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

Submitted By:

Submitted To:

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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.

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

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 98^{th} 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 98^{th} 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

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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 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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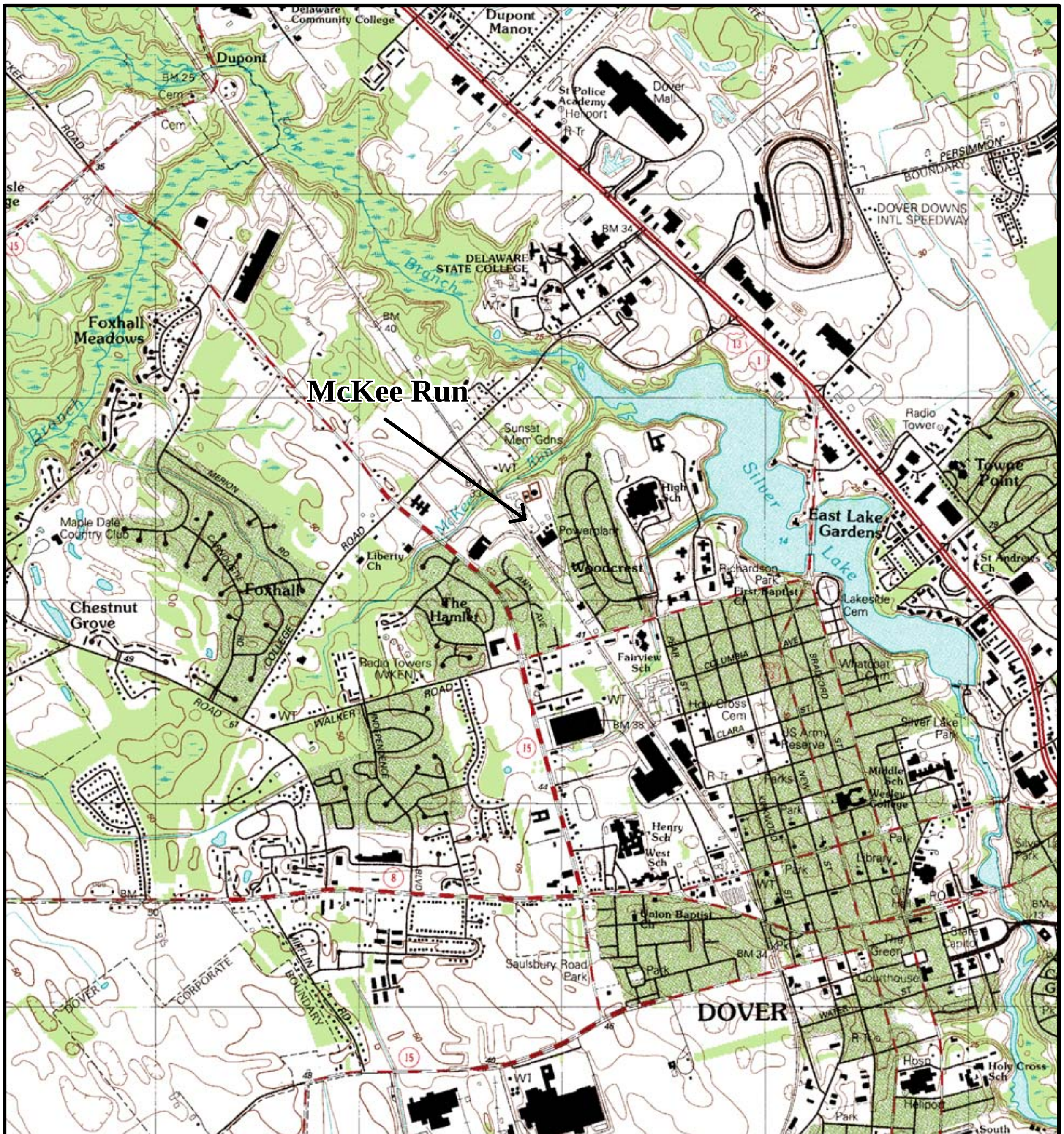
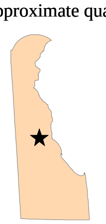


