The State of New Hampshire
DEPARTMENT OF ENVIRONMENTAL SERVICES

Thomas S. Burack, Commissioner

January 14, 2011

Mr. Curt Spalding
Regional Administrator
USEPA New England, Region I
5 Post Office Square, Suite 100
Boston, MA 02109-3912

Re: Revision to New Hampshire's State Implementation Plan to Meet the Requirements of the Clean Air Act, Section 169A, Protection of Visibility (Regional Haze)

Dear Mr. Curt Spalding:

Pursuant to Section 110 of the federal Clean Air Act as amended, the New Hampshire Department of Environmental Services (NHDES) submits two hard copies and one electronic copy of this State Implementation Plan (SIP) revision to fulfill the requirements of section 169A, pertaining to protection of visibility and regional haze. NHDES has prepared this SIP revision in accordance with the general SIP submittal requirements of 40 CFR Part 51 Appendix V and in accordance with USEPA regulations and guidance on regional haze modeling and planning.

As Governor John Lynch's designee, I am requesting EPA's approval of this revision, which includes the adoption of administrative rule Env-A 2300, Mitigation of Regional Haze, and technical support therefore.

The USEPA, the Federal Land Managers, and other interested stakeholders have provided comments on the SIP. NHDES has addressed these comments in the SIP revision and has included documentation certifying the public process.

If you have any questions regarding this submittal, please contact Jeff Underhill at (603) 271-1102.

Sincerely,

Robert R. Scott
Director, Air Resources Division

rrs/chm
enclosure: NH Regional Haze SIP Revision w/ attachments
via email and postal service

cc: Anne Arnold, USEPA Region I
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New Hampshire
Regional Haze SIP Revision

January 14, 2011

Mid-Atlantic/Northeast Visibility Union (MANE-VU)

Prepared by

NEW HAMPSHIRE DEPARTMENT OF Environmental Services

Air Resources Division

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ACKNOWLEDGEMENTS

The New Hampshire Department of Environmental Services would like to express appreciation to the dedicated staffs of the NESCAUM, MARAMA, and MANE-VU regional organizations and to the dedicated staffs of the MANE-VU member states for their invaluable assistance and timely contributions in the development of New Hampshire's Regional Haze SIP Revision.

FOREWORD

This document revises New Hampshire's State Implementation Plan (SIP) to meet requirements of the Clean Air Act related to protection of visibility. SIPs are dynamic documents describing the state's statutory and regulatory (i.e., enforceable) emission control measures that will be implemented to ensure compliance with National Ambient Air Quality Standards and goals. SIPs must be reviewed and updated periodically to stay current with administrative requirements, changing air quality standards or conditions, and new or amended federal programs. The terms "SIP" and "SIP revision" are sometimes used interchangeably in reference to new or revised portions of a state implementation plan. Regional Haze SIP, or Regional Haze Plan, refers specifically to that portion of the State Implementation Plan which addresses visibility improvement.

1. THE REGIONAL HAZE ISSUE

In 1999, the Environmental Protection Agency (EPA) issued regulations to improve visibility in 156 national parks and wilderness areas across the United States. The affected areas include many of our best known natural places, including the Grand Canyon, Yosemite, Yellowstone, Mount Rainier, Shenandoah, the Great Smokies, Acadia, and the Everglades. In New Hampshire, the two affected areas are Great Gulf Wilderness and Presidential Range - Dry River Wilderness.

These regulations address visibility impairment in the form of regional haze. Haze is an atmospheric phenomenon that obscures the clarity, color, texture, and form of what we see. It is caused primarily by anthropogenic (manmade) pollutants but can also be caused by a number of natural phenomena, including forest fires, dust storms, and sea spray. Some haze-causing pollutants are emitted directly to the atmosphere by anthropogenic emission sources such as electric power plants, factories, automobiles, construction activities, and agricultural burning. Others occur when gases emitted into the air (haze precursors) interact to form new particles that are carried downwind.

Emissions from these activities generally span broad geographic areas and can be transported hundreds or thousands of miles. Consequently, regional haze occurs in every part of the nation. Because of the regional nature of haze, EPA's regulations require the states to consult with one another toward the national goal of improving visibility – specifically, at the 156 parks and wilderness areas designated under the Clean Air Act as mandatory Class I Federal Areas.

The Regional Haze Rule calls for each state to establish *reasonable progress goals* for visibility improvement and to formulate a *long-term strategy* for meeting these goals. These requirements apply to any state having a Class I area as well as any state that contributes to visibility impairment at any (downwind) Class I area. The visibility goals must be designed both to improve visibility on the haziest days and to ensure that no degradation occurs on the clearest days.

A state's long-term strategy must include enforceable emission reduction measures designed to meet reasonable progress goals. The first long-term strategy covers the 10-15-year period ending in 2018, and subsequent revisions are to be issued every 10 years thereafter. In identifying the emission reduction measures to be included in the long-term strategy, states should address all types of manmade emissions contributing to visibility degradation in Class I areas, including those from mobile sources; stationary sources (such as factories); smaller, so-called "area" sources (such as residential wood stoves and small boilers); and prescribed fires.

In developing their plans, states can take into account emission reductions attributable to ongoing air pollution control programs at the state, regional, or national levels. For most states and regions of the country, however, additional emission control measures beyond those already on the books will be necessary if national visibility goals are to be achieved. In addition, the Regional Haze Rule mandates that control measures be implemented for certain existing sources placed into operation between 1962 and 1977. This portion of the rule is known as *BART*, for *Best Available Retrofit Technology*.

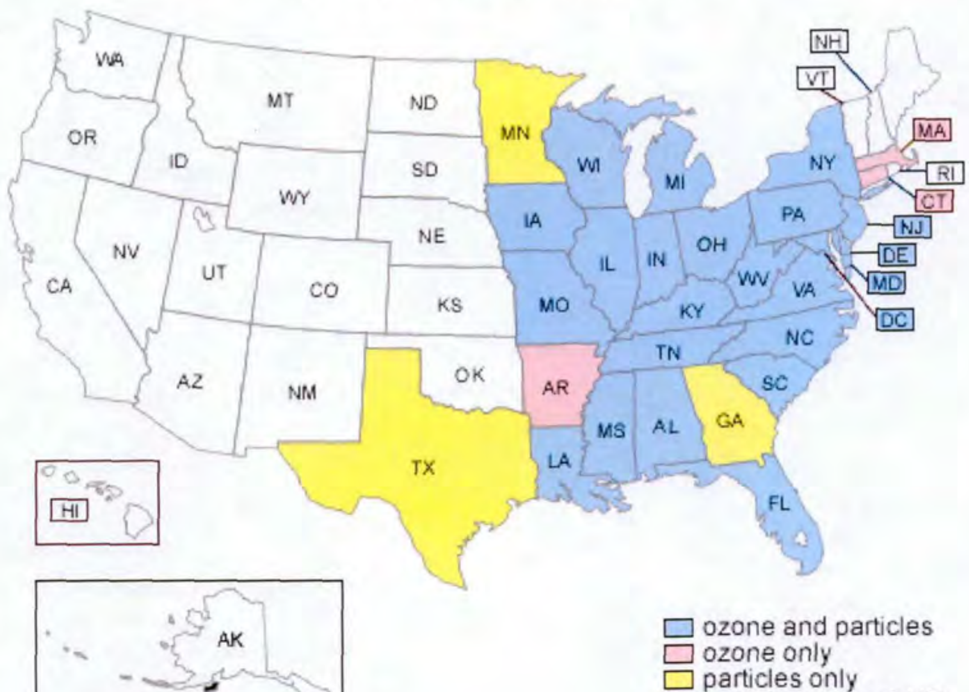
Each state's plan for addressing regional haze will take the form of a State Implementation Plan (SIP) revision. New Hampshire's SIP revision, presented here, was developed after extensive consultations with other states and regional planning organizations. In particular, New Hampshire contributed to many analyses and reports produced by the member states of the Northeast States for Coordinated Air Use Management (NESCAUM) and the Mid-Atlantic/Northeast Visibility Union (MANE-VU) for the purpose of coordinated regional haze planning. New Hampshire also consulted with states outside the Northeast and with the provinces of eastern Canada.

The regulatory, organizational, and technical basis for New Hampshire's regional haze plan will be found in Sections 1 through 8 of this SIP document. The prescriptive elements of New Hampshire's plan – Best Available Retrofit Technology (BART) provisions, reasonable progress goals, and long-term strategy – are described in detail in Sections 9 through 11.

1.1 Regional Haze Planning after Remand of CAIR

On March 10, 2005, EPA issued the Clean Air Interstate Rule (CAIR). This important federal rule was designed to achieve major permanent reductions in sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions in the eastern United States through a cap-and-trade system using emission allowances. CAIR would permanently cap emissions originating in 28 eastern states and the District of Columbia (Figure 1.1). Although New Hampshire was not designated as a participating CAIR state, this program would greatly affect future air quality in the state.

Figure 1.1: Map of CAIR States



http://www.epa.gov/cair/

According to EPA's CAIR website, SO_2 emissions in the affected states would be reduced by more than 70 percent from 2003 levels, and NO_X emissions by more than 60 percent from 2003 levels, upon full implementation of CAIR (see http://www.epa.gov/cair/).

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit found that CAIR violated basic provisions of the Clean Air Act. The Court vacated CAIR in its entirety and remanded to EPA to promulgate a new rule consistent with the Court's opinion. EPA appealed the decision amid widespread concern that, despite its flaws, some form of CAIR was preferable to the sudden regulatory void created by the Court's decision. Upon reconsideration, on December 23, 2008, the Court stayed the vacatur of CAIR but maintained the remand to EPA to promulgate a new rule consistent with the Court's July 11, 2008, opinion.

Because CAIR formed the regulatory underpinnings for most of the emission reductions that were to produce visibility improvements in mandatory Class I areas, the vacatur of CAIR would have represented a major difficulty for the individual states in attempting to comply with the Regional Haze Rule. While all eastern states have depended in varying degree on CAIR in the preparation of their regional haze SIPs, some Southeast states have relied almost entirely on CAIR to demonstrate compliance with the rule.

The CAIR Phase I requirements remain in place, and CAIR's regional control programs continue to operate while EPA develops replacement rules in response to the remand. On July 6, 2010, EPA announced a new rule to implement the Clean Air Act requirements pertaining to transport of air pollution across state boundaries. The proposed Transport Rule responds to the Court remand of CAIR and will replace CAIR when final (see http://www.epa.gov/airtransport/).

