Delaware State Implementation Plan Revision:
Regional Haze 5-Year Periodic Report

Progress Towards the
Reasonable Progress Goals for Visibility
In Class I Federal Areas
And
Determination of Adequacy of
Existing Implementation Plan

Final

September 24, 2013

EXECUTIVE SUMMARY

Regional haze is defined as visibility impairment that is produced by a multitude of sources and activities which emit fine particles and their precursors, and which are located across a broad geographic area. These emissions are transported over large regions and can obscure vistas integral to the value of our national parks, forests and wilderness areas ("Class I" federal areas). The Clean Air Act mandates requirements to protect visibility, especially in Class I Federal areas. In 1999, the U.S. Environmental Protection Agency (EPA) finalized the Regional Haze Rule (RHR) to address visibility impairment at Class I areas.

The RHR calls for state, tribal, regional planning organizations (RPO) and federal agencies to work together to improve visibility in 156 Class I areas. Specifically, states are required to develop a series of state implementation plans (SIP) to reduce visibility impairment with the express intent that by 2064, the visibility in all Class I areas will be returned to natural conditions. The first such SIP must establish interim goals and emissions reduction strategies for 2018, based on trends from various sources including point, area, and mobile (both onroad and nonroad) source emissions, biogenic, and wildfire and agricultural emissions.

Visibility assessments prepared by the RPO: Mid-Atlantic/Northeast Visibility Union (MANE-VU) determined that for the initial Regional Haze SIPs, ammonium sulfate was the largest contributor to visibility impairment at Class I areas and reduction of sulfur dioxide (SO_2) emissions is the most effective means of reducing ammonium sulfate. As such, the majority of the focus with regard to existing and planned emission controls pertains to the largest sources of SO_2 emissions. These sources consist of electric generating units (EGUs) and large industrial boilers. Hence, MANE-VU's long term strategy to reduce SO_2 to improve visibility prior to 2018 includes:

- Timely implementation of Best Available Retrofit Technology,
- Reducing the sulfur content of fuel oil,
- Reducing sulfur dioxide emissions from electric power plants,
- Seeking to reduce emissions outside MANE-VU that impair visibility in our region, and
- Continuing to evaluate other measures such as energy efficiency, alternative clean fuels, and measures to reduce emissions from wood and coal combustion.

On September 25, 2008 Delaware submitted it's "*Delaware Visibility State Implementation Plan"* (regional haze SIP) to EPA to comply with the 2018 MANE-VU strategy.[1] Many of the EGUs and large industrial boilers within Delaware have committed to and have installed controls through a number of mechanisms, including Delaware's multi-pollutant regulation, federally enforceable permits, and state and federal consent agreements. Reductions associated with many of these mechanisms were used to estimate the 2018 visibility improvements at the Brigantine Wilderness Class I area in New Jersey.[2] However, since Delaware submitted its initial regional

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[1] EPA approved Delaware's regional haze SIP on July 19, 2011 (76 Federal Register 42557).

[2] It was determined during the MANE-VU consultation process that Delaware contributed significantly to only the Edwin B. Forsythe National Wildlife Refuge (Brigantine Wilderness Area), in New Jersey.

haze SIP in 2008, additional regulations and actions have been imposed which will reduce visibility impairing pollutants. Moreover, as recently as the summer of 2012, several large EGUs have announced plans to either shutdown sources or curtail emissions by converting to natural gas, leading to even more significant reductions in SO_2 emissions. As this report will show, these additional mandates will help ensure that the reasonable progress goals are attained well before 2018.

Section 308(g) of the RHR also requires each state to report on progress in improving visibility five (5) years after submitting the initial SIP. Known as "5-Year Progress Reports" (Report), they must be in the form of SIP revisions that comply with the procedural requirements of the United States Clean Air Act, as amended. This Report fulfills the requirements of 40 CFR 51.308(g) requiring periodic reports evaluating progress in implementing the measures included in Delaware's 2008 SIP. This document also fulfills the requirements of 40 CFR Part 51.308(h), 308(i), and 40 CFR 51 Parts 102 and 103.

It is for these reasons that the Delaware Department of Natural Resources and Environmental Control (DNREC) submits a negative declaration to EPA, specifying that the ***Delaware 2008 Visibility State Implementation Plan*** is sufficient for meeting the requirements outlined in the RHR. Furthermore, no additional controls are necessary, based on this first Report.

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LIST OF ACRONYMS

ATP	Anti-Tampering Procedures
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
B & F	Best and Final (2018 emission projections)
Bext	Beta Extinction
BTU	British Thermal Unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMD	EPA Clean Air Markets Division
CEM	Continuous Emissions Monitor
CENRAP	Central Regional Air Planning Association
CFR	Code of Federal Register
CNG	Compressed Natural Gas
CI	Compression-Ignition Engine
CMAQ	Community Multi-scale Air Quality [model]
CO	Carbon Monoxide
CSAPR	Cross-State Air Pollution Rule
DAQ	Division of Air Quality (Delaware)
DNREC	Department of Natural Resources and Environmental Control (Delaware)
dv	Deciview
EGU	Electricity Generating Unit
EPA	U.S. Environmental Protection Agency
ESD	Emission Standards Division (EPA)
ESP	Electrostatic Precipitator
FCCUs	Fluid Catalytic Cracking Units
FCUs	Fluid Coking Units
FGD	Flue Gas Desulfurization
FLM	Federal Land Manager
FP	Fuel System Pressure Test
FR	Federal Register
GC	Gas Cap Test
GDP	Gross Domestic Product
GVWR	Gross Vehicle Weight Rating
HAP	Hazardous Air Pollutant
HC	Hydrocarbon
HH	Handheld Engine
hp	Horsepower
hr	Hour
I/M	Inspection/Maintenance
IC	Industrial/Commercial OR Internal Combustion
ICI	Industrial,/Commercial/ Institutional
IMPROVE	Interagency Monitoring of Protected Visual Environments
kgal	Thousand Gallons
LAC	Light Absorbing Carbon

lb	Pound
LEV	Low Emission Vehicle
LPG	Liquefied Petroleum Gas
LTS	Long Term Strategy
MACT	Maximum Achievable Control Technology
MANE-VU	Mid-Atlantic/Northeast Visibility Union
MARAMA	Mid-Atlantic Regional Air Management Association
MARPOL	International Convention for the Prevention of Pollution from Ships Treaty
MATS	Mercury and Air Toxics Standards
MMBTU	Million British Thermal Units
MMscf	Million Standard Cubic Feet
MOVES	Motor Vehicle Emission Simulator
MRPO	Midwest Regional Planning Organization
MY	Model Year
NAAQS	National Ambient Air Quality Standards
NCD	National County Database
NEI	National Emissions Inventory
NESCAUM	Northeast States for Coordinated Air Use Management
NHH	Non-Handheld Engine
NLEV	National Low Emission Vehicle Program
NMHC	Non-Methane Hydrocarbon
NMIM	National Mobile Inventory Model
NMMA	National Marine Manufacturers Association
NOx	Nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
OC	Organic Carbon
OCM	Organic Carbon Mass
ORVR	On-Board Refueling Vapor Recovery
OTAQ	Office of Transportation and Air Quality
OTB	On The Books
OTC	Ozone Transport Commission
OTR	Ozone Transport Region
OTW	On The Way
PAL	Plant-wide Applicability Limit
PM	Particulate matter
PM10	Particulate matter of diameter of 10 micrometers or less
PM2.5	Particulate matter of diameter of 2.5 micrometers or less
PSD	Prevention of Significant Deterioration
PTE	Potential To Emit
RACT	Reasonably Available Control Technology
RAVI	Reasonably Attributable Visibility Impairment
REMSAD	Regional Modeling System for Aerosols and Deposition
RHR	Regional Haze Rule
RIA	Regulatory Impact Analysis
RPG	Reasonable Progress Goal

RPO	Regional Planning Organization
RVP	Reid Vapor Pressure
scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SD/I	Stern-Drive /Inboard Marine Engine
SIP	State Implementation Plan
SMP	Smoke Management Plan
SNCR	Selective Non-catalytic Reduction
SO2	Sulfur dioxide
tpy	Tons Per Year
TSM	Total Selective Metals
URP	Uniform Rate of Progress
VIEWS	Visibility Information Exchange Web System
VISTAS	Visibility Improvement State and Tribal Association of the Southeast
VOC	Volatile Organic Compound
WOE	Weight of Evidence
WRAP	Western Regional Air Partnership

Describing Progress Towards the Reasonable Progress Goals for Visibility in Class I Federal Areas and Determination of Adequacy of Existing Implementation Plan

A. INTRODUCTION

1. REQUEST

The State of Delaware is requesting that the United States Environmental Protection Agency (EPA) approve this submittal as meeting the requirements for a periodic report describing the progress toward meeting the reasonable progress set forth in the Delaware regional Haze State Implementation Plan (SIP) as required by 40 CFR 51.308(g).

Based on the evidence presented herein, the DNREC is proposing a negative declaration to the EPA Administrator specifying that no additional controls are necessary during this, the first five-year progress report period.

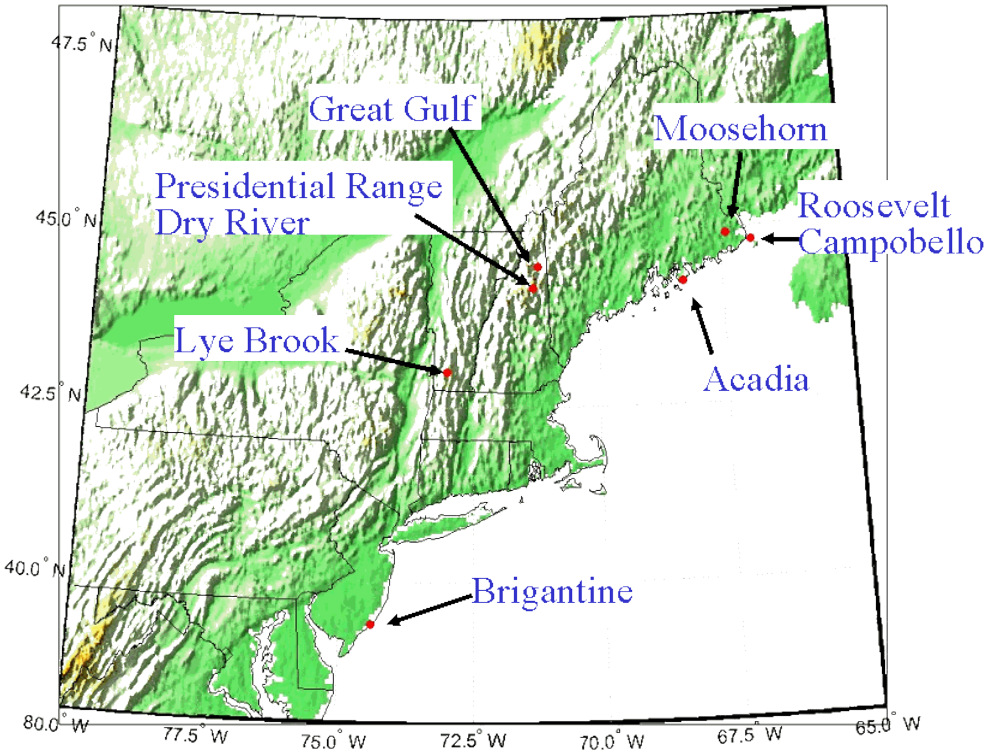
2. BACKGROUND

Regional haze is defined as visibility impairment that is produced by a multitude of sources and activities which emit fine particles and their precursors, and which are located across a broad geographic area. These emissions are transported over large regions, including national parks, forests and wilderness areas ("Class I" federal areas). The Clean Air Act (CAA) mandates protection of visibility, especially in Class I areas.

Fine particles ($PM_{2.5}$) may either be emitted directly or formed from emissions of precursors, the most important of which are sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Particles affect visibility through the scattering and absorption of light, and fine particles - particles similar in size to the wavelength of light - are most efficient, per unit of mass, at reducing visibility. Therefore, reducing fine particles (particles with a diameter less than 2.5 µm), in the atmosphere is generally considered to be an effective method of reducing regional haze, and thus improving visibility. The most important sources of $PM_{2.5}$ and its precursors are coal-fired power plants, industrial boilers and other combustion sources. Other significant contributors to $PM_{2.5}$ and visibility impairment include mobile source emissions, area sources, fires, and wind blown dust.

The U.S. Clean Air Act sets requirements to protect the air quality-related values of national parks and wilderness areas. Specifically, Section 169A of the Act requires the "prevention of any future, and the remedying of any existing impairment of visibility in Class I areas which impairment results from manmade air pollution." Areas protected by this portion of the Act include national parks exceeding 6,000 acres, wilderness areas and national memorial parks exceeding 5,000 acres, and all international parks in existence on August 7, 1977. There are 156 Class I areas in the United States, of which seven are in the mid-Atlantic and Northeast, as shown in Figure 1.

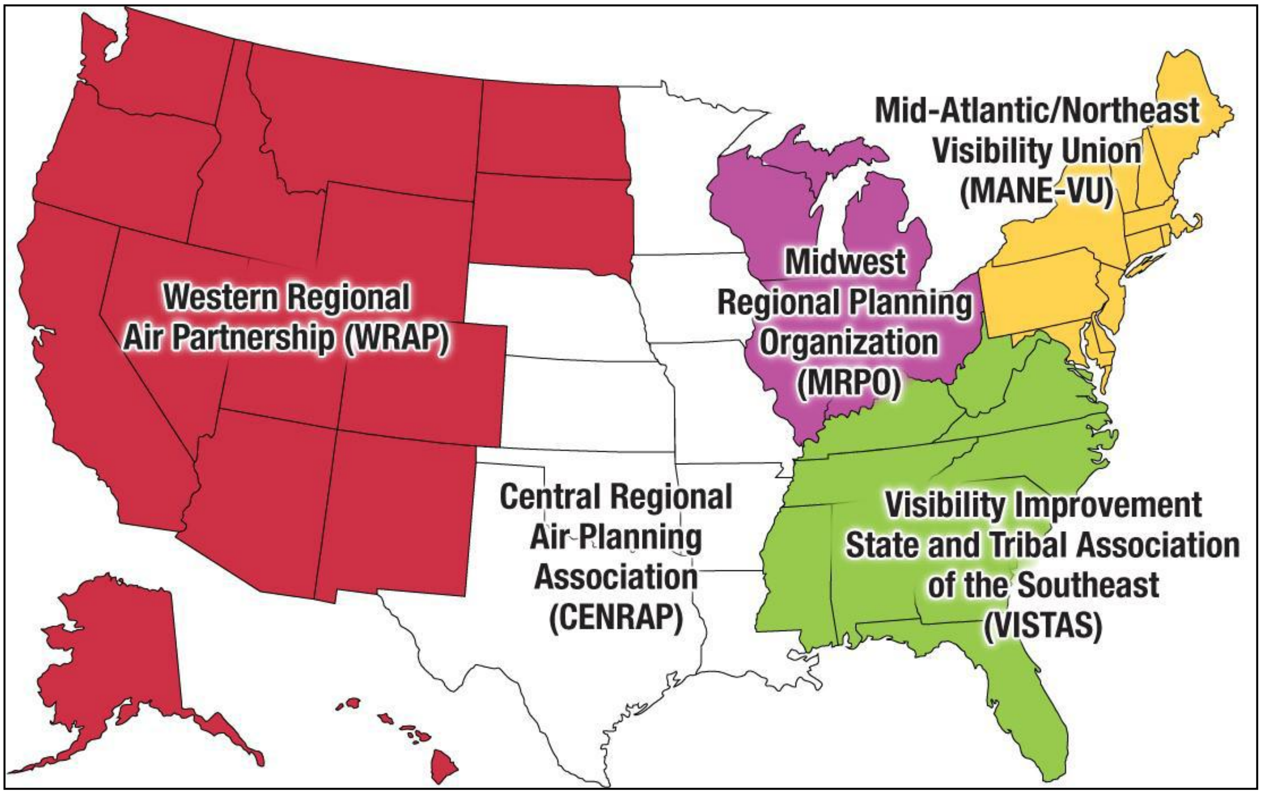
Figure 1 - MANE-VU Class I Areas



The Clean Air Act directed the U.S. Environmental Protection Agency (EPA) to promulgate regulations to assure reasonable progress toward meeting the national goal of improved visibility in Class I areas. On July 1, 1999, the EPA finalized the Regional Haze Rule (64 FR 35714) (40 CFR 51.300-308). The rule calls for state, tribal, and federal agencies to work together to improve visibility.

In cooperation with the States, EPA designated five Regional Planning Organizations (RPO) to assist with the coordination and cooperation states and tribes needed to address the visibility issue. Delaware is a member of the Mid-Atlantic/Northeast Visibility Union (MANE-VU). Figure 2 shows a map of all the U.S. Regional Planning Organizations.

Figure 2 - Map of U.S. Regional Planning Organizations



EPA's Regional Haze Rule (RHR) requires States to develop a series of state implementation plans (SIP) to reduce visibility impairment with the express intent that by 2064, the visibility in all Class I areas will be returned to natural conditions. The RHR further states the first such SIP must establish interim reasonable progress goals and emissions reduction strategies by 2018, for various air pollution sources including area sources, mobile sources (both onroad and nonroad sources), and point sources.

States and tribes in the northeast and mid-Atlantic region, along with Federal Land Management Agencies and the EPA, worked together through MANE-VU to develop strategies for reducing the haze that obscures natural vistas in areas designated in the CAA as Class I areas.

3. REQUIREMENTS FOR PERIODIC PROGRESS REPORTS

This 5-Year progress report is a SIP revision which fulfills the requirements of 40 CFR Part 51, Section 308(g), 308(h), 308(i) and 40 CFR Part 51 Sections 102 and 103. The following paragraphs summarize those requirements.

3.1. GENERAL AND PROCEDURAL REQUIREMENTS

The RHR requires the 5-Year progress report to be in the form of a SIP revision that complies with the procedural requirements of the CAA as well as the requirements of the RHR. Because Delaware's first regional haze SIP was submitted to EPA on September 25, 2008 (available on DNREC's website[3]), this 5-year progress report is due to EPA by September 25, 2013. The periodic report must address the following CFR requirements:

(1) 40 CFR §51.102 (public hearings);

(2) 40 CFR §51.103 (EPA submittal requirements);

(3) 40 CFR Part 51 Section 308(g) - evaluate progress towards the reasonable progress goals established in the initial SIP for each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the State;

(4) 40 CFR Part 51 Section 308(h) - determination of the adequacy of existing implementation plan;

(5) 40 CFR Part 51 Section 308(i) - provide continued coordination with other states with Class I areas impacted by Delaware, as well as consult with FLMs and EPA in order to maintain and improve the visibility in the Class I area. (40 CFR Part 51 Section 308(i) requires States to give FLMs 60 days to review and draft comments on the proposed SIP, prior to the public hearing on any SIP revision related to Regional Haze.)

3.2. REQUIRED ELEMENTS OF THE PROGRESS REPORT SIP

40 CFR Part 51 Section 308(g) says that 5-Year Progress Reports must contain at a minimum the following elements:[4]

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[3] http://www.dnrec.delaware.gov/whs/awm/Info/Regs/Documents/DE_Visibility_SIP_fnl_Clean_%209_24_08(web).pdf

[4] "Interagency Monitoring of Protected Visual Environments" (IMPROVE) monitors are necessary for certain analysis and assessments of visibility. There are no Class I areas within Delaware's borders, and Delaware does not operate an IMPROVE network of monitors. IMPROVE monitors are necessary for certain analysis and assessments. Accordingly, EPA stated in their July 19, 2011 approval of *Delaware's Visibility State Implementation Plan* (76 FR 42557) that Delaware was not required to address the following elements as part of its 2008 *Delaware Visibility State Implementation Plan*. Thus it is appropriate that Delaware also not address them within its *5-Year Progress Report*:

a) Calculation of baseline and natural visibility conditions,
b) Establishment of reasonable progress goals,
c) Monitoring requirements, and
d) Reasonably Attributable Visibility Impairment (RAVI) requirements.

(1) A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class I Federal areas both within and outside the State.

(2) A summary of the emissions reductions achieved throughout the State through implementation of the measures described in paragraph (g)(1) of this section.

(3) For each mandatory Class I Federal area within the State, the State must assess the following visibility conditions and changes, with values for most impaired and least impaired days expressed in terms of 5-year averages of these annual values:

- The current visibility conditions for the most impaired and least impaired days;
- The difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions;
- The change in visibility impairment for the most impaired and least impaired days over the past 5 years.

(4) An analysis tracking the change over the past 5 years in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity. The analysis must be based on the most recent updated emissions inventory, with estimates projected forward as necessary and appropriate, to account for emissions changes during the applicable 5-year period.

(5) An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred over the past 5 years that have limited or impeded progress in reducing pollutant emissions and improving visibility.

(6) An assessment of whether the current implementation plan elements and strategies are sufficient to enable the State, or other States with mandatory Federal Class I areas affected by emissions from the State, to meet all established reasonable progress goals.

(7) A review of the State's visibility monitoring strategy and any modifications to the strategy as necessary.

Each of these required elements is addressed in subsequent sections of this document.

4. ADEQUACY OF EXISTING SIP

The RHR also establishes the following requirements for determining the adequacy of the current Delaware regional Haze SIP, as submitted to EPA on September 25, 2008.

> 51.308(h) *Determination of the adequacy of existing implementation plan.* At the same time the State is required to submit any 5-year progress report to EPA in accordance with paragraph (g) of this section, the State must also take one of the following actions based upon the information presented in the progress report:
>
> (1) If the State finds that an additional substantive SIP revision is not required, then it may submit a “negative declaration" to EPA after opportunity for public review and comment. The EPA anticipates that if the State is implementing a reasonable set of strategies according to the schedule as developed in the previous comprehensive SIP revision, and that visibility trends show that reasonable progress goals should be achieved over the 10-year long-term strategy period, then the State should be able to certify, through a negative declaration, that no additional control measures are needed at the time of this mid-course review.
>
> (2) If the State finds that over the past 5 years there has been a substantial increase in emissions by intrastate sources, or there has been a deficiency in plan implementation, the Regional Haze Rule requires the State to revise the SIP within 1 year, rather than waiting for the next 10-year comprehensive review. Such a mid-course correction would be designed to achieve the existing reasonable progress goal for the relevant Class I area. The EPA believes that it is appropriate for the State to take prompt action to address intrastate problems since they would not need to participate in further regional planning.
>
> (3) If the State finds that there is a substantial increase in emissions or a deficiency in plan implementation resulting primarily from interstate emissions, section 51.308(h)(2) calls for the State to re-initiate the regional planning process with other States so that the deficiency can be addressed in the next comprehensive SIP revision due in 5 years.
>
> (4) If the State finds that international emissions sources are responsible for a substantial increase in emissions affecting visibility conditions in any Class I area or causing a deficiency in plan implementation, the State must submit a technical demonstration to EPA in support of its finding. If EPA agrees with the State's finding, EPA will take appropriate action to address the international emissions through available mechanisms.

B. SUMMARY OF THE EXISTING DELAWARE REGIONAL HAZE SIP

1. TECHNICAL BASIS FOR SULFUR DIOXIDE EMISSION REDUCTION OBLIGATIONS

MANE-VU's technical basis for the SO_2 emission reductions necessary to meet reasonable progress goals is summarized in this section (additional details may be found in the Delaware 2008 regional haze SIP References[5]). The paragraphs which follow also discuss the pollutants, source regions, and types of sources considered in developing this long term strategy.

40 CFR Section 51.308(d)(3)(iii) requires states/tribes to document the technical basis for the state's/tribe's apportionment of emission reductions necessary to meet reasonable progress goals (RPG) in each Class I area affected by the state's/tribe's emissions. In Delaware's 2008 regional haze SIP, DNREC relied on numerous technical analyses developed by MANE-VU in order to demonstrate that Delaware's SO_2, NOx, volatile organic compounds (VOC), ammonia and particulate matter (PM) emission reductions, when coordinated with those of other States and Tribes, are sufficient to achieve the 2018 reasonable progress goals in the Class I areas.

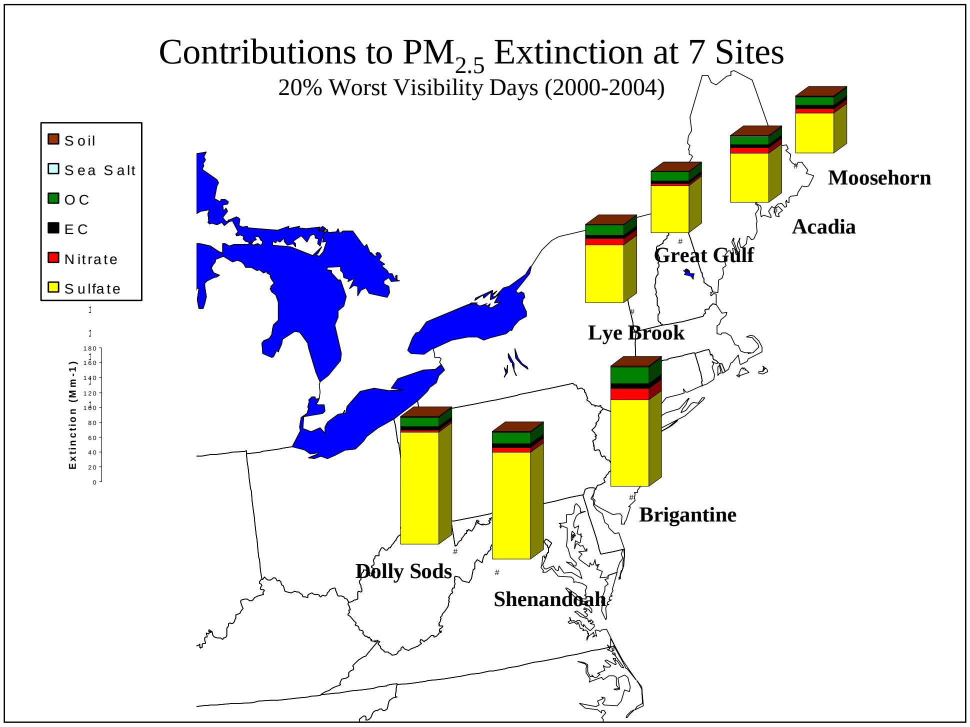
Finalized in August 2006, MANE-VU's technical analysis (Contribution Assessment) reflects a conceptual model in which sulfate emerged as the most important single constituent of fine particle pollution and the principle cause of visibility impairment across the MANE-VU region. Sulfate alone accounted for anywhere from one-half to two-thirds of total fine particle mass on the 20 percent haziest days at MANE-VU Class I sites. As a result of the dominant role of sulfate in the formation of regional haze in the Northeast and Mid-Atlantic region, MANE-VU concluded that an effective emissions management approach would rely heavily on broad-based regional SO_2 control efforts in the eastern United States.

[5] Delaware 2008 Regional haze SIP "contribution" references:

- Baseline and Natural Background Visibility Conditions—Considerations and Proposed Approach to the Calculation of Baseline and Natural Background Visibility Conditions at MANE-VU Class I Areas (NESCAUM, December 2006)
- The Nature of the Fine Particle and Regional Haze Air Quality Problems in the MANE-VU Region: A Conceptual Description (NESCAUM, November 2006)
- Contributions to Regional Haze in the Northeast and Mid-Atlantic United States (NESCAUM, August 2006) (called the Contribution Assessment)
- Assessment of Reasonable Progress for Regional haze in MANE-VU Class I Areas (MACTEC, July 2007)(called the Reasonable Progress Report)
- Five-Factor Analysis of BART-Eligible Sources: Survey of Options for Conducting BART Determinations (June, 2007)
- Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities (NESCAUM, March 2005)
- MANE-VU Modeling for Reasonable Progress Goals: Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits (NESCAUM, February 2008) 2018 Visibility Projections (NESCAUM, March 2008)

Figure **3** shows the dominance of SO_2 in the $PM_{2.5}$ light-extinction calculated from the 2000-2004 baseline data. [6]

Figure 3 - Contributions to $PM_{2.5}$ Light Extinction at Seven Class I Sites



2. MODELING AND SOURCE ATTRIBUTION STUDIES - CONTRIBUTING STATES AND REGIONS

The MANE-VU Contribution Assessment used various modeling techniques, air quality data analysis, and emissions inventory analysis to identify source categories and states that contribute to visibility impairment in MANE-VU Class I areas. Table 1 shows the results of the state-by-state contributions to sulfate impacts using the Regional Modeling System for Aerosols and Deposition model (REMSAD). This table also highlights the importance of emissions from outside the MANE-VU region.

[6] Figure 3 and Table 1 include Dolly Sods, but not Otter Creek Wilderness Area. Both are federally mandated Class I area located near each other in the Monongahela National Forest. However, since Otter Creek Wilderness did not have an IMPROVE monitor, and thus air quality data, it was not included in the NESCAUM contribution assessment used in Delaware's 2008 Regional Haze SIP (i.e. Figure 3 and Table 1).

Table 1 - Percent of Modeled Sulfate Due to Emissions from Listed States[7]

Contributing States or Areas	Acadia, Maine (%)	**Brigantine, New Jersey (%)**	Dolly Sods , West Virginia (%)(6)	Great Gulf and Presidential Range Dry River, New Hampshire (%)	Lye Brook, Vermont (%)	Moosehorn and Roosevelt Campobello, Maine (%)	Shenandoah, Virginia (%)
Connecticut	0.76	0.53	0.04	0.48	0.55	0.56	0.08
Delaware	0.96	**3.20**	0.30	0.63	0.93	0.71	0.61
District of Columbia	0.01	0.04	0.01	0.01	0.02	0.01	0.04
Maine	6.54	0.16	0.01	2.33	0.31	8.01	0.02
Maryland	2.20	4.98	2.39	1.92	2.66	1.60	4.84
Massachusetts	10.11	2.73	0.18	3.11	2.45	6.78	0.35
New Hampshire	2.25	0.60	0.04	3.95	1.68	1.74	0.08
New Jersey	1.40	4.04	0.27	0.89	1.44	1.03	0.48
New York	4.74	5.57	1.32	5.68	9.00	3.83	2.03
Pennsylvania	6.81	12.84	10.23	8.30	11.72	5.53	12.05
Rhode Island	0.28	0.10	0.01	0.11	0.06	0.19	0.01
Vermont	0.13	0.06	0.00	0.41	0.95	0.09	0.01
MANE-VU	36.17	34.83	14.81	27.83	31.78	30.08	20.59
Midwest RPO	11.98	18.16	30.26	20.10	21.48	10.40	26.84
VISTAS	8.49	21.99	36.75	12.04	13.65	6.69	33.86
Other	43.36	25.02	18.18	40.03	33.09	52.83	18.71

MANE-VU Class I states considered the modeling results documented in the Contribution Assessment to determine which states should be consulted in developing the long term strategy for improving visibility in MANE-VU Class I areas. Because sulfate was the primary pollutant of concern and the REMSAD model results quantified sulfate impacts, three methods of evaluating states' impacts using REMSAD results were considered:

(1) States/regions that contributed 0.1 $\mu g/m^3$ sulfate or greater on the 20 percent worst visibility days in the base year (2002);

(2) States/regions that contributed at least 2 percent of total sulfate observed on 20 percent worst visibility days in 2002;

(3) The top ten contributing states on the 20 percent worst visibility days in 2002.