approximate quadrangle location



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

McKee Run
Generating Station
Dover, Delaware

Figure 1
Facility Location Map

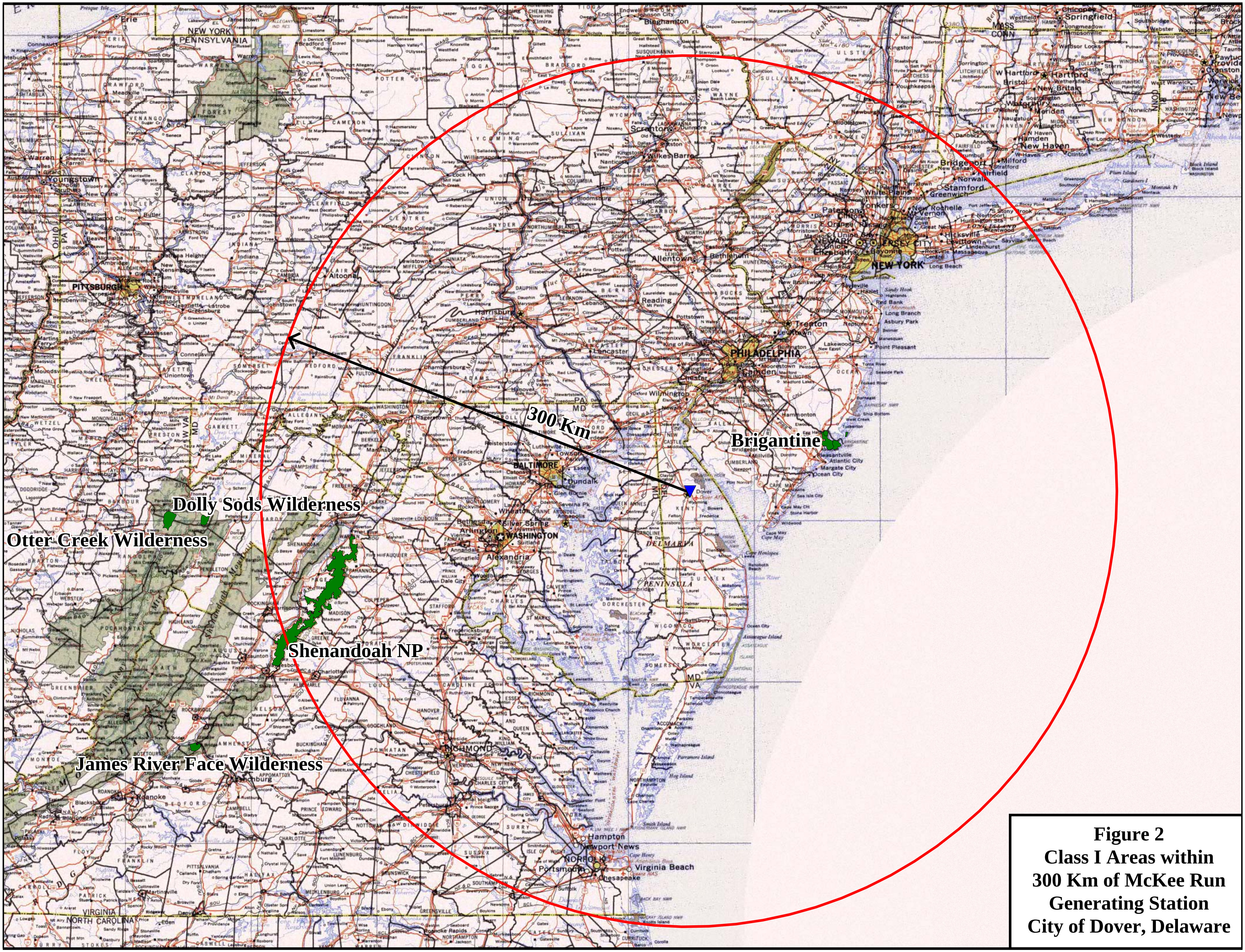


Figure 2
Class I Areas within
300 Km of McKee Run
Generating Station
City of Dover, Delaware

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.