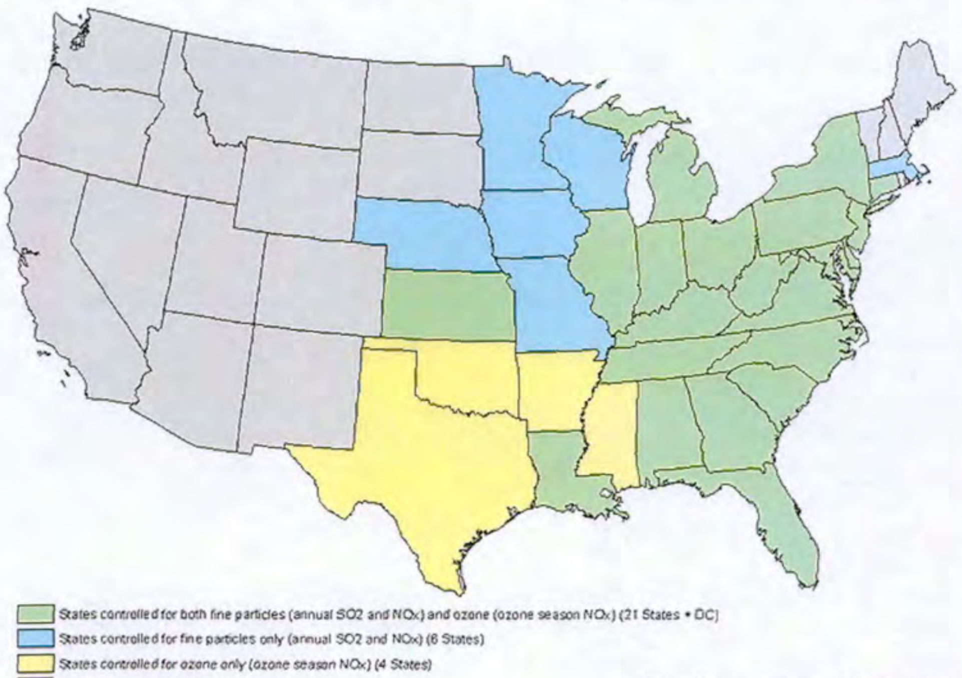
This rule would require 31 states and the District of Columbia (Figure 1.1a) to significantly improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other states:

- Twenty-eight states would be required to reduce both annual SO_2 and NOx emissions. By reducing the emissions from the upwind states, the proposal would help downwind states attain air quality standards, specifically the 24-hour $PM_{2.5}$ standards established in 2006 and the 1997 annual $PM_{2.5}$ standards.

- Twenty-six states would be required to reduce NOx emissions during the hot summer months of the ozone season because they contribute to downwind states' ozone pollution. By reducing the emissions from the upwind states, the proposal would help downwind states' attain air quality standards, specifically the 1997 ground-level ozone standard.

The final rule is expected in late spring 2011.

Figure 1.1a: Map of Transport Rule States



http://www.epa.gov/airtransport/

At this point it is not possible to comprehend all of the ramifications for regional haze planning resulting from the remand and replacement of CAIR. There may be some short-term slippage or loss in projected emission reductions as a consequence of the Court's July 11, 2008, decision. Over the longer term, New Hampshire anticipates that future emission controls under the Transport Rule and other CAIR-successor legislation will be at least as stringent as CAIR originally would have obtained. As to the validity of the already-completed planning components, a number of mitigating circumstances apply:

- With the introduction of the Transport Rule, the regulatory equivalency of CAIR and BART is removed as a BART compliance option. Application of BART provisions where the old CAIR previously might have sufficed is likely to yield even greater emission reductions from BART-eligible facilities.
- New Hampshire and many other states have instituted their own emission reduction programs through multi-pollutant legislation and other means. New Hampshire applauds the efforts of other states and encourages them to follow through with the implementation of laws, consent decrees, and other measures that would complement emission reductions from federal programs.
- Strict adherence to the spirit of the Clean Air Act in future national initiatives will probably result in emission reductions exceeding those previously projected for CAIR. A major limitation of the original CAIR was that it relied on interstate emissions trading and did not respond to the specific language of the Clean Air Act, Section 110(a)(2)(D), which prohibits *any* source or activity within a state from impairing the ability of another state to meet national air quality standards or visibility requirements. CAIR was only one tool, not an all-purpose remedy, for addressing the problem of interstate transport of pollutants.

- EPA's own emission reduction projections for electric generating units – the largest emission source category – are at least as great under the proposed Transport Rule as those put forth for CAIR (see Table 1.1). The comparison is valid for overall emissions but is not necessarily true for emissions on a state-by-state basis.

Table 1.1: Simple Comparison of SO_2 and NOx Total Emissions from Electric Generating Units in the CAIR or Transport Rule Regions* (Million Tons)

Pollutant	2005 Actual	2012		2014	
		Transport Rule	CAIR**	Transport Rule	CAIR**
SO_2	9.5	4.1	5.1	3.3	4.6
NOx – Annual	2.9	1.6	1.7	1.6	1.7
NOx – Ozone Season	1.0	0.7	0.8	0.7	0.8

* Emissions totals include states covered by either the Transport Rule or CAIR. For $PM_{2.5}$ (SO_2 and annual NOx), the following 30 states are included: AL, CT, DE, DC, FL, GA, IL, IN, IA, KS, KY, LA, MD, MA, MI, MN, MS, MO, NE, NJ, NY, NC, OH, PA, SC, TN, TX, VA, WV, WI. For ozone (ozone-season NOx), the following 30 states are included: AL, AR, CT, DE, DC, FL, GA, IL, IN, IA, KS, KY, LA, MD, MA, MI, MS, MO, NJ, NY, NC, OH, OK, PA, SC, TN, TX, VA, WV, WI.

** CAIR SO_2 totals are interpolations from emissions analysis originally done for 2010 and 2015. CAIR NOx totals are as originally projected for 2010. This CAIR modeling represents a scenario that differed somewhat from the final CAIR (the modeling did not include a regionwide ozone season NOx cap and included $PM_{2.5}$ requirements for the state of Arkansas).

Source: Table III.A–4 of Proposed Rules, *Federal Register*, Vol. 75, No. 147, August 2, 2010.

For the reasons given, NHDES expects that future emissions and air quality levels under post-CAIR scenarios are likely to be better than or, in the worst case, not very different from values predicted by MANE-VU's completed modeling, even though that modeling was based on implementation of CAIR as it was before the remand. Consequently, the reasonable progress goals and long-term strategy developed for New Hampshire's regional haze SIP still represent a defensible position from which to go forward with measures to improve visibility at MANE-VU's Class I Areas.

New Hampshire and the other MANE-VU states have maintained all along that the regional haze SIPs should look beyond the provisions of CAIR to identify additional emission control measures that could be effectively employed to mitigate regional haze. In this respect, New Hampshire and the rest of MANE-VU stand apart from some other states in asserting that additional measures beyond CAIR and the present Transport Rule are essential to meeting established visibility goals at MANE-VU's Class I Areas.

In describing New Hampshire's current situation, it may be helpful to note that the remand of CAIR and its subsequent replacement with the Transport Rule are complicating factors but not absolute impediments to making visibility progress in the near term. The salient points to consider are as follows:

- Because New Hampshire is a non-CAIR state and a non-Transport Rule state, these federal programs do not directly affect any of New Hampshire's proposed in-state control strategies for visibility improvement. The control measures identified in this regional haze SIP for in-state sources should be able to proceed without delay or obstruction.

- New Hampshire will meet its "fair share" of emissions in comparison with other MANE-VU states and the original CAIR states, as New Hampshire's long-term strategy demonstrates (see Section 11).
- Sources in upwind states release most of the pollutants contributing to visibility impairment at New Hampshire's Class I areas. Therefore, New Hampshire will continue to depend on mitigative actions by other states if visibility goals are to be achieved for in-state Class I areas.
- By the time of the first regional haze SIP progress report (expected to be completed in 2013[1]) the regulatory framework should be clearer; and it is hoped that new modeling results will be available. If so, it will then be possible to fine-tune regional haze plans to meet the post-CAIR reality. **New Hampshire is committed to reviewing and updating its regional haze SIP as new information becomes available.**

It should be noted that many references to the original CAIR program appear throughout New Hampshire's Regional Haze SIP. These references serve two purposes: 1) They provide historical context, and 2) they help to maintain continuity with the large body of completed work – much of it based on CAIR – that serves as the foundation for regional haze planning in the MANE-VU states to date.

1.2 The Basics of Haze

Small particles and certain gaseous molecules in the atmosphere cause poor visibility by scattering and absorbing light, thereby reducing the amount of visual information about distant objects that reaches an observer. Some light scattering by air molecules and naturally occurring aerosols occurs even under natural conditions.[2]

The distribution of particles in the atmosphere depends on meteorological conditions and leads to various forms of visibility impairment. When high concentrations of pollutants are well mixed in the atmosphere, they form a uniform haze. When temperature inversions trap pollutants near the surface, the result can be a sharply demarcated layer of haze. Plume blight – a distinct, frequently brownish plume of pollution from a particular emissions source – occurs under stable atmospheric conditions, where pollutants take a long time to disperse.

Visibility impairment can be quantified using three different, but mathematically related measures: light extinction per unit distance (e.g., inverse megameters, or Mm^{-1})[3]; visual range (i.e., how far one can see); and deciviews (dv), a useful metric for measuring increments of visibility change that are just perceptible to the human eye. Each can be estimated from the ambient concentrations of individual particle constituents, taking into account their unique light-scattering (or absorbing) properties and making appropriate adjustments for relative

[1] 40 CFR 51.308(g) states that the first progress report is due 5 years from the submittal of the initial implementation plan. The regional haze SIP was originally due on December 17, 2007. In New Hampshire's case, it is expected that the first progress report will be completed and submitted in 2013, near the midpoint of the 10-year initial planning period from 2008 to 2018.

[2] The fact that air molecules scatter more short-wavelength (blue) light accounts for the blue color of the sky. The term "aerosol" is defined as a suspension of particles in a gas. In this report, the term refers to particles suspended in the atmosphere.

[3] In units of inverse length. An inverse megameter (Mm^{-1}) is equal to one over one thousand kilometers.

humidity. Assuming natural conditions, visibility in the Northeast and Mid-Atlantic is estimated to be about 23 Mm^{-1}, which corresponds to a visual range of about 106 miles or 8 dv (the lower the dv, the better the visibility). Under current polluted conditions in the region, average visibility ranges from 103 Mm^{-1} in the south to 55 Mm^{-1} in the north; these values correspond to a visual range of 24 to 44 miles or 23 to 17 dv, respectively. On the worst 20 percent of days, visibility impairment in Northeast and Mid-Atlantic Class I areas ranges from about 25 to 30 dv.

The small particles that commonly cause hazy conditions in the East are primarily composed of sulfate, nitrate, organic carbon, elemental carbon (soot), and crustal material (e.g., soil dust, sea salt, etc.). Of these constituents, only elemental carbon impairs visibility by absorbing visible light; the others scatter light. Sulfate, nitrate, and organic carbon[4] are secondary pollutants that form in the atmosphere from precursor pollutants, primarily sulfur dioxide (SO_2), oxides of nitrogen (NO_X), and volatile organic compounds (VOCs), respectively. By contrast, soot and crustal material and some organic carbon particles are released directly to the atmosphere. Particle constituents also differ in their relative effectiveness at reducing visibility. Sulfates and nitrates, for example, contribute disproportionately to haze because of their chemical affinity for water. This property allows them to grow rapidly, in the presence of moisture, to the optimal particle size for scattering light (i.e., 0.1 to 1 micrometer).

1.3 Anatomy of Regional Haze

Monitoring data collected over the last decade show that fine particle[5] concentrations, and hence visibility impairment, are generally highest near industrial and highly populated areas of the Northeast and Mid-Atlantic. Particle concentrations are lower, and visibility conditions are better, at the more northerly Class I sites (such as the Great Gulf and Presidential Range - Dry River Wildernesses in New Hampshire), where visibility on the 20 percent best days[6] is close to natural, unpolluted conditions. By contrast, visibility at the more southerly Brigantine site in New Jersey is substantially impaired even on the 20 percent clearest days. On the 20 percent haziest days, visibility impairment is substantial throughout the region.

Sulfate is the dominant contributor to fine particle pollution throughout the eastern U.S. On the haziest 20 percent of days, it accounts for one-half to two-thirds of total fine particle mass and is responsible for about three-quarters of total light extinction at Class I sites in the Northeast and Mid-Atlantic. Even on the clearest 20 percent of days, sulfate typically constitutes 40 percent or more of total fine particle mass in the region. Moreover, sulfate accounts for 60 to 80 percent of the difference in fine particle mass concentrations on hazy versus clear days.