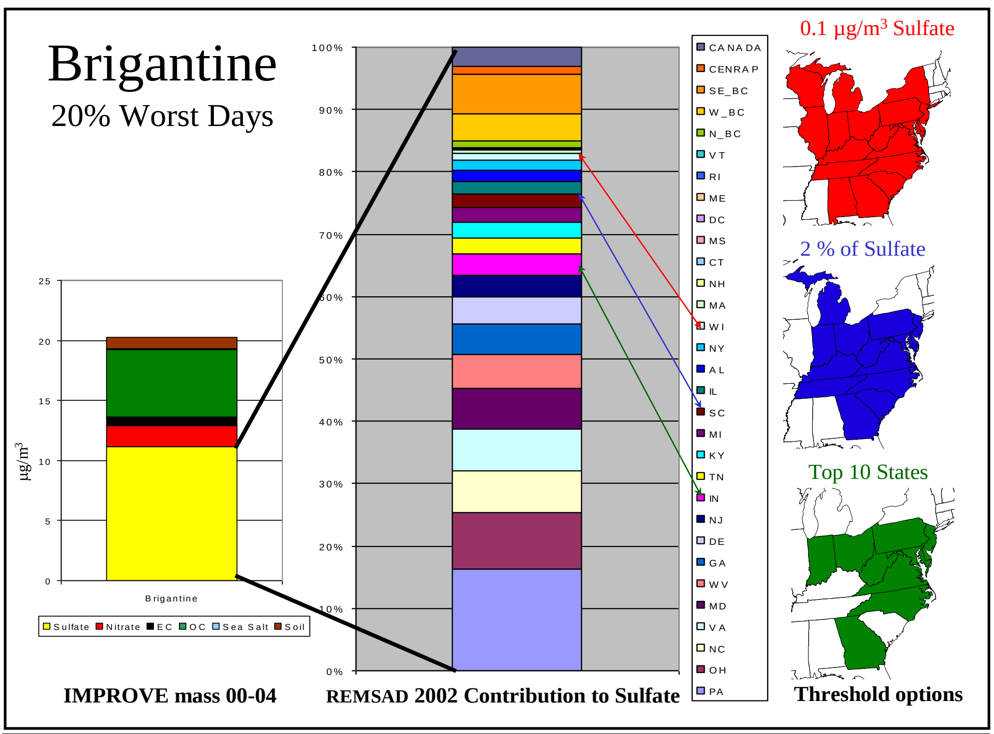
[7] Percentages based on 2002 annual average sulfate impact estimated with REMSAD model as described in MANE-VU Contribution Assessment, Chapter 4 and summarized on page 8-2 of the Contribution Assessment.

For purposes of deciding how broadly to consult, the MANE-VU States decided to use method 2, which identified states that contributed at least 2 percent of total sulfate observed on the 20 percent worst visibility days in 2002, as significant contributors.

Figure 4 shows modeled sulfate contributions to Brigantine Wilderness Area. On the left side is the IMPROVE monitored $PM_{2.5}$ mass data by species for 2000-2004 (the baseline years). The yellow, bottom portion of the bar chart is the measured sulfate concentration. The second part of Figure 4, in the center, shows the REMSAD sulfate modeling results for 2002. This middle bar chart indicates contributions of states and regions to the total modeled sulfate concentrations.

Finally, on the right side of Figure 4 are three maps which correspond to the three potential methods for evaluating states impacts that are identified above. The top map shows states contributing at least 0.1 μg/m^3 of sulfate; the middle map shows states contributing at least 2 percent of total sulfate; and the bottom map highlights the ten states contributing the greatest amount of the sulfate to Brigantine Wilderness Area in 2002.

Figure 4 - Modeled 2002 Contributions to Sulfate by State at Brigantine Wilderness Area



Thus, based on the *MANE-VU Contribution Assessment* and the application of the "≥ 2% rule," emissions from Delaware were determined to *significantly* contribute to visibility degradation *exclusively* to Brigantine Wilderness Area.

For the Brigantine Wilderness Area (BWA), on the 20 percent worst visibility days in 2000-2004, *sulfate accounted for **66 percent** of the particles responsible for light extinction*. After sulfate, organic carbon (OC) consistently accounted for the next largest fraction of light extinction due to particles. Organic carbon accounted for 13 percent of light extinction on the 20 percent worst visibility days at Brigantine Wilderness Area, followed by nitrate which accounted for 9 percent of light extinction.

Because of the findings above, it is not surprising that an emissions sensitivity analysis conducted by MANE-VU predicted that reductions in SO_2 emissions from EGU and non-EGU industrial point sources will result in the greatest improvements in visibility in the Class I areas in the MANE-VU region, more than any other visibility-impairing pollutant (particularly for Brigantine Wilderness Area, see Figure 3). As a result of the dominant role of sulfate in the formation of regional haze in the Northeast and Mid-Atlantic Region, MANE-VU concluded that an effective emissions management approach should rely heavily on broad-based regional SO_2 control efforts in the eastern United States.

3. CURRENT REASONABLE PROGRESS GOALS AND LONG TERM STRATEGY

3.1. REASONABLE PROGRESS GOALS

For the initial regional haze SIPs, the RHR at 40 CFR 51.308(d)(1) required States to establish reasonable progress goals (RPG) for each Class I area within the state that provide for reasonable progress towards achieving natural visibility. EPA released guidance on June 7, 2007 to use in setting reasonable progress goals.[8] RPGs are interim goals that represent incremental visibility improvement over time toward the goal of natural background conditions by 2064. The goals were required to provide for improvement in visibility for the most impaired days, and ensure no degradation in visibility for the least impaired days over the 10-year period for which a SIP covers (2008-2018 for the initial SIPs).

In accordance with the requirements of 40 CFR §51.308(d)(1), MANE-VU Class I States established RPGs for their various Class I areas, of which only the Brigantine Wilderness Area is of interest in this 5-year progress report (see Section B.2). To calculate the rate of progress represented by each reasonable progress goal, MANE-VU compared baseline visibility conditions to natural visibility conditions in each Class I area and determined the uniform rate of visibility improvement (expressed in deciviews, or “dv”) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. The RPGs were developed using the Community Multi-scale Air Quality (CMAQ) modeling platform described in the *MANE-VU Modeling for Reasonable Progress Report, Appendix N*.

Table 2 shows the baseline and 2064 natural background visibility, as well as the calculated RPG for the Brigantine Wilderness Area, based on modeled 2018 emission projections.[9]

[8] http://www.epa.gov/ttn/caaa/t1/memoranda/reasonable_progress_guid071307.pdf

[9] http://www.nescaum.org/topics/regional-haze/regional-haze-documents

Table 2 - Reasonable Progress Goals for the Brigantine Wilderness Area (dv)

	Baseline Visibility (2000-2004)	Natural Background Conditions in 2064	Reasonable Progress Goal for 2018	2018 CMAQ Projections
20% Worst Days	29.0	12.2	25.1	25.1
20% Best Days	14.3	5.5	12.2	12.2

3.2. LONG TERM STRATEGY - MANE-VU REGIONAL COURSE OF ACTION

As discussed previously, the MANE-VU Contribution Assessment[10] produced a conceptual model of regional haze in which sulfate emerged as the most important single constituent of haze-forming fine particle pollution and the principal cause of visibility impairment across the region. Sulfate alone accounts for anywhere from one-half to two-thirds of total fine particle mass on the 20 percent haziest days at MANE-VU Class I sites. Even on the 20 percent clearest days, sulfate generally accounted for the largest fraction (40 percent or more) of total fine particle mass in the region. Sulfate has an even larger effect when one considers the differential visibility impacts of different particle constituents. It typically accounts for 70–82 percent of estimated particle-induced light extinction at northeastern and mid-Atlantic Class I sites.

Therefore, MANE-VU's long-term strategy (LTS) included measures to control sources of SO_2 both within the MANE-VU region and in other states that were determined to significantly contribute to regional haze at MANE-VU Class I Areas. The largest source category responsible for SO_2 emissions within these areas was determined to be EGUs and industrial boilers, and EPA's Clean Air Interstate Rule (CAIR) was the strategy of choice for most states to reduce emissions from EGUs by 2018. [11,12]

[10] Contributions to Regional Haze in the Northeast and Mid-Atlantic United States. NESCAUM, 2006 http://www.nescaum.org/documents/contributions-to-regional-haze-in-the-northeast-and-mid-atlantic--united-states/

[11] Although the Delaware 2008 Regional haze SIP included CAIR in the section discussing reductions, Delaware did not rely on CAIR directly. CAIR was discussed in the 2008 SIP because it was included as a control measure for 2018, and thus was instrumental in modeling for establishing RPGs for all MANE-VU Class I areas. As demonstrated in this section, Delaware complied with EGU SO2 and NOx reductions via 7 DE Admin Code 1146.

[12] On May 12, 2005, the EPA promulgated CAIR, which required reductions in emissions of NO_X and SO_2 from large fossil fuel fired EGUs. These emission reductions were included as part of the MANE-VU 2018 modeling effort (and thus indirectly in establishing the RPGs). The U.S. Court of Appeals for the D.C. Circuit ruled on petitions for review of CAIR and CAIR Federal Implementation Plans, including their provisions establishing the CAIR NO_X annual and ozone season and SO_2 trading programs. On July 11, 2008, the Court issued an opinion vacating and remanding these rules. However, parties to the litigation requested rehearing of aspects of the Court's decision, including vacating them. The December 23, 2008 ruling leaves CAIR in place, until the EPA issues a new rule to replace CAIR in accordance with the July 11, 2008 Court decision. On July 6, 2011, the EPA finalized the Cross State Air Pollution Rule (CSAPR). EPA intended for this rule to replace CAIR beginning 2012, and requiring 27 states in the eastern half of the United States to reduce power plant emissions. The EPA also issued a supplemental proposal for six states to make summer time NO_X reductions. This supplemental proposal, when finalized, would bring the total number of states participating in the program to 28. CSAPR was estimated to reduce 2005 emissions from EGUs by 6,500,000 tons of SO_2 annually and 1,400,000 tons of NO_X annually in covered states. These estimates represented a 71 percent reduction in SO_2 and a 52 percent reduction in NO_X from 2005 levels. On December 30, 2011, the U.S. Court of Appeals for the D.C. Circuit issued a ruling to stay the CSAPR

The RPGs adopted by the MANE-VU Class I States represent implementation of the regional course of action set forth by MANE-VU on June 20, 2007 in two Resolutions: "Statement of the Mid-Atlantic/Northeast Visibility Union (MANE-VU) Concerning a Course of Action within MANE-VU toward Assuring Reasonable Progress," and "The Resolution of the Commissioners of States with Mandatory Class I Federal Areas within the Mid-Atlantic Northeast Visibility Union (MANE-VU) Regarding Principles for Implementing the Regional Haze Rule (Resolution).

On June 20, 2007, the Mid-Atlantic and Northeast States agreed to pursue a coordinated course of action designed to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal Areas within MANE-VU and to leverage the multi-pollutant benefits that such measures may provide for the protection of public health and the environment. This course of action includes pursuing the adoption and implementation of the following "emission management" strategies by MANE-VU states, as appropriate and necessary:

- Timely implementation of BART requirements;

- A low sulfur fuel oil strategy in the inner zone States (New Jersey, New York, Delaware, and Pennsylvania, or portions thereof) to reduce the sulfur content of: distillate oil to 0.05% sulfur by weight (500 ppm) by no later than 2012, of #4 residual oil to 0.25% sulfur by weight by no later than 2012, of #6 residual oil to 0.3 – 0.5% sulfur by weight by no later than 2012, and to further reduce the sulfur content of distillate oil to 15 ppm by 2016;

- A low sulfur fuel oil strategy in the outer zone States (the remainder of the MANE-VU region) to reduce the sulfur content of distillate oil to 0.05% sulfur by weight (500 ppm) by no later than 2014, of #4 residual oil to 0.25 – 0.5% sulfur by weight by no later than 2018, and of #6 residual oil to no greater than 0.5% sulfur by weight by no later than 2018, and to further reduce the sulfur content of distillate oil to 15 ppm by 2018, depending on supply availability;

- A 90% or greater reduction in sulfur dioxide emissions from each of the electric generating unit stacks identified by MANE-VU (comprising a total of 167 stacks) as reasonably anticipated to cause or contribute to impairment of visibility in each mandatory Class I Federal area in the MANE-VU region. If it is infeasible to achieve that level of reduction from a unit, alternative measures will be pursued in such State; and

- Continued evaluation of other control measures including energy efficiency, alternative clean fuels, and other measures to reduce SO_2 and nitrogen oxide (NO_x) emissions from all coal-burning facilities by 2018 and new source performance standards for wood

pending judicial review. On August 17, 2012, the D.C. Circuit Court of Appeals vacated CSAPR. On October 5, 2012, EPA requested a rehearing *en branc* of the CSAPR vacatur. CAIR remains in effect in light of this decision.

combustion. These measures and other measures identified will be evaluated during the consultation process to determine if they are reasonable and cost-effective.

- The application of reasonable controls on non-EGU sources resulting in a 28% reduction in non-EGU SO_2 emissions, relative to on-the-books, on-the-way 2018 projections used in regional haze planning, by 2018, which is equivalent to the projected reductions MANE-VU will achieve through its low sulfur fuel oil strategy; [13]

MANE-VU's LTS to reduce visibility impairment allowed each state up to 10 years to pursue adoption and implementation of reasonable and cost-effective NO_x and SO_2 control measures.

[13] The 28 percent (%) emission reduction from non-EGU sources outside MANE-VU was intended to represent a similar emission reduction as the MANE-VU Low Sulfur Fuel Oil strategy in the areas inside MANE-VU. This strategy intentionally did not define a specific control measure. It was the intention of the MANE-VU states to enable contributing states to define how they would achieve this additional reduction in a way that is most reasonable for the sources in their state. Based on MANE-VU's initial analysis of available projection inventories for 2018, these targets were estimated as 151,000 and 308,000 tons per year reduction in non-EGU SO2 emissions from the Midwest RPO and VISTAS RPO respectively. MANE-VU reached a consensus with the Midwest RPO during the consultation process that 131,600 tons per year was a more accurate estimate of the magnitude of a 28 percent reduction relative to their projected 2018 non-EGU SO2 emissions of 470,000 tons per year.

C. PERIODIC PROGRESS REPORT

[40 CFR 51.308(g)]

40 CFR 51.308(g) of the RHR requires the state to submit:

> *A report to the Administrator every 5 years evaluating progress towards the reasonable progress goals for each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the state.*

As demonstrated in Delaware's 2008 regional haze SIP and in Section B.2, emissions from Delaware significantly impact only the Brigantine Wildness Area (BWA), which is the closest Class I area to Delaware. The remainder of this 5-year Progress Report will be primarily oriented towards addressing Delaware emission reduction obligations as part of the LTS, post-SIP updates and visibility improvement at Brigantine Wilderness Area.

1. STATUS AND REDUCTIONS: IMPLEMENTATION MEASURES IN SIP

[40 CFR 51.308(g)(1)] and [40 CFR 51.308(g)(2)]

40 CFR 51.308(g)(1) requires "*A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for Class I areas both within and outside the state*." Sections 51.308(g)(2) requires **"***A summary of the emissions reductions achieved throughout the State through implementation of the measures described in* [40 CFR 51.308(g)(1].*"*

The EPA Principles document ("guidance")[14] interprets 51.308(g)(1 and,2) as:

1. To meet this requirement [51.308(g)(1)], the report should identify the control measures in the state's regional haze SIP that apply to sources within the state that the state relied on to meet the requirements of the regional haze program, and;
2. To meet this requirement [51.308(g)(2)], progress reports should identify and estimate emissions reductions to date in visibility-impairing pollutants from the SIP measures discussed above.[15]

[14] *General Principles for the 5-Year Regional Haze Progress Reports for the Initial Regional Haze State Implementation Plans (Intended to Assist States and EPA Regional Offices in Development and Review of the Progress Reports)*. U.S. Environmental Protection Agency. April 2013.

[15] EPA further states, "Also, in meeting this requirement, judgment is appropriate in the degree of quantification for the measures that were relied upon. If a measure is listed as a relied upon measure under 51.308(g)(1) or 51.309(d)(10)(i)(A), this does not necessarily mean a detailed quantification is required for each measure under 51.308(g)(2), especially if a given measure is a relatively small contributor to the overall "emissions reductions achieved throughout the State through implementation of the measures."

Due to the nature of DNREC's EGU regulatory status and emission reduction analysis of BART and the "167 Stacks" in Delaware's initial regional haze SIP; for this 5-year progress report Sections 51.308(g)(1) and 51.308(g)(2) will be combined and discussed under one section.

This section provides a status and emissions assessment of how Delaware met the MANE-VU LTS obligations, and how Delaware continues to meet those obligations.[16] This summary also provides a status of the *significant* Delaware SO_2 and NOx emission reduction measures that were included in the Delaware 2008 SIP emissions projections inventory used for the MANE-VU modeling to set RPGs at Class I areas. This summary includes discussions of benefits associated with each measure. Such benefits are quantified wherever possible. In instances where implementation of a measure did not occur in a timely manner, information is provided on the source category and its relative impact on the overall future year emissions inventories.

The MANE-VU 2018 "on the books" and "on the way" (OTB/OTW) emissions inventory accounted for all emission controls in place since 2002, as well as specific emission controls that will achieve additional reductions by 2018. A separate MANE-VU regional inventory was also developed for purposes of modeling SO_2 control measures which would determine Class I areas meeting uniform rate of progress through reasonable control measures through modeling 2018 scenarios (called the "Best & Final" emission projections). Delaware's SIP was approved by EPA contingent upon the Best and Final emissions (see 76 Federal Register 42557 for EPA's analysis).

As noted in Section B.3.1 of this report and above, in establishing reasonable progress goals MANE-VU Class I states' LTS focused on implementation of emissions reductions from:

(1) BART

(2) EGUs

(3) Low sulfur fuels

(4) Continued evaluation of other control measures (including energy efficiency, alternative clean fuels, and other measures to reduce SO2 and nitrogen oxide (NOx) emissions from all coal-burning facilities by 2018 and new source performance standards for wood combustion).

1.1. BEST AVAILABLE RETROFIT TECHNOLOGY (MANE-VU LTS #1)

In the 1977 Amendments to the Clean Air Act, Congress directed EPA and the states to identify existing sources that had been in operation for no more than 15 years and that caused or contributed to visibility impairment in National Parks and Wilderness Areas designated as Class

[16] Delaware's initial regional haze SIP relied only upon *existing* federal and state regulations. No "commitments" were necessary. Thus, the 2008 SIP already demonstrated Delaware met its obligations for Brigantine Wilderness Area to meet its RPGs.

I areas. Those sources were to install and operate best available retrofit technology (BART) to reduce their impacts on Class I areas. The BART requirement is an important element of EPA's regional haze rule. Initially promulgated in 1999 and revised most recently in 2005, the BART portion of EPA's rule required BART determinations to be part of the State Implementation Plan (SIP). The state must require sources to comply with any BART determinations as expeditiously as practicable, but no later than five years after EPA approval of the SIP.

40 CFR 51.308(g)(1) requires that the progress report describe the status of implementation of all measures included in the SIP for achieving reasonable progress goals for Class I areas within and outside the State that are affected by emissions from within the State. As described in Section B.3.2 of this report and noted above; in establishing reasonable progress goals MANE-VU Class I states relied in part on timely implementation of BART requirements.[17] The following section provides information on the progress of Delaware in implementing BART requirements.[18]

1.1.1. BART - Sulfur Dioxide and Oxides of Nitrogen

In its September 25, 2008 *Visibility State Implementation Plan* (2008 regional haze SIP), Delaware provided detailed discussion of its development of 7 DE Admin Code 1146, a non-trading emissions control regulation for EGUs that was established primarily as a measure to aid in the attainment of the ozone and fine particulate matter ambient air quality standards, and to reduce emissions of the neurotoxin mercury. 7 DE Admin Code 1146 was promulgated in 2006, and included staged NOx and SO_2 control stringency requirements that took effect in 2009 and 2012. 7 DE Admin Code 1146 provides for stringent control of EGU NOx and SO_2 emissions by implementation of unit-specific annual NOx and SO_2 mass emissions caps and short term (rolling 24-hour) NOx and SO_2 emission rate limits (lb/MMBTU). In its regional haze SIP, Delaware demonstrated that 7 DE Admin Code 1146 was superior to a unit-by-unit BART analysis with regards to SO_2 and NOx emissions control for EGUs, and included 7 DE Admin Code 1146 in the regional haze SIP as an alternative measure to BART for SO_2 and NOx under 40 CFR 51.308(e)(2)(i).

In its 2008 regional haze SIP, Delaware documented that there were four EGUs located in Delaware that were subject to BART. These four units are shown in the following table:

[17] Based on EPA regulations and guidance, several MANE-VU states relied on CAIR as meeting BART requirements for some Electricity Generating Units (EGUs). CAIR was challenged in court and remanded to EPA for revision. Because EPA's CAIR program was overturned by the courts, some MANE-VU states made determinations for BART-eligible CAIR EGUs instead of relying on CAIR for BART. In 2011, EPA replaced CAIR with the Cross State Air Pollution Rule (CSAPR). CSAPR was challenged and subsequently vacated. EPA has appealed that decision. In the meantime, CAIR remains in place. On November 19, 2012, EPA Assistant Administrator Gina McCarthy provided guidance on the states' ability to rely on CAIR for purposes of implementing the Regional Haze Rule.

[18] Further visibility benefits are likely to result from installation of new emission controls at BART-eligible facilities located in neighboring states outside MANE-VU. However, the MANE-VU modeling did not account for BART controls outside MANE-VU and, consequently, did not include visibility improvements at MANE-VU Class I Areas that would be likely to accrue from such measures.

Table 3 - Delaware Units Subject to BART

Facility	BART Eligible Unit	Nameplate Rating (MW)	Initial Year of Operation	Primary Fuel on September 25, 2008	Heat Input Rating (MMBTU/hr)
Edge Moor	4	177	1966	Bituminous Coal	1867
Edge Moor	5	446	1973	Residual Fuel Oil	4695
Indian River	3	177	1970	Bituminous Coal	1904
McKee Run	3	114	1975	Residual Fuel Oil	1180

For Delaware's four BART eligible EGUs, BART "presumptive" limits (as discussed in Appendix Y of 40 CFR Part 51 – *Guidelines for BART Determinations Under the Regional Haze Rule*) were determined in the 2008 regional haze SIP. Note that 40 CFR Part 51.308(e)(2)(i)(C) provides that continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate may be used in this analysis. The BART presumptive NOx and SO_2 emission rate limits for the four Delaware BART eligible EGUs are shown in the following table:

Table 4 - BART presumptive NOx and SO_2 emission rate limits

Facility	BART Eligible Unit	2015 BART Presumptive SO_2 Rate	2015 BART Presumptive NO_x Rate
Edge Moor	4	0.15 lb/MMBTU	0.28 lb/MMBTU
Edge Moor	5	1.0 % Sulfur Fuel Oil	Existing (0.29/MMBTU)
Indian River	3	0.15lb/MMBTU	0.39 lb/MMBTU
McKee Run	3	1.0 % Sulfur Fuel Oil	Existing (0.32/MMBTU)

In the 2008 regional haze SIP it was shown that the SO_2 and NOx reductions expected from those BART-eligible units, relative to a baseline year 2002 actual emissions (from CAMD), due to presumptive BART was as follows:

Table 5 - 2002 Actual SO_2 and NOx vs. Presumptive BART (initial Haze SIP)

Facility	Unit	2002 Actual SO_2 Emissions (tons)	2002 Actual NO_x Emissions (tons)	Presumptive BART SO_2 (tons)	Presumptive BART NO_x (tons)	Estimated SO_2 Reduction from Presumptive BART (tons)	Estimated NO_x Reduction from Presumptive BART (tons)
Edge Moor	4	5051	1096	728	1359	4323	-263
Edge Moor	5	2132	1289	3547	1289	-1415	0
Indian River	3	4682	664	324	841	4358	-177
McKee Run	3	700	345	960	345	-260	0
Total		**12565**	**3394**	**5559**	**3834**	**7006**	**-440**

As shown in Table 5, for the Delaware BART eligible units, application of presumptive BART SO_2 and NOx emission rate limits were projected to achieve only limited annual SO_2 and NOx reductions relative to the units' 2002 baseline year. This is principally due to the fact that Delaware had promulgated regulations that served to control SO_2 and NOx emissions from this group of EGUs. The subject Delaware regulations were effective prior to 2002 and they served to control fuel sulfur content and also reflected application of NOx Reasonably Available Control Technology (RACT). Assuming that any new Delaware regulation specifically implementing presumptive BART would have reflected a "no backsliding" provision (relative to the 2002 baseline year), the Delaware BART eligible EGUs may have been estimated to reduce SO_2 emissions by 8,681 tons/year with no net reduction in annual NOx emissions.

Delaware's 2008 regional haze SIP documented that its 7 DE Admin Code 1146 achieved SO_2 and NOx reductions in excess of those that would be achieved by application of BART alone. The additional reductions beyond BART were documented to be achieved by 7 DE Admin Code 1146's stringent short term (24-hour rolling average) SO_2 and NOx emission rate limits and stringent annual SO_2 and NOx mass emission caps that were applicable to 8 coal-fired and residual oil-fired EGUs. 7 DE Admin Code 1146's SO_2 and NOx emission rate and mass emissions caps became effective in 2009, with a second stage of more stringent NOx and SO_2 emission rate limits becoming effective in 2012. Delaware's EGUs that were subject to 7 DE Admin Code 1146 are shown in the following table:

Table 6 - Delaware's EGUs Subject to 7 DE Admin Code 1146

Facility	Unit	Nameplate Rating (MW)	Initial Year of Operation	Primary Fuel on September 25, 2008	Heat Input Rating (MMBTU/hr)
Edge Moor	3	75	1954	Bituminous Coal	1117
Edge Moor	4	177	1966	Bituminous Coal	1867
Edge Moor	5	446	1973	Residual Fuel Oil	4695
Indian River	1	82	1957	Bituminous Coal	1090
Indian River	2	82	1959	Bituminous Coal	1186
Indian River	3	177	1970	Bituminous Coal	1904
Indian River	4	442	1980	Bituminous Coal	5091
McKee Run	3	114	1975	Residual Fuel Oil	1180

Subsequent to the promulgation of 7 DE Admin Code 1146, sources subject to the requirements of 7 DE Admin Code 1146 utilized a variety of methods to achieve significant SO_2 and NOx reductions. These emissions reduction methods included installation of controls, fuel switches, and acceptance of operating restrictions. The following list indicates SO_2 and NOx emissions reduction methodologies associated with the sources that were subject to 7 DE Admin Code 1146:

- Edge Moor Unit 3 was formerly a primarily coal-fired EGU that was subject to 7 DE Admin Code 1146. Subsequent to promulgation of 7 DE Admin Code 1146, this unit has taken permit (permit AQM-003/00007) conditions to convert from utilizing coal as the unit's primary fuel with residual fuel-oil as a secondary fuel, to utilizing natural gas as the primary fuel with residual fuel-oil as the secondary fuel. Because the unit remains capable of combusting residual fuel oil, the unit remains subject to 7 DE Admin Code 1146. However, some of the permit conditions taken in conjunction with the fuel conversion are more restrictive than those of 7 DE Admin Code 1146. Specifically, the more restrictive permit conditions include restricting total annual operating hours to no more than 5168 hours/year (with no more than 876 of those hours firing residual fuel oil) and an annual NOx mass emissions limit of 265 tons/year. The unit remains subject to the 7 DE Admin Code 1146 residual fuel oil sulfur limit of 0.5% by weight and NOx emissions rate limit of 0.125 lb/MMBTU (requirement beginning January 1, 2012). While not specifically identified as a permit condition, the restriction on hours of operation and fuel sulfur content effectively cap the annual SO_2 mass emissions levels to approximately 251 tons/year.

- Edge Moor Unit 4 was formally a primarily coal-fired EGU that was subject to 7 DE Admin Code 1146. Subsequent to promulgation of 7 DE Admin Code 1146, this unit has taken permit (permit AQM-003/00007) conditions to convert from utilizing coal as the primary fuel with residual fuel-oil as a secondary fuel, to utilizing natural gas as the primary fuel with residual fuel oil as the secondary fuel. Because the unit remains capable of combusting residual fuel oil, the unit remains subject to 7 DE Admin Code 1146. However, some of the permit conditions taken in conjunction with the fuel conversion are more restrictive than those of 7 DE Admin Code 1146. Specifically, the more restrictive permit conditions include restricting total annual operating hours to no more than 5168 hours/year (with no more than 876 of those hours firing residual fuel oil) and an annual NOx mass emissions limit of 265 tons/year. The unit remains subject to the 7 DE Admin Code 1146 residual fuel oil sulfur limit of 0.5% by weight and NOx emissions rate limit of 0.125 lb/MMBTU (requirement beginning January 1, 2012). While not specifically identified as a permit condition, the restriction on hours of operation and fuel sulfur content effectively cap the annual SO_2 mass emissions levels to approximately 419 tons/year.

- Edge Moor Unit 5, using residual fuel oil as primary fuel and natural gas as a secondary fuel, remains subject to 7 DE Admin Code 1146. Applicable specific requirements of 7 DE Admin Code 1146 include the NOx mass emissions rate limit of 0.125 lb/MMBTU (beginning January 1, 2012), an annual NOx mass emissions limit of 1348 tons/year, and an annual SO_2 mass emissions limit of 4600 tons/year.

- Indian River Unit 1, a coal-fired unit that was subject to the requirements of 7 DE Admin Code 1146, was mothballed in April of 2011 as required under consent decree (C.A. No. 07C-02-283FSS).

- Indian River Unit 2, a coal-fired unit that was subject to the requirements of 7 DE Admin Code 1146, was mothballed in April of 2010 as required under consent decree (C.A. No. 07C-02-283FSS).

- Indian River Unit 3, a coal-fired unit subject to the requirements of 7 DE Admin Code 1146, is currently operating under a consent decree (C.A. No. 07C-02-283FSS) and will be permanently shutdown in accordance with the requirements of the consent decree no later than December 31, 2013.

- Indian River Unit 4 is a coal- fired unit subject to the requirements of 7 DE Admin Code 1146. The unit has installed NOx controls (SCR) and SO_2 controls flue gas desulfurization (FGD). These controls became operational in December 2011. The unit is in compliance with a consent decree (C.A. No. 07C-02-283FSS) SO_2 emissions rate limitation of 0.2 lb/MMBTU (rolling 24-hour average) and NOx emissions rate limitation of 0.10 lb/MMBTU (rolling 24-hour average). The unit remains subject to the requirements of 7 DE Admin Code 1146 for an annual SO_2 mass emissions cap of 3657 tons/year and an annual NOx mass emissions cap of 2032 tons/year.

- McKee Run Unit 3 was formerly a primarily residual oil-fired EGU that was subject to the requirements of 7 DE Admin Code 1146. The unit has elected to take permit (permit AQM-001/00002) conditions converting from the utilization of residual fuel oil as the primary fuel to utilizing natural gas as the primary fuel and low-sulfur #2 fuel oil (0.05% sulfur by weight) as the secondary fuel. The permit conditions for this unit also include a facility-wide annual SO_2 mass emissions cap of 400 tons/year and an annual NOx mass emissions cap of 244 tons/year.