<u>Visibility Modeling Approach and Technical Information</u>

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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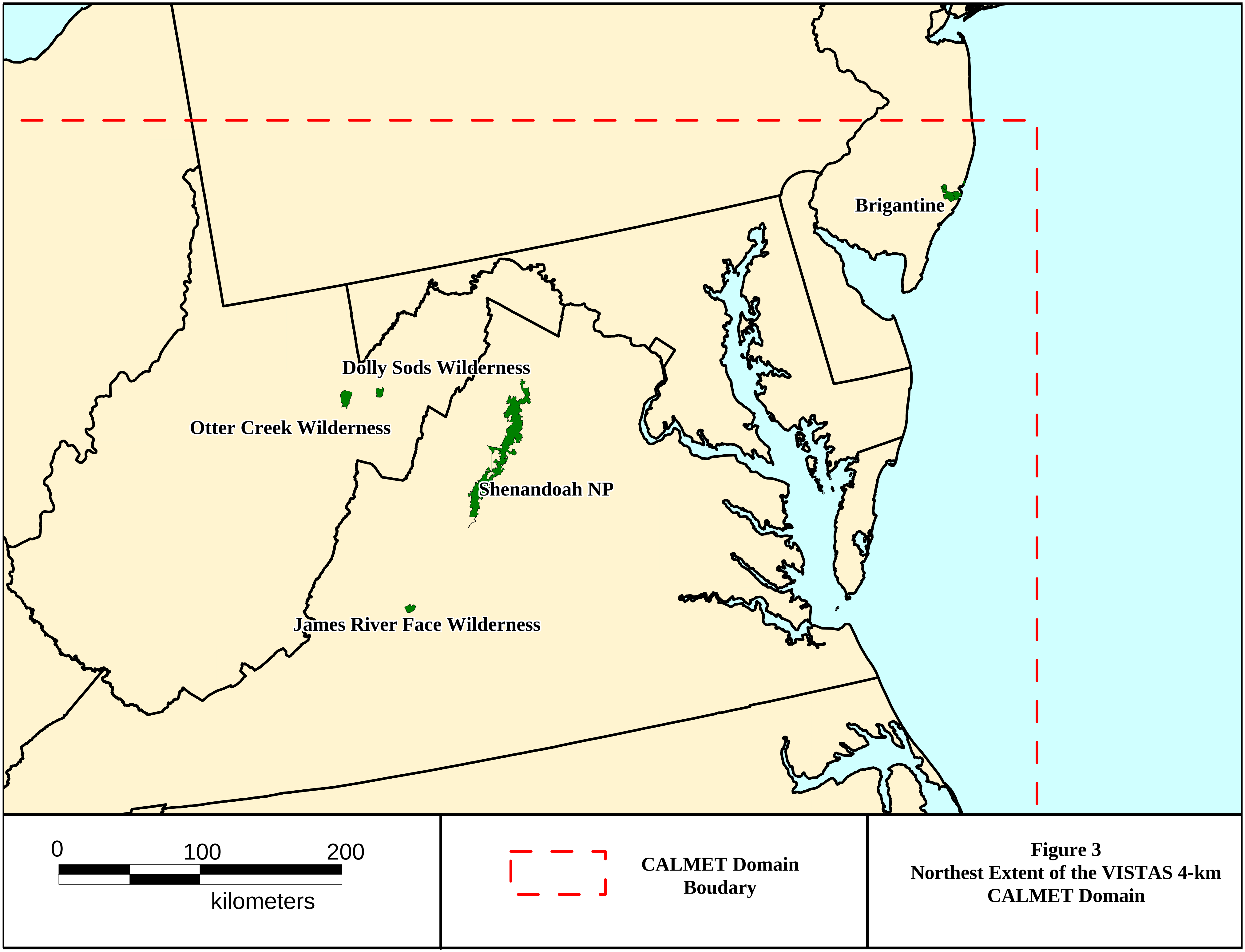

Figure 3
Northest Extent of the VISTAS 4-km CALMET Domain

- 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 (98^{th} 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.