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4 The term "organic carbon" encompasses a large number of hydrogen and carbon containing molecules. Light scattering secondary organic aerosols result from the oxidation of hydrocarbons that are emitted from many different sources, ranging from automobiles to solvents, to natural vegetation. Organic carbon can be emitted as a primary particle from sources such as wood burning, meat cooking, automobiles, and paved road dust.

5 "Fine particles" refers throughout this study to particles less than or equal to 2.5 micrometers in diameter, consistent with US EPA's recently proposed fine particle National Ambient Air Quality Standard (NAAQS).

6 "20 percent best visibility conditions" are defined throughout this report as the simple average of the lower 20^{th} percentile of a cumulative frequency distribution of available data (expressed in deciviews). Similarly, "20 percent worst visibility conditions" represent the upper 20^{th} percentile of the same distribution of available data.

Organic carbon consistently accounts for the next largest fraction of total fine particle mass; its contribution typically ranges from 20 to 30 percent on the haziest days. Notably, organic carbon accounts for as much as 40 to 50 percent of total mass on the clearest days, indicating that biogenic hydrocarbon sources (i.e., vegetation) are important at Class I areas in the region.

The relative contributions of nitrate, elemental carbon, and fine soil are smaller than those of sulfate and organic carbon – typically less than 10 percent of total mass and varying with location. However, in some settings such as a monitoring site in Washington, DC,[7] nitrate plays a considerably larger role, pointing to the importance of local NO_X sources to fine-particle pollution in urban environments.

About half of the worst visibility days in the New Hampshire Class I Areas occur in the summer when meteorological conditions are more conducive to the formation of sulfate from SO_2 and to the oxidation of organic aerosols. The remaining worst visibility days are divided nearly equally among spring, winter, and fall. In contrast to sulfate and organic carbon, the nitrate contribution is typically higher in the winter months.[8] The crustal and elemental carbon fractions do not show a clear pattern of seasonal variation. In addition, winter and summer transport patterns are different, possibly leading to different contributions from upwind pollutant source regions.

The basis for EPA's regional haze regulations is recognition that visibility impairment is fundamentally a regional phenomenon. Emissions from numerous sources over a broad geographic area commonly create hazy conditions across large portions of the eastern U.S. as a result of the long-range transport of airborne particles and precursor pollutants in the atmosphere. The key sulfate precursor, SO_2, for example, has an atmospheric lifetime of several days and is known to be subject to transport distances of hundreds of miles. NO_X and some organic carbon species are also subject to long-range transport, as are small particles of soot and crustal material.

The importance of transport dynamics is well illustrated by a particularly severe haze episode that occurred in mid-July of 1999. During this episode, unusually hot and humid conditions coincided with the development of a high-pressure system over the Mid-Atlantic States that produced atmospheric stagnation over the heavily urbanized, southern portion of the northeastern Regional Planning Organization region (i.e., Philadelphia - DC - southern New Jersey). At the same time, wind patterns above the area of stagnation brought a steady flow of air from the Midwest into the New England states. This set of conditions resulted in several days of unusually high concentrations of fine-particle pollution throughout the region. On July 17, 1999, ambient sulfate concentrations at Acadia National Park were 40 percent higher than any previous measurement at that site since the late 1980s. On the same day, visibility at the Burlington, Vermont, airport was limited to just 3 miles. As is often the case, high concentrations of ground-level ozone accompanied these severe haze conditions. These coinciding conditions occurred because haze and ground-level ozone – although they are fundamentally different phenomena – tend to form and accumulate under similar meteorological conditions.

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[7] The Washington, DC, site is part of the IMPROVE nationwide monitoring network and is mentioned here for the purposes of comparison.

[8] This is largely due to the fact that the ammonium nitrate bond is more stable at lower temperatures. The role of ammonia in combination with both sulfate and nitrate is discussed further in later sections.

1.4 Regulatory Framework

In amendments to the Clean Air Act (CAA) in 1977, Congress added Section 169A (42 U.S.C. 7491), setting forth the following national visibility goal:

> "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution."

The "Class I" designation was given to each of 158 areas in existence as of August 1977 that met the following criteria:

- all national parks greater than 6000 acres
- all national wilderness areas and national memorial parks greater than 5000 acres
- one international park

In 1980, Bradwell Bay, Florida, and Rainbow Lake, Wisconsin, were excluded for purposes of visibility protection as federal Class I areas. Today, 156 national park and wilderness areas remain as Class I visibility protection areas (Figure 1.2).

Figure 1.2: Locations of Federally Protected Mandatory Class I Areas

Over the following years, modest steps were taken to address the visibility problems in Class I areas. The control measures taken mainly addressed plume blight from specific pollution sources, a localized phenomenon, and did little to address regional haze issues in the Eastern United States.

When the Clean Air Act was amended, again, in 1990, Congress added Section 169B (42 U.S.C. 7492), authorizing further research and regular assessments of progress made. In 1993, the National Academy of Sciences concluded that "current scientific knowledge is adequate and control technologies are available for taking regulatory action to improve and protect visibility."

In addition to authorizing creation of visibility transport commissions and setting forth their duties, Section 169B(f) of the CAA mandated creation of the Grand Canyon Visibility Transport Commission (GCVTC) to make recommendations to EPA for the region affecting the visibility of the Grand Canyon National Park. GCVTC submitted its report to EPA in June 1996, following four years of research and policy development. This report, as well as the many research reports prepared by the GCVTC, contributed invaluable information to EPA in its development of regulations for visibility improvement.

1.4.1 The Regional Haze Rule

The federal requirements that states must meet to achieve national visibility goals are contained in Title 40: Protection of Environment, Part 51 – Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Subpart P – Protection of Visibility (40 CFR 51.300-309). Known more simply as the Regional Haze Rule, these regulations were adopted on July 1, 1999, and went into effect on August 30, 1999. The rule seeks to address the combined visibility effects of various pollution sources over a large geographic region. This wide-reaching pollution net means that many states – even those without Class I Areas – are required to participate in haze reduction efforts. The specific requirements for States' regional haze SIPs are set forth in 40 CFR 51.308, Regional Haze Program Requirements.

In consultation with the states and tribes, EPA designated five Regional Planning Organizations (RPO) to assist with the coordination and cooperation needed to address the regional haze issue. The Mid-Atlantic and Northeast states, joined by the District of Columbia and tribes in the Northeast, formed the Mid-Atlantic / Northeast Visibility Union (MANE-VU).[9]

EPA's adoption of the Regional Haze Rule was not without controversy and legal challenges. On May 24, 2002, the U.S. Court of Appeals for the District of Columbia Circuit ruled on the challenge brought by the American Corn Growers Association against the Regional Haze Rule. The Court remanded the BART provisions of the rule to EPA and denied industry's challenge to the haze rule goals of achieving natural visibility levels and zero degradation. On June 15, 2005, EPA finalized a rule addressing the court's remand.

On February 18, 2005, the U.S. Court of Appeals for the D.C. Circuit issued another ruling vacating the Regional Haze Rule in part and sustaining it in part. For more information see

[9] MANE-VU includes the following member states: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and the District of Columbia. A more complete description of MANE-VU appears in Section 3 of this SIP.

Center for Energy and Economic Development v. EPA, no. 03-1222, (D.C. Cir. Feb. 18, 2005) ("*CEED* v. EPA"). In this case, the court granted a petition challenging provisions of the Regional Haze Rule governing the optional emissions trading program for certain Western States and Tribes (the WRAP Annex Rule).

In the aftermath of these decisions, EPA's final rulemaking incorporated the following changes to the Regional Haze Rule:

- Revised the regulatory text in 40 CFR 51.308(e)(2)(i) in response to the *CEED* court's remand, to
    - Remove the requirement that the determination of BART be based on cumulative visibility analyses, and
    - Clarify the process for making such determinations, including the application of BART presumptions for electric generating units (EGUs) as contained in 40 CFR 51, Appendix Y;
- Added new regulatory text in 40 CFR 51.308(e)(2)(vi) to provide minimum elements for cap-and-trade programs in lieu of BART; and
- Revised regulatory text in 40 CFR 51.309 to reconcile the optional framework for certain Western states and tribes to implement the recommendations of the GCVTC with the *CEED* decision.

1.4.2 State Implementation Plan

New Hampshire submits this State Implementation Plan revision to meet the requirements of EPA's Regional Haze Rule. To facilitate states' efforts, EPA prepared a checklist summarizing the requirements of the final Regional Haze Rule. Attachment A is a copy of the checklist with cross-references to sections of New Hampshire's Regional Haze SIP showing how the requirements have been met.

New Hampshire's Regional Haze Plan addresses the core requirements of 40 CFR 51.308(d) and the BART components of 40 CFR 50.308(e). In addition, this SIP addresses requirements pertaining to regional planning, and state/tribe and Federal Land Manager (FLM) coordination and consultation.

40 CFR 51.308(f) requires the New Hampshire Department of Environmental Services (NHDES) to submit periodic revisions to its Regional Haze SIP by July 31, 2018, and every ten years thereafter. **NHDES acknowledges and will comply with this schedule.**

40 CFR 51.308(g) requires NHDES to submit a report to EPA every 5 years that evaluates progress toward the reasonable progress goal for each mandatory Class I area located within the state and each mandatory Class I area located outside the state that may be affected by emissions from within the state. **NHDES will submit the first progress report, in the form of a SIP revision, within 5 years from submittal of the initial State Implementation Plan, but in no case later than December 31, 2013.**

Pursuant to 40 CFR 51.308(d)(4)(v), **NHDES will also make periodic updates to the New Hampshire's emissions inventory** (see Section 7, Emissions Inventory). NHDES proposes to complete these updates to coincide with the progress reports.

Lastly, pursuant to 40 CFR 51.308(h), **NHDES will submit a determination of adequacy of its regional haze SIP revision whenever a progress report is submitted.** Depending on the findings of its five-year review, New Hampshire will take one or more of the following actions at that time, whichever actions are appropriate or necessary:

- If New Hampshire determines that the existing State Implementation Plan requires no further substantive revision in order to achieve established goals for visibility improvement and emissions reductions, NHDES will provide to the EPA Administrator a negative declaration that further revision of the existing plan is not needed.
- If New Hampshire determines that its implementation plan is or may be inadequate to ensure reasonable progress as a result of emissions from sources in one or more other state(s) which participated in the regional planning process, New Hampshire will provide notification to the EPA Administrator and to those other state(s). New Hampshire will also collaborate with the other state(s) through the regional planning process, if viable regional organizations exist, for the purpose of developing additional strategies to address any such deficiencies in New Hampshire's plan.
- If New Hampshire determines that its implementation plan is or may be inadequate to ensure reasonable progress as a result of emissions from sources in another country, New Hampshire will provide notification, along with available information, to the EPA Administrator.
- If New Hampshire determines that its implementation plan is or may be inadequate to ensure reasonable progress as a result of emissions from sources within the state, New Hampshire will revise its implementation plan to address the plan's deficiencies within one year from this determination.

1.5 New Hampshire's Class I Areas

In New Hampshire, the U.S. Forest Service manages two Class I wilderness areas: the Great Gulf Wilderness and the Presidential Range - Dry River Wilderness, both located in New Hampshire's White Mountain National Forest.

Figure 1.3: Mt. Washington from the Southeast at Sunrise

These Class I areas flank the northern and southern slopes of the nationally renowned Mt. Washington, in the Presidential Range of the White Mountains (Figure 1.3). Mt. Washington is the highest mountain in the Northeast and attracts visitors (who can climb, drive, or ride to its summit) to enjoy expansive views from above tree line. Any action taken to improve visibility in the adjacent Great Gulf and Presidential Range-Dry River Wilderness Areas will also improve the vistas from the summit of Mt. Washington. The White Mountain National Forest is the main tourist attraction in New Hampshire and ranks among the most popular National Forests in the country with over 7 million visitors annually (source: U.S. Forest Service, http://www.fs.fed.us/r9/forests/white_mountain/about/history/index.php).