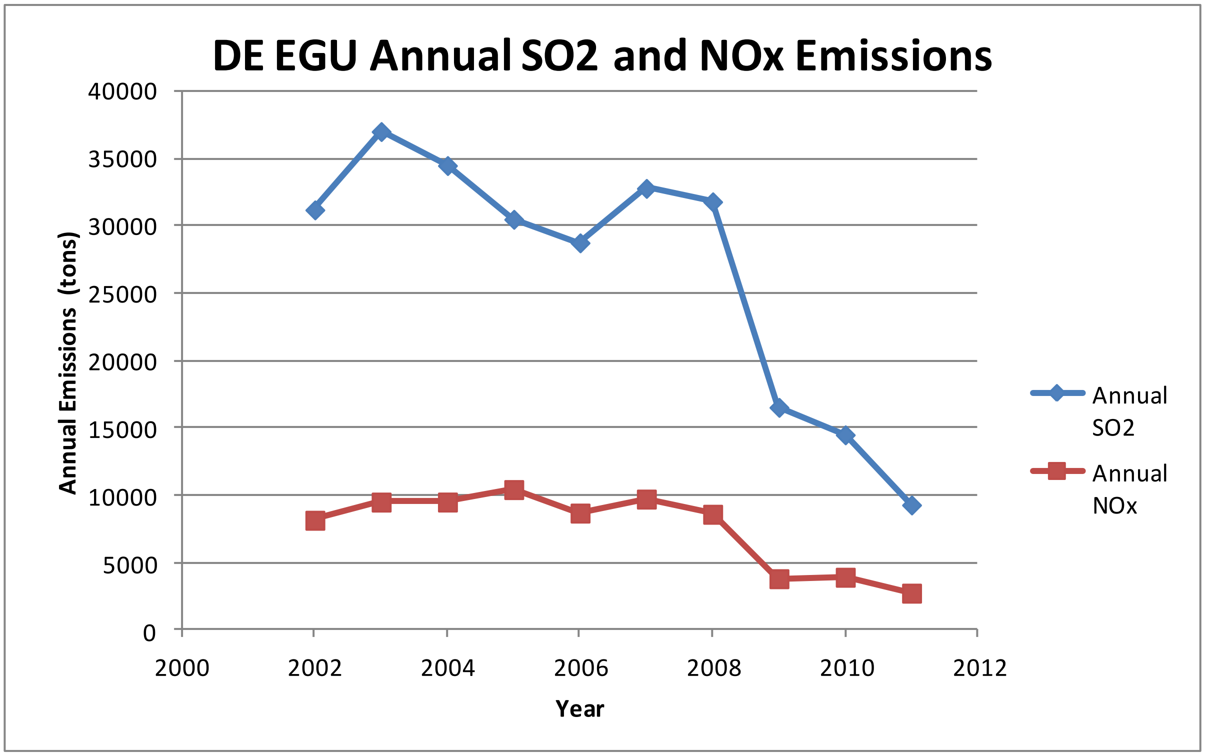
The SO_2 and NOx emissions limitations of 7 DE Admin Code 1146, and related consent decrees and permit conditions, have served to significantly reduce the SO_2 and NOx emissions from Delaware's EGUs that were subject to 7 DE Admin Code 1146.
Table 7 shows the total annual SO_2 and NOx mass emissions from this group of EGUs. The data was taken from the EPA's Clean Air Markets Program data (CAMD)[19], and includes the baseline year 2002 through calendar year 2011, the last calendar year with full year data available in the EPA's CAMD at the time of preparation of this document. Figure 5 represents the DE EGU annual SO_2 and NOx emissions data from
Table **7.**

[19] CAMD collects emissions of NO_x, SO_2 and heat input (HI) from large point sources in order to implement the emissions cap and trade program under the Acid Rain Control Program, the NO_x Budget Trading Program, or the Clean Air Interstate Rule found in Volume 40 Part 75 of the Code of Federal Regulations (CFR). These rules require hourly reporting of SO_2 and NO_X emissions from each participating unit. Most of the CAMD units are traditional power plants that sell electricity to the electrical grid (EGUs). There are, however, other types of units that report to CAMD that are not considered to be EGUs, such as petroleum refineries and cement kilns. For this report, only the EGU data was used. The annual unit level CAMD NO_X and SO_2 emissions files for 2011 were downloaded for use in this project. (CAMD2011)

Table 7 - CAMD emissions (2002-2011)

Year	Annual Total NO_x (tons)	Annual Total SO_2 (tons)
2002	8143	31183
2003	9492	36998
2004	9495	34475
2005	10419	30482
2006	8675	28738
2007	9714	32778
2008	8587	31785
2009	3803	16524
2010	3911	14485
2011	2731	9278

Figure 5 – DE CAMD EGU annual SO_2 and NOx (2002-2011)



It can be seen in the data from Table 7 and Figure 5 that there was a step change reduction in SO_2 and NOx annual emissions beginning in 2009. The 2009 SO_2 and NOx emissions step change corresponds to the first stage of SO_2 and NOx emissions reduction requirements imposed by 7 DE Admin Code 1146.

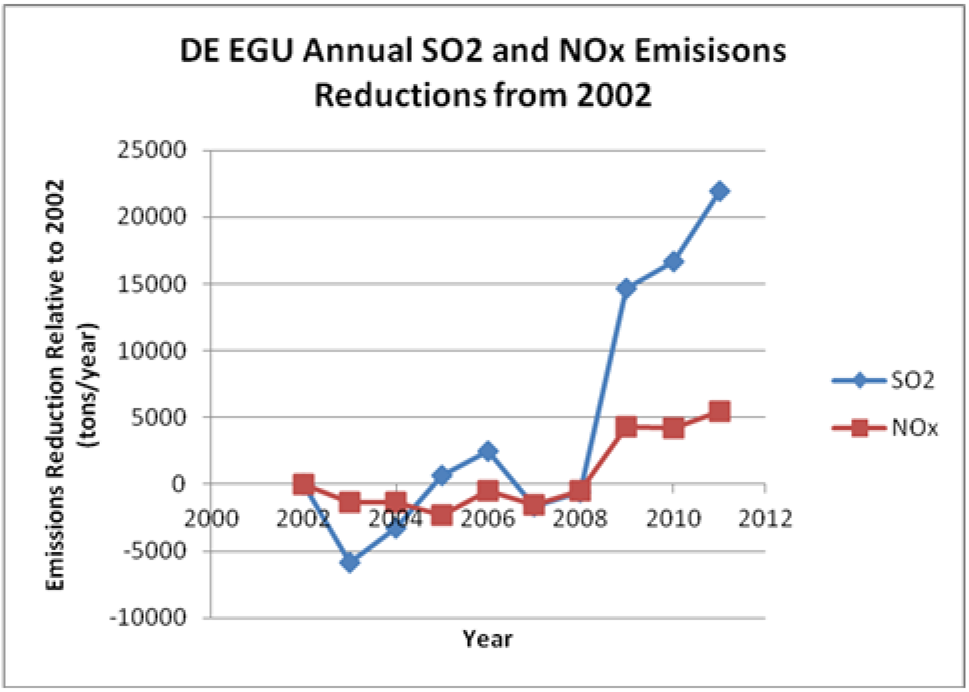
The following table for Delaware's EGUs subject to 7 DE Admin Code 1146 shows the amount of SO_2 and NOx emissions reductions that have annually occurred relative to the 2002 baseline year emissions:

Table 8 – CAMD SO_2 and NOx emissions reductions relative to the 2002 baseline year emissions

Year	Annual Total NO_x (tons)	Annual Total SO_2 (tons)	NO_x Reduction from 2002 (tons)	SO_2 Reduction from 2002 (tons)
2002	8143	31183	0	0
2003	9492	36998	-1349	-5815
2004	9495	34475	-1352	-3292
2005	10419	30482	-2276	701
2006	8675	28738	-532	2445
2007	9714	32778	-1571	-1595
2008	8587	31785	-444	-602
2009	3803	16524	4340	14659
2010	3911	14485	4232	16698
2011	**2731**	**9278**	**5412**	**21905**

Figure 6 represents the DE EGU annual SO_2 and NOx emissions data from Table 8.

Figure 6 - SO2 and NOx emissions since the 2002 baseline year



From the data in Table 8 and Figure 6 it can be seen that relative to the 2002 baseline year, the EGUs that were subject to 7 DE Admin Code 1146 have made significant reductions in SO_2 and NOx emissions beginning in 2009.

The Table 8 data indicates that by 2011 the EGUs that were subject to 7 DE Admin Code 1146 had reduced SO_2 mass emissions by 21,905 tons per year (approximately 70%) and reduced NOx mass emissions in 2011 by 5,412 tons per year (approximately 66%). These actual reductions are greater than the 8,681 tons of SO_2 reductions and zero tons of NOx reductions estimated to have been achieved from Delaware's BART eligible EGUs under the emissions limitations of only presumptive BART.

This data indicates that Delaware's 7 DE Admin Code 1146, and related permit conditions and consent decrees, have demonstrated effective, significant SO_2 and NOx emissions reductions requirements, and have already achieved annual SO_2 and NOx emission reductions in excess of those anticipated under presumptive BART only.

It should be noted that all of the SO_2 and NOx emissions limitations of 7 DE Admin Code 1146, and related consent decrees and permit conditions, were not reflected in the 2011 and earlier operating data discussed above. The 2011 and post-2011 emissions reduction provisions that will serve to reduce SO_2 and NOx emissions from these units include the following:

- 7 DE Admin Code 1146's second stage of stringency for SO_2 emissions rate was effective January 1, 2012.

- 7 DE Admin Code 1146's second stage of stringency for NOx emissions rate was effective January 1, 2012.

- Indian River Unit 1 was not mothballed until April 2011, in compliance with its consent decree.

- Indian River Unit 3 is not required to be mothballed by consent decree until December 31, 2013.

- Indian River Unit 4 did not complete its installation and commence operation of its new SO_2 and NOx controls until December 2011, in compliance with its consent decree.

All of the above SO_2 and NOx emissions reduction provisions for the EGUs originally subject to 7 DE Admin Code 1146 will be in effect by 2014. For each of the subject units, Table 9 shows the 2002 baseline year SO_2 and NOx emissions (from CAMD), the estimated SO_2 and NOx emissions under presumptive BART rates (assuming utilization of 2002 baseline heat input levels), and the estimated SO_2 and NOx Potential-to-Emit (PTE). It should be noted that the PTE values are based upon enforceable hard emissions caps or estimated from enforceable operating restrictions, and therefore represent values that are unlikely to be reached except during years of extremely high generation demand from the subject units.

Table 9 - 2002-Presumptive BART-2014 PTE Emissions

Facility	Unit	2002 Actual SO2 Emissions (tons)	2002 Actual NOx Emissions (tons)	Estimated Annual SO2 Emissions Under Presumptive BART (tons)	Estimated Annual NOx Emissions Under Presumptive BART (tons)	Estimated 2014 SO2 PTE (tons)	Estimated 2014 NOx PTE (tons)
Edge Moor	3	3344	922	3344	922	251	265
Edge Moor	4	5051	1096	728	1359	419	483
Edge Moor	5	2132	1289	3547	1289	4600	1348
Indian River	1	3950	707	3950	707	0	0
Indian River	2	3833	641	3833	641	0	0
Indian River	3	4682	664	324	841	0	0
Indian River	4	7491	2479	7491	2479	3657	2032
McKee Run	3	700	345	960	345	400	244
	Total	31183	8143	24177	8583	9327	4372

The estimated 2014 SO_2 PTE total of 9327 tons/year shown in Table 9 represents a reduction of 21,856 tons (approximately 70%) from the actual 2002 SO_2 emissions of 31,183 tons for the same units. The actual 2002 to 2014 PTE SO_2 emissions reduction of 21,856 tons/year also greatly exceeds the SO_2 reduction of 8,681 tons/year that would be estimated to result from the Delaware BART eligible EGUs meeting presumptive BART SO_2 limits (relative to 2002 actual emissions).

The estimated 2014 NOx PTE total of 4372 tons/year shown in Table 9 represents a reduction of 3,771 tons/year (approximately 46%) from the actual 2002 NOx emissions of 8143 tons for the same units. The actual 2002 to 2014 PTE NOx emissions reduction of 3,771 tons/year also exceeds the NOx reduction of zero tons that would be estimated to result only from Delaware's BART eligible EGUs meeting presumptive BART NOx limits (relative to 2002 actual emissions).

If the data in Table 9 is revised to reflect the SO_2 and NOx emissions on a facility basis, rather than on a unit basis, it can be seen that Delaware's 7 DE Admin Code 1146, and related permit conditions and consent decrees, also results in facility emissions that are far less than the emissions from that facility under a presumptive BART only scenario. Table 10 reflects this per facility emissions scenario.

Table 10 - SO_2 and NOx emissions on a facility basis

Facility	2002 Actual SO_2 Emissions (tons)	2002 Actual NO_x Emissions (tons)	Estimated Annual SO_2 Emissions Under Presumptive BART (tons)	Estimated Annual NO_x Emissions Under Presumptive BART (tons)	Estimated 2014 SO_2 PTE (tons)	Estimated 2014 NO_x PTE (tons)
Edge Moor	10527	3307	7619	3570	5270	2096
Indian River	19956	4491	15598	4668	3657	2032
McKee Run	700	345	960	345	400	244

Based upon comparison with actual baseline year (2002) emissions and unit capacities, it is clear that the emission rate limits of 7 DE Admin Code 1146, and related permit conditions and consent decrees, achieve greater annual SO_2 and NOx emissions reductions than would be achieved only through application of presumptive BART emissions limits on Delaware's BART eligible EGU sources. Further, application of Delaware's 7 DE Admin Code 1146's, and related permit conditions and consent decrees, SO_2 and NOx emission rate limits to this larger fleet of EGUs results in total SO2 and NOx emissions reductions significantly greater than those that would be achieved by presumptive BART alone. The requirements of Delaware's 7 DE Admin Code 1146, and related permit conditions and consent decrees, do not result in a substantial difference in distribution of emissions relative to BART only for Delaware's BART-eligible EGU sources, meeting the requirements of 40 CFR 51.308(e)(3). In fact, there is no difference in the distribution of emissions as, like BART, the requirements of 7 DE Admin Code 1146, and related permit conditions and consent decrees, apply on a unit-by-unit basis (i.e., no trading).

The analysis, development, and implementation of Delaware's 7 DE Admin Code 1146, and related permit conditions and consent decrees, in conjunction with the above emissions calculations, provide a demonstration that the requirements of 7 DE Admin Code 1146, and related permit conditions and consent decrees, have achieved and will continue to achieve greater reasonable progress than would have resulted from the installation and operation of BART at all EGU sources subject to BART in Delaware, as discussed in 40 CFR 51.308(e)(2). As demonstrated above, the requirements of 7 DE Admin Code 1146, and related permit conditions and consent decrees, also fulfill the requirements of 40 CFR 51.308.(e)(3);

> "*A state which opts under 40 CFR 51.308(e)(2) to implement an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART may satisfy the final step of the demonstration required by that section as follows: If the distribution of emissions is not substantially different than under BART, and the alternative measure results in greater emissions reductions, then the alternative measure may be deemed to achieve greater reasonable progress*."

1.1.2. BART - Particulate Matter

In its 2008 regional haze SIP, and in accordance with 40 CFR 51.308(e)(2)(i)(A), Delaware's DNREC identified four EGUs located in the state of Delaware that have the potential to contribute to impairment of visibility in a Class I area, and were therefore considered BART eligible. The four Delaware BART eligible EGUs and related technical information that was current for the 2008 regional haze SIP are shown in the following table:

Table 11 - Delaware BART-subject EGUs

Facility	Unit	Boiler Type	Primary Fuel	Date of Commercial Operation	Heat Input Capacity (MMBTU/hr)
Edge Moor	4	Tangentially-fired	Bituminous Coal	4/1/1966	1867
Edge Moor	5	Dry bottom wall-fired	Residual Fuel Oil	8/1/1973	4695
Indian River	3	Dry bottom wall-fired	Bituminous Coal	6/1/1970	1904
McKee Run	3	Dry bottom wall-fired	Residual Fuel Oil	9/1/1975	1180

BART determinations are required in accordance with 40 CFR 51.308(e)(1)(ii)(A). BART determinations are required to be based on an analysis of the best system of available continuous emission control technologies and associated emission reductions achievable by those control technologies. 40 CFR 51.308(e)(1)(ii)(A) requires the analysis to take into consideration the following five factors for the technologies available:

(1) Cost of compliance

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

(3) Pollution control equipment in use at the source

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

(5) The degree of improvement in visibility which may reasonably be anticipated to result from use of the technology.

As documented in the 2008 regional haze SIP, the owner/operator of Delaware's four BART eligible EGUs were requested to conduct BART determinations using the 5-factor analysis for PM. Consistent with the MANE-VU Board (June, 2004) decision, these four analyses included consideration of potential visibility impacts as a result of installing various controls for primary particulate matter. Based upon DNREC's review of the BART determinations and other related information, primary particulate matter BART was established for each of Delaware's four BART eligible EGUs. For each of those four BART eligible EGUs, the following sections discuss the status of the implementation of primary particulate matter BART for the respective BART eligible EGU.

Edge Moor Unit 4

Edge Moor Unit 4 incorporates a tangential-fired steam generator with an 1867 MMBTU/hour heat input capacity supplying a steam turbine generator with a nameplate rating of approximately 177 MW. At the time of submittal of Delaware's 2008 regional haze SIP, Edge Moor Unit 4 utilized bituminous coal as its primary fuel, with #6 fuel oil and natural gas as secondary fuels, and included a cold side precipitator for particulate emissions control. As a BART eligible unit, Edge Moor Unit 4's owner operator, Conectiv (now owned by Calpine), was requested by Delaware' DNREC to conduct a BART determination.

In the 2008 regional haze SIP, Delaware's DNREC documented that Conectiv had provided an analysis of the available control technologies for Edge Moor Unit 4, and a "five factor analysis" pursuant to the requirements of 40 CFR 51.308(e)(1)(ii)(A) for the technologically feasible options. Conectiv identified the technologically feasible options for Edge Moor Unit 4 to include the existing ESP and the addition of a dry sorbent injection (DSI) system, and an ESP/DSI combination to include a downstream baghouse. Conectiv's analysis indicated that the addition of a baghouse was not cost-effective for the purposes of improving visibility in Class I areas, and identified BART for Edge Moor Unit 4 as continued use of the existing ESP and addition of a DSI system. As documented in the 2008 regional haze SIP, Delaware's DNREC reviewed and concurred with the Conectiv analysis, and made the determination that the Edge Moor Unit 4's existing ESP and the addition of a DSI system were considered BART for Edge Moor Unit 4.

Subsequent to the 2008 regional haze SIP submittal, Conectiv installed a DSI system to Edge Moor Unit 4. The installation and operation of the DSI, in addition to the operation of the existing ESP, served to complete the requirements for particulate matter BART for Edge Moor Unit 4.

In 2010, the Edge Moor facility was purchased by Calpine Mid-Atlantic Generation (Calpine). Calpine subsequently made the decision to convert Edge Moor Unit 4 from utilizing coal as the primary fuel to utilizing pipeline natural gas as the primary fuel. Calpine requested permit conditions to convert Edge Moor Unit 4 from utilizing bituminous coal as the primary fuel and #6 fuel oil as a secondary fuel, to utilizing natural gas as the primary fuel and 0.5% sulfur, #6 fuel oil as the secondary fuel. Calpine also requested permit restrictions on total annual operating hours: restricting total annual operating hours to no more than 5168 hours/year with no more than 876 of those hours firing residual fuel oil. Delaware's DNREC approved the requested permit conditions (permit AQM-003/00007) and the fuel and operating hour permit conditions were incorporated into Edge Moor Unit 4's operating permit.

With regards to primary particulate emissions, pipeline natural gas is among the cleanest steam generator fuels. Relative to a pulverized coal-fueled steam generator utilizing an ESP (and firing coal fuels similar to those most recently combusted at Edge Moor Unit 4), AP-42 emissions factors estimate an approximate 90% reduction in particulate emissions when firing pipeline natural gas, as shown in the following table.

Table 12 - AP-42 Emissions Factors – Coal Relative to Natural Gas

AP-42 Bituminous Coal PM_{10} Emissions Factor* (lb/ton)	**AP-42 Bituminous Coal PM_{10} Emissions Factor with Representative Coal*** (lb/MMBTU)**	**AP-42 Natural Gas Filterable PM Emissions Factor (lb/MMscf)**	**AP-42 Natural Gas Filterable PM Emissions Factor**** (lb/MMBTU)**	**Reduction in Estimated Emissions Rate (%)**
0.054A**	0.0218	1.9	0.0019	91

Notes: * Emissions factor for dry bottom, coal fired steam generator utilizing an ESP and firing bituminous coal.
** "A" represents the coals ash content in %
*** Assumes bituminous coal with 10% ash and 24.78 MMBTU/ton
**** Assumes heat content of 1020 BTU/scf

Table 12 indicates that the conversion of Edge Moor Unit 4 from utilizing bituminous coal as its primary fuel to natural gas as its primary fuel provides particulate matter emissions reductions in excess of those anticipated in Delaware's 2008 regional haze SIP. Therefore, it is Delaware DNREC's determination that the conversion of Edge Moor Unit 4 to pipeline natural gas primary fuel meets the requirements for primary particulate matter BART for Edge Moor Unit 4, and that Edge Moor Unit 4 is already achieving the BART particulate matter emissions reductions as a result of the equipment and operational modifications associated with the conversion to natural gas as the unit's primary fuel.

Edge Moor Unit 5

Edge Moor Unit 5 incorporates an opposed wall fired steam generator with a 4695 MMBTU/hour heat input capacity supplying a steam turbine generator with a 446 MW nameplate rating. Edge Moor Unit 5 utilizes #6 fuel oil as the primary fuel, and also has part-load capability of firing pipeline natural gas. As a BART eligible unit, Edge Moor Unit 5's owner operator, Conectiv, was requested by Delaware to conduct a BART determination.

In the 2008 regional haze SIP, Delaware's DNREC documented that Conectiv had provided an analysis of the available control technologies for Edge Moor Unit 5, and a "five factor analysis" pursuant to the requirements of 40 CFR 51.308(e)(1)(ii)(A) for the technologically feasible options. Conectiv identified no technologically feasible options for Edge Moor Unit 5 except the use of a lower sulfur (0.5% sulfur) residual fuel oil. As documented in the 2008 regional haze SIP, Delaware's DNREC reviewed the Conectiv BART analysis, concurred with its findings, and established that the use of 0.5% sulfur residual fuel oil was considered BART for Edge Moor Unit 5.

In compliance with the requirements of 7 DE Admin Code 1146, beginning January 2009 only residual fuel oils with a sulfur content of 0.5% or less were being accepted for delivery for combustion in Edge Moor Unit 5. The restriction to accept only residual fuel oils with a sulfur content of 0.5% or less has been incorporated into Edge Moor Unit 5's operating permit (permit AQM-003/00007). Therefore, Edge Moor Unit 5 is in compliance with the particulate matter BART for the unit identified in Delaware's 2008 regional haze SIP and permit conditions serve to help ensure continued compliance.

Indian River Unit 3

Indian River Unit 3 incorporates a bituminous coal fueled wall-fired steam generator with a 1904 MMBTU/hr heat input capacity rating that utilizes a cold side electrostatic precipitator (ESP). The steam generator serves a steam turbine generator with an approximate 177 MW nameplate rating. As a BART eligible unit, Indian River Unit 4's owner operator, NRG, was requested by Delaware to conduct a BART determination.

In its 2008 regional haze SIP, Delaware 's DNREC documented that NRG had provided an analysis of the available control technologies for Indian River Unit 3, and a "five factor analysis" pursuant to the requirements of 40 CFR 51.308(e)(1)(ii)(A) for the technologically feasible options. NRG identified no technologically feasible options for Indian River Unit 3 other than the continued operation of the existing ESP. As documented in the 2008 regional haze SIP, Delaware reviewed the NRG analysis, concurred with its findings, and established that the continued use of the existing ESP was considered BART for Indian River Unit 3.

Indian River Unit 3 is in compliance with the particulate matter BART for the unit identified in Delaware's 2008 regional haze SIP.

Subsequent to the 2008 regional haze SIP, NRG entered into a consent decree (C.A. No. 07C-02-283FSS) that requires Indian River Unit 3 be mothballed no later than December 31, 2013. The shutdown of Indian River Unit 3 will eliminate all of Indian River Unit 3's particulate matter emissions and their subsequent contribution to visibility impairment.

McKee Run Unit 3

McKee Run Unit 3 incorporates a wall-fired steam generator with an 1180 MMBTU/hour heat input capacity supplying a steam turbine generator with a nameplate rating of approximately 114 MW. At the time of submittal of Delaware DNREC's 2008 regional haze SIP, McKee Run Unit 3 utilized 1% sulfur residual fuel oil as its primary fuel (and pipeline natural gas as a secondary fuel) and incorporated a mechanical cyclone separator and ash reinjection for particulate emissions control. As a BART eligible unit, McKee Run Unit 3's owner, the City of Dover, was requested by Delaware's DNREC to conduct a BART determination.

In its 2008 regional haze SIP, Delaware documented that the City of Dover had provided an analysis of the available control technologies for McKee Run Unit 3, and a "five factor analysis" pursuant to the requirements of 40 CFR 51.308(e)(1)(ii)(A) for the technologically feasible options. The City of Dover's analysis indicated that BART for McKee Run Unit 3 was a fuel switch from 1% sulfur residual fuel oil to 0.5% sulfur fuel oil. As documented in the 2008 regional haze SIP, DNREC reviewed the City of Dover's analysis, concurred with its findings, and established that a fuel switch from 1% sulfur #6 residual fuel oil to 0.5% sulfur fuel oil was considered BART for Indian River Unit 3.

Subsequent to Delaware's 2008 regional haze SIP submittal, the City of Dover made the decision to perform a fuel switch at McKee Run Unit 3. The City of Dover requested permit revisions to switch McKee Run Unit 3 from using #6 residual fuel oil as the primary fuel (with pipeline natural gas as a secondary fuel) to pipeline natural gas as the primary fuel (with 0.05% sulfur #2 fuel oil as a secondary fuel). The requested permit revisions were approved and incorporated into McKee Run Unit 3's operating permit (permit AQM-001/00002).

With regards to primary particulate emissions, pipeline natural gas is among the cleanest steam generator fuels. Relative to a residual fuel oil fueled steam generator utilizing 0.5% sulfur #6 residual fuel oil, AP-42 emissions factors estimate an approximate 82% reduction in primary particulate emissions when firing pipeline natural gas, as shown in Table 13.

.

Table 13 - AP-42 Emissions Factors – Residual Oil Relative to Natural Gas

AP-42 #6 Residual Fuel Oil Uncontrolled Filterable PM Emissions Factor* (lb/kgal)	AP-42 #6 Residual Fuel Oil Controlled Filterable PM Emissions Factor for 1% Sulfur Fuel Oil*** (lb/MMBTU)	AP-42 #6 Residual Fuel Oil Controlled Filterable PM Emissions Factor for 0.5% Sulfur Fuel Oil*** (lb/MMBTU)	AP-42 Natural Gas Filterable PM Emissions Factor (lb/MMscf)	AP-42 Natural Gas Filterable PM Emissions Factor**** (lb/MMBTU)	Reduction in Estimated Emissions Rate (%)
9.19(S)**+3.22	0.0165	0.0104	1.9	0.0019	82

Notes: * Steam generator with heat input rating greater than 100 MMBTU/hr
** "S" represents fuel oil sulfur content in %
*** Assumes fuel oil heat content of 150 MMBTU/hr and cyclone separator efficiency of 80%
**** Assumes natural gas heat content of 1020 BTU/scf.

This indicates that the conversion of McKee Run Unit 3 from utilizing 0.5% sulfur #6 residual fuel oil as its primary fuel to natural gas as its primary fuel provides particulate matter emissions reductions in excess of those anticipated in Delaware's 2008 regional haze SIP. Therefore, it is Delaware DNREC's determination that the conversion of McKee Run Unit 3 to pipeline natural gas primary fuel meets the requirements for primary particulate matter BART for McKee Run Unit 3, and that McKee Run Unit 3 is already achieving the BART particulate matter emissions reductions as a result of the equipment and operational modifications associated with the conversion to natural gas as the unit's primary fuel.

The following table summarizes the equipment and operational standards, and implementation status, of the primary PM BART for Delaware's BART eligible EGUs:

Table 14 - Equipment and Operational Standards, and Implementation Status, of PM BART for Delaware's BART Subject EGUs

Facility	Unit	2008 regional haze SIP Submittal Primary Particulate BART	BART Updates since 2008 Regional Haze SIP	Current Compliance Status due to BART Updates since DE 2008 Regional Haze SIP
Edge Moor	4	Continued use of bituminous coal primary fuel and existing ESP, and addition of DSI.	Discontinue use of coal fuel and switch to natural gas as the primary fuel.	Discontinued use of coal fuel and switched to natural gas as primary fuel, requirements incorporated into operating permit.
Edge Moor	5	Use of 0.5% sulfur #6 residual fuel oil as primary fuel.	No change from 2008 regional haze SIP: Use of 0.5% sulfur #6 residual fuel oil as primary fuel.	In compliance with requirements to combust 0.5% sulfur #6 residual fuel oil. Requirements incorporated into operating permit.

Indian River	3	Continued use of bituminous coal primary fuel and existing ESP.	No change from 2008 regional haze SIP: Continued use of bituminous coal primary fuel and use of existing ESP.	In compliance with fuel and ESP operating requirements. By consent decree, unit will be mothballed no later than December 31, 2013.
McKee Run	3	Use of 0.5% sulfur #6 residual fuel oil as primary fuel.	Discontinued use of 0.5% sulfur #6 fuel oil and switch to natural gas as the primary fuel.	Discontinued use of residual fuel oil and switched to natural gas as primary fuel, requirements incorporated into operating permit.

1.2. DELAWARE EGU CONTROL MEASURES (MANE-VU LTS #2)

Edge Moor Unit 5 and Indian River Units 1-4 were among the "167 stacks" at Delaware EGU facilities identified by MANE-VU to have the highest emissions in the eastern United States and which had the greatest impact on MANE-VU Class 1 areas. The Delaware regional haze SIP discussed its obligations under the MANE-VU LTS to reduce SO_2 emissions by 90% from those EGUs. Therefore, controlling emissions from Delaware's Edge Moor Unit 5 and Indian River Units 1-4 has resulted in a positive impact towards improving visibility in the Brigantine Wilderness Area.

While establishing the emission management measures for "167 stack sources" to reduce SO_2 emissions by 90% in order to improve the visibility in Class 1 areas, MANE-VU recognized that achieving a 90% reduction from every individual "167 stack" could prove difficult. In order to provide flexibility for States to achieve the required levels of SO_2 reductions, the MANE-VU resolution stated, "If it is infeasible to achieve that level of reduction from a 167 unit, alternative measures will be pursued in such State, which could include other point sources."

In its 2008 regional haze SIP, Delaware indicated that the 90% reduction in SO_2 from the Edge Moor Unit 5 and Indian River Units 1-4 was relative to a baseline of calendar year 2002 actual SO_2 mass emissions levels from those units. Based on the actual 2002 SO_2 mass emissions from the subject Delaware EGUs, Delaware determined that the actual SO_2 reduction obligation for those units was 19,909 tons/year. Delaware's analysis indicated that it was not feasible to achieve an SO_2 mass emissions reduction of 19,909 tons/year from Edge Moor Unit 5 and Indian River Units 1-4 alone. Alternatively, in the 2008 regional haze SIP document Delaware indicated that SO_2 emissions reductions from all of the EGU units affected by Delaware's 7 DE Admin Code 1146, Electric Generating Unit (EGU) Multi-Pollutant Regulation, would exceed 19,909 tons of annual SO_2 reductions. Delaware indicated that the SO_2 emissions reductions achieved by 7 DE Admin Code 1146 demonstrated that Delaware had met its obligation.

Delaware's 7 DE Admin Code 1146 established SO_2 emissions control requirements for coal-fired and residual oil-fired EGUs located in Delaware. For residual fuel oil-fired EGUs, the fuel oil sulfur content was required by the regulation to not exceed 0.5% sulfur by weight. For coal-fired EGUs, the units were required to not exceed an SO_2 emission rate limit of 0.37 lb/MMBTU (rolling 24-hour basis) beginning in May 2009. Beginning January 1, 2012 the coal-fired EGUs were required to not exceed a more stringent SO_2 emission rate of 0.26 lb/MMBTU (rolling 24-hour basis). Delaware's 7 DE Admin Code 1146 also established hard annual SO_2 emission caps for each of the EGUs subject to the regulation, beginning January 1, 2009.

Subsequent to Delaware's regional haze 2008 SIP submittal, and the promulgation of and, units subject to 7 DE Admin Code 1146 the regulation have come into compliance with the regulation or have come into compliance with consent decrees and permanent, federally enforceable permit conditions related to the regulation. The compliance status of the units that were subject to 7 DE Admin Code 1146 is summarized below:

- Edge Moor Unit 3 has taken permit (permit AQM-003/00007) conditions to convert from a utilizing coal as the primary fuel with residual fuel-oil as a secondary fuel to utilizing natural gas as the primary fuel with residual fuel oil as the secondary fuel. The permit for the unit includes a restriction on the annual total hours of operation on residual fuel oil (no greater 876 hrs/yr) and a restriction on total annual operating hours to not exceed 59% capacity factor. These operating limits effectively cap the annual SO_2 mass emissions levels.

- Edge Moor Unit 4 has taken permit (permit AQM-003/00007) conditions to convert from utilizing coal as the primary fuel with residual fuel-oil as a secondary fuel to utilizing natural gas as the primary fuel with residual fuel oil as the secondary fuel. The permit for the unit includes a restriction on the annual total hours of operation on residual fuel oil (no greater 876 hrs/yr) and a restriction on total annual operating hours to not exceed 59% capacity factor. These operating limits effectively cap the annual SO_2 mass emissions levels below those included in 7 DE Admin Code 1146.

- Edge Moor Unit 5, using residual fuel oil as primary fuel, is in compliance with the requirements 7 DE Admin Code 1146, including the associated annual SO_2 mass emissions cap.

- Indian River Unit 1, a coal-fired unit, was mothballed in April of 2011 as required under consent decree (C.A. No. 07C-02-283FSS).

- Indian River Unit 2, a coal-fired unit, was mothballed in April of 2010 as required under consent decree (C.A. No. 07C-02-283FSS).

- Indian River Unit 3, a coal-fired unit, is currently operating under a consent decree (C.A. No. 07C-02-283FSS) and will be mothballed no later than December 31, 2013.

- Indian River Unit 4, a coal- fired unit, has installed controls and is in compliance with a consent decree (C.A. No. 07C-02-283FSS) SO_2 emissions rate limitation of 0.2 lb/MMBTU (rolling 24-hour average) and the SO_2 annual mass emissions cap of 7 DE Admin Code 1146.

