nitrates. Contributions of the other particulate components are linear and can just be calculated according to Equation 1.

If the impact due to NO_2 is also to be considered, then the source impact due to this component is, according to Equation 1,

$$b_{ext}(NO_2) = 0.33 \cdot [NO_2], \qquad \text{(Eq. A-4)}$$

where $[NO_2]$ is in ppb. It is reasonable to assume that the ambient NO_2 concentrations under natural conditions would be so small as to cause negligible light absorption, so the corresponding term is not needed in the natural conditions calculation.

The contributions due to the various components are summed together as in Equation 1 to obtain the total extinction $b_{ext,T}$ and the natural background extinction $b_{ext,N}$. The

fractional change in extinction is then calculated as the difference, normalized by the natural background extinction

$$(b_{ext,T} - b_{ext,N})/b_{ext,N}, \qquad \text{(Eq. A-5)}$$

a result that can also be expressed in deciviews.

These formulas are used in the CALPOST-IMPROVE Processor. Similar formulas apply for nitrates and organics. There is no nonlinearity in the remaining terms in Equation 1.

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