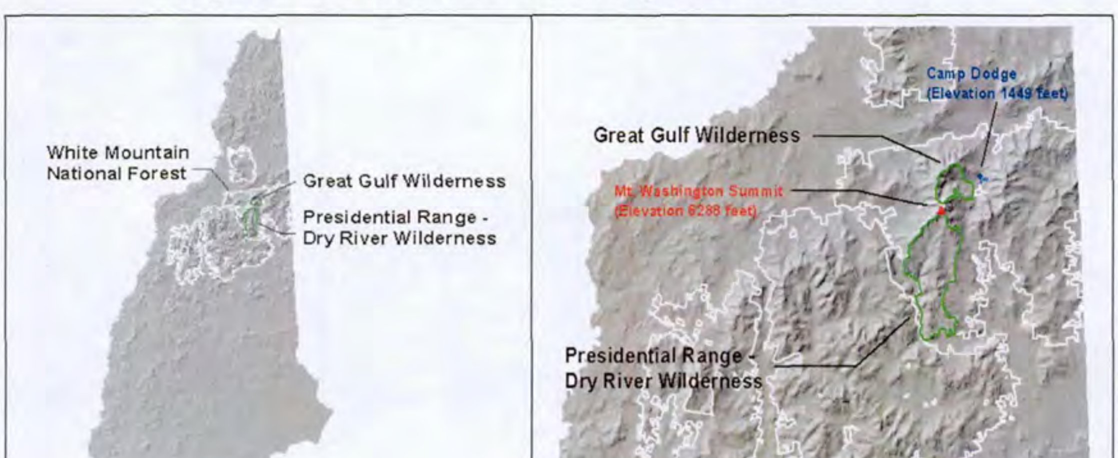
The Great Gulf Wilderness and the Presidential Range - Dry River Wilderness are two of 156 protected areas designated in 1977 as mandatory federal Class I areas for the purposes of the visibility protection program. Each of these areas covers thousands of acres containing high mountain terrain, scenic vistas, and interesting or unique geologic formations and vegetation communities. Many species of wildlife are present, including a number of alpine-zone residents. Among the alpine fauna are the northern bog lemming and two rare butterfly species. Cool, crystal-clear streams, cascades, and high-elevation ponds are common throughout the two areas, and the region is full of natural woodland. Hardwoods are most abundant on the lower slopes; mixed birches, maples, and spruce-fir dominate the mid-slopes; and spruce-fir are most common on the upper mountainsides. The unusual low-elevation tree line in the White Mountains of New Hampshire is caused by the high winds and harsh conditions this area experiences through the year. The result is a fragile, near-Arctic-tundra vegetation at the higher elevations.

The delicate ecosystems in both wilderness areas have been under stress resulting from years of highly acidic precipitation, which has leached plant nutrients from the soils and acidified mountain streams and ponds. The damage done by air pollution to Great Gulf and Presidential Range - Dry River Wilderness Areas will take decades to repair.

1.5.1 Great Gulf Wilderness

The Great Gulf Wilderness is located in Greens Grant in the White Mountain National Forest of northern New Hampshire (Figure 1.4). Occupying the northeastern slopes of the Presidential Range, Great Gulf covers an area of 5,552 acres and ranges in elevation from 1,680 to 5,807 feet.

Figure 1.4: Location of New Hampshire's Class I Areas



The Great Gulf Wilderness is formed by a high mountain valley located north-northeast of the Mt. Washington summit (Figures 1.5 and 1.6). The valley has steep walls rising from 1,100 feet to 1,600 feet above the valley floor. The area includes many rivulets that drain eastward to the West Fork of the Peabody River. For visitors, the Great Gulf has 21.3 miles of marked trails, which offer some of the best views of the ridges and summits of the Presidential Range. Great Gulf receives about 20,000 visitors annually.

Figure 1.5: View of Great Gulf Wilderness from Mt. Washington

http://www.penemco.com/matthew/

Figure 1.6: Views of Great Gulf Wilderness from Lower Elevation on Clear (6 deciview) and Hazy (28 deciview) Days

http://www.wilderness.net

1.5.2 Presidential Range - Dry River Wilderness, New Hampshire

The Presidential Range - Dry River Wilderness is also located in Greens Grant in the White Mountain National Forest of northern New Hampshire (Figure 1.4); however, at 27,380 acres, it is about five times larger than the Great Gulf Wilderness. Ranging in elevation from 880 to 5,413 feet, the Presidential Range - Dry River Wilderness constitutes a rugged expanse of mountains and valleys lying to the south of Mt. Washington's summit. On its western side, the area flanks other peaks in the Presidential Range, including Mt. Eisenhower and Mt. Monroe. The wilderness area extends across and beyond the central valley of the Dry River to the Saco River, encompassing numerous brooks and smaller, heavily forested mountains (Figure 1.7).

Figure 1.7: Presidential Range - Dry River Wilderness in Autumn.

http://www.wilderness.net

As the name suggests, the Dry River is almost without water by late summer but swells quickly during heavy rains. There are ten trails in the wilderness area totaling 46.1 miles in length. Because of its remote location, this area receives fewer visitors than Great Gulf (about 7,000 annually). Its southern portion has almost no trails, is very steep and rugged, and offers a rare degree of solitude.

1.5.3 Monitoring and Recent Visibility Trends

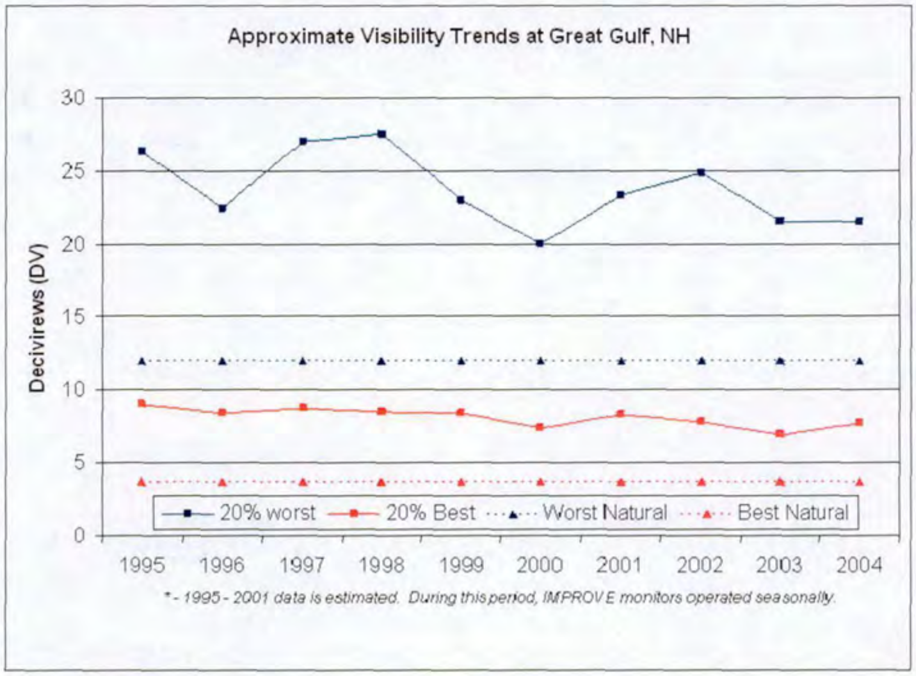
Visibility monitoring at Great Gulf Wilderness and Presidential Range - Dry River Wilderness is accomplished with instruments located at a single site at Camp Dodge. This monitoring station, which represents both wilderness areas, measures and records light scattering, aerosols, and relative humidity (Table 1.2). The collected data are compiled and sorted to ascertain visibility levels on the 20 percent most and least visibility-impaired days, and this information is tracked over time to look for trends in visibility.

Table 1.2: Visibility Monitoring at Great Gulf and Presidential Range - Dry River Wilderness Areas

Parameter	Instrument
Scattering coefficient	Nephelometer
Aerosol	IMPROVE module A
Aerosol	IMPROVE module B
Aerosol	IMPROVE module C
Aerosol	IMPROVE module D
Meteorology	Relative humidity

Figure 1.8 depicts recent visibility trends (in annual average deciviews) at Great Gulf Wilderness and Presidential Range - Dry River Wilderness for the 20 percent most and least visibility-impaired days for each year from 1995 to 2004. The graph also shows the reconstructed natural background level. The difference between the 20 percent haziest days and the natural background level shows the magnitude of the gap that needs to be closed in order to attain the national visibility goal established in the Clean Air Act.

Figure 1.8: Visibility Trends at Great Gulf and Presidential Range - Dry River Wilderness Areas



The plotted trend lines serve only as semi-quantitative indicators of baseline conditions for a number of reasons:

- As of 1999, there were no complete years of sampling data for the Great Gulf site; so the trend lines represent only the subset of summer months from May or June through September.
- Since the haziest days typically occur in the warmest months, average deciview values for the 20 percent most visibility-impaired summertime days would almost certainly be higher than the corresponding value for the year as a whole.
- The short time span of the trend plots (10 years' worth of data) makes it impossible to draw definitive conclusions about recent visibility trends in New Hampshire.

Despite these caveats, the trend plots do suggest the following:

- The 20 percent most visibility-impaired days have visibility readings in the order of 10 deciviews above the worst natural background level; and
- The 20 percent least visibility-impaired days have visibility readings in the order of 4 deciviews above the best natural background level.

2. AREAS CONTRIBUTING TO REGIONAL HAZE

40 CFR 51.308I(3) of the Regional Haze Rule requires states to determine their contributions to visibility impairment at mandatory Class I areas. Through source apportionment modeling (more fully described in Section 8, Understanding the Sources of Visibility-Impairing Pollutants), MANE-VU has identified and evaluated the major contributors to regional haze at MANE-VU Class I Areas as well as Class I areas in nearby Regional Planning Organizations (RPOs). The complete findings are contained in a report produced by the Northeast States for Coordinated Air Quality Management (NESCAUM) entitled, "Contributions to Regional Haze in the Northeast and Mid-Atlantic United States," August 2006, otherwise known as the Contribution Assessment (Attachment B).

The regional modeling performed by MANE-VU included a pollutant tagging scheme to produce a comprehensive assessment of the individual contributions from 28 nearby states to visibility impairment at the New Hampshire Class I areas and six other nearby Class I areas. The modeling also provided a partial accounting of the contributions from several states along the western and southern edges of the modeling domain (i.e., boundary conditions) where only a portion of the states' emissions were tracked. Modeling was conducted for the base year 2002 and then projected to year 2018, when currently anticipated emission control programs would be in place.