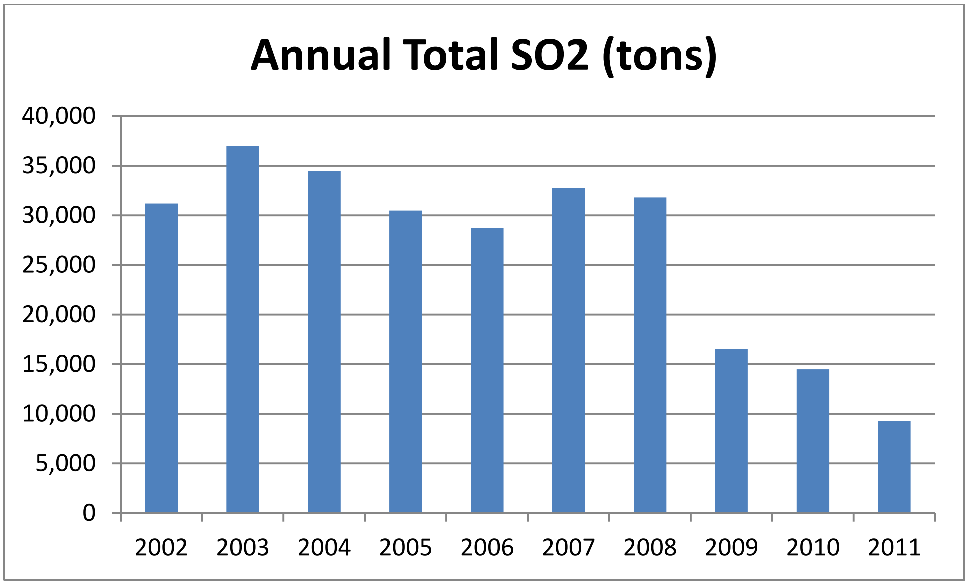
- McKee Run Unit 3 has taken permit (permit AQM-001/00002) conditions converting from utilizing residual fuel oil as the primary fuel to utilizing natural gas as the primary fuel along. Low-sulfur #2 fuel oil is utilized as the secondary fuel. Permit conditions for this unit also incorporate a facility-wide annual SO_2 emissions cap that is lower than the SO_2 mass emissions cap for Unit 3 alone in 7 DE Admin Code 1146.

As a result of 7 DE Admin Code 1146 and related consent decrees and permit conditions, annual SO_2 emissions for this group of EGUs has seen significant reductions since 2009, the year when Phase I of the regulation went into effect. The following table shows annual 2002 through 2011 combined SO_2 emissions from Edge Moor Units 3 through 5, Indian River Units 1 through 4, and McKee Run Unit 3.

Table 15 - 2002 Through 2011 Combined SO_2 Emissions from Edge Moor Units 3 - 5, Indian River Units 1 - 4, and McKee Run Unit 3 (CAMD)

Year	Annual SO_2 Emissions (tons/yr)
2002	31,183
2003	36,998
2004	34,475
2005	30,482
2006	28,738
2007	32,778
2008	31,785
2009	16,524
2010	14,485
2011	9,278

Figure 7 - 2002 to 2011 EGU SO_2 Emissions (CAMD)



While the above bar chart clearly shows significant reductions in annual SO_2 mass emissions beginning in 2009, Delaware's obligation was to achieve annual SO_2 emissions reductions of 19,909 tons/year by 2018 (e.g., 90%) relative to actual 2002 SO_2 mass emissions from Edge Moor Unit 5 and Indian River Units 1-4.

Table 16 shows the annual 2009-2011 SO_2 emissions reductions achieved by the EGUs subject to 7 DE Admin Code 1146 and related federally enforceable consent decrees and permit conditions. As can be seen in the table, beginning in 2011 the annual SO_2 emission reductions have exceeded the 2018 "target" level of 19,909 tpy.

Table 16 - 2009, 2010 and 2011 SO_2 reductions from EGUs Subject to 7 DE Admin Code 1146 (CAMD)

Year	Reduction in SO_2 from 2002 (tpy)
2009	14,660
2010	16,698
2011	21,906

Further, the SO_2 mass emissions caps, rates, and operating limits related to 7 DE Admin Code 1146 (along with related consent decrees and permit limits) will ensure that the SO_2 mass emissions from Delaware's EGUs in the future will continue to exceed the SO_2 mass emissions reduction obligations relative to these EGUs. By 2014, the estimated potential to emit (PTE) of SO_2 for the EGUs subject to 7 DE Admin Code 1146 (and the related consent decrees and permit conditions) is 9,327 tons/year. Relative to the Delaware "167" units' actual 2002 SO_2 emissions, this 2014 PTE value represents an estimated annual SO_2 mass emissions reduction of 21,856 tons/year.

However, the estimated annual SO_2 potential to emit (PTE) value for the EGUs subject to 7 DE Admin Code 1146 and related consent decrees and permit conditions) discussed above does not give a true representation of the annual SO_2 emissions that may be estimated from these units by 2014. The reason for this is that these units typically do not exhibit high annual capacity factors. Using the highest annual heat input for the individual subject units between 2002 and 2011 as a basis of future operation, the estimated annual SO_2 emissions from the affected units for 2014 and beyond is 5,859 tons per year (see Table 17). Relative to the Delaware "167" units' actual 2002 SO_2 emissions, this value represents an estimated annual SO_2 mass emissions reduction of 25,324 tons/year (e.g. significantly more than the required 19,909 tpy in the initial regional haze SIP).

Table 17 - Estimated Annual SO2 Emissions from Affected Units for 2014 and Beyond

Facility Name	Unit ID	Highest Annual Heat Input 2002 - 2011 (MMBTU)	Estimated 2014 SO2 Emissions Rate (lb/MMBTU)	Basis for 2014 SO2 Rate	Estimated Annual SO2 Emissions 2014 (tons)
Edge Moor	3	6,616,763	0.5 on oil, 0.0024 on gas	Regulation 1146, Permit 59% maximum capacity factor with no more than 10% on oil	251
Edge Moor	4	12,953,962	0.5 on oil, 0.0024 on gas	Regulation 1146, Permit 59% maximum capacity factor with no more than 10% on oil	418
Edge Moor	5	11,274,929	0.5	Regulation 1146 - 0.5% max sulfur fuel oil	2,819
Indian River	1	6,467,250	0	Mothballed by Consent Decree	0
Indian River	2	5,273,245	0	Mothballed by Consent Decree	0
Indian River	3	11,325,422	0	Mothballed by Consent Decree	0
Indian River	4	23,232,281	0.2	Consent Decree	2,323
McKee Run	3	1,919,684	0.05	Consent Decree - 0.05% max sulfur fuel oil	48
Total					**5,859**

1.2.1. Status and Reductions of other EGU Control Measures in Delaware's 2008 Regional Haze SIP

The following emission controls originating from existing or on-the-way (OTW) Delaware measures to reduce emissions from the EGUs were considered in the regional modeling used to establish the MANE-VU Reasonable Progress Goals:

- 7 DE Admin Code 1144, Control of Stationary Generator Emissions, SO_2, PM, VOC and NO_X emission control, State-wide, Effective January 2006. EPA SIP approval date 5/29/2008 (73 FR 23101).

- 7 DE Admin Code 1148, Control of Stationary Combustion Turbine Electric Generating Unit Emissions, NO_X emission control, State-wide, Effective July, 2007. This regulation was approved into the Delaware SIP by EPA on 12/10/2008 (73 FR 66554).

Table 18 and 19 show the NOx emission trends due to each regulation (SO_2 and $PM_{2.5}$ emission reductions are insignificant for 7 *DE Admin Code 1144, and 7 DE Admin Code 1148* only addresses NOx).

Table 18 – 7 DE Admin Code 1144 (NOx reductions, tpy)

Facility	Unit ID	Unit Description	Implementation Date	2002	2008
CITY OF LEWES POWER PLANT	001	CATERPILLER ELEC PK #1	4/1/2007	1.3	0.0
CITY OF LEWES POWER PLANT	002	CATERPILLER ELEC PK #2	4/2/2007	1.3	0.0
CITY OF SEAFORD-ELECTRIC POWER PLANT	001	GENERATOR #1	4/3/2007	17.5	0.0
CITY OF SEAFORD-ELECTRIC POWER PLANT	002	GENERATOR #2	4/4/2007	16.7	0.0
CITY OF SEAFORD-ELECTRIC POWER PLANT	003	GENERATOR #3	4/5/2007	13.9	0.0
CITY OF SEAFORD-ELECTRIC POWER PLANT	004	GENERATOR #4	4/6/2007	13.9	0.0
CITY OF SEAFORD-ELECTRIC POWER PLANT	006	GENERATOR #6	4/7/2007	20.9	0.0
			TOTALS	**86**	**0**

Note: City of Lewes Power Plant was closed prior to 2008.

Table 19 – 7 DE Admin Code 1148 (NOx reductions, tpy)

Facility	Unit ID	Unit Description	Implementation Date	2002	2008
CONECTIV DELMARVA GENERATION - DEL CITY	002	TURBINE #10	5/1/2009	9.0	1.0
CONECTIV DELMARVA GENERATION - WEST_SUBST	001	TURBINE	5/2/2009	8.0	0.6
CONECTIV DELMARVA GENERATION - EDGE MOOR	001	GAS TURBINE	5/3/2009	5.2	0.0
CONECTIV DELMARVA GENERATION - CHRISTIANA	001	TURBINE #11	5/4/2009	13.1	0.7
CONECTIV DELMARVA GENERATION - CHRISTIANA	002	TURBINE # 14	5/5/2009	13.0	0.8
INDIAN RIVER GENERATING STATION	005	TURBINE #10	5/6/2009	0.9	1.4
			TOTALS	**49**	**5**

- INVISTA (co-gens) Consent Decree – United States of America, et. al., v. Invista. a r. l. U.S. District Court, District of Delaware. Case No. 1:09-cv-00244-GMS. This consent decree resulted in Invista retiring all three of their coal-fired co-gen boilers. 2011 emissions are given to reflect the retirements post-2008 NEI, as used for non-EGUs and because Invista does not report CEM data to CAMD. Tables 20-22 show the emission reductions of SO_2, NOx and $PM_{2.5}$ due to the consent decree.

Table 20 - INVISTA Unit Shutdown – SO_2 Emission Reductions

SO_2					
Unit ID	**Unit Description**	**Effective Date of Unit Shutdown**	**2002**	**2008**	**2011**
001	Coal Boiler 1	4/17/2009	741	1,083	0
002	Coal Boiler 2	12/1/2009	1,264	1,043	0
003	Coal Boiler 3	2/26/2009	1,092	989	0
Totals			**3,097**	**3,115**	**0**

Table 21 - INVISTA Unit Shutdown – NOx Emission Reductions

NOx					
Unit ID	**Unit Description**	**Effective Date of Unit Shutdown**	**2002**	**2008**	**2011**
001	Coal Boiler 1	4/17/2009	311	292	0
002	Coal Boiler 2	12/1/2009	634	316	0
003	Coal Boiler 3	2/26/2009	547	276	0
Totals			**1,492**	**884**	**0**

Table 22 - INVISTA Unit Shutdown – $PM_{2.5}$ Emission Reductions

PM2.5					
Unit ID	**Unit Description**	**Effective Date of Unit Shutdown**	**2002**	**2008**	**2011**
001	Coal Boiler 1	4/17/2009	44	63	0
002	Coal Boiler 2	12/1/2009	74	59	0
003	Coal Boiler 3	2/26/2009	62	58	0
Totals			**180**	**180**	**0**

The Invista-Seaford facility replaced boilers 1-3 with two steam boilers. The first is a 94 MMBTU/hr package boiler firing pipeline natural gas or #2 fuel oil, utilizes flue gas recirculation for NOx control in compliance with 7 DE Admin Code 1112 and operates in compliance with its permitted NOx mass emissions limit of 39 tons/year and a permitted NOx emissions rate of 0.10 lb/MMBTU when firing natural gas and 0.11 lb/MMBTU when firing #2 fuel oil.

The second is a 220 MMBTU/hr boiler firing pipeline natural gas or #2 fuel oil, utilizes layered NOx reduction technologies to meet the requirements of 7 DE Admin Code 1112 and 40 CFR Part 60 Subpart Db. The NOx reduction technologies utilized on this boiler are low NOx burners, flue gas recirculation, and SCR, with a permitted NOx mass emissions limit of 118 tons per year firing #2 fuel oil and 12 tons per year firing natural gas, and a permitted NOx emissions rate of 0.20 lb/MMBTU calculated on a 30 day rolling average

1.3. LOW SULFUR OIL STRATEGY (MANE-VU LTS #3)

As noted earlier in this report, in establishing the reasonable progress goals; MANE-VU Class I states relied in part on implementation of a low sulfur fuel strategy within MANE-VU, as well as efforts to reduce emissions through other reasonable measures by 2018. The assumption underlying the MANE-VU low-sulfur fuel oil strategy was that refiners could, by 2012, produce home heating and fuel oils that contain 50 percent less sulfur for the heavier grades (#4 and #6 residual), and a minimum of 75 percent, and maximum of 99.25 percent, less sulfur in #2 fuel oil (also known as home heating oil, distillate, or diesel fuel) at an acceptably small increase in price to the end user. As much as 75 percent of the total sulfur reductions achieved by this strategy come from using the low-sulfur #2 distillate for space heating in the residential and commercial sectors. While costs for these emissions reductions remain somewhat uncertain, they appear reasonable in comparison to costs of controlling other sectors as documented in the *MANE-VU Reasonable Progress Report*, estimated at $550 to $750 per ton.

At the time that the first regional haze SIPs were submitted there were logistical issues in supplying large quantities of low-sulfur oils to the northern New England region by the goal of a 2012 implementation date. This oil is barged into the region in quantities that allow for blending with high-sulfur fuels to produce 1-percent sulfur fuels. Capacities were limited by Federal restrictions that prevented large ships from transferring fuels between two U.S. ports. The New England states intend to build full capacity for 0.5-percent-sulfur #6 fuel oil by 2018. The MANE-VU states agreed that a low-sulfur oil strategy was reasonable to pursue by 2018, and several MANE-VU states adopted regulations implementing this strategy.

Delaware did not commit to low-sulfur fuels in its initial regional haze SIP because 1) Delaware did not feel that adequate supplies of low-sulfur fuel were available to meet the 2012 deadline for inner zone states, 2) EPA Region 3 would not allow Delaware to submit a "committal" SIP and 3) Delaware demonstrated that it nevertheless met the equivalent SO_2 emission reductions of a "hypothetical" low-sulfur fuel regulation. The SO_2 "equivalent reductions" were accomplished via 7 DE Admin Code 1146, which provided "surplus" SO_2 reductions from EGUs beyond the MANE-VU 167 Stack "ask" of 19,909 tpy, as discussed in Section 11.3 of Delaware's 2008 regional haze SIP (e.g. the EGU SO_2 surplus was greater than the SO_2 reductions from a hypothetical low-sulfur fuel regulation).

However, Delaware adopted a new low-sulfur fuel regulation which will go into effect in 2016.[20] Because this regulation is adopted (effective date of July 11, 2013), Delaware will have gone beyond the SO_2 reductions in the MANE-VU LTS "ask" for both the "167 Stacks" and low-sulfur fuels. Based on the assumptions in its initial regional haze SIP, this new regulation will achieve post-2008 additional SO_2 reductions of 2,605 tpy (as calculated from the 2002 base year).

The old and new limits for fuel sulfur content in Delaware are shown in Table 23:

Table 23 – 7 DE Admin Code 1108 (low-sulfur fuel regulation) – Old vs. New Sulfur Limits/Effective Dates

Fuel Type	Pre-Regulation limits	New Regulation Limits (ppm)	Effective Date
No. 2 and Lighter	3,000	15	July, 2016
No. 4	10,000	2,500	July, 2016
No. 5 and No. 6	10,000	5,000	July, 2016

1.4. STATUS OF OTHER DELAWARE-SPECIFIC CONTROL MEASURES DISCUSSED IN DELAWARE'S 2008 SIP

This section discusses implementation of the additional state specific provisions included in Delaware's 2008 regional haze SIP, i.e. LTS #4 (Continued evaluation of other control measures including energy efficiency, alternative clean fuels, and other measures to reduce SO_2 and nitrogen oxide, etc.) The discussion only includes significant measures for the visibility impairing pollutants SO_2, NOx and $PM_{2.5}$.

[20] The effective date of the regulation is July 11, 2013. The final regulation can be found at: http://www.dnrec.delaware.gov/whs/awm/Info/Regs/Pages/AQMPlansRegs.aspx

To develop the 2018 emissions inventory used for modeling conducted to help MANE-VU Class I states set Reasonable Progress Goals, control factors were applied to the 2018 MANE-VU inventory for non-EGUs to represent national, regional, or state control measures. The following discussion indicates the status and reductions of significant control measures applied to non-EGU sources within Delaware.

1.4.1. Non-EGU Point Sources Measures Discussed In the Initial Sip

- **Consent Decree with Premcor Refinery** at Delaware City (formerly Motiva Enterprises), New Castle County, Control of SO_2, and NO_X Emissions from Boilers and Heaters, Effective 2006, Civil Action No. H-01-0978 lodged in the United States Court for the Southern District of Texas on March 21, 2001 (the federal consent decree).

  The Refinery consent decree required SO_2 emission reductions from Fluid Catalytic Cracking Units (FCCUs) and Fluid Coking Units (FCUs). For the FCCUs/FCUs, the Consent Decree control requirements required the installation of wet gas scrubbers for SO_2 control. For the 2018 projections, a 90 percent SO_2 control efficiency was assumed as a conservative estimate of the SO_2 reductions from the installation of a wet gas scrubber for both units.

  For NOx control at FCCUs/FCUs, the Consent Decrees required selective catalytic reduction (SCR) for Unit 12, and selective non-catalytic reduction (SNCR) for Unit 2. Some of the units have already been permitted to include the control requirements. A 90 percent NOx control efficiency was assumed for SCR and a 60 percent reduction was assumed from the installation of SNCR in the 2018 projections.

  Tables 24-26 show the reductions due to the Consent Decree between the 2002 base year and the 2008 Delaware PEI for those units.

Table 24 - Refinery SO_2 Emission Reductions (tpy) and Status

SO_2				
Unit ID	**Unit Description**	**Effective Date of Controls**	**2002**	**2008**
2	Fluid Coker CO Boiler (FCU)	6/30/2006	18,328	52
12	Cracker CO Boiler (FCCU)	12/31/2006	11,420	174
Totals			**29,748**	**226**

Table 25 - Refinery NOx Emission Reductions (tpy) and Status

NOx				
Unit ID	**Unit Description**	**Effective Date of Controls**	**2002**	**2008**
2	Fluid Coker CO Boiler (FCU)	6/30/2006	610	446
12	Cracker CO Boiler (FCCU)	12/31/2006	739	578
Totals			**1,349**	**1,024**

Table 26 - Refinery $PM_{2.5}$ Emission Reductions (tpy) and Status (Co-benefit of Wet Gas Scrubber)

$PM_{2.5}$				
Unit ID	**Unit Description**	**Effective Date of Controls**	**2002**	**2008**
2	Fluid Coker CO Boiler (FCU)	6/30/2006	447	111
12	Cracker CO Boiler (FCCU)	12/31/2006	596	60
Totals			**1,043**	**171**

- 7 DE Admin Code 1142. Section 1, Control of NO_X Emissions from Industrial Boilers, NO_X emission control, Effective December 2001. This regulation was approved into the Delaware SIP by EPA on 11/22/01 (67 FR 70315). Section 2, Control of NO_X Emissions from Industrial Boilers and Process Heaters at Petroleum Refineries, NO_X emission control, New Castle County, Effective July 2007. This regulation was revised and approved into the Delaware SIP by EPA on 5/15/12 (77 FR 28489). **Sources subject to this regulation are located specific to the Delaware City Refinery.**

Table 27 shows the 2002, 2008 and 2018 emissions, followed by a discussion of the current status of the regulation and a new plant-wide applicability limit (PAL) put into effect after the SIP submittal.

Table 27 - 2002, 2008 and 2018 Refinery NOx Emissions

Annual NOx Emissions (tpy) from Units Subject to Regulation 1142			
Unit	**2002**	**2008**	**2018**
Boiler 1	370	200	0
Boiler 2	205	41	0
Boiler 3	342	254	0
Boiler 4	419	184	0
Heater #2 For Unit 21-H-2 (Pt. Id 7)	88	75	119
Crude Unit Heater 21-H-701 (Pt. Id 105)	73	45	99
TOTALS	**1497**	**799**	**218**

As part of Delaware's initial SIP submission, NOx emissions are controlled under 7 DE Admin Code 1112 (NOx RACT). However, after the SIP submission, NOx is now also controlled under a NOx Plant-wide Applicability Limit (PAL) established pursuant to Section 2.0 of 7 DE Admin Code 1142 and 1125. The NOx PAL began in 2011 at 2,525 TPY (i.e., actual 2008 emission levels), and decreases to 1,650 TPY beginning 2015. The Delaware regional haze SIP 2018 NOx projections for the refinery were 2,071 tpy. The federally enforceable PAL of 1,650 tpy will be less than the 2018 facility-wide projections included in Delaware's initial SIP – another example of how Delaware's reductions are going beyond those indicated in the 2008 SIP.

Delaware's March 15, 2011 SIP revision, "*Demonstration that Amendments to Section 2.0 of 7 DE Admin Code 1142, Control of NO_x Emissions from Industrial Boilers and Process Heaters at Petroleum Refineries Do not Interfere with Any Applicable Requirement of the Clean Air Act*" provides a detailed discussion of the facility-wide NOx cap.

The following information demonstrates the stringency of the facility-wide NOx cap:

- Thirteen of the refineries industrial boilers were subject to the EPA NOx SIP Call, which was implemented in Delaware under 7 DE Admin Code 1139.
- The initial 2,525 NOx cap is significantly less than annualized NOx SIP Call cap[21] of 3,333 tpy, which indicates that implementation of RACT and NSR at the refinery have resulted in the implementation of NOx controls at the refinery.

[21] The referenced SIP revision includes a demonstration that the refinery emissions are uniform across the year, and regulation on a TPY basis and not on an ozone season basis is acceptable. Based on this the 1139 budgets were annualized by multiplying by 12/5.

- The 1,650 tpy NOx cap represents a 35% reduction beyond RACT limits (i.e., actual 2008 levels), and more than an additional 50% reduction below NOx SIP Call levels. In addition, all future growth at the refinery must occur under this NOx cap.
- The federally enforceable PAL of 1,650 tpy will be less than the 2018 facility-wide 2018 projections included in Delaware's initial SIP.

- **NOx SIP Call – Phase I**

  Compliance with the NOx SIP Call in the Ozone Transport Commission (OTC) states was scheduled for May 1, 2003. The requirements applied to all MANE-VU states except Maine, New Hampshire, and Vermont. While the program applies primarily to electric generating units (EGUs), the NOx SIP Call applies to non-EGUs such as large industrial boilers and turbines. The NOx SIP Call did not mandate which sources must reduce emissions; rather, it required states to meet an overall emission budget and gave them flexibility to develop control strategies to meet that budget. All states in the MANE-VU region affected by the NOx SIP Call chose to meet their NOx SIP Call requirements by participating in the NOx Budget Trading Program. MARAMA's contractor reviewed the available state rules and guidance documents to determine the affected non-EGU sources and ozone season NOx allowances for each source. Future year emissions for non-EGU boilers/turbines were capped at the allowance levels. Since the allowances are given in terms of tons per ozone season (5 months May to September), DNREC calculated annual emissions by multiplying the ozone season allowances by a factor of 12 (annual) / 5 (ozone season).

  However, the MANE-VU modeling for the NOx SIP Phase I did not include sources in Delaware.[22] Nonetheless, Delaware regulates the significant sources of NOx in the state via various regulations such as 1142, 1146 and 1148 or SIP revisions. For example, Delaware's March 15, 2011 SIP revision, "*Demonstration that Amendments to Section 2.0 of 7 DE Admin Code 1142, Control of NO_x Emissions from Industrial Boilers and Process Heaters at Petroleum Refineries Do not Interfere with Any Applicable Requirement of the Clean Air Act*" provides a detailed discussion of the facility-wide NOx cap at the refinery, i.e., the following information demonstrates the stringency of the facility-wide NOx cap:

- Thirteen of the refineries industrial boilers were subject to the EPA NOx SIP Call, which was implemented in Delaware under 7 DE Admin Code 1139.
- The initial 2,525 NOx cap is significantly less than annualized NOx SIP Call cap[23] of 3,333 tpy, which indicates that implementation of RACT and NSR at the refinery have resulted in the implementation of NOx controls at the refinery.

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[22] *Development of Emission Projections For 2009, 2012, and 2018 For NonEGU Point, Area, and Nonroad Source In the MANE-VU Region Final Report*. MACTEC. February, 2007

[23] The referenced SIP revision includes a demonstration that the refinery emissions are uniform across the year, and regulation on a TPY basis and not on an ozone season basis is acceptable. Based on this the 1139 budgets were annualized by multiplying by 12/5.

- The 1,650 tpy NOx cap represents a 35% reduction beyond RACT limits (i.e., actual 2008 levels), and more than an additional 50% reduction below NOx SIP Call levels. In addition, all future growth at the refinery must occur under this NOx cap.

- **NOx SIP Call – Phase II**

  The final Phase II NOx SIP Call rule was promulgated on April 21, 2004. States had until April 21, 2005, to submit SIPs meeting the Phase II NOx budget requirements. The Phase II rule applies to large IC engines, which are primarily used in pipeline transmission service at compressor stations. MARAMA's contractor identified affected units using the same methodology as was used by EPA in the proposed Phase II rule (i.e., a large IC engine is one that emitted, on average, more than 1 ton per day during 2002). The final rule reflects a control level of 82 percent for natural gas-fired IC engines and 90 percent for diesel or dual fuel categories. However, no Delaware units were identified or modeled in the 2018 projections; therefore there were no Delaware-specific reductions from this control measure.

- **NOx RACT in 1-hour Ozone SIPs**

  Emission reductions requirements from NOx reasonably available control technology (RACT) requirements in 1-hour Ozone SIP areas were implemented in, or prior to, 2002. These reductions were already for in the MANE-VU 2002 inventory since the 2002 inventory was based on 2002 actual emissions which include any reductions due to NOx RACT. Therefore, there are no Delaware-specific reductions from this control measure.

- **NOx OTC 2001 Model Rule for ICI Boilers**

  The Ozone Transport Commission (OTC) developed control measures for industrial, commercial, and institutional (ICI) boilers in 2001. Information about the proposed OTC NOx emission limits by fuel type and size range was obtained from Table III-1 of *Control Measure Development Support Analysis of Ozone Transport Commission Model Rules* (E.H. Pechan & Associates, Inc., March 31, 2001). Information about the emission limits contained in the existing state rules (prior to adoption of the OTC 2001 model rule) was obtained from Tables III-2 through III-9 of the Pechan document. Information about the emission limits contained in the current state rules (as they existed in June 2006) was obtained from the individual states' regulations. The percent reduction for ICI boilers was estimated by state, fuel type, and size range by comparing the current state emission limits (as they existed in June 2006) with the state emission limits as they existed in 2001. Pennsylvania adopted the OTC 2001 model rule in five southeastern counties (Bucks, Chester, Delaware, Montgomery, and Philadelphia) for boilers in the 100 to 250 million Btu/hour range. New Jersey adopted the OTC 2001 model rule for natural gas-fired boilers with a maximum heat rate of at least 100 million Btu/hour. For other states (such as Delaware), the emission limits in 2006 did not change from the emission limits in 2001. Therefore, there were no Delaware-specific reductions from this control measure in the Best and Final modeling.

- **2-, 4-, 7-, and 10-year MACT Standards**

  Maximum achievable control technology (MACT) requirements' control efficiencies were also applied, as documented in the report entitled *Control Packet Development and Data Sources,* dated July 14, 2004. [24] The point source MACT and associated emission reductions were designed from Federal Register (FR) notices and discussions with EPA's Emission Standards Division (ESD) staff. These MACT requirements apply only to units located at a major source of hazardous air pollutants (HAP). MARAMA's contractor did not apply reductions for MACT standards with an initial compliance date of 2002 or earlier, assuming that the effects of these controls are already accounted for in the inventories supplied by the States. Emission reductions were applied only for MACT standards with an initial compliance date of 2003 or greater. Because the MANE-VU inventory does not identify HAP major sources, the reductions from post-2002 MACT standards were applied on a more general scale to all sources with certain SCCs. Every source with an SCC determined to be affected by a post-2002 MACT standard was assigned an incremental percent reduction for the applicable MACT standard.

  The only MACT reductions applied to Delaware projections were for the Industrial Boilers, Institutional/Commercial Boilers and Process Heaters MACT. Other MACT Source Categories were not applicable to Delaware either due insignificant emissions, or because those sources do not operate in Delaware (*Development of Emission Projections For 2009, 2012, and 2018 For NonEGU Point, Area, and Nonroad Source In the MANE-VU Region*. Final Report (page 2-10. MARAMA February, 2007.)[25]

Table 28 shows the Delaware-specific category affected (non-VOC and non-PM10), and the incremental control efficiencies applied for post-2002 MACT standards.

[24] http://www.epa.gov/air/interstateairquality/pdfs/Non-EGU_nonpoint_Control_Development.pdf
[25] http://www.dnrec.delaware.gov/whs/awm/Info/Regs/Documents/Appendix%207-4%20MANEVU_Emission_Projections_TSD_.pdf

Table 28 - Delaware MACT Source Categories with Modeled Reductions in the initial DE Regional Haze SIP (non-VOC/PM10 SCCs with Compliance Dates On or After 2002)

MACT Source Category	40CFR63 Subpart	Initial Date Promulgated	Compliance Date in initial SIP	Pollutants Affected	2018 MANE-VU Modeled Control Efficiency (%)	Reductions
Industrial Boilers, Institutional/ Commercial Boilers and Process Heaters	DDDDD	9/13/04	9/13/07	$PM_{2.5}$, SO_2	4, 40	See discussion below

- **Industrial Boiler/Process Heater MACT**

In Delaware's 2008 regional haze SIP, it was indicated that Delaware 40 CFR Section 51.308(d)(3)(v)(A) requires states to consider emission reductions from ongoing pollution control programs in the development of a state's long term strategy. The long term air pollution control programs that were utilized in the development of Delaware's long term strategy included the EPA's then-under-development programs to reduce air pollutant emissions from major source industrial boilers and process heaters (referred to as boiler MACT). The controls anticipated to result from the EPA's boiler MACT program was included in the 2018 MANE-VU projections emissions inventory that included the state of Delaware, and therefore was utilized by the state of Delaware in the development of its overall long term strategy.

Subsequent to Delaware's 2008 SIP submittal, on March 21, 2011 the EPA proposed emissions standards related to the boiler MACT. In support of the EPA's March 21, 2011 rule, the EPA prepared its February 2011 "Regulatory Impact Analysis [RIA]: National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters". In the February 2011 document the EPA indicated that particulate sulfate is the largest contributor to regional haze in the eastern United States. (It should be noted that the RIA document indicated that modeling conducted in conjunction with the March 21, 2011 final rule estimated an average visibility improvement of 0.51 deciviews in annual 20% worst visibility days over all Class I area monitors based on controls for major sources utilizing solid fuels.) However, on December 23, 2011 the EPA announced that it was reconsidering some of the emissions standards related to the "boiler MACT".

Following its reconsideration, the EPA published on January 31, 2013 its "National, Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule". As discussed in the December 19, 2012 EPA memorandum "Regulatory Impact Results for the Reconsideration Final Rule for National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources", the January 31, 2013 final rule included two major changes. The first change was the addition of additional sources that were subject to the rule; 72 major source facilities that incorporated a total of 336 additional boilers and process heaters. The EPA has estimated that approximately 14,000 boilers will be subject to the requirements of the boiler MACT, with approximately 1,700 of those boilers required to meet numerical emissions limits and approximately 12,300 of those boilers required to follow work practice standards, such as annual tune-ups.