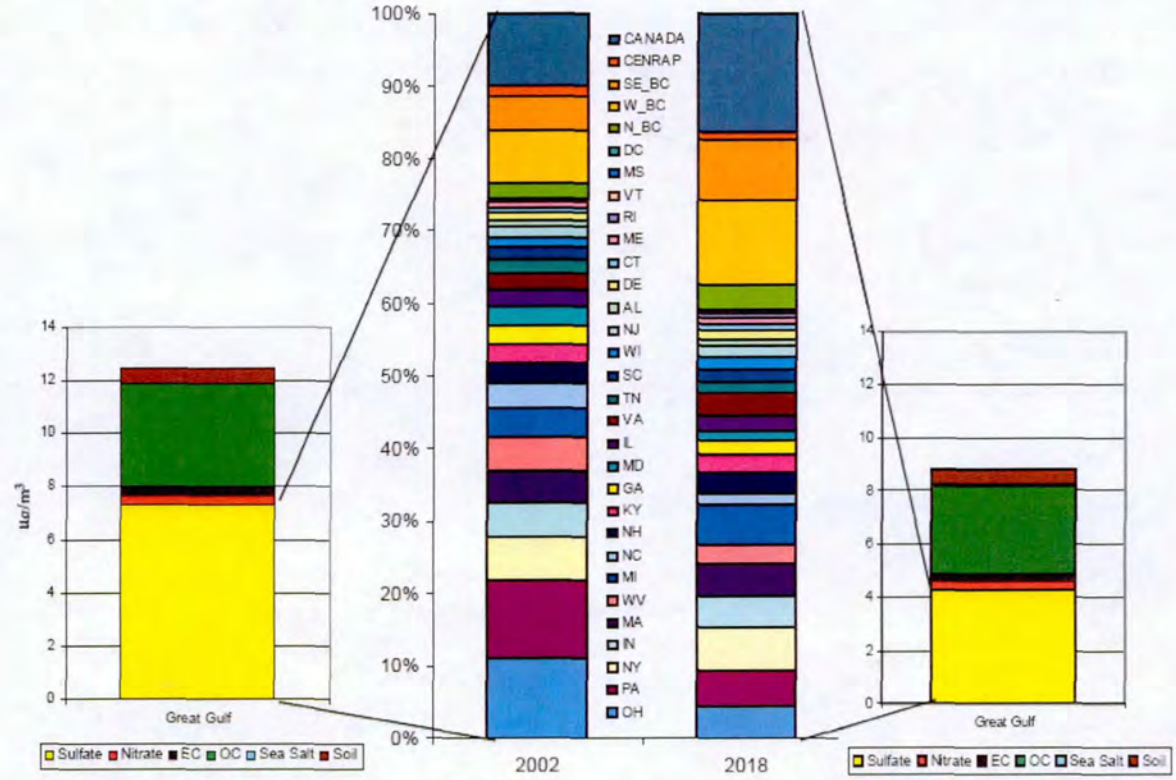
Modeling results indicate that the relative contributions of states within the modeling domain will decrease significantly by 2018 as a result of anticipated SO_2 emission reductions from implementation of existing state programs, applicable portions of the federal Clean Air Interstate Rule (or its replacement, the Transport Rule), and additional state and federal control measures described in following sections of this document. At the same time, there will be large *increases* in the *relative* contributions from Canada and the boundary areas. These predicted increases are not absolute increases in mass but are due simply to the fact that contributions from outside the modeling domain will represent a larger share of the total after the various emission control programs within the U.S. portion of the modeling domain have reduced contributions from within the domain.

It is noteworthy that projected SO_2 reductions from emission sources in New Hampshire are on pace with states originally enrolled in the CAIR program even though New Hampshire was not included in this program. As do many other states, New Hampshire has its own program for reducing SO_2 emissions.

According to the completed MANE-VU modeling, sulfate concentrations at the Great Gulf and Presidential Range - Dry River Wilderness Areas on the 20 percent worst visibility days will decline from 7.3 $\mu g/m^3$ in 2002 (representing the baseline period of 2000-2004) to 4.6 $\mu g/m^3$ in 2018. Included in these values is New Hampshire's own sulfate contribution, which is projected to drop from 0.4 $\mu g/m^3$ in 2002 to 0.3 $\mu g/m^3$ in 2018. Mirroring the results for sulfate, fine particulate matter ($PM_{2.5}$) concentrations from all sources are projected to fall by a similar percentage, from 12.5 $\mu g/m^3$ in 2002 to 9.2 $\mu g/m^3$ in 2018. The modeling that produced these results is described in Section 7, Air Quality Modeling, and in "2018 Visibility Projections," May 13, 2008 (Attachment Q). The emission control programs responsible for the projected visibility improvements are described in Section 11, Long-Term Strategy.

Figure 2.1 shows the magnitude of the 2002 (measured) and 2018 (projected) sulfate concentrations at the Great Gulf and Presidential Range - Dry River Wilderness Areas, as well as the relative mass contributions of each state, on the 20 percent worst visibility days. Similar findings apply to the other Class I areas (graphical figures for these other sites are available in the Contribution Assessment but, for brevity, are not repeated here).

Figure 2.1: Measured and Projected Mass Contributions in 2002 and 2018 at Great Gulf and Presidential Range - Dry River Wilderness Areas on 20 Percent Worst Visibility Days



IMPROVE mass 00-04 **REMSAD Contribution to Sulfate** **CMAQ RRF-Based 2018 Mass**

2.1 Class I Areas Affected by New Hampshire's Emission Sources

Emission sources within New Hampshire have had measurable impacts on visibility at Class I areas both within the state and at downwind locations. The magnitude of these impacts is described in detail in MANE-VU's Contribution Assessment (Attachment B). Table 2.1 briefly lists the affected Class I areas and New Hampshire's percent contribution to total annual sulfate at each area in the 2002 baseline year, as determined from the modeling.

Table 2.1: New Hampshire's Contributions to Total Annual Average Sulfate Impact (Percent, Mass Basis) at Eastern Class I Areas in 2002

Mandatory Class I Area(s)	Percent Contribution
Great Gulf Wilderness* & Presidential Range - Dry River Wilderness*	3.95
Acadia National Park*	2.25
Moosehorn Wilderness* & Roosevelt Campobello International Park*	1.74
Lye Brook Wilderness*	1.68
Brigantine Wilderness*	0.60
Shenandoah National Park	0.08
Dolly Sods Wilderness	0.04

*MANE-VU Class I Area

Interestingly, New Hampshire's own SO_2 emissions account for only about 4 percent of visibility-impairing sulfate in New Hampshire's Class I Areas and approximately 2 percent of visibility-impairing sulfate in the downwind Class I areas of Acadia National Park, Moosehorn Wilderness, Roosevelt Campobello International Park, and Lye Brook Wilderness. Also, New Hampshire's emissions account for less than 1 percent of visibility-impairing sulfate in the more southerly Class I areas of Brigantine Wilderness, Shenandoah National Park, and Dolly Sods Wilderness.

2.2 States Contributing to Visibility Impairment in New Hampshire's Class I Areas

Through participation in the MANE-VU regional haze planning process, New Hampshire has identified the states and Canadian provinces contributing to visibility impairment at New Hampshire's two Class I areas: the Great Gulf Wilderness and the Presidential Range - Dry River Wilderness. Table 2.2 lists the states and regions responsible for visibility degradation at these Class I areas, and the corresponding percentage contributions to total sulfate impact. Taken from MANE-VU's Contribution Assessment, the data provide clear evidence that the large majority of sulfate pollution at New Hampshire's Class I areas originates from sources outside the state and, more significantly, from sources outside the MANE-VU region. Note that "other" sources contribute nearly a quarter of the total sulfate impact. These sources represent all emissions from outside the modeling domain (i.e., boundary conditions, including emissions coming primarily from regions lying west of the Mississippi River).

Table 2.2: Contributions of Individual MANE-VU States and Other Regions to Total Annual Average Sulfate Impact (Percent, Mass Basis) at New Hampshire's Class I Areas in 2002

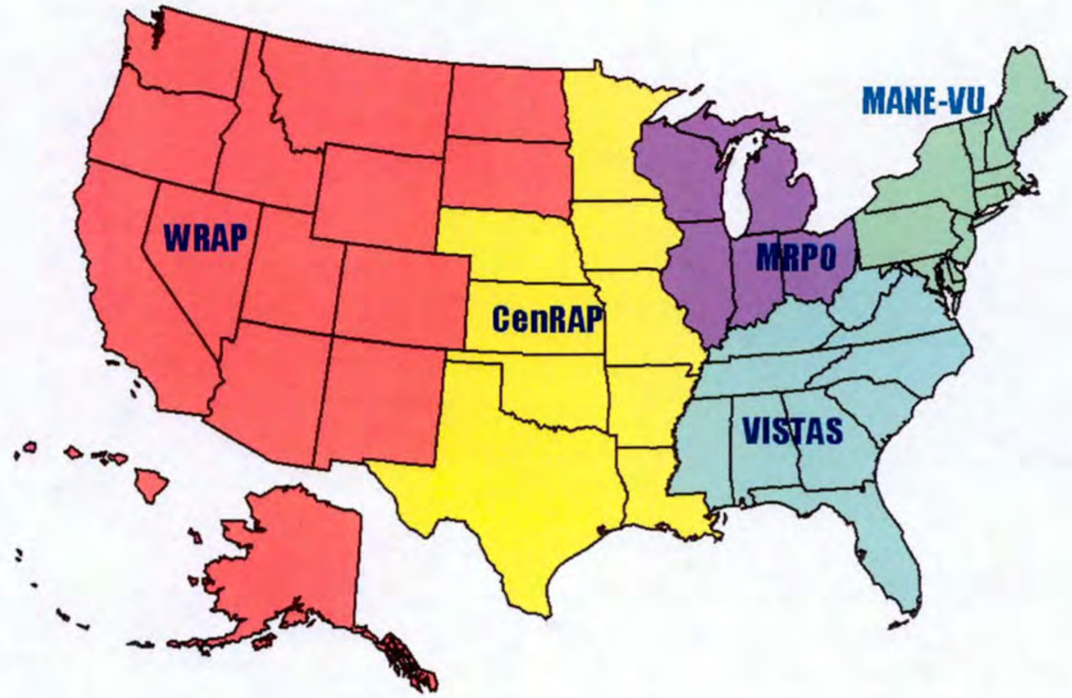
State or Region	Percent Contribution
Pennsylvania	8.30
New York	5.68
New Hampshire	3.95
Massachusetts	3.11
Maine	2.33
Maryland	1.92
New Jersey	0.89
Delaware	0.63
Connecticut	0.48
Vermont	0.41
Rhode Island	0.11
District of Columbia	0.01
MANE-VU	27.83
MRPO	20.10
VISTAS	12.04
CenRAP	1.65
Canada	14.84
Other	23.54

Note: Indicated percent contributions from, VISTAS, CenRAP, and Canada apply only to those portions lying within the modeling domain (see Figure 7.1). Actual contributions, especially from CenRAP, would be higher than stated.

3. REGIONAL PLANNING AND CONSULTATION

In 1999, EPA and affected states/tribes agreed to create five Regional Planning Organizations (RPOs) to facilitate interstate coordination on State Implementation Plans (SIPs) addressing regional haze. The RPOs, and states/tribes within each RPO, are required to consult on emission management strategies toward visibility improvement in affected Class I areas. As shown in the accompanying map (Figure 3.1), the five RPOs are MANE-VU (Mid-Atlantic/Northeast Visibility Union), VISTAS (Visibility Improvement State and Tribal Association of the Southeast), MRPO (Midwest Regional Planning Organization), CenRAP (Central Regional Air Planning Association), and WRAP (Western Regional Air Partnership). New Hampshire is a member of MANE-VU.

Figure 3.1: EPA-Designated Regional Planning Organizations (RPOs).



3.1 Mid-Atlantic / Northeast Visibility Union (MANE-VU)

MANE-VU's work is managed by the Ozone Transport Commission (OTC) and carried out by OTC, the Mid-Atlantic Regional Air Management Association (MARAMA), and the Northeast States for Coordinated Air Use Management (NESCAUM). The states, tribes, and federal agencies comprising MANE-VU are listed in Table 3.1. Individuals from the member states, tribes, and agencies, along with professional staff from OTC, MARAMA, and NESCAUM, make up the various committees and workgroups. MANE-VU also established a Policy Advisory Group (PAG) to provide advice to decision-makers on policy questions. EPA, Federal Land Managers, states, and tribes are represented on the PAG, which meets on an as-needed basis.

Table 3.1: MANE-VU Members

Connecticut	Rhode Island
Delaware	Vermont
Maine	District of Columbia
Maryland	Penobscot Nation
Massachusetts	St. Regis Mohawk Tribe
New Hampshire	U.S. Environmental Protection Agency*
New Jersey	U.S. Fish and Wildlife Service*
New York	U.S. Forest Service*
Pennsylvania	U.S. National Park Service*

*Non-voting member

Since its inception on July 24, 2001, MANE-VU has created an active committee structure to address both technical and non-technical issues related to regional haze. The primary committees are the Technical Support Committee (TSC) and the Communications Committee, While the work of these committees are instrumental to policies and programs, all policy decisions reside with and are made by the MANE-VU Board.

The TSC is charged with assessing the nature and magnitude of the regional haze problem within MANE-VU, interpreting the results of technical work, and reporting on such work to the MANE-VU Board. This committee has evolved to function as a valuable resource on all technical projects and issues for MANE-VU. The TSC has established a process to ensure that important regional-haze-related projects are completed in a timely fashion, and members are kept informed of all MANE-VU tasks and duties. In addition to the formal working committees, there are three standing workgroups of the TSC assigned by topic area: the Emissions Inventory Workgroup, the Modeling Workgroup, and the Monitoring/Data Analysis Workgroup.

The Communications Committee is charged with developing approaches to inform the public about the regional haze problem and making recommendations to the MANE-VU Board to facilitate that goal. This committee oversees the production of MANE-VU's newsletter and outreach tools, both for stakeholders and the public, regarding regional issues affecting MANE-VU's members.

3.2 Regional Consultation and the "Ask"

On May 10, 2006, MANE-VU adopted the Inter-RPO State/Tribal and FLM Consultation Framework (Attachment C). That document set forth the principles presented in Table 3.2. The MANE-VU states and tribes applied these principles to the regional haze consultation and SIP development process. Issues addressed included regional haze baseline assessments, natural background levels, and development of reasonable progress goals – described at length in later sections of this SIP.

Table 3.2: MANE-VU Consultation Principles for Regional Haze Planning

1. All State, Tribal, RPO, and Federal participants are committed to continuing dialogue and information sharing in order to create understanding of the respective concerns and needs of the parties.
2. Continuous documentation of all communications is necessary to develop a record for inclusion in the SIP submittal to EPA.
3. States alone have the authority to undertake specific measures under their SIP. This inter-RPO framework is designed solely to facilitate needed communication, coordination and cooperation among jurisdictions but does not establish binding obligation on the part of participating agencies.
4. There are two areas which require State-to-State and/or State-to-Tribal consultations ("formal" consultations): (i) development of the reasonable progress goal for a Class I area, and (ii) development of long-term strategies. While it is anticipated that the formal consultation will cover the technical components that make up each of these policy decision areas, there may be a need for the RPOs, in coordination with their State and Tribal members, to have informal consultations on these technical considerations.
5. During both the formal and informal inter-RPO consultations, it is anticipated that the States and Tribes will work collectively to facilitate the consultation process through their respective RPOs, when feasible.
6. Technical analyses will be transparent, when possible, and will reflect the most up-to-date information and best scientific methods for the decision needed within the resources available.
7. The State with the Class I area retains the responsibility to establish reasonable progress goals. The RPOs will make reasonable efforts to facilitate the development of a consensus among the State with a Class I area and other States affecting that area. In instances where the State with the Class I area can not agree with such other States that the goal provides for reasonable progress, actions taken to resolve the disagreement must be included in the State's regional haze implementation plan (or plan revisions) submitted to the EPA Administrator as required under 40 CFR §51.308(d)(1)(iv).
8. All States whose emissions are reasonably anticipated to contribute to visibility impairment in a Class I area, must provide the Federal Land Manager ("FLM") agency for that Class I area with an opportunity for consultation, in person, on their regional haze implementation plans. The States/Tribes will pursue the development of a memorandum of understanding to expedite the submission and consideration of the FLMs' comments on the reasonable progress goals and related implementation plans. As required under 40 CFR §51.308(i)(3), the plan or plan revision must include a description of how the State addressed any FLM comments.
9. States/Tribes will consult with the affected FLMs to protect the air resources of the State/Tribe and Class I areas in accordance with the FLM coordination requirements specified in 40 CFR §51.308(i) and other consultation procedures developed by consensus.
10. The consultation process is designed to share information, define and document issues, develop a range of options, solicit feedback on options, develop consensus advice if possible, and facilitate informed decisions by the Class I States.
11. The collaborators, including States, Tribes and affected FLMs, will promptly respond to other RPOs'/States'/Tribes' requests for comments.

The following points offer a snapshot of several important ways in which MANE-VU member states and tribes have cooperatively addressed regional haze:

- *Prioritization*: MANE-VU developed a process to coordinate MARAMA, OTC, and NESCAUM staff in developing budget priorities, project rankings, and the eventual federal grant requests.
- *Issue Coordination*: MANE-VU established a conference call and meeting schedule for each of its committees and workgroups. In addition, its MANE-VU directors regularly discussed pertinent issues.
- *SIP Policy and Planning*: MANE-VU states/tribes collaborated on the development of a regional haze SIP template and the technical aspects of the SIP development process.
- *Capacity Building*: To educate its staff and members, MANE-VU included technical presentations on conference calls and organized workshops with nationally recognized experts. Presentations on data analysis, Best Available Retrofit Technology (BART) applicability, inventory topics, modeling, and control measures were effective education and coordination tools.
- *Routine Operations*: MANE-VU staff at OTC, MARAMA, and NESCAUM established a coordinated approach to budget tracking, project deliverables and due dates, workgroup meetings, inter-RPO consultations, etc.

Both formal and informal consultations within MANE-VU have been ongoing since the organization's establishment in 2001; but the bulk of formal consultation took place in 2007, as outlined in Table 3.3. Further documentation of consultation meetings and calls is included in Attachment D.

Table 3.3: Summary of MANE-VU's Consultations on Regional Haze Planning

MANE-VU Intra-Regional Consultation Meeting, March 1, 2007:

MANE-VU members reviewed the requirements for regional haze plans, preliminary modeling results, the work being done to prepare the MANE-VU report on reasonable progress factors, and control strategy options under review.

MANE-VU Intra-State Consultation Meeting, June 7, 2007:

The MANE-VU Class I states adopted a statement of principles, and all MANE-VU members discussed draft statements concerning reasonable controls within and outside of MANE-VU. Federal Land Managers also attended the meeting, which was open to stakeholders.

MANE-VU Conference Call, June 20, 2007:

The MANE-VU states concluded discussions of statements concerning reasonable controls within and outside MANE-VU and agreed on the statements called the MANE-VU "Ask" (see Part 3.2.2 of this SIP), including a statement concerning controls within MANE-VU, a statement concerning controls outside MANE-VU, and a statement requesting a course of action by the U.S. EPA. Federal Land Managers also participated in the call. Upon approval, all statements as well as the statement of principles adopted on June 7 were posted and publicly available on the MANE-VU website. The MANE-VU Ask was determined to represent New Hampshire's needs for meeting Regional Haze rule requirements and was thus adopted as the New Hampshire Ask.

MANE-VU Class I States' Consultation Open Technical Call, July 19, 2007:

The MANE-VU/New Hampshire Ask was presented to states in other RPOs, RPO staff, and Federal Land Managers; and an opportunity was provided to request further information. This call was intended to provide information to facilitate informed discussion at follow-up meetings.

MANE-VU Consultation Meeting with MRPO, August 6, 2007:

This meeting, held at LADCO offices in Chicago, was attended by representatives of MANE-VU and MRPO states as well as staff. The meeting provided an opportunity to formally present the MANE-VU/ New Hampshire Ask to MRPO states and to consult with them on the reasonableness of the requested controls. Federal Land Manager agencies also attended the meeting.

MANE-VU Consultation Meeting with VISTAS, August 20, 2007:

This meeting, held at State of Georgia offices in Atlanta, was attended by representatives of MANE-VU and VISTAS states. The meeting provided an opportunity to formally present the MANE-VU/New Hampshire Ask to VISTAS states and to consult with them on the reasonableness of the requested controls. Federal Land Manager agencies also attended the meeting.

MANE-VU / MRPO Consultation Conference Call, September 13, 2007:

As a follow-up to the meeting held on August 6 in Chicago, this call provided an opportunity for MANE-VU to clarify further what was being asked of the MRPO states. The flexibility in the Ask was explained. MRPO and MANE-VU staff agreed to work together to facilitate discussion of further controls on ICI boilers and EGUs.

MANE-VU Air Directors' Consultation Conference Call, September 26, 2007:

MANE-VU members clarified their understanding of the Ask and provided direction to modeling staff regarding interpretation of the Ask for purposes of estimating visibility impacts of the requested controls.

3.2.1 New Hampshire-Specific Consultations

40 CFR 51.308(d)(3)(i) of the Regional Haze Rule requires the State of New Hampshire to consult with other states/tribes to develop coordinated emission management strategies. This requirement applies both when emissions from a state/tribe are reasonably anticipated to contribute to visibility impairment in Class I areas outside the state/tribe and when emissions from other states/tribes are reasonably anticipated to contribute to visibility impairment at mandatory Class I areas within a state/tribe.

New Hampshire consulted with other states/tribes by participating in the MANE-VU and inter-RPO processes leading to the creation of coordinated strategies on regional haze. This coordinated effort considered the individual and aggregated impacts of states'/tribes' emissions on Class I areas within and outside the states/tribes.

As described in Section 2, Areas Contributing to Regional Haze, emissions originating in New Hampshire have had, and will continue to have, impacts on other Class I areas in the region. Accordingly, New Hampshire has entered into consultations with the states and provinces in which the affected Class I areas are located (Table 3.4).

Table 3.4: Class I Area States Requesting Consultation with New Hampshire

Class I Federal Area	State / Province
Great Gulf Wilderness	New Hampshire
Presidential Range - Dry River Wilderness	New Hampshire
Acadia National Park	Maine
Moosehorn Wilderness	Maine
Roosevelt Campobello International Park	Maine / New Brunswick
Lye Brook Wilderness	Vermont
Brigantine Wilderness	New Jersey

The listed states represent only a fraction of those with whom New Hampshire has entered into consultations on regional haze. Through the MANE-VU process, more than twenty states and Canadian provinces have been identified as contributing to visibility degradation in New Hampshire's two Class I areas: the Great Gulf Wilderness and the Presidential Range - Dry River Wilderness. On April 2, 2007, NHDES sent letters formally requesting consultation under the Regional Haze Rule to states and Canadian provinces – specifically, those shown via modeling to contribute at least 2 percent of visibility-impairing sulfates at Class I Areas in New Hampshire (refer to Contribution Assessment, Attachment B), and all other states located within MANE-VU.

To maintain consistency within MANE-VU, every MANE-VU member was requested to consult with New Hampshire. Several states outside MANE-VU were also requested to join this consultation in response to the findings of MANE-VU's evaluations. In addition, the Canadian Provinces of Ontario and Quebec were invited to join in informal consultation with New Hampshire, although they are under no legal obligation to meet U.S. requirements. Table 3.5 provides a complete listing of states, provinces, and regional planning organizations invited to participate in consultations with New Hampshire on measures to mitigate regional haze. Note that all MANE-VU states with Class I areas have similarly requested consultation with New Hampshire on the regional haze issue.