The second major change between the March 2011 final rule and the January 2013 final rule was a change to a number of the emissions rate limitations for the various emissions unit subcategories, primarily due to data corrections and the inclusion of new data used to determine the emissions rate limitations. The emissions rate limitation changes resulted in emissions limitations for the various subcategories of subject units as follows:

- For HCl, 10 limits that are more stringent, 3 limits that are less stringent, and 1 that was unchanged from the March 21, 2011 final rule
- For mercury, 3 limits that are more stringent and 11 limits that are less stringent than the March 21, 2011 final of the rule
- For PM, 2 limits that are more stringent, 7 limits that are less stringent, and 5 limits that are unchanged from the March 21, 2011 final rule
- For CO, 4 limits that are more stringent and 10 limits that are less stringent than the March 21, 2011 final of the rule

The EPA estimated that the January 2013 final rule would impact the actual emissions reductions relative to the March 2011 final rule. The December 19, 2012 EPA memorandum "Regulatory Impact Results for the Reconsideration Final Rule for National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources" also indicated that the changes in the emissions limitations were estimated to result in the installation of fewer controls for the liquid fuel subcategories of units. The memorandum indicated that the estimate for fewer controls installation was due to an increase in the numerical particulate matter (PM) emissions rate limit for heavy oil-fueled units resulting in fewer installed PM controls, an increase in the numerical hydrogen chloride (HCl) limit resulting in fewer wet scrubber installations, and increases in numerical carbon monoxide (CO) emissions resulting in the installation of fewer oxidation catalysts.

The following table shows data taken from the December 19, 2012 EPA memorandum "Regulatory Impact Results for the Reconsideration Final Rule for National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources".

Table 29 - Comparison of March 2011 and January 2013 Boiler MACT Final Rule National $PM_{2.5}$ and SO_2 Reductions

	Direct $PM_{2.5}$ (tons/year)	SO_2 (tons/year)
Estimated Emissions Reductions from March 2011 Final Rule	28,990	439,619
Additional Reductions Due to Increase in Subject Units	+1,314	+74,152
Additional Reductions Due to Changes in Control Provisions	-13,753	+57,956
Estimated Emissions Reductions from January 2013 Final Rule	16,593	571,727

It can be seen in the above table that the changes in scope and range of control provisions in the January 2013 final rule resulted in a significant increase in the amount of SO_2 reductions relative to the March 2011 final rule by a value of approximately 132,108 tons per year. It can also be seen in the above table that the changes in scope and range of control provisions in the January 2013 final rule resulted in a significant net loss in direct $PM_{2.5}$ emissions reductions relative to the March 2011 final rule, by a value of approximately 12,397 tons per year. Reducing SO_2 and $PM_{2.5}$ emissions individually or in tandem tends to improve the level of visibility in any given location. The changes in $PM_{2.5}$ and SO_2 emissions reductions shown in the above table will tend to have opposing effects on regional haze.

As discussed earlier, the EPA estimated that the January 2013 final rule will reduce the overall emission of sulfur dioxide and thereby tend to reduce the amount of atmospheric sulfates. The reduction in atmospheric sulfates resulting from the January 2013 final rule will have a positive effect from a regional haze standpoint. However, as discussed above, the EPA estimated that the January 2013 final rule will increase the overall emission of direct $PM_{2.5}$, relative to the March 2011 final rule. This increase in $PM_{2.5}$ emissions of the January 2013 final rule will tend to have a negative impact from a regional haze standpoint relative to that resulting from the March 2011 final rule. A review of the EPA's data used in developing the EPA's final rules indicate that the EPA did not estimate that the effects on Delaware's units subject to the boiler MACT would follow the overall rule impact trend. The following table shows the emissions reductions estimated by EPA for Delaware's population of units identified by the EPA as subject to the EPA's boiler MACT:

Table 30 - Comparison of Delaware SO_2 and $PM_{2.5}$ Emissions under the March 2011 and January 2013 Boiler MACT

	Baseline SO_2 Emissions (tons)	Estimated SO_2 Reductions Resulting from Rule (tons)	Baseline $PM_{2.5}$ Emissions (tons)	Estimated $PM_{2.5}$ Reductions Resulting from Rule (tons)
March 2011 Final Rule	4827.02	3286.71	466.39	4.66
January 2013 Final Rule	4827.02	3251.84	466.39	4.66
Change		**-34.87**		**0**

It can be seen in the above table that, for Delaware, the changes to the boiler MACT from the March 2011 final rule to the January 2013 final rule resulted in an estimated loss in SO_2 reductions of 34.87 tons/year and an estimated no change in $PM_{2.5}$ emissions reductions. It can also be seen in the data in the above table that the baseline emissions utilized by the EPA in the development of the final rules did not change for Delaware between the March 2011 and January 2013 final rules.

A review of the EPA's data indicates that for Delaware's fleet of units identified by the EPA as subject to the boiler MACT, the only difference in emission rates for Delaware units was related to the three Invista coal fired boilers. In the EPA's estimation of the effect of the boiler MACT on these units, the EPA assumed that scrubbers would be installed for HCl control, and that the scrubbers would be designed to meet the HCl emissions rate limitation of the respective final rule. The EPA also assumed that the scrubbers would also serve to reduce SO_2 emissions. However, HCl emissions limitation was revised between the March 2011 final rule and the January 2013 final rule. As a result, the EPA the estimated the required HCl removal effectiveness for compliance with the March 2011 boiler MACT to be approximately 81.74% and the EPA estimated the required HCL removal effectiveness for compliance with the January 2013 boiler MACT to be approximately 80.88%. The change in the scrubber effectiveness also served to reduce the SO_2 removal effectiveness between the March 2011 final rule and the January 2013 final rule, thereby reducing the amount of SO_2 reduction. For the purposes of compliance with the boiler MACT, the EPA did not estimate that these units would be converted to natural gas.

For the heavy liquid fuel units located in Delaware that were identified by EPA as subject to the boiler MACT, the subject units were classified as limited use units and were assumed to only adopt work standards with no additional emissions controls. For the purposes of compliance with the boiler MACT, the EPA did not estimate that these units would be converted to natural gas.

The remaining Delaware units that were identified by the EPA as subject to the boiler MACT utilized either natural gas as the primary fuel or process gas as the primary fuel. For the purposes of compliance with the boiler MACT, for the units that were not already identified as utilizing natural gas as the primary fuel, the EPA did not estimate that any of the subject units would be converted to natural gas fuel. These units were assumed to adopt the work standards with no additional emissions controls.

The EPA did not include natural gas conversion in its emissions compliance estimations for any of the Delaware units subject to the boiler MACT that were not already shown to have natural gas as its primary fuel.

However, subsequent to the establishment of the baseline inventory utilized by the EPA in the development of the final rules, a number of Delaware sources subject to the March 2011 and January 2013 boiler MACT final rules have already made reductions in SO_2 and $PM_{2.5}$ emissions as a result of existing Delaware regulations, consent decrees, and business decisions. The following table shows the more significant changes in Delaware's units, that are subject to the March 2011 and January 2013 final rules, subsequent to the establishment of the EPA's baseline:

Table 31 - Delaware Boiler MACT Inventory Update

Facility	Affected Unit EPA Inventory Information	Delaware Inventory Update
Chrysler - Newark Assembly	Six Gas/Liquid-Fired Boilers	Units have been retired and facility dismantled
McKee Run Units 1&2	Two Residual Fuel Oil-Fired Boilers	Converted to natural gas primary, 0.05% sulfur #2 fuel oil secondary fuel
Invista	Three Coal-Fired Boilers	Converted to natural gas primary, low sulfur #2 fuel oil secondary fuel

The changes to the Delaware units subject to the boiler MACT noted in the above table "Delaware Boiler MACT Inventory Update" will result in additional SO_2 emissions reductions from those facilities. Utilizing the data in the EPA's baseline, the changes noted in the above table were estimated to have the following effects on SO_2 emissions relative to the EPA baseline and the March 2011 and January 2013 final rules:

Table 32 - Delaware SO_2 emissions relative to the EPA Boiler MACT baselines

Facility	Boiler MACT Baseline SO_2 Emissions (tons)	March 2011 SO_2 Reductions (tons)	January 2013 SO_2 Reductions (tons)	SO_2 Reductions Due to DE Specific Actions (tons)
Chrysler - Newark Assembly	4.09	0.04	0.04	4.09
McKee Run Units 1&2	23.66	0.24	0.24	23.42
Invista	4010.58	3278.54	3243.68	3974.56
Total	**4038.33**	**3278.82**	**3243.96**	**4002.06**

The changes to the Delaware units subject to the boiler MACT noted in the above table "Delaware Boiler MACT Inventory Update" will also result in additional $PM_{2.5}$ emissions reductions from those facilities. As shown in Table 33, utilizing the data in the EPA's baseline, the changes noted in the above table were estimated to have the following effects (on $PM_{2.5}$ emissions relative to the EPA baseline and the March 2011 and January 2013 final rules:

Table 33 - Delaware $PM_{2.5}$ emissions relative to the EPA Boiler MACT baselines

Facility	Boiler MACT Baseline PM2.5 Emissions (tons)	March 2011 PM2.5 Reductions (tons)	January 2013 PM2.5 Reductions (tons)	PM2.5 Reductions Due to DE Specific Actions (tons)
Chrysler - Newark Assembly	1.8961	0.019	0.019	1.8961
McKee Run Units 1&2	0.2142	0.0021	0.0021	0.0023
Invista	31.0606	0.3106	0.3106	18.5256
Total	**33.1709**	**0.3317**	**0.3317**	**20.424**

Tables 32 and 33 show the SO_2 and $PM_{2.5}$ emissions reductions that will occur for certain Delaware units subject to the boiler MACT under the March 2011 final rule, under the January 2013 model rule, and under the Delaware specific conditions. It can also be seen in the tables that for the specific subject units the Delaware specific conditions result in SO_2 and $PM_{2.5}$ emissions reductions greater than those achieved by either the March 2011 boiler MACT final rule or the January 2013 boiler MACT final rule. The following table shows the estimated overall effect on SO_2 and $PM_{2.5}$ emissions reductions, relative to the EPA's baseline, of the March 2011 boiler MACT final rule, the January 2013 boiler MACT final rule, and the combined effect of the January 2013 boiler MACT final rule and Delaware specific emissions reductions:

Table 34 - Delaware's SO_2 and $PM_{2.5}$ Boiler MACT Estimated Emissions Reductions: March 2011 and January 2013 Final Rules and Delaware Specific Reductions

Pollutant	Boiler MACT Baseline 2011 & 2013 (tons)	March 2011 Boiler MACT Reductions (tons)	January 2013 Boiler MACT Reductions (tons)	Delaware Specific and January 2013 Boiler MACT Reductions (tons)
SO_2	4827.02	3286.71 (68%)	3251.85 (67%)	4009.96 (83%)
$PM_{2.5}$	466.39	4.66 (1%)	4.66 (1%)	24.76 (5%)

Note: Values in parenthesis are % reduction from baseline

The January 2013 boiler MACT incorporated revisions to the March 2011 boiler MACT that effectively increased the estimated reductions of SO_2 for the overall population of units subject to the boiler MACT. But the revisions incorporated in the January 2013 boiler MACT also served to effectively decrease the estimated reduction of $PM_{2.5}$ for the overall population of units subject to the boiler MACT. For the population of units subject to the boiler MACT located in Delaware, it can be seen in the above table that the revision of the boiler MACT from March 2011 to January 2013 was estimated by the EPA to result in a slight loss in SO_2 emissions reductions and no change in the estimated $PM_{2.5}$ reductions. However, it can also be seen in the above table that changes to boiler MACT subject units in Delaware (as a result of Delaware specific regulations, consent decrees, and business decisions in conjunction with the January 2013 boiler MACT) have resulted estimated SO_2 and $PM_{2.5}$ emissions reductions in excess of those estimated by the EPA for either the March 2011 boiler MACT or the January 2013 boiler MACT.

Therefore it is anticipated that the revisions incorporated in the January 2013 boiler MACT, in conjunction with Delaware specific actions, will not result in any increase in estimated SO_2 or $PM_{2.5}$ emissions from Delaware's sources subject to the boiler MACT that would adversely impact the effect of those emissions on regional haze.

1.4.2. Area Source Measures Discussed In The 2008 Sip

State of Delaware Measures

- **Agricultural and Forestry Smoke Management**

  40 CFR 51.308(d)(3)(v)(E) requires each state to consider smoke management plans (SMP) related to agricultural and forestry management in developing the long-term strategy to improve visibility at Class I areas. As discussed in Delaware's *2008 regional haze SIP*, 2002 $PM_{2.5}$ emissions from agricultural and prescribed burning for forestry smoke management were insignificant at 11 tpy. As of 2008, total agriculture and forestry $PM_{2.5}$ emissions from prescribed burns were only 14 tpy. Thus, DNREC's expectations discussed in its 2008 regional haze SIP were proven correct in that these emissions did not change significantly, and therefore continues to maintain that smoke

management for visibility purposes continue to be a low priority for the next five year period (2013-2018).

Furthermore, a Smoke Management Plan (SMP) is a required element of a SIP only when the smoke impacts from fires can be managed for improved visibility at Class I areas. Since Delaware's 2008 emissions inventory data continue to show that agricultural and forestry PM emissions remain insignificant, a SMP remains unnecessary.[26] Consequently, visibility impacts from agricultural and forestry burns will continue to not be considered when issuing burn authorizations.

- **Measures to Mitigate Impacts of Construction Activities**

  40 CFR 51.308(d)(3)(v)(B) of the Regional Haze Rule requires each state to consider measures to mitigate the impacts of construction activities on regional haze. MANE-VU's Contribution Assessment found that, from a regional haze perspective, crustal material generally does not play a major role in visibility impairment at MANE-VU Class I areas. Delaware's speciated monitoring network shows that crustal material averages only 4-5 percent of total $PM_{2.5}$. Nevertheless, the crustal fraction at any given location can be heavily influenced by the proximity of construction activities; and construction activities occurring in the immediate vicinity of MANE-VU Class I Areas could have a noticeable effect on visibility.

The following measures were included in Delaware's 2008 regional haze SIP and implementation is proceeding as indicated:

- **7 DE Admin Code 1106 - Particulate Emissions from Construction and Materials Handling** (effective 2/01/1981, administratively revised 9/01/2008). In summary, regulation 1106 states that any persons doing demolition, land clearing, land grading (including grading for roads), excavation, material transport, or the use of non-paved roads on private property are required to employ control dust control measures, when the Department determines that such activities could emit dust in quantities sufficient to cause air pollution.

Area sources measures in Delaware's regional haze SIP that will reduce $PM_{2.5}$ emissions by 2018 are open burning (regulation revised in 2007) and Residential Woodstoves 40 C.F.R. Part 60 Subpart AAA New Source Performance Standards ("NSPS") for PM, VOC and NOx emission control (due to turnover).

[26] The Department reiterates from its 2008 regional haze SIP that Delaware's Regulation 1113 (Open Burning), prohibits prescribed and agricultural burning from May through September. Although the Department does not consider the Open Burning regulation a "Smoke Management Plan" (SMP), May through September is the season typically associated with the worst 20% visibility-impairing days at Brigantine, so this regulation may benefit the Brigantine Class I area to a small degree.

Table 35 shows the effective date and FR citation of the Delaware regulation and EPA NSPS.

Table 35 - Area Sources Measures in Delaware's Initial SIP

Title of Regulation	DE SIP Effective Date	FR Date	FR Citation	2002 $PM_{2.5}$ (tpy)	2008 $PM_{2.5}$ (tpy)
7 DE Admin Code 1113 - Open Burning	10/22/2007	8/11/2010	75 FR 48566	116	52
Residential Woodstoves 40 C.F.R. Part 60 Subpart AAA New Source Performance Standards ("NSPS")	NA	2/26/1988	53 FR 5860	1116	403

1.4.3. Mobile Sources Controls Discussed in the 2008 SIP

1.4.3.1. Federal Mobile Source Control Programs

Tier 2 Vehicle and Gasoline Sulfur Program: (40 CFR Part 80, Subpart H; 40 CFR Part 85; 40 CFR Part 86): The EPA's Tier 2 fleet averaging program for onroad vehicles, modeled after the California LEV II standards, became effective in the 2005 model year. The Tier 2 program allows manufacturers to produce vehicles with emissions ranging from relatively dirty to very clean, but the mix of vehicles a manufacturer sells each year must have average NO_X emissions below a specified value. Mobile emissions continue to benefit from this program as motorists replace older, more polluting vehicles with cleaner vehicles. Emissions reductions are reflected in onroad and nonroad mobile source emission estimates provided in C.3.

***On-Board Refueling Vapor Recovery (ORVR) Rule*:** The 1990 Clean Air Act (CAA) Amendments contain provisions that require passenger cars to capture refueling emissions. In 1994, EPA published the ORVR Rule establishing standards for refueling emissions controls for passenger cars and light trucks. The onboard controls were required to be phased in for all new car production by 2000 and for all light trucks by 2006. The rule established a refueling emission standard of 0.20 grams per gallon of dispensed fuel, which was expected to yield a 95 percent reduction of VOC emissions over uncontrolled levels. The CAA authorizes EPA to allow state and local agencies that are not in the ozone transport region (OTR) to phase out Stage II programs, even in the worst nonattainment areas, once EPA has determined that onboard systems are in widespread use. Additional requirements apply under section 184(b)(2) of the CAA to states in the OTR.

***Heavy-Duty Diesel Engine Emission Standards for Trucks and Buses*:** EPA set a PM emissions standard of 0.01 grams per brake-horsepower-hour (g/bhp-hr) for new heavy-duty diesel engines in trucks and buses, to take full effect in the 2007 model year. This rule also includes standards for NO_X and non-methane hydrocarbons (NMHC) of 0.20 g/bhp-hr and 0.14 g/bhp-hr, respectively. These NO_X and NMHC standards were phased in together between 2007 and 2010. Lowering sulfur in diesel fuel enables modern pollution control technology to be effective on the trucks and buses that use this fuel. EPA required a 97-percent reduction in the sulfur content of highway diesel fuel from its previous level of 500 parts per million (low-sulfur diesel) to 15 parts per million (ultra-low sulfur diesel). These requirements were successfully implemented on the timeline in the regulation. Emissions reductions are reflected in onroad mobile source emissions estimates for 2008 and later years (see Section C.3.).

***Emission Standards for Large Industrial Spark-Ignition Engines and Recreational Vehicles*:** EPA has adopted new standards for emissions of NO_X, hydrocarbons (HC), and carbon monoxide (CO) from several groups of previously unregulated nonroad engines. Included are large industrial spark-ignition engines and recreational vehicles. The affected spark-ignition engines are those powered by gasoline, liquid propane, or compressed natural gas rated over 19 kilowatts (kW) (25 horsepower). These engines are used in commercial and industrial applications, including forklifts, electric generators, airport baggage transport vehicles, and a variety of farm and construction applications. Nonroad recreational vehicles include snowmobiles, off-highway motorcycles, and all-terrain vehicles. These rules were initially effective in 2004 and will be fully phased-in by 2012.

1.4.3.2. Delaware-Specific Mobile Source Programs Discussed In The SIP

Because onroad sources are estimated using EPA models, and inherently include growth and controls in the form of fleet turnover, it is not feasible to break out onroad reductions due exclusively to controls. However, the emission summary tables in Section C.3 will show the NOx and $PM_{2.5}$ emission changes over the years.[27]

Delaware's initial regional haze SIP listed the following state-specific mobile control measures which were to be included in the MANE-VU 2018 projections:

- **7 DE Admin Code 1131, Low Enhanced Inspection and Maintenance**. Delaware's enhanced I/M program was first approved into the Delaware SIP by EPA on September 30, 1999 (64 FR 52657). Revisions to the enhanced I/M program were made with an effective date of 10/11/2001, which EPA approved on 11/26/2003 (68 FR 66343).

  The I/M programs for New Castle County include a biennial onboard diagnostic testing program (OBD II) since 2002 for 1996 and later model year vehicles. Vehicle emission computer systems are checked for any diagnostic trouble codes present, a symptom of excess emissions which is a failing result for the vehicle. Older vehicles, starting with model year (MY) 1968, are given a curb idle test (MY 1968-1980) or a two-speed idle test (MY 1981- 1995). A tailpipe probe is inserted for 60 seconds to determine exhaust concentrations of hydrocarbons and carbon monoxide. Depending on the model year, vehicles with an excess emission concentration of either pollutant will fail the test. Older

[27] 2012 onroad emissions of sulfate (SO_2) are insignificant, and were not included in this report.

vehicles (MY 1975-1995) are also given a fuel system pressure test (FP) and a gas cap (GC) test. Air pressure is applied to the fuel system from the fuel inlet to the canister. After air pressure has been applied, pressure degradation is monitored. Vehicles fail the fuel system pressure test if it cannot maintain the equivalent pressure of eight inches of water for up to two minutes after being pressurized to 14.0 ± 0.5 inches of water. A similar pressure test is applied to the vehicle's gas cap.

- **Transportation Conformity.** Delaware's SIP contains provisions that are consistent with the Section176(c) conformity requirements. In Delaware's SIP, general conformity requirements are contained in 7 DE Admin Code 1135, Conformity of General Federal Actions to the State Implementation Plans, (Regulation for General Conformity), which was approved into the Delaware SIP by EPA on 08/11/2010. (75 FR 48566) Transportation conformity requirements are contained in 7 DE Admin Code 1132, Transportation Conformity, which has an effective date of 9/11/2008 and approved into the Delaware SIP by EPA on 08/11/2010 (75 FR 48566).

- **7 DE Admin Code 1140 National Low Emission Vehicle Program.** Delaware belongs to the Northeast Ozone Transport Region (OTR). The States in this region have adopted a low-emission vehicle program that began with the 1999 model year. The National LEV program (NLEV), which began with the 2001 model year, is the default modeled in MOVES. Therefore, to correctly model the Northeast Ozone Transport Region LEV program in place in Delaware, the early NLEV database was used in the MOVES run specification. The phase-in schedule of the Northeast Ozone Transport Region LEV program is shown in Table 36. This phase-in schedule was applied to gasoline-powered passenger cars, passenger trucks, and light commercial trucks under 8,501 GVWR. Transportation conformity requirements are contained in 7 DE Admin Code 1140, National Low Emission Vehicle Program, which has an effective date of 09/11/2008; and was approved into the Delaware SIP by EPA on 08/11/2010 (75 FR 48566).

Table 36 - LEV Implementation Schedule in the Northeast OTR

Model Year	Federal Tier I Standards	Transitional LEV Standards	LEV Standards	Tier 2 Standards
1999	30%	40%	30%	
2000		40%	60%	
2001 - 2003			100%	
2004 and later				100%

Two Delaware control programs, the anti-tampering procedures (ATP) performed at the inspections lanes and the anti-idling regulation (DNREC, 2005) were not accounted for in the mobile runs since the MOBILE6 (or MOVES) model does not provide for inputting these programs. For the ATP control program, vehicles that are tested are also checked to see if the catalytic converter, gas cap and fuel inlet restrictor are present. Vehicles will fail inspection if any of these devices are missing. 7 DE Admin Code 1145, Excessive Idling of Heavy Duty Vehicles, is a post-Delaware regional haze SIP measure designed to eliminate emissions caused by extending idling. While MOVES delineates emissions processes for extended idling, the control programs currently available within MOVES do not account for anti-idling measures. Delaware currently has no off-model method to determine emission benefits from either ATP or 7 DE Admin Code 1145.

1.4.4. Controls on Nonroad Sources Expected by 2018

The nonroad source sector is comprised of nonroad engines included in EPA's NONROAD model, as well as other nonroad engines not accounted for in the NONROAD model, including aircraft, commercial marine vessels, and locomotive engines. The sections that follow describe the projection process used to develop 2009/2012/2018 nonroad projection estimates for sources found in the NONROAD model and those sources estimated outside of the model (locomotives, airplanes and commercial marine vessels).

1.4.4.1. Nonroad Model Sources

NONROAD model source categories include equipment such as recreational boats and watercraft; recreational vehicles; farm, industrial, mining, and construction machinery; and lawn and garden equipment. Also included are aircraft ground support equipment and rail maintenance equipment. These equipment types are powered by engines using diesel, gasoline, compressed natural gas (CNG), and liquefied petroleum gas (LPG). EPA released a revised version of NONROAD during December 2005 called NONROAD 2005. EPA's National Mobile Inventory Model (NMIM) is a consolidated modeling system that incorporates the NONROAD and MOBILE models, along with a county database of inputs. EPA also released an updated version of NMIM called NMIM2005, which incorporates the NONROAD2005 model.

MACTEC utilized the NMIM2005 model to develop projections for nonroad engines included in the NONROAD2005 model. Projected emission estimates were calculated using NMIM default data. Prior to starting the NMIM2005 runs, MACTEC confirmed with U.S. EPA's Office of Transportation and Air Quality (OTAQ) that the database used for fuel sulfur content, gas Reid Vapor Pressure (RVP) values and reformulated fuel programs was current and up to date for the MANE-VU region. The information received from OTAQ indicated that these values were the most current.

NMIM2005 runs were then developed for each projection year. These included 2009, 2012 and 2018. Emission calculations were made at the monthly level and consolidated to provide annual values. This enabled monthly temperatures and changes in reformulated gas to be captured by the program.

Because the NONROAD Model used to develop the nonroad source emissions did not include aircraft, commercial marine vessels, and locomotives, MANE-VU's contractor, MACTEC, developed the inventory for these sources. Nonroad mobile source emissions for the 2018 emission inventory were calculated with EPA's NONROAD2005 emissions model as incorporated into the NMIM2005 (National Mobile Inventory Model) database. The NONROAD model accounts for emissions benefits associated with federal nonroad emission control requirements such as the following:

- *Control of Air Pollution; Determination of Significance for Nonroad Sources and Emission Standards for New Nonroad Compression Ignition Engines at or Above 37 Kilowatts*

  59 FR 31036, June 17, 1994. This rule establishes Tier 1 exhaust emission standards for HC, NOx, CO, and PM for nonroad compression-ignition (CI) engines ≥37kW (≥50hp). Marine engines are not included in this rule. The start dates and pollutants affected vary by hp category as follows:

  - 50-100 hp: Tier 1,1998; NOx only
  - 100-175 hp: Tier 1, 1997; NOx only
  - 175-750 hp: Tier 1, 1996; HC, CO, NOx, PM
  - >750 hp: Tier 1, 2000; HC, CO, NOx, PM

- *Emissions for New Nonroad Spark-Ignition Engines At or Below 19 Kilowatts; Final Rule* 60 FR 34581. July 3, 1995. This rule establishes Phase 1 exhaust emission standards for HC, NOx, and CO for nonroad spark-ignition engines ≤19kW (≤25hp). This rule includes both handheld (HH) and non-handheld (NHH) engines. The Phase 1 standards became effective in 1997 for:

  - Class I NHH engines (<225cc),
  - Class II NHH engines (≥225cc),
  - Class III HH engines (<20cc), and
  - Class IV HH engines (≥20cc and <50cc).

  The Phase 1 standards became effective in 1998 for: Class V HH engines (≥50cc)

- *Final Rule for New Gasoline Spark-Ignition Marine Engines; Exemptions for New Nonroad Compression-Ignition Engines at or Above 37 Kilowatts and New Nonroad Spark-Ignition Engines at or Below 19 Kilowatts* 61 FR 52088. October 4, 1996. This rule establishes exhaust emission standards for HC+NOx for personal watercraft and outboard (PWC/OB) marine SI engines. The standards were phased in from 1998-2006.

- *Control of Emissions of Air Pollution from Nonroad Diesel Engines* 63 FR 56967 October 23, 1998. This final rule sets Tier 1 standards for engines under 50 hp, phasing in from 1999 to 2000. The rule also phases in more stringent Tier 2 standards for all engine sizes from 2001 to 2006, and even more stringent Tier 3 standards for engines rated from 50 hp to 750 hp from 2006 to 2008. The Tier 2 and Tier 3 standards apply to NMHC+NOx, CO, and PM. The start dates by hp category and tier are as follows:

- hp: < 8kW and 8-19kW Tier 1,2000; Tier 2, 2005; no Tier 3
- 25-50 hp: Tier 1, 1999; Tier 2, 2004; no Tier 3
- 50-100 hp: Tier 2, 2004; Tier 3, 2008
- 100-175 hp: Tier 2, 2003; Tier 3, 2007
- 175-300 hp: Tier 2, 2003; Tier 3, 2006
- 300-600 hp: Tier 2, 2001, Tier 3, 2006
- 600-750 hp: Tier 2, 2002; Tier 3, 2006
- >750 hp: Tier 2, 2006, no Tier 3

Note: This rule does not apply to marine diesel engines above 50 hp.

- *Phase 2: Emission Standards for New Nonroad Non-handheld Spark Ignition Engines At or Below 19 Kilowatts* 64 FR 15207. March 30, 1999. This rule establishes Phase 2 exhaust emission standards for HC+NOx for nonroad non-handheld (NHH) spark-ignition engines ≤19kW (≤25hp). The Phase 2 standards for Class I NHH engines (<225cc) became effective on August 1, 2007 (or August 1, 2003 for any engine initially produced on or after that date). The Phase 2 standards for Class II NHH engines (≥225cc) were phased in from 2001-2005.

- *Phase 2: Emission Standards for New Nonroad Spark-Ignition Handheld Engines At or Below 19 Kilowatts and Minor Amendments to Emission Requirements Applicable to Small Spark-Ignition Engines and Marine Spark-Ignition Engines*; Final Rule 65 FR 24268 April 25, 2000. This rule establishes Phase 2 exhaust emission standards for HC+NOx for nonroad handheld (HH) spark-ignition engines ≤19kW (≤25hp). The Phase 2 standards were phased in from 2002-2005 for Class III and Class IV engines and were phased in from 2004-2007 for Class V engines.

- *Control of Emissions From Nonroad Large Spark-Ignition Engines and Recreational Engines (Marine and Land-Based)*; Final Rule 67 FR 68241. November 8, 2002. This rule establishes exhaust and evaporative standards for several nonroad categories:

  (1) Two tiers of emission standards are established for large spark-ignition engines over 19 kW. Tier 1 includes exhaust standards for HC+NOx and CO and was phased in from 2004-2006. Tier 2 became effective in 2007 and includes exhaust standards for HC+NOx and CO as well as evaporative controls affecting fuel line permeation, diurnal emissions and running loss emissions.

  (2) Exhaust and evaporative emission standards are established for recreational vehicles, which include snowmobiles, off-highway motorcycles, and all-terrain vehicles (ATVs). For snowmobiles, HC and CO exhaust standards are being phased-in from 2006-2012. For off-highway motorcycles, HC+NOx and CO exhaust emission standards were phased in from 2006-2007. For ATVs, HC+NOx and CO exhaust emission standards were phased in from 2006-2007. Evaporative

emission standards for fuel tank and hose permeation apply to all recreational vehicles beginning in 2008.

(3) Exhaust emission standards for HC+NOx, CO, and PM for recreational marine diesel engines over 50 hp during 2006-2009, depending on the engine displacement. These are “Tier 2” equivalent standards.

- *Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel; Final Rule (Clean Air Nonroad Diesel Rule – Tier 4)* 69 FR 38958, June 29, 2004. This final rule sets Tier 4 exhaust standards for CI engines covering all hp categories (except marine and locomotives), and also regulates nonroad diesel fuel sulfur content.

(1) The Tier 4 start dates and pollutants affected vary by hp and tier as follows:

Rated Power	**First Year that Standards Apply**	**PM (g/hp-hr.)**	**NOx (g/hp-hr.)**
hp < 25	2008	0.30	-
25 ≤ hp < 75	2013	0.02	3.5*
75 ≤ hp < 175	2012-2013	0.01	0.30
175 ≤ hp < 750	2011-2013	0.01	0.30
hp ≥ 750	2011-2014 2015	0.075 0.02/0.03**	2.6/0.50† 0.50††

* The 3.5 g/hp-hr. standard includes both NOx and nonmethane hydrocarbons.
† The 0.50 g/hp-hr. standard applies to gensets over 1200 hp.
** The 0.02 g/hp-hr. standard applies to gensets; the 0.03 g/hp-hr. standard applies to other engines.
†† Applies to all gensets only.

(2) This rule will reduce nonroad diesel fuel sulfur levels in two steps. First, starting in 2007, fuel sulfur levels in nonroad diesel fuel will be limited to a maximum of 500 ppm, the same as for current highway diesel fuel. Second, starting in 2010, fuel sulfur levels in most nonroad diesel fuel will be reduced to 15 ppm.

- *Control of Emissions from Nonroad Spark-Ignition Engines and Equipment; Final Rule (Bond Rule)*, 73 FR 59034 October 8, 2008. This rule establishes exhaust and evaporative standards for small SI engines and marine SI engines.