Table 3.5: States (Listed by Regional Planning Organization) and Provinces Contributing to Visibility Impairment at New Hampshire's Class I Areas

MANE-VU	VISTAS	MRPO	International
Connecticut	Georgia	Illinois	Ontario, Canada
Delaware	Kentucky	Indiana	Quebec, Canada
District of Columbia	North Carolina	Michigan	
Maine	South Carolina	Ohio	
Maryland	Tennessee		
Massachusetts	Virginia		
New Jersey	West Virginia		
New York			
Pennsylvania			
Rhode Island			
Vermont			

As a result of the invitation to consult, Ontario, Canada, invited representatives of NHDES, Vermont Department of Environmental Conservation (VTDEC), Maine Department of Environmental Protection (MEDEP), New York Department of Environmental Conservation (NYDEC), and NESCAUM to join the Shared Air Summit in Toronto on June 12, 2007, followed by an informal consultation meeting with representatives from Ontario on June 13, 2007. At these meetings, Ontario announced its plan to shut down all coal electrical generation and challenged participating states to pursue similar goals. Considerable discussion took place regarding trans-border air pollution transport and its affect on human health.

Formal inter-regional consultation meetings took place on August 6, 2007, in Rosemont, Illinois, (for Midwestern states) and on August 20, 2007, in Atlanta, Georgia, (for Southern states). Consultation continues with the Midwestern states, seeking common approaches for reducing power plant emissions beyond the levels defined under the original CAIR rule, controls on industrial boilers, and cleaner-burning fuels for mobile sources. Ongoing consultation with MRPO focuses mainly on the health benefits of reducing ozone and small particulate emissions; however, the control measures being considered would also result in visibility improvements.

Throughout the consultation process, New Hampshire was guided by the principals contained in a resolution adopted by the MANE-VU Class I states on June 7, 2007. In the resolution, the Class I states agreed to set reasonable progress goals for 2018 that would provide visibility improvement at least as great as that which would be achieved under a uniform rate of progress to reach natural visibility conditions by 2064. The goals would be set by the Class I states at levels reflecting implementation of measures determined to be reasonable after consultation with the contributing states. At the same time, the Class I states recognized that each state should be given the flexibility to choose other measures that achieve the same or greater benefits.

The final results of New Hampshire's consultation efforts will ultimately rest with the individual states as they develop and implement their own regional haze SIPs. The other MANE-VU states have agreed to incorporate certain control measures into their SIPs, but most of these plans are still under development. For the non-MANE-VU states, New Hampshire has the expectation that the same or equivalent control measures will be included in those states plans. However, some states – particularly those within the VISTAS region –

have already submitted draft SIPs that do not go as far in controlling emissions as MANE-VU would like. See Subpart 3.2.2.3 and Part 3.2.4, below, for further discussion related to the non-MANE-VU states.

3.2.2 The MANE-VU "Ask"

In addition to having a set of guiding principles for consultation (as described in Table 3.2, above), MANE-VU needed a consistent technical basis for emission control strategies to combat regional haze. After much research and analysis, on June 20, 2007, MANE-VU adopted the following pair of documents (available in Attachment E), which provide the technical basis for consultation among the interested parties and define the basic strategies for controlling pollutants that cause visibility impairment at Class I areas in the eastern U.S.:

- "Statement of the Mid-Atlantic / Northeast Visibility Union (MANE-VU) Concerning a Course of Action within MANE-VU toward Assuring Reasonable Progress," and
- "Statement of the Mid-Atlantic / Northeast Visibility Union (MANE-VU) Concerning a Request for a Course of Action by States outside of MANE-VU toward Assuring Reasonable Progress."

Together, these documents are known as the MANE-VU "**Ask**." Because New Hampshire agrees in total to the language and substance of these documents, the **MANE-VU's Ask is also the New Hampshire Ask**. The particular emission management strategies that comprise the Ask are described in Subparts 3.2.2.1 through 3.2.2.3, below.

3.2.2.1 Meeting the "Ask" – MANE-VU States

The member states of MANE-VU have stated their intention to meet the terms of the Ask in their individual State Implementation Plans. The Ask for member states promises that each state will pursue the adoption and implementation of the following emission management strategies, as appropriate and necessary:

- ***Timely implementation of BART requirements***, in accordance with 40 CFR 51.308(e).
- ***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 reduce the sulfur content of distillate oil further 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 reduce the sulfur content of distillate oil further to 15 ppm by 2018, depending on supply availability;
- ***A targeted EGU strategy*** for the top 100 electric generating unit (EGU) emission points, or stacks, identified by MANE-VU as contributing to visibility impairment at each mandatory Class I area in the MANE-VU region. (The combined list for all

seven MANE-VU Class I Areas contains 167 distinct emission points. Consequently, this strategy is sometimes referred to as the 167-stack strategy.) The targeted EGU strategy calls for a 90-percent or greater reduction in sulfur dioxide (SO_2) emissions from all identified units. If it is infeasible to achieve that level of reduction from these specific units, equivalent alternative measures will be investigated in such state; and

- ***Continued evaluation of other control measures***, including improvements in energy efficiency, use of alternative (clean) fuels, further control 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 combustion. These and other measures will be evaluated during the consultation process to determine whether they are reasonable strategies to pursue.

⇨ **NHDES supports the SIPs of each of its fellow MANE-VU states, provided that these commitments are incorporated into approvable State Implementation Plans.**

3.2.2.2 Meeting the "Ask" – New Hampshire

New Hampshire, being a MANE-VU member state, adopted the Ask at the MANE-VU Board meeting on June 7, 2007. New Hampshire intends to meet the terms of this agreement by controlling its two in-state BART-eligible sources with timely control strategies as well as pursuing the low-sulfur fuel oil strategy. Both BART-eligible sources also fall on the list of the top 167 contributing EGU emission points.

The larger of these facilities (Merrimack Station Unit MK2) will be controlled with scrubber technology by July 1, 2013 to comply with New Hampshire law. The other facility, a smaller, oil-fired unit (Newington Station Unit NT1), will control fuel sulfur levels under BART requirements to reduce SO_2 emissions. NHDES has determined that controlling the latter facility to the 90-percent level of the Ask is not reasonable at this time and will seek alternative measures to achieve the equivalent overall reduction in SO_2 emissions. The facility has low utilization (about 5 percent in 2007), making it cost-ineffective to retrofit with scrubber technology. NHDES anticipates that controls installed at Merrimack Station, the largest SO_2 source within the state, will result in reductions greater than the 90 percent specified under the Ask, thereby offsetting, at least partially, the expected lesser control level at the oil-fired unit. Additional reductions in SO_2 emissions are planned through the use of lower-sulfur fuels across a variety of source categories, including industrial, commercial, and institutional (ICI) boilers and home heating units. For more details, refer to Section 11, Long-Term Strategy.

3.2.2.3 Meeting the "Ask" – States outside MANE-VU

New Hampshire agrees with the MANE-VU Ask for consulting states outside the MANE-VU region. This Ask requests the affected states to pursue adoption and implementation of the following control strategies, as appropriate and necessary:

- ***Timely implementation of BART requirements***, as described for the MANE-VU states;
- ***A targeted EGU strategy***, as described for the MANE-VU states, for the top 167 EGU stacks contributing the most to visibility impairment at mandatory Class I areas in the MANE-VU region, or an equivalent SO_2 emission reduction within each state;
- ***Installation of reasonable control measures on non-EGU sources*** by 2018 to achieve

an additional 28 percent reduction in non-EGU SO_2 emissions beyond current on-the-books/on-the-way (OTB/OTW) measures, resulting in an emission reduction that is equivalent to that from MANE-VU's low-sulfur fuel oil strategy (see Section 11, Long-Term Strategy);

- ***Continued evaluation of other control measures***, including additional reductions in SO_2 and NO_X emissions from all coal-burning facilities by 2018 and promulgation of new source performance standards for wood combustion. These and other measures will be evaluated during the consultation process to determine whether they are reasonable strategies to pursue.

⇨ **NHDES looks for each consulting state to address specifically, in its Regional Haze SIP, each element of the MANE-VU Ask.**

NHDES is concerned that non-MANE-VU states may be inclined not to adopt MANE-VU's Ask because of the associated costs, potential conflicts, and relative lack of perceived benefits within their jurisdictions. On the basis of consultations held, MANE-VU members believe that some non-MANE-VU states will choose not to pursue reductions beyond basic post-CAIR controls and BART requirements. New Hampshire understands that, among non-MANE-VU states that have already submitted their regional haze SIPs to EPA, a number of the affected states have decided not to address major elements of the MANE-VU Ask in their plans.

There are some positive developments, however. Many states of the MRPO are working with MANE-VU states to investigate the potential for widespread use of low-sulfur fuel oil and installation of emission controls on ICI boilers within their regions. The Midwest states would be more likely than Southeast states to adopt a low-sulfur oil strategy because the VISTAS states do not have the same extent of fuel oil usage and lack the inventory infrastructure found in more northerly states. Both MRPO and VISTAS claim that a substantial portion of the top 167 contributing EGU stacks will be controlled. However, instead of taking concrete actions on uncontrolled or under-controlled facilities, many of these states appear to be satisfied with meeting minimal requirements and are not looking for additional emission reductions. Further discussion of these issues is provided in Part 3.2.4, below.

3.2.3 Technical Ramifications of Differing Approaches

MANE-VU states intended to develop a modeling platform that was common in terms of meteorology and emissions with each of the other nearby RPOs. The RPOs worked hard to form a common set of emissions with similar developmental assumptions. Even with the best of intentions, it became difficult to keep up with each RPO's updates and corrections. Each rendition of emissions inventory improved its quality, but even a single update to one RPO's emissions required each of the other RPOs to adopt the updates. With each rendition, the revised emissions had to be re-blended with the full set of emission files for all associated RPOs in the modeling domain. Because each rendition put previous modeling efforts out of date, and a single modeling run could take more than a month to complete, inventory updates have contributed to SIP delays. The emission inventory conflicts have been excessively time-consuming and caused most states to miss the official filing date of December 17, 2007.

The RPOs also took differing perspectives on which version of the EGU dispatching model to use. At the beginning of the process, International's Integrated Planning Model (IPM®) version 2.1.9 was available, and EPA agreed to its use for emissions preparation. Subsequently, IPM version 3.0 became available and was preferred by some users because of its updated fuel costs. MRPO adopted IPM v3.0 for its use, but VISTAS stayed with IPM v2.1.9. Rather than develop non-comparative datasets for its previous IPM analyses, MANE-VU opted also to remain with IPM v2.1.9. Therefore, for the three eastern RPOs, differing emissions assumptions eventually worked their way into the final set of modeling assumptions.

MANE-VU's most recent visibility projections take into account on-the-books/on-the-way (OTB/OTW) emissions control programs for 2018, and go further by including additional reasonable controls in the region, as developed through the MANE-VU Ask. It should be noted that other RPOs may not have included such measures in their final modeling and, as a result, may have been able to complete their analyses ahead of New Hampshire's. Where that is the case, those states' modeling results will be inconsistent with meeting the terms of the Ask – a situation that may not be adequately addressed in their individual SIPs.

3.2.4 Consultation Issues

40 CFR 51.308(d)(1)(iv) of the Regional Haze Rule describes another consultation requirement for Class I states. If a contributing state does not agree with a Class I state on its reasonable progress goal, the Class I state must describe in its SIP submittal the actions taken to resolve the disagreement.

While states without Class I areas are required to consult at the request of states with Class I areas, the Regional Haze Rule does not actually require the states to agree on a common course of action. Instead, if agreement cannot be reached, the disagreement needs to be described in each state's SIP along with a description of what actions were taken to resolve the disagreement. Most states willingly consulted with NHDES and took New Hampshire's regional haze Ask under serious consideration. In fact, all of the MANE-VU states worked together to strategize on how to develop a common approach to meeting the Ask. All states involved in these discussions found that working together helped them to develop plans that would produce region-wide visibility and health benefits. In particular, reductions in SO_2 emissions, because they would yield lower ambient concentrations of fine particle ($PM_{2.5}$) pollution, would help all MANE-VU states in meeting the NAAQS and would have direct benefits to public health and welfare.