(1) Phase 3 HC+NOx exhaust emission standards are established for Class I NHH engines starting in 2012 and for Class II NHH engines starting in 2011. There are

no new exhaust emission standards for handheld engines. New evaporative standards are adopted for both handheld and non-handheld equipment. The new evaporative standards control fuel tank permeation, fuel hose permeation, and diffusion losses. The evaporative standards begin in 2012 for Class I NHH engines and 2011 for Class II NHH engines. For handheld engines, the evaporative standards are phased-in from 2012-2016.

(2) More stringent HC+NOx and CO standards are established for marine SI PWC/OB engines beginning in 2010. In addition, new exhaust HC+NOx and CO standards are established for stern-drive and inboard (SD/I) marine SI engines also beginning in 2010. High performance SD/I engines are subject to separate HC+NOx and CO exhaust standards that were phased-in from 2010-2011. New evaporative standards were also adopted for all marine SI engines that control fuel hose permeation, diurnal emissions, and fuel tank permeation emissions. The hose permeation, diurnal, and tank permeation standards take effect in 2009, 2010, and 2011, respectively.

- ***Nonroad Diesel Emissions Program****:* The EPA adopted standards for emissions of NO_X, hydrocarbons, and carbon monoxide (CO) from several groups of nonroad engines, including industrial spark-ignition engines and recreational nonroad vehicles. Industrial spark-ignition engines power commercial and industrial applications and include forklifts, electric generators, airport baggage transport vehicles, and a variety of farm and construction applications. Nonroad recreational vehicles include snowmobiles, off-highway motorcycles, and all-terrain vehicles. These rules were initially effective in 2004 and were fully phased in by 2012.

  The nonroad diesel rule set standards that reduced emissions by more than 90 percent from nonroad diesel equipment and, beginning in 2007, the rule reduced fuel sulfur levels by 99 percent from previous levels. The reduction in fuel sulfur levels applied to most nonroad diesel fuel in 2010 and applied to fuel used in locomotives and marine vessels in 2012.

1.4.4.2. Aircraft, Commercial Marine, And Locomotives

Since aircraft, commercial marine vessels, and locomotives are not included in the NONROAD model, emission projections for these sources were developed separately. The starting point for the emission projections was Version 3 of the MANE-VU 2002 Nonroad emission inventory (*Documentation of the MANE-VU 2002 Nonroad Sector Emission Inventory, Version 3, Draft Technical Memorandum*, March 2006).

The approach to developing emission projections for these sources was for MARAMA's contractor (MACTEC) to use combined growth and control factors developed from emission projections for U.S. EPA's Clean Air Interstate Rule (CAIR) development effort. MACTEC obtained emission projections developed for the CAIR rule. MACTEC then calculated the combined growth and control factors by determining the ratio of emissions between 2002 and each of the MANE-VU projection years (2009, 2012, and 2018). The CAIR emissions were available for 2001, 2010, 2015 and 2020. Thus, MACTEC developed intermediate year estimates using linear interpolation between the actual CAIR years and the MANE-VU years. Using this approach State/county/SCC/pollutant growth/control factors were developed for use in projecting the MANE-VU base year data to the year of interest. These values were then used to multiply times the base year value to obtain the projected values. Since the development of the CAIR factors included both growth and controls due to federal programs, no separate control factors were developed for these sources for Delaware and thus a status of these federal measures is not listed.

1.4.5. Miscellaneous Measures in the SIP

1.4.5.1. Prevention of Significant Deterioration

Delaware will continue carrying out the required review of proposed sources' impact on visibility under 40 C.F.R. § 52.26 and 52.28, by implementing the Prevention of Significant Deterioration (PSD) permit requirements for new or modified major sources of air pollutants located within 100 kilometers of the Class I area, or within a larger radius on a case-by-case basis, in accordance with all applicable Federal rules for review of the impacts on Class I areas.

7 DE Admin Code 1125 (PSD) is SIP approved, codified under 40 CFR 52.420(c) and implemented through the requirements of 7 DE Admin Code 1125, Preconstruction Review. Delaware implements its Construction and Operation Permit Program requirements under 7 DE Admin Code 1102 and 1125. These existing permitting programs ensure that the construction and modification of both major and minor stationary sources do not cause or contribute to a violation of any NAAQS or cause significant visibility impairment in Class I areas. 7 DE Admin Code 1125 fulfills parts C and D of Title I of the CAA; governing preconstruction review and permitting of any new or modified major stationary sources of air pollutants. 1125 is approved in the DE SIP. Under 1125 any major source or modification that results in a net significant increase of SO_2 and NOx (40 TPY or greater) or $PM_{2.5}$ (15 tpy or greater) must apply Best Available Control Technology (BACT) to reduce those emissions.

1.4.5.2. Enforceability

Delaware's initial SIP was approved by the EPA on May 31, 1972. Since this initial approval, the Delaware SIP has been revised numerous times to address air quality non-attainment and maintenance issues, as well as regional haze. This was done by updating plans and inventories, and adding new and revised regulatory control requirements. Delaware's SIP is compiled in the Code of Federal Regulations at 40 C.F.R. Part 52 Subpart I. Legislative authority for the Delaware air quality program relating to the responsibilities in the CAA is codified in Title 7 "Conservation" of the Delaware Code, Chapter 60 – Delaware's comprehensive water and air resources conservation law[28], which gives the Delaware Department of Natural Resources and Environmental Control (DNREC) the power and duty to implement the provisions of the CAA in the State of Delaware.

Delaware has established and currently operates a program to provide for the enforcement of the enforceable emission limitations and other control measures, means, or techniques, as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of the CAA, and to regulate the modification and construction of any stationary source within areas covered by its SIP as necessary to assure the visibility goals are achieved, including permit programs required in parts C and D. At present, Delaware, through its Division of Air Quality, exercises its programmatic authority to utilize the enforcement powers set out in 7 Del. C. §6005 entitled "Enforcement; civil and administrative penalties; expenses"; 7 Del. C. §6013 entitled "Criminal penalties"; and 7 Del. C. §6018 entitled "Cease and desist order." Delaware will continue to operate this program and may makes changes that it believes in its discretion are appropriate, while continuing to fulfill this obligation.

1.5. NEW EMISSION CONTROL MEASURES NOT INCLUDED IN THE INITIAL 2008 HAZE SIP

Since development of the Delaware regional haze SIP a number of federal rules and state regulations and requirements have been developed that were not included in 2018 estimates. The sections below provide information on these requirements, and where possible, estimates of additional reductions are provided. These reductions provide extra assurances that the Brigantine Wilderness Area will meet its reasonable progress goals in a timely manner.

1.5.1. Mercury and Air Toxics Rule

On December 16, 2011, the EPA finalized national CAA standards to reduce mercury and other toxic air pollution from coal- and oil-fired power plants. National Emission Standards for Hazardous Air Pollutants From Coal-Fired and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units [77 FR 9304] was published in the Federal Register on February 16, 2012, with an effective date of April 16, 2012. The final rule established power plant emission standards for mercury, acid-gases, and non-mercury metallic toxic pollutants that will prevent 90 percent of the mercury in coal burned in power plants from being emitted into the air; reduce by 88 percent the acid gas emissions from power plants; and cut power plant SO_2 emissions by 41 percent beyond the reductions expected from CSAPR. These reductions are expected in the 2016 timeframe.

On August 2, 2012, [77FR45967] the EPA issued a partial stay of the effectiveness of the national emission standards for hazardous air pollutants from coal- and oil-fired utility steam

[28] Referred to in this document as "7 Del. C." followed by the specific section citation (e.g., §6005).

generating units issued pursuant to Clean Air Act section 112 that were published in the Federal Register on February 16, 2012 [77 FR 93045].

On November 30, 2012, [77 FR 71323] the EPA proposed to update emission limits for new power plants under the Mercury and Air Toxics Standards (MATS). The updates would only apply to future power plants; would not change the types of state-of-the-art pollution controls that they are expected to install' and would not significantly change costs or public health benefits of the rule.

1.5.2. 2010 Sulfur Dioxide NAAQS

On June 2, 2010, the EPA strengthened the primary NAAQS for SO2 by revising the primary SO_2 standard to 75 ppb averaged over one hour. This short term standard is significantly more stringent than the revoked standards of 140 ppb averaged over 24 hours and 30 ppb averaged over a year. Under the new standard, facilities with significant emissions of SO_2, many of which are EGUs and large industrial boilers, will be required to demonstrate compliance with the standard no later than 2017. Pursuant to the CAA, states are required to submit such demonstrations 18 months from the date of designation of a nonattainment area. The current schedule for the finalization of nonattainment areas for SO_2 is June 2013. Delaware recommended in its letter to EPA on May11, 2011 that all three Delaware counties (New Castle, Kent and Sussex) be designated as unclassifiable for the 2010 primary SO_2 NAAQS based on monitoring data for the period 2008-2010.

EPA plans to use a combination of monitoring and modeling to assess compliance with the 1-hour SO_2 standard. EPA has proposed implementation and modeling guidance and held stakeholder meetings to gather additional information to develop additional guidance and/or a final rule. These additional stakeholder discussions signaled the need to further develop the guidance to include potential alternatives to modeling for designations and compliance.

Delaware DAQ will follow EPA guidance to determine compliance with the NAAQS for SO_2. DAQ will initially focus on whether sources of SO_2 emissions will need additional emissions controls or other emissions reduction measures to attain the NAAQS, should they be nonattainment. Any additional reductions, regional or statewide, in SO_2 emissions will enhance protection of visibility, especially in Federal Class I areas.

1.5.3. Commercial Marine Vessels and North American Emission Control Area

On April 30, 2010 EPA published a direct final Rule entitled "Control of Emissions From New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder", 75 FR 22896. With this Rule, EPA adopted standards that apply to Category 3 (C3) engines installed on U.S. vessels and to marine diesel fuels produced and distributed in the United States. That rule added two new tiers of engine standards for C3 engines: Tier 2 standards that begin in 2011 and Tier 3 standards that begin in 2016. It also includes a regulatory program to implement Annex VI to the International Convention for the Prevention of Pollution from Ships (a treaty called "MARPOL") in the United States, including engine and fuel sulfur limits, and extends the Emission Control Area (ECA) engine and fuel requirements to U.S. internal waters. The rule also revised our domestic CAA diesel fuel program to allow for the production and sale of diesel fuel with up to 1,000 ppm sulfur for use in C3 marine vessels, phasing in by 2015.

On March 26, 2010, the International Maritime Organization officially designated waters off North American coasts as an area in which stringent international emission standards will apply to ships. These standards will reduce air pollution from ships and deliver air quality benefits that extend hundreds of miles inland. In 2020, EPA expects emissions from ships operating in the designated area to be reduced by 320,000 tons for NO_x, 90,000 tons for $PM_{2.5}$, and 920,000 tons for SO_2, which is 23 percent, 74 percent, and 86 percent, respectively, below predicted levels in 2020 absent the Emissions Control Area designation.

Implementation of the Emission Control Area means that ships entering the designated area (such as the Delaware River) would need to use compliant fuel for the duration of their voyage that is within that area, including time in port as well as voyages whose routes pass through the area without calling on a port. The requirements for quality of fuel change over time. From the effective date in 2012 until 2015, the sulfur content of fuel used by all vessels operating in designated areas cannot exceed 10,000 ppm. Beginning in 2015, the sulfur content of fuel used by vessels operating in these areas cannot exceed 1,000 ppm. With regard to NO_x emissions, marine diesel engines installed on a ship constructed on or after January 1, 2011 must comply with the "Tier II" standard. Marine diesel engines installed on a ship constructed on or after January 1, 2015 will be required to comply with the more stringent "Tier III" NO_x standard.

1.5.4. Residual Risk Requirements

The Clean Air Act requires the EPA to assess the risk remaining after application of final technology-based air toxics standards to any source category within 8 years of setting the technology based MACT standards. In the residual risk process, the EPA must assess the remaining health risks from each source category to determine whether the MACT standards provide an ample margin of safety to protect public health and protect against adverse environmental effects. Final rules for this Clean Air Act requirement are expected for 28 source categories between 2011 and 2013. Additional requirements to reduce toxic air emissions under the residual risk assessment may also have co benefits for the reduction of VOC and other criteria pollutant emissions between now and 2018.

1.6. DELAWARE UNIT-SPECIFIC POINT SOURCE REDUCTIONS SINCE SIP SUBMITTAL

Table 37 provides information on units that have shutdown or otherwise installed controls that did not have the associated 2018 emissions reductions included in the Delaware regional haze SIP.

Table 37 – Facility/Unit Shutdowns and Refinery NOx CAP

FACILITY NAME	Unit ID	UNIT DESCRIPTION	Additional Pre-2018 Emission Reductions from the 2002 Base Year (tpy)		
			NOx	**PM25**	**SO2**
Daimler-Chrysler Corporation	ALL	ALL	39	4	0
Indian River Generating Station	3	EGU - Coal Boiler #3	663	286	4,694
City of Lewes Power Plant	ALL	ALL	3	0	0
DE City Refinery (2015 NOx PAL/CAP)	ALL	ALL NOx Units	453	0	0
Totals			**1158**	**290**	**4,694**

Table 38 shows total post-SIP reductions from non-EGUs due to shutdowns, the Refinery NOx CAP and the new low-sulfur fuel regulation. These are additional post-2008 SIP reductions which go beyond the extra reductions discussed in the EGU section of this report (C.1.2), i.e., prior to the 2018 RPG date.

Table 38 – New Post-2008 SIP SO_2 and NOx Reductions by 2018

Post-SIP Measures	"Extra" post-SIP Reductions Calculated From The 2002 Base Year	
	SO2	**NOx**
Facility-Unit Shutdowns/NOx CAP	4,694	1,158
Low-Sulfur Fuel Reg.	2,650	NA
Total	**7,344**	**1,158**

NA = not applicable for this discussion

2. CHANGES IN VISIBILITY FOR EACH MANDATORY FEDERAL CLASS I AREA IN THE STATE

[40 CFR 51.308(g)(3)]

For each mandatory Class I Federal area within the State, the State must assess the following visibility conditions and changes, with values for most impaired and least impaired days expressed in terms of 5-year averages of these annual values.

i. The current visibility conditions for the most impaired and least impaired days;

ii. The difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions;

iii. The change in visibility impairment for the most impaired and least impaired days over the past 5 years.

This requirement only applies to states with Class I areas within their borders.

3. ANALYSIS OF EMISSIONS CHANGES BY SOURCE CATEGORY

[40 CFR 51.308(g)(4)]

40 CFR 51.308(g)(4) requires:

> *An analysis tracking the change over the past 5 years in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity. The analysis must be based on the most recent updated emissions inventory, with estimates projected forward as necessary and appropriate, to account for emissions changes during the past 5-year period.*"

40 CFR 51.308(d)(4)(v) of the RHR requires a statewide inventory of pollutants that are reasonably anticipated to cause or contribute to visibility impairment. As such, this section will focus on $PM_{2.5}$, NOx and SO_2 emissions. Five emission inventory source classifications were developed and include: non-EGUs, EGUs, area sources, off-road and onroad mobile sources.

The Delaware regional haze SIP was developed using the MANE-VU 2002 base year, version 3.3, and 2018 emission inventory projections. The 2008 emissions in this report represent the most recent year of emissions data, and were obtained from Delaware's 2008 periodic emissions inventory (PEI). The emission calculation methodologies can be found in "*2008 Attainment Year State Implementation Plan Emissions Inventory for PM2.5, SO2 and NOx New Castle County, Delaware*" *October 2, 2012* (Appendix A).[29] Statewide emissions for the 2008 PEI are available in Appendix B.

2011 EGU emissions data was also obtained from the EPA Clean Air Markets Division (CAMD) and combined with the non-EGU sectors of the 2008 PEI and 2012 MOVES runs (NOx and $PM_{2.5}$ only[30]) to make a 4th comparative year. These combined 2008 non-EGU PEI, 2011 CAMD and 2012 MOVES inventories are hereafter referred to as the "2008+2011 CAMD" inventory. In summary, DNREC is comparing four inventories to track the change of emissions over time vs. the 2018 projections in Delaware's initial SIP. They are 2002, 2008, 2008+2011CAMD and the 2018 projection inventory ["Best and Final" version (B&F)].[31]

However, it is difficult to make direct comparisons between the 2002, 2008, 2008+2011CAMD and 2018 projections inventories. This is partly because the 2002, 2008 and 2008+2011CAMD

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[29] Appendix A is a 2008 emissions inventory technical support document (TSD) for New Castle County only, and was developed as part of Delaware's PM2.5 Redesignation Request [to attainment] for New Castle county portion of the Philadelphia nonattainment area (submitted to EPA on December 15, 2012). At this time, DNREC does not have a <u>statewide</u> TSD for 2008. However, the methodologies in the TSD remain exactly the same for estimating statewide 2008 emissions as they are were for New Castle 2008 emissions.

[30] As demonstrated in the 2012 SIP revision to Delaware's 2008 PM2.5 Attainment Demonstration, onroad sources are not a significant emitter of SO_2. The 2012 SIP revision and MOVES emissions is available at: http://www.dnrec.delaware.gov/whs/awm/Info/Regs/Documents/PM_SIP_revision_for%20printing1.pdf

[31] The 2008 regional haze SIP 2002 emissions are summarized in Appendix C, and the 2018 2008 regional haze SIP B&F emissions are included in Appendix D (for more details and information on the development of the 2002 and 2018 inventories, please see Delaware's regional haze SIP at:

inventories represent actual and typical historical emissions, while the 2018 inventory is a projection inventory based on predictions of future events. And, all inventories are estimates of emissions based on the best assumptions available at the time of development. Estimates for the 2002 and 2018 inventories were developed starting in 2004 and finalized in early 2008 using different assumptions than those used for the 2008 and 2008+2011CAMD estimates.

Furthermore, estimates of current emissions require the use of emission factors based on surrogate data, since direct measurements are not often available. On the other hand, projections of future emissions also involve assumptions - for example, assumptions about economic growth, population growth, growth in fuel consumption, and the balance among different fuels, such as coal, oil and natural gas. There have been significant changes – in the economy, the balance among fuels, the growth in fuel consumption, the regulatory requirements affecting different industries – that were not foreseen when the 2018 projections were made. Natural gas prices have declined, coal prices have risen, and coal-fired power plants have been shut down. EPA has also updated emission factors. Delaware fuel sales/delivery of residual and distillate fuels have significantly declined since 2000,[32,33] but could always rise again depending on future supply and demand. Further adding to the confusion are changes in emissions models used to estimate emissions, for example MOBILE6.2 and MOVES, while both used to estimate onroad mobile source emissions, give significantly different results for similar inputs.

Finally, the pollutants and source sectors included in these data sources vary. For example, CAMD only collects data on NOx and SO_2, not PM and VOC. Inconsistencies between data sources arise because of differences in calculation methodologies, because different emissions sources are included or emissions factors have changed, due to differences in growth projections, unanticipated shutdowns or new sources, and new control programs.

Above and beyond the inconsistencies discussed in the previous paragraphs, the following discussion provides specific examples of the more common inconsistencies between data sources for each sector between years:

POINT SOURCE INCONSISTENCIES

- **Condensable Emission Factors**: The PM species in the inventory are categorized as particles with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM25-PRI), which includes both condensable particles (PM-CON) and filterable particles (PM25-FIL). In many cases states provide an estimate for PM25-FIL but not PM-CON. As a result, PM25-PRI emissions in the 2008 inventory suite cannot be compared to the 2002 suite.

- **CAMD** only collects data on NOx and SO_2, not PM and VOC.

[32] http://www.eia.gov/dnav/pet/pet_cons_821use_dcu_sde_a.htm
[33] http://www.eia.gov/dnav/pet/pet_cons_821rsd_dcu_nus_a.htm

AREA SOURCE INCONSISTENCIES

Between development of the 2002 and the 2008 PEI, significant improvements were made to estimation methodologies, and emission and growth factors used to estimate area source emissions. However, no attempt has been made to adjust the inventories to account for these changes. Changes affecting the area source sector include:

- **Residential Wood Combustion**: Residential wood combustion is the largest contributor to regional fine particulate emissions. A new calculation tool was developed in advance of the 2008 inventory to estimate emissions from residential wood combustion. For the tool a new suite of SCC source categories was developed. In addition new emission factors and new calculation methodology were developed. Thus, the resulting emissions for this sub-category of area emissions are not comparable between the two inventory suites. While the effect of the new tool varies from state to state, the 2008 inventory suite residential wood combustion $PM_{2.5}$ emission estimate is, on average, 40 percent lower than the 2002 inventory suite for the MANE VU region. [34]

- **Inconsistency in the included source categories between inventory suites:** In addition to residential wood, the estimation methodology for many other smaller sources was improved. In some cases several SCC codes were consolidated into a single combined SCC. In other cases new SCC codes were established. These shifts make a direct comparison of the inventories at the SCC level difficult. An analysis of the consistency between inventories was prepared by MARAMA to assist states in their review of this sector (MARAMA 2013).

- **Road dust $PM_{2.5}$ Direct emissions**: EPA revised the recommended calculation methodology for road dust prior to completion of the 2008 inventory suite. As a result of this revision, the emissions from paved roads generally increased.

- **Energy use growth factor:** The Energy Information Agency (EIA) Annual Energy Outlook (AEO) is used to project future area source fuel combustion emissions. As was described earlier, there has been an overall damping down of fuel use growth projected looking into the future and a significant fuel shift away from coal and toward natural gas. Both of these changes result in lower emissions in future projections. Thus, if 2018 had been projected from base year 2002 using current growth factors, estimated emissions from fuel combustion would have been lower.

- **Shift of sources between area and point source sector:** For a variety of reasons, in some states emissions may be characterized as point sources in one inventory and area sources in another.

[34] Regional Emissions Trends Analysis for MANE-VU States Technical Support Document, Revision 3. Mid-Atlantic Regional Air Management Association (MARAMA). March 22, 2013.

- **Natural variation in the base year:** Emissions such as forest wildfires are dependent upon the year inventoried. These emissions are held constant in the future year for a particular inventory suite, but vary from suite to suite.

NONROAD INCONSISTENCIES

The EPA-developed NMIM/NONROAD model was used in both 2002 and 2008 inventory suites to estimate NONROAD sector emissions. While different versions of the model were used, with slightly different model adjustments, for the most part these differences did not change the resulting emission estimation substantially. The following describe the model adjustments used in the 2002 and 2008 modeling suites.

The NONROAD2005 model was used as a starting point for the 2002 inventory. Changes were made to the National County Database (NCD) database based on state review and comment. Complete documentation of the changes is available in the inventory documentation (MANE-VU 2006). A summary of the adjustments to the default NCD for the 2002 National Mobile Input Model (NMIM) model runs includes:

- Adjustments to fuel characteristics (Reid Vapor Pressure, sulfur and oxygenate fractions) to better represent county-specific fuel characteristics in 2002;
- Default diesel sulfur content values of 2457 parts per million (ppm) for land-based equipment, and 2767 ppm for recreational marine for all MANE VU counties.

The NONROAD2008a (July 2009 NMIM20090504) and the NMIM County Database (version NCD20090531), were used as starting points for the 2008 inventory. Changes were made to the NCD20090531 based on state review and comment. A summary of the adjustments to the default NMIM County Database for the 2008 NMIM model runs includes:

- Adjustments to fuel characteristics (Reid Vapor Pressure, sulfur and oxygenate fractions) to better represent county-specific fuel characteristics in 2008;
- The housing and population data contained in the NONROAD model were updated using 2008 housing information and population estimates.
- Recreational marine vessel populations were revised using population data provided by the National Marine Manufacturers Association (NMMA). Total state populations for each of the three major categories contained in the NONROAD model (outboard, inboard/stern drive and personal watercraft) were provided. Because the population files used by the NONROAD model (and thus NMIM) were configured with population values for various horsepower categories, the fraction of the total for each marine vessel type in each horsepower category was determined from the NONROAD default population files. These fractions were then used to allocate the total state population obtained from NMMA to the various horsepower categories.
- Airport ground Support: The Federal Aviation Administration’s Emissions and Dispersion Modeling System (EDMS) model was used to estimate airport ground support emissions. They were included in the area source sector.

MARINE, AIRPORTS, AND RAILROADS (MAR) INCONSISTENCIES

The methodology used to estimate MAR sources was significantly revised between development of the 2002 and the 2008 inventory suites. In the 2002 inventory suite, the methodologies used to estimate this category were as described in EPA's "Documentation for Aircraft, Commercial Marine Vessel, Locomotive, and other Non-road Components of the National Emissions Inventory". New studies by the Eastern Regional Technical Advisory Committee (ERTAC) and EPA resulted in a reset to a generally higher emissions basis for NO_X and VOC emissions in the 2008 inventory from the airport sector. At the same time, the trend for $PM_{2.5}$ Direct and SO_2 for the MAR sector remains largely unchanged.

ONROAD INCONSISTENCIES

The calculation of mobile emissions is complex because emissions vary with ambient temperature, vehicle type, age, travel speeds, operating modes, and fuel volatility. For this reason, inventory models have been developed by USEPA to perform the numerous calculations to estimate emissions from vehicle exhaust, evaporative and brake and tire wear. For many years, the MOBILE model was used to estimate onroad emissions. The MOBILE model was updated many times with the last version being MOBILE6.2. The term "MOBILE6" is generally used to refer to any of the suite of released MOBILE versions. For regional air quality modeling purposes to account for temporal and spatial meteorological differences, the MOBILE6.2 model was implemented as part of the Sparse Matrix Operator Kernel Emissions (SMOKE) gridded emissions model.

In recent years, USEPA has been developing a new model to estimate onroad mobile emissions called MOVES (**MO**tor **V**ehicle **E**mission **S**imulator). There are two ways of running the MOVES model and they are known as:

- "Inventory" mode that provides emission estimates as mass, and
- "Emissions rate" or "Lookup table" mode that produces lookup tables of emission rates as mass per unit activity. A version of MOVES is available that can be run within SMOKE to account for temporal and spatial meteorological differences for regional air quality modeling purposes. For SMOKE implementation, emission rate tables must first be developed for a wide range of meteorological conditions.

For Delaware's 2008 and 2012 emissions, MOVES was run in the emissions inventory mode.

The shift from using MOBILE6.2 for the 2002 inventory suite, to using the MOVES model for the 2008 and 2012 inventories to estimate onroad emissions represents a significant change in the estimation methodology. A large body of new research on emission factors; in addition to new source groupings were incorporated into the MOVES model. The effect on emissions, estimated by DNREC, was expected to result in:

- Increased NO_X emission estimate by 5 percent
- Minor but lower estimates of VOC emissions
- Increased wintertime $PM_{2.5}$ emissions estimates
- Insignificant SO_2 emissions changes.

Regardless of the inconsistencies discussed above, DNREC had no choice but to use the *available* emissions data for each year in order to compare the four different years, per RHR 308(g)(4) requirements. Table 39, Table 40, and Table 41 show the actual 2002 and projected 2018 SO_2, NOx and $PM_{2.5}$ emissions,[35] respectively, compared to the most recent 5-year inventories (e.g., actual 2008 and actual 2008+2011CAMD).

Table 39 – 2002, 2008, and 2008+2011CAMD vs. 2018 Projections – SO2

SO_2				
Sector	**2002**	**2008**	**2008+2011 CAMD (2)**	**2018 Projections**
EGUs	38,038	37,194	9,291	10,941
Non-EGUs	35,706	3,907	3,907	5,766
Area	1,588	667	667	380
Onroad	584	181	181	128
Nonroad	3,983	2,258	2,258	3,296
TOTAL	**79,900**	**44,206**	**16,304**	**20,511**

1 2011 EGU emissions from CAMD
2 2008+2011 CAMD onroad SO2 emissions assume 2008 levels to be conservative

Table 40 - 2002, 2008, and 2008+2011CAMD vs. 2018 Projections – NOx

NOx				
Sector	**2002**	**2008**	**2008 + 2011 CAMD (2)**	**2018 Projections**
EGUs (1)	11,972	10,903	3,618	12,341
Non-EGUs	4,372	2,900	2,900	4,246
Area	2,608	2,233	2,233	3,014
Onroad (2)	21,341	18,206	12,515	5,917
Nonroad	16,227	10,518	10,518	14,631
TOTAL	**56,520**	**444,760**	**31,784**	**40,149**

1 2011 EGU emissions from CAMD
2 Onroad Emissions for “2008+2011 CAMD” include updated NOx from 2012 MOVES runs.

[35] 2002 baseyear and 2018 emission projections from Delaware’s regional haze SIP and included in Appendix C and D, respectively..

Table 41 - 2002, 2008, and 2008+2011CAMD vs. 2018 Projections – $PM_{2.5}$

$PM_{2.5}$				
Sector	**2002**	**2008**	**2008+2011 CAMD (2)**	**2018 Projections**
EGUs (1)	2,060	2,150	2,150	2,438
Non-EGUs	1,606	759	759	1,254
Area	3,204	2,993	2,993	3,073
Onroad	415	562	390	191
Nonroad	926	748	748	808
TOTAL	**8,210**	**7,212**	**7,040**	**7,764**

1 2011 EGU emissions from CAMD
2 Onroad Emissions for "2008+2011 CAMD" include updated NOx from 2012 MOVES runs.

As noted earlier in this report, MANE-VU identified sulfate as the major contributor to regional haze, and therefore MANE-VU States focused efforts on the control of SO_2 from point sources, primarily EGUs and industrial boilers. As can be seen in Table 39, total SO_2 emissions from point sources in the 2008+2011CAMD column were significantly less than the 2018 point source projections in the Delaware 2008 regional haze SIP (13,198 tpy vs. 16,707 tpy, or 21% less), and about the same percentage less for all source categories.

Furthermore, the 2008+2011CAMD SO_2 emissions do not include the post-2008 SIP shutdown of Indian River Unit 3, the new low-sulfur fuel regulation and the Refinery NOx CAP. As shown below,

Table 42 shows that these additional SO_2 and NOx reductions go significantly beyond what was included in Delaware's 2008 regional haze SIP (e.g., including the post-SIP measures, adjusted SO_2 reductions by 2018 would be an additional 7,344 tpy of SO_2).

Keeping in mind that sulfate is the primary pollutant of concern in the 2008 regional haze SIP, Table 43 combines Table 42 SO_2 reductions with 2008+2011CAMD SO_2 emissions in Table 39, with the result being that post-2016[36] SO_2 emissions are expected to be 8,960 tpy of SO_2 [16,304-7,344] instead of the modeled 2018 projections of 20,511 tpy. This represents an additional reduction of over 50% from what was projected in Delaware's 2008 regional haze SIP (20,511 tpy).

It was the 2018 20,511 tpy SO_2 that was modeled as part of setting Delaware's obligations to meet MANE-VU's LTS, in order to address 2018 RPG at Brigantine Wildlife Area (and all other MANE-VU Class I areas). Thus, by then end of 2016, Delaware will have met its LTS obligations (SO_2 reductions) well beyond those 2018 SO_2 emission obligations discussed in the initial 2008 regional haze SIP.

[36] Indian Rive EGU Unit 3 shuts down in December 2013, the Refinery CAP is fully implemented in 2015, and the low-sulfur fuel regulation takes affect in 2016Hence these additional reductions are referred to as "New" post-2008 reductions".

Table 42 – "New" Post-2008 SIP SO_2 and NOx Reductions prior to 2018

Post-SIP Measures	**"New" post-2008 SIP Reductions (from 2002 BY)**	
	SO_2	**NOx**
Facility-Unit Shutdowns and Refinery NOx CAP (2015)	4,694	1,158
Low-Sulfur Fuel Reg. (2016)	2,650	NA
Total	**7,344**	**1,158**

NA = not applicable

Table 43 – Adjusted SO_2 projections and reductions prior to 2018

Sector	**2002**	**2008**	**2008+2011 CAMD emissions**	**MANE-VU Modeled DE 2018 SO_2 Emissions to meet RPG**
TOTAL from Table 39	79,900	44,206	16,304	20,511
ADDITIONAL REDUCTIONS (Table 42)	NA	NA	7,344	NA
Adjusted post-SIP SO_2 emissions	79,900	44,206	**8,960**	**20,511**

3.1. ECONOMIC CONDITIONS VS. REDUCTIONS

Due the recession which began in late 2008 and is still ongoing as of this submittal, DNREC investigated whether emission reductions were due to the recession, and not control measures. To answer this question, DNREC evaluated the role which economic conditions may have played in the improvement in air quality by evaluating the Gross Domestic Product (GDP) growth rate. The GDP growth rate is an indicator of economic health. If the GDP growth rate is increasing, it is an indication that the activity of emitting sources are increasing. Conversely, if the GDP is declining it is an indication that the activity of emitting sources may be reduced because of economic conditions.

Delaware-specific GDP for all industries, obtained from the U.S. Bureau of Economic Analysis (BEA), is presented in Figure 8.

Figure 8 - 2002 – 2011 Delaware Gross Domestic Product – All Industry

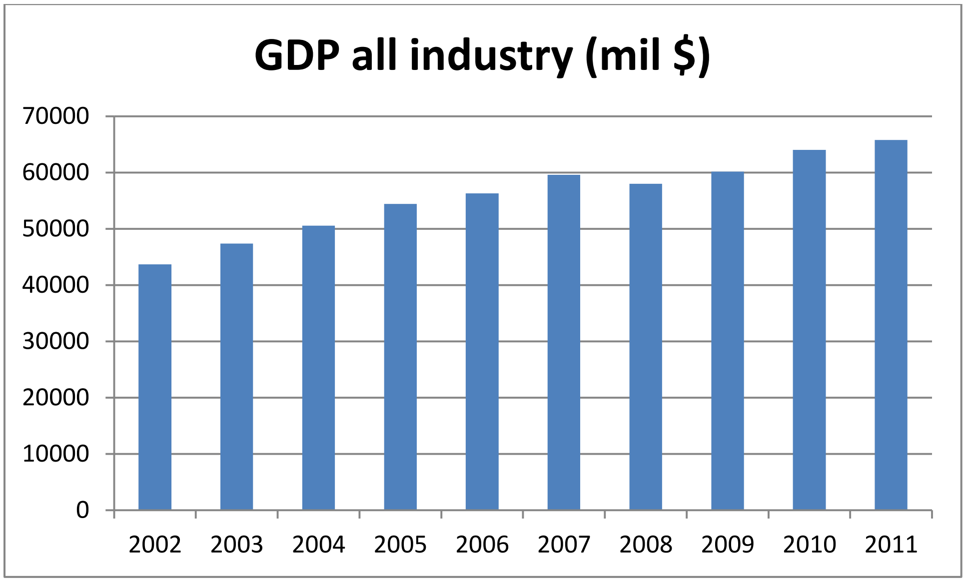

Figure 8 shows that, except for a decline between 2007 and 2008[37], all industries increased GDP in every year from 2002 through 2011. Of specific relevance to air quality is the comparison between the time when Delaware's air quality did not meet the $PM_{2.5}$ standard (i.e., 2002-2006) and the time when it did (i.e., 2007-2011). The GDP in every year between 2007 and 2011 is greater than every year between 2002 and 2006. This analysis of GDP indicates that economic conditions did not significantly contribute to the visibility improvement at Brigantine Wilderness Area.

[37] According to the Delaware Department of Labor the reason for the decline between 2007 and 2008 was an economic recession that began in Delaware in December 2007.

4. ASSESSMENT OF SIGNIFICANT CHANGES IN ANTHROPOGENIC EMISSIONS

[40 CFR 51.308(g)(5)]

40 CFR 51.308(g)(5) of the RHR requires:

> *An assessment of any significant changes in anthropogenic emissions within or outside the state that have occurred over the past 5 years that have limited or impeded progress in reducing pollutant emissions and improving visibility*.[38]

As demonstrated in the previous section Delaware SO_2, NOx and $PM_{2.5}$, emissions reductions have already significantly exceeded the Delaware 2018 SO_2, NOx and $PM_{2.5}$ projections by the year 2012 (see Table 39, Table 40, and Table 41). And, it was those 2018 projections that were modeled in setting RPG goals at Class I areas. Finally, Table 39 represents SO_2 emissions <u>before</u> other state and federal measures not included in the SIP come into play, such as the 2010 SO_2 NAAQS, Delaware's new low-sulfur regulation, and the Indian River Unit 3 shutdown (see C.1.5 and C.1.2).

In EPA's final rulemaking approving Delaware's 2008 regional haze SIP, "*EPA [made] a determination that the Delaware Regional Haze SIP contains the emission reductions needed to achieve Delaware's share of emission reductions agreed upon through the regional planning process. Furthermore, Delaware's Regional Haze Plan ensures that emissions from the State will not interfere with the reasonable progress goals for neighboring states' Class I areas*."[39] Furthermore, EPA declared in their approval of New Jersey's Regional Haze SIP that "*New Jersey's LTS includes measures needed to achieve its share of emissions reductions and includes enforceable emissions limitations, compliance schedules, and other measures necessary to achieve the reasonable progress goals established for the Brigantine National Wildlife Refuge Class I area*." [40] In other words, because all MANE-VU LTS control measures used to establish RPG were already either in place, or an equivalence was established (i.e. low sulfur fuel regulation), Delaware demonstrated in its 2008 regional haze SIP no new measures were needed.

As a result, Delaware is very confident that it has not limited or impeded progress in reducing pollutant emissions and improving visibility at Brigantine Wilderness Area.

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[38] EPA guidance clarifies this phrase as follows: "A "significant change" that can "limit or impede progress" could be either (1) a significant unexpected increase in anthropogenic emissions that occurred over the 5-year period (that is, an increase that was not projected in the analysis for the SIP), or (2) a significant expected reduction in anthropogenic emissions that did not occur (that is, a projected decrease in emissions in the analysis for the SIP that was not realized). This requirement is aimed at assessing whether any such significant emissions changes have occurred within the state over the 5-year period since the SIP was submitted, and for Class I states, whether emissions increases outside the state are affecting a Class I area within the state adversely… For those Class I areas where there is a significant overall downward trend in both visibility and nearby emissions, we expect that this assessment will point to those trends in support of a simple negative declaration satisfying this requirement."

[39] 76 FR 42557

[40] Proposed Rule to Approve New Jersey's Regional Haze SIP. Federal Register Volume 76, Number 155 (Thursday, August 11, 2011). Section IV, B.

5. ASSESSMENT OF ELEMENTS AND STRATEGIES FOR MEETING RPG

[40 CFR 51.308(g)(6)]

40 CFR 51.308(g)(6) of the Regional Haze Rule requires:

> *An assessment of whether the current implementation plan elements and strategies are sufficient to enable the state, or other states with Class I area affected by emissions from the State, to meet all established reasonable progress goals.*

Based upon the relevant IMPROVE data; and 2008+2011 CAMD emission reductions from 2002 vs. 2018 modeled emissions in the initial regional haze SIP, DNREC is convinced that the current implementation plan elements and strategies outlined in the original Delaware SIP are sufficient to enable Delaware and other states with Class I areas affected by emissions from the State (e.g. Brigantine Wilderness area, New Jersey) to meet all established RPGs.

Based on EPA approvals of the Delaware and New Jersey initial Haze SIPs discussed in Section C.4, Delaware has already met the requirements under 40 CFR 51.308(g)(6) of the RHR. Nonetheless, Delaware provides the following assessment for Brigantine Wilderness Area, NJ.

5.1. DESCRIPTION

Brigantine Wilderness is located in southern New Jersey on the Atlantic Coast, about 11 miles north of Atlantic City. The 6,600 acre wilderness area, located within the Edwin B. Forsythe National Wildlife Refuge, comprises four areas: the Holgate Peninsula, Little Beach Island and the marshes west of the island, and two areas near the mouth of the Mullica River. The habitat includes primarily salt marsh, beach, and dune, with a small area of hardwood upland on Little Beach Island.

The Edwin B. Forsythe National Wildlife Refuge is on the *Ramsar List of Wetlands of International Importance* and is part of the Marine Estuarine Reserve Research System. Species that use the refuge include the Atlantic brant, American black duck, peregrine falcon, osprey, and bald eagle. Upland species include songbirds, woodcock, white-tailed deer, and the box turtle. Threatened species include the piping plover.

Figure 9 - Brigantine Wilderness

5.2. EMISSIONS ASSESSMENT

The EPA "guidance states:

> "For each Class I area affected by sources in the state, the report should generally identify the "established" 2018 reasonable progress goal for the first 10-year planning period. In some cases, however, we expect that a state could satisfy the requirement to assess continuing SIP adequacy without referring to the specific numerical targets or the uniform rate of progress goal or "glide path" value ***if the progress report explains that the areas affected by sources in the state achieve visibility progress almost entirely due to reduction in sulfates, and provides evidence that the state is reducing its SO_2 emissions by substantially more than was expected when the SIP was developed, such a discussion would provide a sufficient showing that the state is on track for ensuring reasonable progress in Class I areas, regardless of the specific numeric goals***." [Emphasis added]

Because 1) the Brigantine Wilderness Area's visibility impairment has been shown to be caused primarily by sulfates, 2) the 2008+2011CAMD SO_2 emissions are significantly less than the 2018 projections used for RPG in the initial SIP (*see Table 38*, e.g. 16,303 tpy vs. 20,511 tpy, respectively), and 3) more post-SIP SO_2 reduction measures are on-the-way; Delaware reduced its SO_2 emissions by "*substantially more than was expected when the SIP was developed*", and that this "*provides a sufficient showing that the state is on track for ensuring reasonable progress in Class I areas*."

In order to assess if regional SO_2 contributions to Brigantine Wildlife Area were also declining, Delaware DAQ looked at those states identified as significant contributors of SO_2 (> 2%) to Brigantine Wildlife Area (see Table 1). Table 44 shows how the SO2 emissions from EGUs[41] in those states have declined significantly between 2002 and 2011.

Table 44 - 2002 vs. 2011 EGU SO2 Emissions (CAMD) from States Identified as Significant Contributors to Brigantine Wildlife Area

State	2002 SO2 Emissions (tons)	2011 SO2 Emissions (tons)
DE	32,236	9,306
MA	90,727	22,701
MD	255,360	32,275
NJ	48,269	4,698
NY	231,985	40,756
PA	889,766	330,539
TOTAL	**1,548,342**	**440,275**

Data source: CAMD 2002, 2011

5.3. VISIBILITY AND IMPROVE DATA ASSESSMENT

The goal of the Regional Haze Rule is to restore natural visibility conditions to each of the 156 Class I areas identified in the 1977 Clean Air Act Amendments by the year 2064. Sec. 51.301(q) defines natural conditions: "Natural conditions includes naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration." The Regional Haze SIPs must contain measures that make "reasonable progress" toward this goal by reducing anthropogenic emissions that cause haze.

Central to setting the individual Class I area 2018 "reasonable progress" planning goals by each state under the RHR is the concept of the Uniform Rate of Progress (URP). The URP is the yearly rate of change required to achieve natural dv conditions by 2064 in a linear fashion beginning in 2004. The URP provides a reference to evaluate progress made in the context of the long-term emissions reductions and associated improvement in visibility required to reach natural conditions in 60 years. The conceptual glide path example of URP provided by the EPA in the 1999 RHR is shown as the solid black line in Figure 10. Baseline and period 1 dv values (2005-2009) are based on the mean of five yearly values of the 20% best and 20% worst visibility days at each site. Natural conditions are marked with the dashed line. For each Class I area, if the state-selected 2018 reasonable progress target value for the 20% worst visibility days in dv units is not on or below the glide path, the state must explain why the 2018 URP goal cannot be reasonably achieved and specify the additional time required to achieve natural conditions beyond 2064. The state must also verify that the 20% best visibility days are not projected to degrade.

[41] The MANE-VU consultation process identified EGUs as he greatest source of SO2, and hence sulfates to Class I areas.

Figure 10 - Depiction of the Conceptual Uniform Rate of Progress (URP) Glide Path.

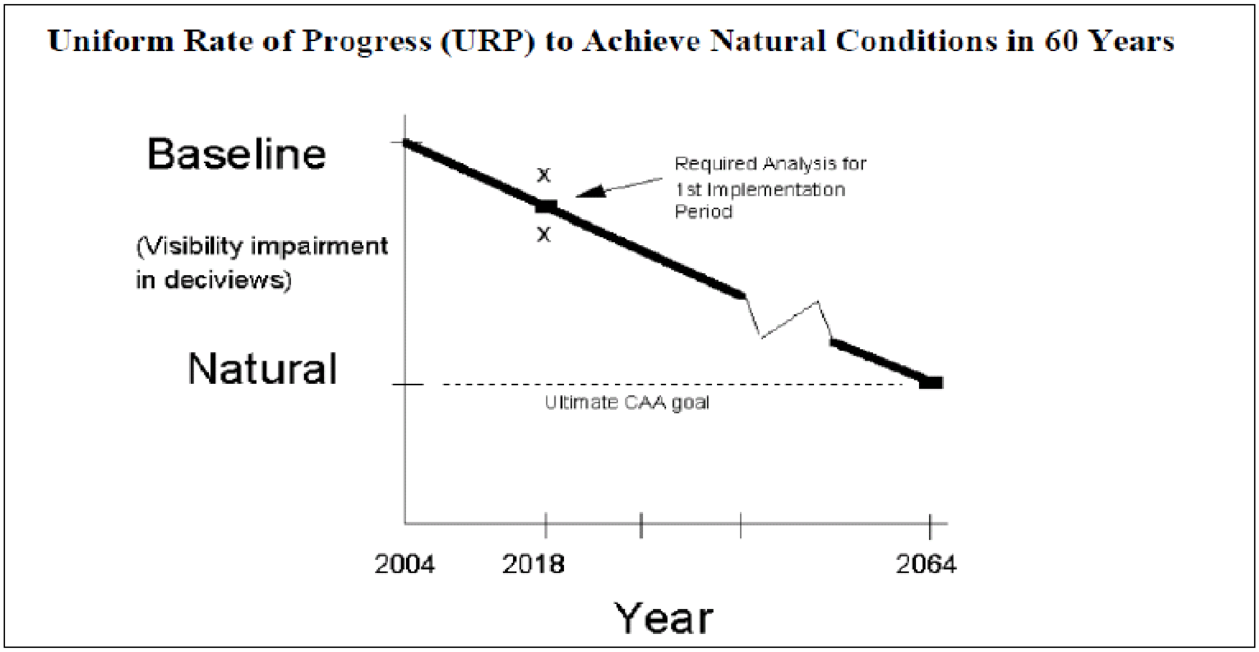
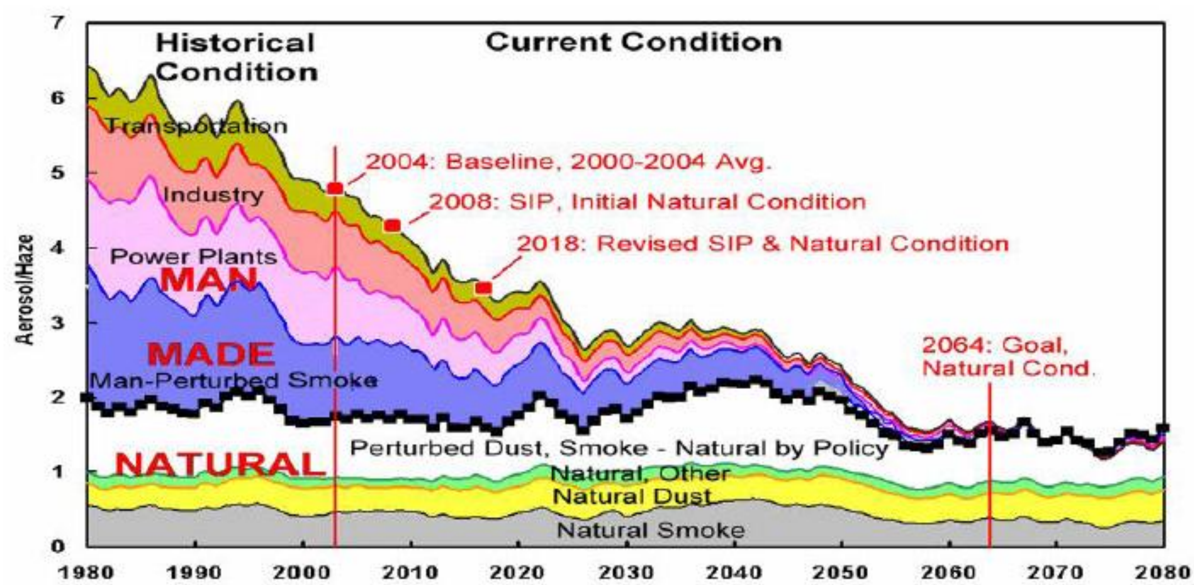


Figure 11 - Depiction of realistic uniform rate of progress (URP) glide path

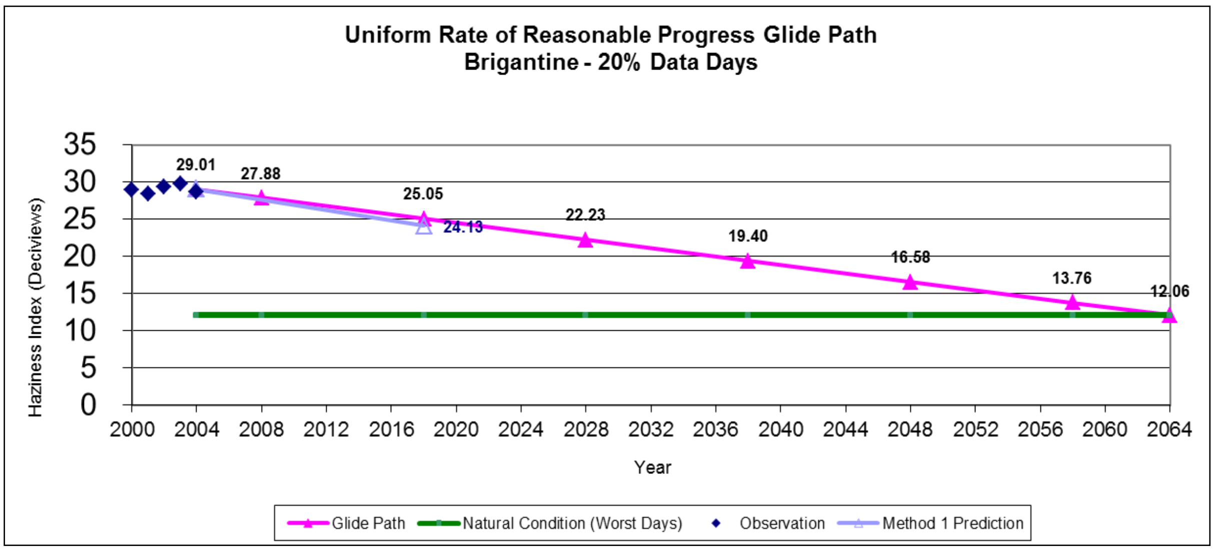


It should be noted that the nature of emissions control programs plus the intermittent activity of some sources make it likely that actual progress will be somewhat erratic and that failure to achieve the URP at any point in the process should be considered in the context of changes to emissions inventories. A more realistic depiction of the variability in haze due to different sources is shown in Figure 11.[42] The magnitude of haze in this schematic is displayed on the y-axis, versus time on the x-axis. For RHR planning, Delaware worked with MANE-VU to define aerosol sources and their historic contributions to regional haze, as well as projected future emissions, which for many categories were difficult to predict. Biomass smoke and windblown dust sources are significant contributors to haze at many IMPROVE sites, though their contributions to haze are often episodic and vary from one year to another.

5.3.1. Visibility Calculations for Brigantine Wilderness Area[43]

For the Brigantine Wilderness Area, Figure 12 shows the URP glide path from 2000-2064, with the (2000-2004) baseline of 29.01, the 10-year goals and the 2064 natural background goal of 12.06 dv.

Figure 12 - Glide path from 2000-2064, Brigantine Wilderness Area



The estimated natural background visibility in the Brigantine Wilderness Area for the 20% worst days is 12.2 deciviews.

The five-year average baseline visibility, using the on-site monitoring data from the years 2000 to 2004, for the Brigantine Wilderness Area is 14.3 deciviews for the 20 percent best visibility days (least impaired) and 29.0 deciviews for the 20 percent worst visibility days (most impaired). These values were calculated for both best and worst visibility in accordance with 40 C.F.R. §51.308(d)(2).

The regulations require that the rate of improvement projected for the long range strategy be compared with the uniform rate of progress. The uniform rate of progress is calculated by dividing the level of improvement needed (current conditions – natural background goal) by the

[42] http://vista.cira.colostate.edu/improve/publications/Reports/2011/PDF/Chapter9.pdf
[43] C.5.3.1 language copied from New Jersey's Regional Haze SIP [(EPA approval date: 1/3/2013, (77 FR 19)]

time to meet the goal, or sixty (60) years. For the 2018 reasonable progress goal, this was calculated as follows:

> 29.0 deciviews – 12.2 deciviews / 60 years (difference between 2004 and 2064)
> = 0.28 deciviews/year x 14 years (between 2004 and 2018)
> = 3.9 deciview improvement by 2018

Or as the 2018 goal (RPG):

> 29.0 – 3.9 = 25.1 deciview in 2018

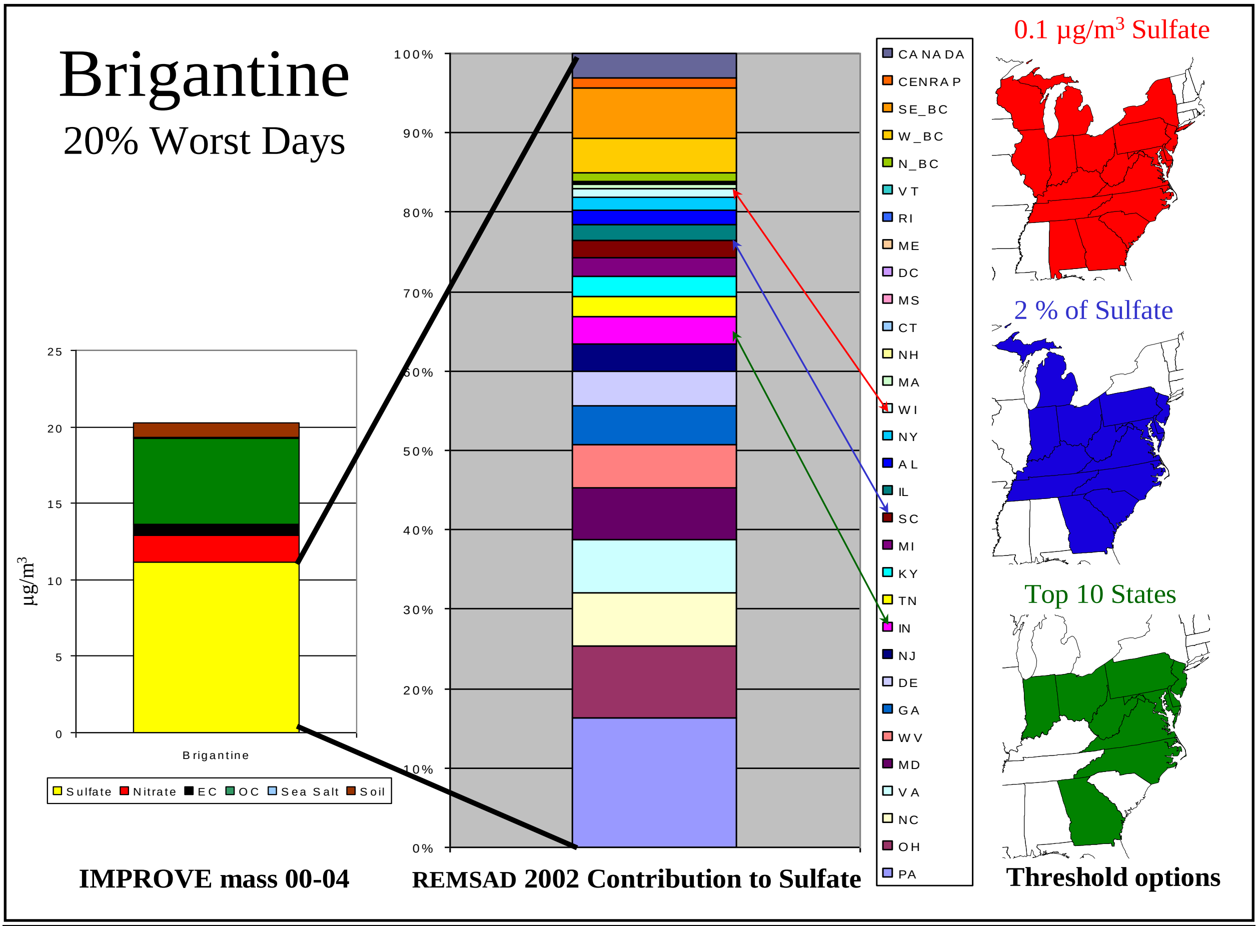
These data are summarized in Table 45.

Table 45 - Reasonable Progress Goals for the Brigantine Wilderness Area (All values expressed as deciviews)

	Baseline Visibility (2000-2004)	Natural Background Conditions in 2064	Reasonable Progress Goal for 2018	2018 CMAQ Projections
20% Worst Days	29.0	12.2	25.1	25.1
20% Best Days	14.3	5.5	12.2	12.2

As previously discussed in B.2, the *MANE-VU Contribution Assessment* demonstrated that, many states significantly contribute sulfate emissions to Brigantine Wilderness Area (based on the application of the "≥ 2% SO_2 rule"). Figure 13 shows the areas which impact the Brigantine Wilderness Area.

Figure 13 - Modeled 2002 Contributions to Sulfate by State at Brigantine Wilderness Area



5.3.2. Tracking Visibility Progress

In May 2010, NESCAUM prepared the report *Tracking Visibility Progress, 2004-2008*, which summarized progress at MANE-VU Class I areas during the five year period ending in 2008. In sum, that report concluded, "Results from prior analyses have shown that sulfate aerosol – the dominant contributor to visibility impairment in the Northeast's Class I areas on the 20 percent worst visibility days – has significant contributions from states throughout the eastern U.S. While slight improvement in overall visibility has been observed, large contributions to sulfate aerosol remain from all three of the eastern regional planning organizations (RPOs)." [44]

A year later, the 2011 IMPROVE Report V: *Spatial and Seasonal Patterns and Temporal Variability of Haze and its Constituents in the United States*, reported on five-year average reconstructed light extinction (the regional haze tracking metric) at IMPROVE sites for the

[44] *Tracking Visibility Progress* is posted on NESCAUM's website at http://www.nescaum.org/topics/regional-haze/regional-haze-documents. (See p. 6.)

baseline 2000-2004 period as well as for the next five-year period, 2005-2009.[45] These five year averages include total light extinction as well as the extinction contributed by separate pollutant species for the haziest 20% of days and for the clearest 20% of days for each of these 5-year periods. Visibility at all MANE-VU Class I Area IMPROVE sites improved for the 2005-2009 period compared to the 2000-2004 baseline period. These improvements occurred for both the haziest 20% days (which are required to get gradually cleaner over time) as well as for the cleanest 20% days (which are required to get no worse over time). Improvements in total light extinction on both the haziest and the cleanest days resulted from reductions in light extinction from all four of the major visibility-impairing pollutant species: sulfates, nitrates, particulate organic matter, and elemental carbon.

Results are summarized below. For more details, see Chapter 9 and Appendix G of the IMPROVE Report V.

Tables 46 and 47, and Figures 14 and 15 compare the 2000-2004 with 2005-2009 IMPROVE parameters at Class I sites in the MANE-VU region as reported in the IMPROVE Report V.

Table 46 - Visibility Improvements on Haziest 20% Days in MANU-VU Class I Areas

Haziest 20%	Brigantine		Lye Brook		Great Gulf		Acadia		Moosehorn	
	2000-04	2005-09	2000-04	2005-09	2000-04	2005-09	2000-04	2005-09	2000-04	2005-09
Sulfate Bext	127.1	107.4	87.3	79.0	76.6	52.5	69.2	57.2	58.5	45.7
Nitrate Bext	15.7	12.2	9.1	5.6	3.0	1.8	8.0	6.4	6.4	4.6
POM Bext	24.2	14.9	15.3	10.8	14.4	10.5	11.2	9.6	11.9	9.7
EC Bext	7.0	6.1	4.8	4.0	3.9	3.2	4.3	3.5	4.4	3.1
Soil Bext	1.0	0.7	0.6	0.5	0.6	0.4	0.5	0.3	0.4	0.3
Coarse Bext	5.4	7.3	1.8	2.5	3.0	2.6	1.9	2.3	2.1	1.7
Sea Salt Bext	0.4	1.2	0.1	0.3	0.1	0.2	1.3	1.6	0.9	1.8
Total PM Bext	180.8	149.8	119.0	102.7	101.6	71.2	96.4	80.9	84.6	66.9
Deciview (dv)	29.0	27.3	24.4	23.0	22.8	20.2	22.9	21.5	21.7	19.9

[45] Jenny L. Hand, et al., *Spatial and Seasonal Patterns and Temporal Variability of Haze and its Constituents in the United States: Report V*, June 2011, posted on the improve website at http://vista.cira.colostate.edu/improve/publications/Reports/2011/2011.htm

Table 47 - Visibility Improvements on Clearest 20% Days in MANE-VU Class I Areas

Clearest 20%	Brigantine		Lye Brook		Great Gulf		Acadia		Moosehorn	
	2000-04	2005-09	2000-04	2005-09	2000-04	2005-09	2000-04	2005-09	2000-04	2005-09
Sulfate Bext	14.8	13.5	4.4	3.4	5.8	4.8	6.8	5.0	6.7	5.0
Nitrate Bext	3.9	3.6	1.2	0.8	1.0	0.6	1.1	0.7	1.1	0.7
POM Bext	4.5	3.6	1.3	0.8	2.0	1.5	2.2	1.9	3.1	2.1
EC Bext	2.4	1.9	0.6	0.4	0.8	0.7	0.9	0.7	1.0	0.7
Soil Bext	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Coarse Bext	3.2	3.3	0.5	0.5	0.9	0.6	0.7	0.8	1.1	0.8
Sea Salt Bext	1.4	2.5	0.0	0.1	0.2	0.1	0.4	0.6	0.3	0.6
Total PM Bext	30.4	28.6	8.1	6.1	10.8	8.4	12.2	9.8	13.4	10.0
Deciview (dv)	14.3	13.9	6.4	5.2	7.7	6.6	8.8	7.7	9.2	7.8

Figure 14 - Visibility Improvements on Haziest 20% Days in MANU-VU Class I Areas

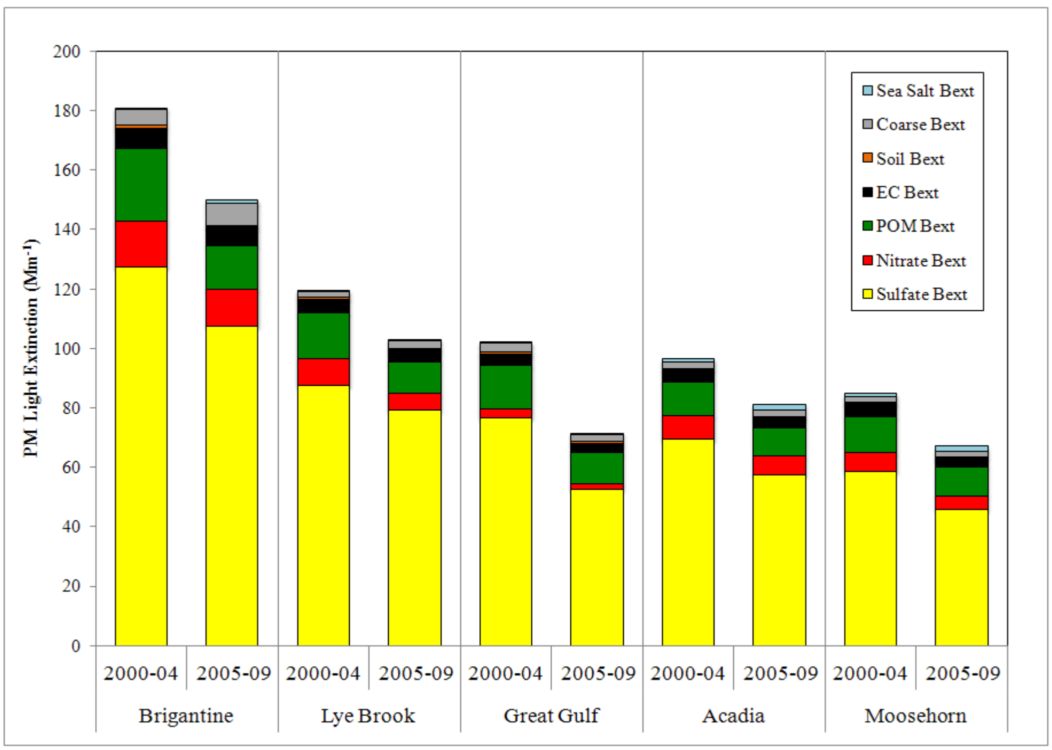
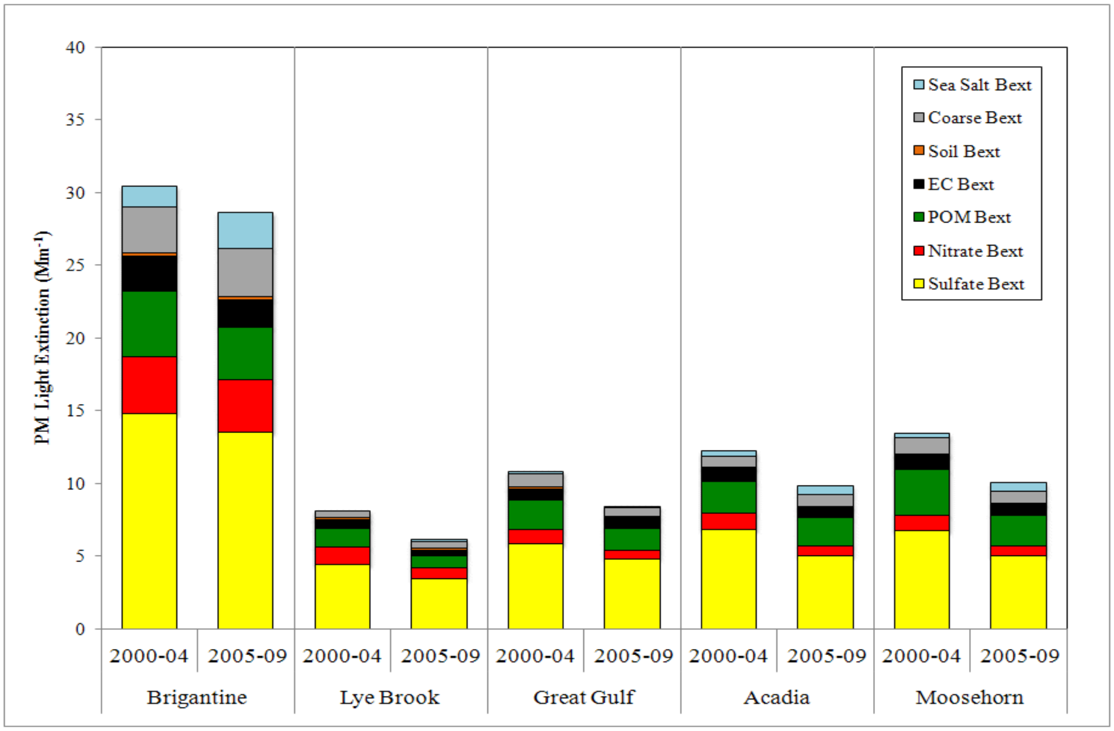


Figure 15 - Visibility Improvements on Clearest 20% Days in MANE-VU Class I Areas



On April 30, 2013 NESCAUM released the report, *Tracking Visibility Progress, 2004-2011*, which updated the progress at MANE-VU Class I areas during the five year period ending in 2011. The remaining discussion in this Section incorporates much of its language directly from the NESCAUM *Tracking Visibility Progress, 2004-2011* report (*see* Appendix E).

Figure 16 presents the annual Haze Index on the 20 percent most and least impaired days at Brigantine Wildlife Area between 2000 and 2011 in the context of short- and long-term visibility goals (Table A-1 in Appendix E presents these data numerically). Annual average best and worst visibility day Haze Index values are represented by blue and purple diamonds, respectively. Five-year back annual averages are represented by solid red (worst) and blue (best) lines. Red (worst) and black (best) plus signs represent the 2018 RPGs described in the state haze SIP. The red (worst) and black (best) dotted lines represent the glidepaths to meet 2018 RPGs. Red (worst) and black (best) dashed lines represent the glidepaths to meet long-term natural visibility goals; the worst-day glidepath is also called the "uniform rate of progress" line, and the best-day glidepath is also called the "no degradation" line.[46] The grey region denotes the range of 20-percent best to worst haze levels expected to occur under natural conditions. Thus, the uniform rate of progress line intersects with highest portion of the grey area in 2064.

[46] For the Brigantine and Dolly Sods Wilderness Areas, whose haze levels on the 20 percent best days during the 2000 to 2004 baseline period were higher than estimated natural conditions on the 20 percent worst days, the no degradation line (representing the long-term best-day goal) is higher than the uniform rate of progress line (representing the long-term worst-day goal) at dates approaching 2064. This nonsensical situation by 2064 is an artifact of technical guidance and only represents stated haze level goals, not anticipated results (NESCAUM 2011).

Figure 16 Annual Haze Index Levels at Brigantine Wilderness Area

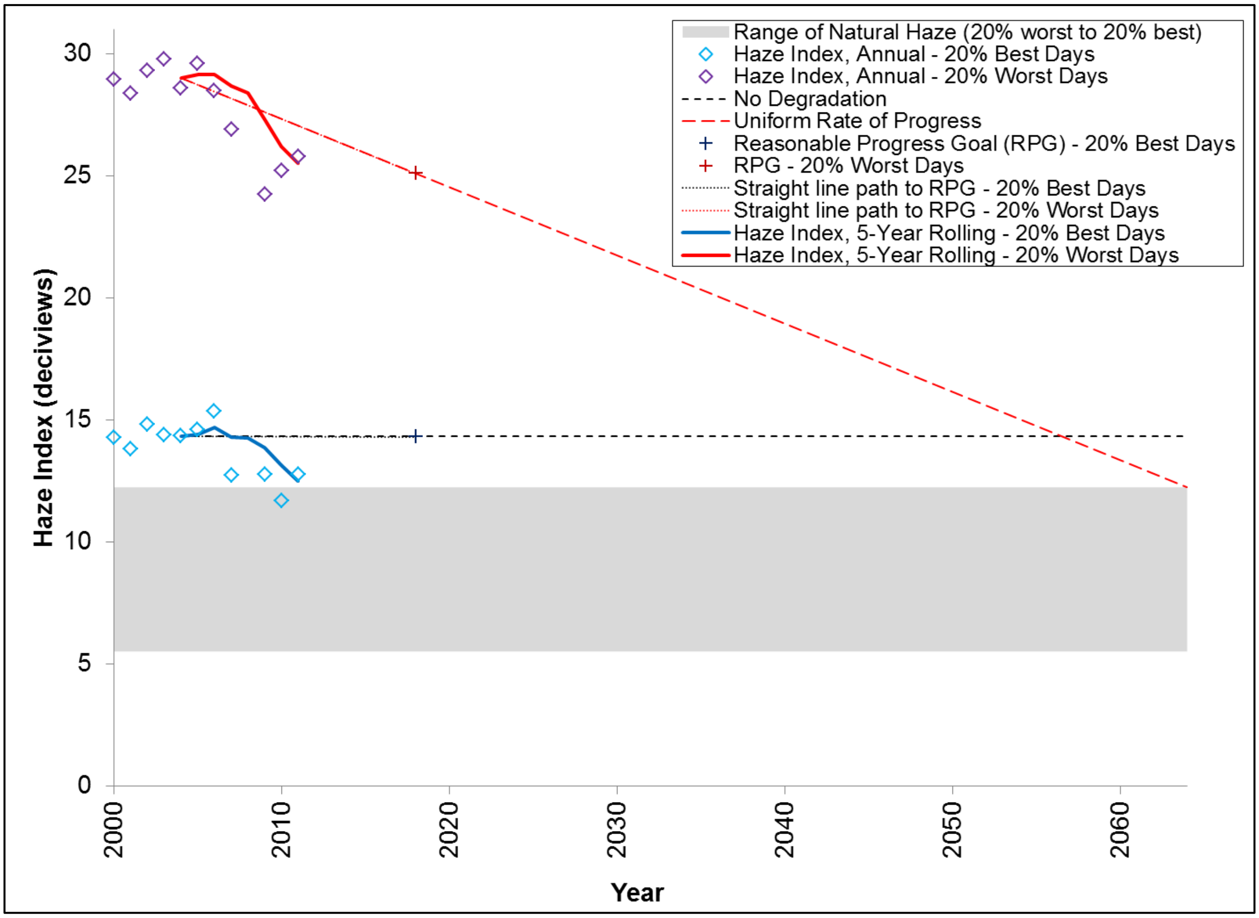


Figure 16 indicates that haze levels on the best and worst days from 2000 through 2011 have dropped at Brigantine Wildlife Area. Trends evident in NESCAUM's last report (NESCAUM 2010) for annual average haze levels on best and worst days through 2008 have largely continued through 2010. In 2011, most of the areas experienced around the same or slightly higher levels of haze on both best and worst days as compared to 2010. The steep drop in Haze Index values for the 20 percent worst days, therefore, appears to have occurred primarily during the period between 2007 and 2010 for these areas.

Comparison of the five-year annual average haze index to the glidepaths for the 2018 SIP commitments show that all areas in and adjacent to the MANE-VU region are on pace to meet those commitments (see Appendix E). In fact, the 2018 RPGs will be met if 5-year average levels for best and worst days are maintained at Acadia National Park and at the Great Gulf, Lye Brook, and Moosehorn Wilderness Areas. However, the small uptick in annual average haze levels in 2011 for most areas in the MANE-VU region demonstrates that efforts are still needed to ensure that 2018 RPGs will be met and to prevent backsliding. The small relative increase for 2011 over the previous several years is almost certainly due, at least in part, to special and converging circumstances: the economic downturn followed by slow recovery, unusual meteorology, and possibly the rapid shift toward natural gas.

At Brigantine Wilderness Area and both Class I areas adjacent to the MANE-VU region, best-day visibility levels are already below 2018 RPGs, but worst-day visibility levels require additional progress to meet the short-term goals. Although Delaware has demonstrated it has met its obligations, the additional progress may be met during the 2013-2018 timeframe by other states. If not, then the issue must be addressed as part of the up-coming 2018 Regional Haze SIPs.
In addition to analyzing trends in overall visibility changes at the sites, NESCAUM also examined the data for changes in individual PM constituent contributions to visibility impairment. Figure 17 and 18 present the annual Haze Index by constituent on the 20 percent least and most impaired days at Brigantine between 2000 and 2011 in the context of RPGs.

The figures also show individual constituent values as stacked bar charts for sulfate, nitrate, organic carbon mass (OCM), light absorbing carbon (LAC), soil, course mass, sea salt, and Rayleigh extinction levels on best (left, "a") and worst (right, "b") days. The total of the stacked bars represent annual Haze Index values, and are marked by circles connected by a thin black line. The thick black line represents five-year back annual averages from 2004 to 2011. The 2018 RPG from the state haze SIP is marked with a black plus sign. Two red lines descend from the 2004 five-year back average (i.e., the baseline value): the red dotted line represents the glidepath to the 2018 RPG; and the red dashed line represents the glidepath to the 2064 natural visibility goal, or the "uniform rate of progress" line.

Figure 17 Individual Constituent Contribution to Annual Haze Index Levels at Brigantine Wilderness Area on 20 Percent Best Days

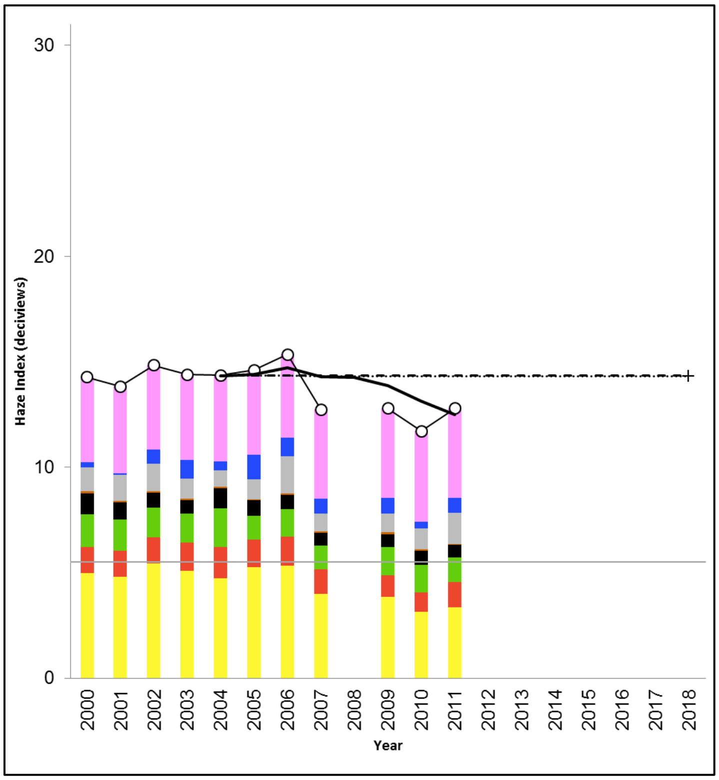
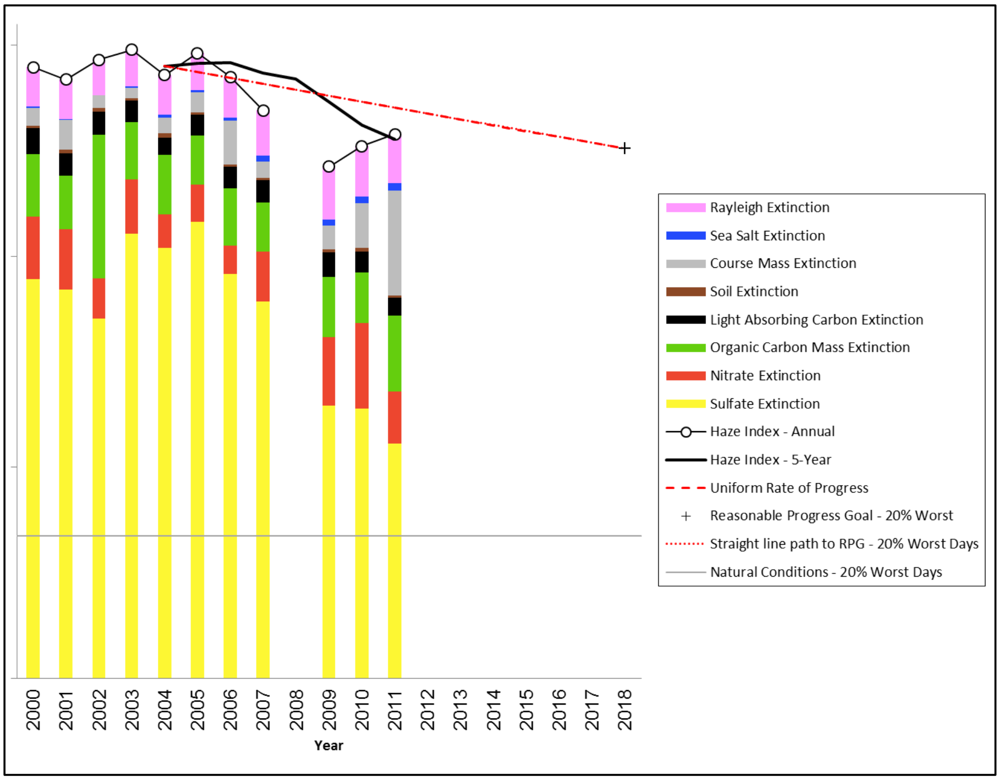


Figure 18 Individual Constituent Contribution to Annual Haze Index Levels at Brigantine Wilderness Area on 20 Percent Worst Days



These figures confirm that large reductions in overall Haze Index values on the 20 percent worst days are primarily due to decreases in sulfate visibility impacts. Steady decreases in sulfate and nitrate contributions have also reduced overall haze levels on the least impaired days.
Despite the reduced contribution from sulfate on the worst days at most of the MANE-VU Class I areas, the overall level of haze has remained largely unchanged since about 2009 on the worst days due to increases in contributions from sea salt and organic carbon mass, depending on the site. At Brigantine, the contribution from course mass in 2011 was unusually high, indicating a possible anomaly for that year. This increase in course mass contribution offset reductions in both nitrate and sulfate levels from the preceding years. Contribution from OCM appears to be highly variable from year to year at most sites. For instance, high OCM extinction levels at Brigantine and Lye Brook Wilderness Areas in 2002, and at Great Gulf Wilderness Area in 2011 on the worst days, undercut declines in contributions from sulfate to raise overall haze levels for those years.

Sulfate remains the most significant contributor to light extinction at all Class I areas on the most impaired days in and adjacent to the MANE-VU region, followed by OCM and nitrate. For the most part, light extinction from soil and sea salt, which help indicate the extent to which natural haze processes contribute to overall haze levels, are insignificant when compared to extinction from sulfate and nitrate. Based on these figures, continued progress in sulfate and nitrate levels appears to be driving the trend in overall improvement in worst- and best-day haze level reductions.

To examine the individual constituent trends more closely, NESCAUM plotted the range of individual light extinction on best and worst days from 2000 through 2011 at the Class I areas against the estimated light extinction under natural conditions. Figures 19-22 show the range of light extinction levels at the Brigantine Wildlife Area as compared to natural light extinction for selected constituents. Estimated natural light extinction is represented in each chart by the lighter grey band, and observed extinction by the other band. For the case of the carbonaceous species, OCM and LAC, the green band is observed OCM and the dark grey band is observed LAC. Note that the observations do not represent the range of the highest and lowest 20 percent light extinction levels for those constituents; rather, they represent the range of constituent light extinction levels on the 20 percent least and most impaired visibility days.

It is clear from these charts that levels of extinction from sulfate have dropped significantly since 2002, although still remaining at levels much higher than the estimated natural range at all sites. Extinction due to nitrate has also dropped steadily, and at several sites is approaching natural levels on the best days. At Brigantine Wilderness Area, extinction due to nitrate remains considerably higher than the natural baseline. Also at Brigantine Wilderness Area, carbonaceous matter has been holding steadily above natural levels with little observable trend downward, and course mass light extinction levels also remain above natural levels, though the 2011 peak in course mass light extinction may be a result of construction activity near the monitor location (NESCAUM, 2013).

Figure 19 Range of Observed and Estimated Natural Light Extinction for SO2 at Brigantine Wilderness Area on 20 Percent Best and Worst Visibility Days

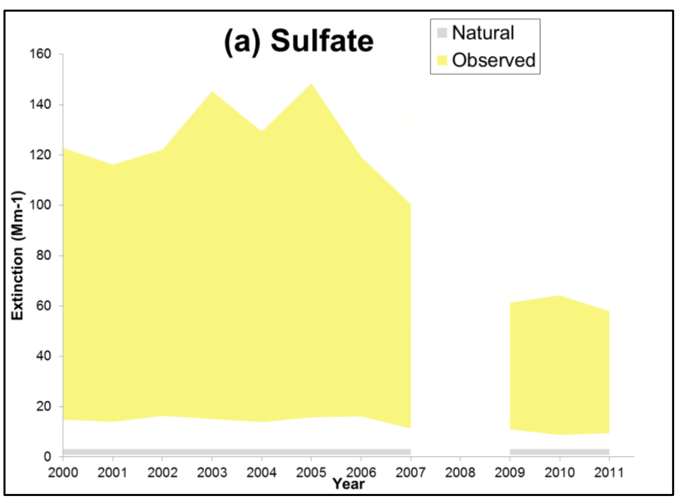


Figure 20 Range of Observed and Estimated Natural Light Extinction for Nitrate at Brigantine Wilderness Area on 20 Percent Best and Worst Visibility Days

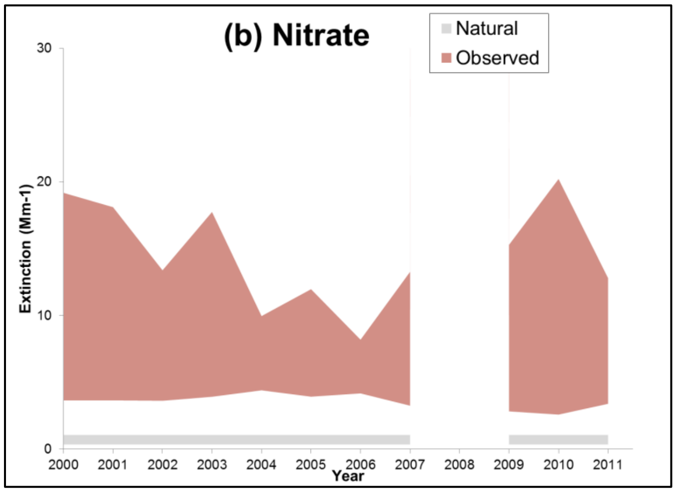


Figure 21 Range of Observed and Estimated Natural Light Extinction for Carbonaceous Matter at Brigantine Wilderness Area on 20 Percent Best and Worst Visibility Days

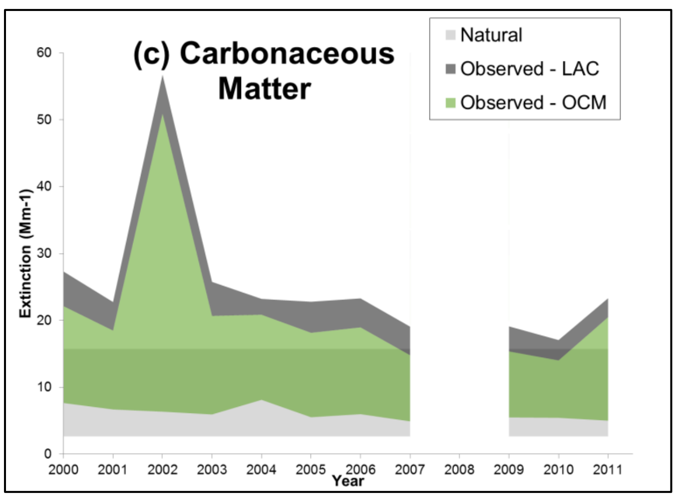
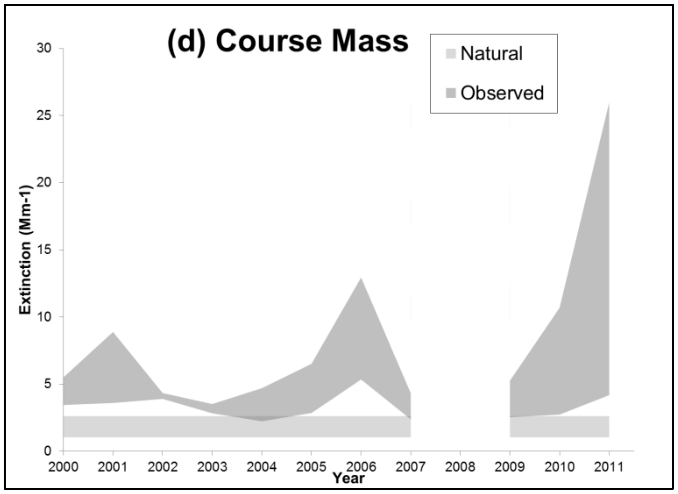


Figure 22 Range of Observed and Estimated Natural Light Extinction for Course Mass at Brigantine Wilderness Area on 20 Percent Best and Worst Visibility Days



The NESCAUM "Tracking Visibility Progress, 2004-2011" report concludes with the following Visibility Progress assessments:

- The visibility data examined in this report demonstrate that broad, regional efforts to reduce emissions of visibility-impairing pollutants are having a beneficial effect at the region's Class I areas. The most recent IMPROVE data indicate that the states continue to be on track to meet their 2018 reasonable progress goals for improved visibility. Further progress may occur through additional pollution reductions achievable under recently adopted or proposed regulatory programs.

- Despite variability in the year-to-year data, there are definite downward trends in overall haze levels at the Class I areas in and adjacent to the MANE-VU region. Based on rolling five-year averages demonstrating progress since the 2000-2004 baseline period, the MANE-VU Class I areas appear to be on track to meet their 2018 RPGs for both best and worst visibility days. The trends are mainly driven by large reductions in sulfate light extinction, and to a lesser extent, nitrate light extinction. Levels of carbonaceous matter (OCM and LAC) appear to be approaching natural levels at most of the MANE-VU Class I areas. In some cases, the levels set by these goals have already been met, and progress beyond the 2018 RPGs appears achievable. Though it is on track to meet its 2018 RPGs, challenges remain for the Brigantine Wilderness Area. Sulfate light extinction levels are higher at this site than at others across the region, and continued sulfate reductions would be a significant driver in continuing to improve visibility at this site.

5.4. SUMMARY OF IMPROVE DATA AND VISIBILITY IMPROVEMENT AT BRIGANTINE WILDERNESS AREA

In their final rulemaking approving Delaware's *2008 regional haze SIP*, EPA stated, "In setting RPGs, states must provide for an improvement in visibility for the most impaired days over the (approximately) 10-year period of the SIP, and ensure no degradation in visibility for the least impaired days over the same period."

As can be seen from the discussion, tables and graphs in this Section, that visibility improvement at Brigantine Wilderness Area has occurred for the most impaired days, and no degradation of visibility has occurred for the least impaired days (2000-2004 vs. 2005-2011). Thus, in terms of visibility improvement and available data, reasonable progress for Brigantine Wilderness Area is on track to be met.[47]

6. ASSESSMENT OF MONITORING STRATEGIES

[40 CFR 51.308(g)(7)]

40 CFR 51.308(g)(7) of the RHR requires:

> *A review of the state's visibility monitoring strategy, and any modifications to the strategy as necessary.*

Section 40 CFR 51.308(g)(7) of the Regional Haze Rules requires each state with a Class I area to review the State's visibility monitoring strategy and any modifications to the strategy as necessary.

This requirement is not applicable to Delaware because there are not any Class I areas or IMPROVE monitors in the State.

[47] DNREC notes that the nature of emissions control programs and meteorology, plus the intermittent activity of some sources (Saharan dust, wildfires, etc.) make it likely that actual progress will be somewhat erratic and that failure to achieve the URP at any point in the process should be considered in the context of changes to emissions inventories and/or meteorology.

D. ADEQUACY OF THE EXISTING SIP

[40 CFR51.308(h)]

1. REQUIREMENT TO DETERMINE THE ADEQUACY OF THE EXISTING SIP

40 CFR 51.308(h) of the RHR states:

> (h) *Determination of the adequacy of existing implementation plan.* At the same time the State is required to submit any 5-year progress report to EPA in accordance with paragraph (g) of this section, the State must also take one of the following actions based upon the information presented in the progress report:
>
> (1) If the State determines that the existing implementation plan requires no further substantive revision at this time in order to achieve established goals for visibility improvement and emissions reductions, the State must provide to the Administrator a negative declaration that further revision of the existing implementation plan is not needed at this time.
>
> (2) If the State determines that the implementation plan may be inadequate to ensure reasonable progress due to emissions from sources in another State(s) which participated in a regional haze planning process, the State must provide notification to the Administrator and to the other State(s) which participated in the regional planning process with the States. The State must also collaborate with the other State(s) through the regional haze planning process for the purpose of developing additional strategies to address the plan's deficiencies.
>
> (3) Where the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another country, the State shall provide notification, along with available information, to the Administrator.
>
> (4) Where the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions form sources within the State, the State shall revise its implementation plan to address the plan's deficiencies within one year.

2. DELAWARE DETERMINATION

Based on the options above and the evidence presented herein, DNREC is proposing a negative declaration to the EPA Administrator, specifying that no additional controls are necessary during this, the first five-year progress report period. Therefore, no further revision of the existing Delaware implementation plan is needed.

In keeping with the EPA's recommendations related to consultation, DNREC enlisted the support of appropriate state, local and tribal air pollution agencies, as well as the corresponding

FLMs and EPA Region 3 to formulate this report. The Regional Haze Rule at 40 CFR 51.308(i) requires that the state provide the Federal Land Manager(s) responsible for Class I areas affected by emissions from within the state an opportunity for consultation, in person and at least 60 days before holding any public hearing on this progress report SIP. As part of this meeting this RHR requirement, DNREC made an advanced, draft copy of this report available to the aforementioned agencies and sought their input. Delaware sent the draft SIP revision to the FLMs on May 1, 2013. Delaware sent the proposed SIP revision to the FLMs as part of the public review comment period on July 18, 2013. Delaware notified the FLMs of public hearings held on August 22, 2013. Comments received, along with DNREC's responses can be found in Appendix F.

In addition, DNREC also published a Notice of Public Hearing and Comment Period in the *Delaware State News* and the *News Journal* on July 17, 2013, providing more than 30-days for the public comment period. A public hearing was held on August 22, 2013, and the record remained open until September 6, 2013. Comments were not received during or after the hearing.

The State of Delaware, DNREC commits to continued consultation among the states and FLMs as it relates to any SIP revisions and/or the implementation of other programs having the potential to contribute to visibility impairment. The State anticipates that this will occur in much the same fashion as did the pre-hearing meetings, comments, and responses, as required by 40 CFR 51.308(i)(3).

E. CONCLUSION

Pursuant to the requirements of 40 CFR 51.308(g), (h), and (i), Delaware submits this Progress Report as a SIP revision as adopted by the Delaware Department of Natural Resources and Environmental Control (DNREC). Administrative requirements from Appendix V to CFR Part 51 require Delaware to demonstrate it has legal authority to adopt and implement this Plan. Delaware has adopted this SIP revision in accordance with Delaware State laws and rules. Legislative authority for the Delaware air quality program relating to the responsibilities in the CAA is codified in Title 7 "Conservation" of the Delaware Code, Chapter 60 – Delaware's comprehensive water and air resources conservation law, which gives DNREC the power and duty to implement the provisions of the CAA in the State of Delaware.

This SIP revision also complies with 40 CFR 51.102 and 103 to offer the public the opportunity to request a hearing and/or comment on a proposed SIP revision and to submit the SIP revision to EPA. Delaware provided public notice of the opportunity to comment on the SIP revision on July 17, 2013 in the Delaware State News and News Journal, as well as in the August 1, 2013 Delaware Register of Regulations. Delaware held a public hearing regarding this SIP revision on August 22, 2013. In accordance with 40 CFR 51.308(i), Delaware provided Federal Land Managers (FLM) an opportunity for consultation, in person and at least 60 days before holding any public hearing on this SIP revision. The draft SIP was emailed to the FLMs on May 1, 2013 and hard copies were also delivered to the FLMs on May 3, 2013, via express mail. Joint comments were received via email from the FLMs on July 1, 2013 (U.S. Department of Interior: Fish and Wildlife and National Park Service). The FLM comments and DAQ responses can be found in Appendix F. Delaware will continue to coordinate and consult with the Federal Land Managers on future SIP revisions, including progress reports, as well as during the implementation of programs having the potential to contribute to visibility impairment in the mandatory Class I areas.

The requirements addressed in the previous sections include the status of implementing committed control measures, summaries and analyses of emission and monitoring changes, and assessments of impacts on Class I areas identified in the original Regional Haze SIP. This Report also includes a determination that the original SIP remains adequate to achieve continued progress towards the 2018 visibility conditions goal for mandatory Class I areas impacted by sources in Delaware (e.g. Brigantine Wilderness area).

The *Delaware Visibility State Implementation Plan (*2008 regional haze SIP*)* submitted to the U.S. EPA on September 25, 2008 contains the emission reductions needed to achieve Delaware's share of emission reductions agreed upon through the regional planning process. Furthermore, the *2008 regional haze SIP* ensures that emissions from the State will not interfere with the reasonable progress goals for the Brigantine Wilderness Class I area. In addition, EPA approved Delaware's 2008 regional haze SIP on July 11, 2011 (76 FR 42557) because it also meets the applicable visibility related requirements of the CAA section 110(a)(2) including, but not limited to 110(a)(2)(D)(i)(II) and 110(a)(2)(J), relating to visibility protection for the 1997 8-Hour Ozone NAAQS and the 1997 and 2006 $PM_{2.5}$ NAAQS. Furthermore, U.S. Department of Interior comments conclude with, *"[This Report] provide[s] evidence that DE will meet or exceed the emissions reductions that were included in its 2008 State Implementation Plan and* *will not interfere with the ability of neighboring states to meet the reasonable progress goals set for Class I areas.*

As per 40 CFR Part 51 Section 308(h), if the EPA believes that the State is implementing a reasonable set of strategies according to the schedule as developed in the previous comprehensive SIP revision (e.g., Delaware's 2008 regional haze SIP), and that visibility trends show that reasonable progress goals should be achieved over the 10-year long-term strategy period, then the State should be able to certify, through a negative declaration, that no additional control measures are needed at the time of that State's mid-course review. Based on the required calculations and assessments in this progress report, **Delaware is making a negative declaration along with this SIP revision, which finds that no additional control measures are needed at this time.**

In summary, this 5-Year Progress Report fulfills all requirements for progress reports pursuant to 40 CFR 51.102, 40 CFR 51.103 and 40 CFR Part 51 Sections 308 (g), (h) and (i), and thus meets EPA criteria for full approval.