A few non-MANE-VU states did not respond to New Hampshire's consultation requests or responded by downplaying the magnitude of their states' contributions to visibility impairment at New Hampshire's Class I areas. Some states claimed that CAIR alone set the standard for reasonableness. By this rationale, any measure more expensive than CAIR on a cost-per-ton basis would not be reasonable. A uniform rate of progress was all that some states felt was required; and if that set of conditions could be met with CAIR (or its successor), then no other measures needed to be considered. Also a concern for New Hampshire is the possibility that some states may have performed modeling for establishment of reasonable progress goals without including the effects of a rigorous BART determination for the non-EGU sector. It is apparent that the various regions of the country have differing interpretations of how the Regional Haze Rule should be applied.

In a letter to MANE-VU dated April 25, 2008 (Attachment F), VISTAS indicated that for its member states, most actions exceeding CAIR requirements would not be reasonable. MANE-VU has taken a more rigorous position with respect to additional control measures – including the belief that controls on ICI boilers and use of low-sulfur fuels are reasonable measures *and* that it is not reasonable to assume reductions from EGUs for planning purposes unless they are explicitly incorporated into a State Implementation Plan. More specifically, MANE-VU believes that a sector-wide average of 50-percent control on coal-fired boilers and 75-percent control on oil-fired boilers are reasonable targets that can be achieved cost-effectively. Also, MANE-VU believes that low sulfur fuels – even though they are less widely available in the Southeast U.S. than in the Northeast – still represent a reasonable control measure in light of the widespread requirement for use of such fuels throughout the MANE-VU region. The reasonableness of these additional controls is examined more fully in Section 10, Reasonable Progress Goals.

During the consultation process, disagreements such as these were worked through to the maximum extent possible, and the results of these consultations are summarized below:

- *Situation*: BART analyses and projected controls were not fully incorporated into the VISTAS emissions inventory provided to MANE-VU. VISTAS stated that they would further review BART-applicable controls.

  → *Outcome*: In MANE-VU's modeling to determine reasonable progress goals, MANE-VU made no adjustments to controls in the VISTAS region to reflect application of BART beyond the information that VISTAS provided.

- *Situation*: The low-sulfur fuel oil strategy adopted by MANE-VU elicited concerns from MRPO and VISTAS as not being reasonable because of the limited availability of low-sulfur fuel oil and the historically lower usage of this fuel within their regions.

  → *Outcome*: MANE-VU agreed to modify the Ask to reflect greater flexibility in providing for alternative measures that would produce a comparable rate of emission reductions. Accordingly, the Ask for non-MANE-VU states was modified to provide for an overall 28 percent reduction in SO_2 emissions wherever they were found to be reasonable. In MANE-VU's modeling to determine reasonable progress goals, SO_2 emissions from non-EGU sources in non-MANE-VU contributing states were reduced by this same amount.

- *Situation*: MANE-VU received no response from other RPOs concerning non-EGU control measures that they did consider reasonable.

  → O*utcome*: As a default position, MANE-VU's modeling included emission adjustments for those regions based on MANE-VU's own analyses of what constituted reasonable control measures from non-EGU sources (see Section 10 , Reasonable Progress Goals).

- *Situation*: The targeted EGU strategy was thought by some non-MANE-VU states to be too restrictive and too difficult to achieve. MANE-VU recognized that a 100-percent compliance with this portion of the Ask was unlikely to occur because the CAIR trading market would probably dominate. However, MANE-VU had hoped that non-MANE-VU states would make a more concerted effort toward meeting this request. MANE-VU did receive a partial list of facilities that were expected to comply.

→ *Outcome*: For the top contributing EGU stacks located within the MANE-VU, MRPO, and VISTAS regions, expected emission reductions resulting from the Ask were distributed among facilities on the basis of recommendations received during inter- and intra-regional consultations. To maintain the CAIR emissions budget as predicted by the modeling, excess emission reductions (also predicted by the modeling) were uniformly added back to EGUs in all three regions.

While the original CAIR rule would have been the primary determinant of which EGUs among the top 167 stacks are to be fitted with emission controls, at the same time, MANE-VU recognized that these units are the primary sources affecting visibility in the MANE-VU states. For the initial planning, MANE-VU has allowed flexibility as to how other RPOs meet the Ask. However, MANE-VU expects that, over time, these actual facilities will need to be controlled if significant improvements in visibility at affected Class I areas are to be realized.

MANE-VU believes that the goals of the Ask will be attained only by means of binding obligations to EGU emission reductions beyond the levels of control that CAIR originally would have provided. MANE-VU therefore maintains that additional federal action is needed to achieve the visibility benefits shown to be feasible through sensitivity modeling (see Attachment G, "MANE-VU Modeling for Reasonable Progress Goals: Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008) and demonstrated to be available at reasonable cost (see Attachment H, Alpine Geophysics, LLC, "Documentation of 2018 Emissions from Electric Generating Units in the Eastern United States for MANE-VU's Regional Haze Modeling," Final Report, August 16, 2009).

MANE-VU's position on this issue is formally expressed in its "Statement of the Mid-Atlantic / Northeast Visibility Union (MANE-VU) Concerning a Request for a Course of Action by the U.S. Environmental Protection Agency (EPA) toward Assuring Reasonable Progress," adopted June 20, 2007. This statement, more commonly known as MANE-VU's National Ask, is included in Attachment E.

Although other RPOs did not adopt all of the same philosophies or processes for their regional haze SIPs, the consultation process maintains a central role in regional haze planning. New Hampshire is pleased with the significant opportunities identified for ongoing consultation with other states concerning long-term strategies not only for regional haze mitigation but also for improved air quality in general.

3.2.5 State/Tribe and Federal Land Manager Coordination

New Hampshire will continue to coordinate and consult with the Federal Land Managers during the development of future progress reports and plan revisions, as well as during the implementation of programs having the potential to contribute to visibility impairment in the mandatory Class I areas.

40 CFR 51.308(i) of the Regional Haze Rule requires coordination between states/tribes and the Federal Land Managers (FLMs). Opportunities have been provided by MANE-VU for FLMs to review and comment on each of the technical documents developed by MANE-VU and included in this SIP. New Hampshire has identified agency contacts to the FLMs as required under 40 CFR 51.308(i)(1). New Hampshire has consulted with the FLMs in the development of this plan and, in accordance with 40 CFR 51.308(i)(2), has provided the

FLMs an opportunity for consultation, in person, at least 60 days prior to holding any public hearing on the SIP. The draft SIP was submitted to the FLMs on August 1, 2008, for review and comment.

Pursuant to 40 CFR 51.308(i)(3), New Hampshire has requested and received comments on the regional haze SIP from the Federal Land Managers. NHDES received preliminary comments from the U.S. Department of the Interior (DOI), National Park Service (NPS) and U.S. Fish and Wildlife Service (FWS) on August 27, 2008, and from the U.S. Department of Agriculture, U.S. Forest Service (USFS) on August 28, 2008. Formal comments from DOI -NPS and FWS on the SIP were received in a letter dated September 26, 2008. Conference calls to discuss the agencies' comments took place on August 28 and September 18, 2008, with representatives from NPS, USFS, USFWS, EPA, and NHDES in attendance. Following these consultations, NHDES revised the draft implementation plan to address the agencies' comments. A public hearing on the draft final SIP was held at NHDES headquarters on Wednesday, June 24, 2009. The U.S. Department of the Interior, National Park Service provided final written comments during the public comment period, which ended on June 26, 2009. Subsequently, in a letter dated December 20, 2010, DOI-NPS provided additional written comments coincident with a second public hearing on the Regional Haze SIP revision. Those comments have been duly considered and addressed in the completion of the SIP.

A compilation of comments received, responses by NHDES, and summaries of conference calls is presented in Attachment I of this plan. All of these documents were made available for public review during the public comment period. (Note: The MANE-VU states also received comments from other stakeholders during the planning process; their comments can be found in Attachment J.)

The comments submitted by the FLMs were both general and specific. The reviewing agencies found New Hampshire's Regional Haze SIP to be well written and comprehensive. The uncertainty surrounding the future of CAIR and discrepancies in modeling (especially inclusion of the MANE-VU Ask) between MANE-VU and other RPOs were identified as broad topics for further discussion through the consultation process. Comments of a specific nature were relatively minor for the most part. The agencies requested that NHDES provide additional information in support of New Hampshire's BART analyses. NHDES's responses to the agencies' comments are addressed point-by-point in the response document contained in Attachment I.

40 CFR 51.308(i)(4) requires procedures for continuing consultation between the states/tribes and FLMs on the implementation of the visibility protection program. In particular, New Hampshire will consult with the designated visibility protection program coordinators for the National Park Service, U. S. Fish and Wildlife Service, and U.S. Forest Service, periodically and as circumstances require, on the following implementation items:

1. Status of emissions strategies identified in the SIP as contributing to improvements in the worst-day visibility;
2. Summary of major new source permits issued;
3. Status of New Hampshire's actions toward completing any future assessments or rulemakings on sources identified as probable contributors to visibility impairment, but not directly addressed in the most recent SIP revision;

4. Any changes to the monitoring strategy or status of monitoring stations that might affect tracking of reasonable progress;
5. Work underway for preparing the 5-year SIP review and/or 10-year SIP revision, including any items where the FLMs' consideration or support is requested; and
6. Summary of topics discussed in ongoing communications (e.g., meetings, emails, etc.) between New Hampshire and the FLMs regarding implementation of the visibility improvement program.

3.2.6 EPA Consultation and Review

New Hampshire has consulted with EPA on many occasions in the course of regional haze modeling and plan development, and EPA has provided specific input regarding completion of the SIP. On July 10, 2008, NHDES received written comments from EPA on an early SIP draft that was submitted to the agency for preliminary review. On October 24, 2008, NHDES received additional written comments from EPA on a modified version that was identical to the draft SIP reviewed by the FLMs. Following the public hearing, in a letter dated June 26, 2009, EPA provided formal comments on the draft final SIP. In conjunction with subsequent further revisions to the Regional Haze SIP, EPA made additional comments on February 25, 2010, November 22, 2010, and December 20, 2010.

New Hampshire has addressed EPA's comments by making appropriate amendments to the SIP, all of which are incorporated into the present document. EPA's specific comments and NHDES's responses are included in Attachment I.

4. ASSESSMENT OF BASELINE AND NATURAL VISIBILITY CONDITIONS

Pursuant to 40 CFR 51.308(d)(2) of the Regional Haze Rule, states must determine baseline and natural visibility conditions for each Class I area within their jurisdictions. This information allows states to assess current levels of visibility degradation and provides a basis for setting reasonable progress goals toward restoration of natural visibility conditions in Class I areas.

The effectiveness of any plan to reduce regional haze in Class I areas is dependent on the availability of reliable data. The Interagency Monitoring of Protected Visual Environments (IMPROVE) program was established in 1985 to provide the data necessary to support the creation of Federal and State implementation plans for the protection of visibility in Class I areas. IMPROVE has made it possible to assess current visibility conditions, track changes in visibility, and identify the chemical species and emission sources responsible for visibility impairment. In particular, IMPROVE data were used to calculate baseline and natural conditions for MANE-VU Class I Areas.

The IMPROVE monitors listed in Table 4.1 provide data representative of Class I Areas in the MANE-VU region.

Table 4.1: IMPROVE Monitors for MANE-VU Class I Areas

IMPROVE Site / Location	Class I Area(s) Served	Latitude, Longitude	State
ACAD1 Acadia National Park	Acadia National Park	44.38, -68.26	Maine
MOOS1 Moosehorn Wilderness	Moosehorn Wilderness; Roosevelt Campobello International Park	45.13, -67.27	Maine
GRGU1 Great Gulf Wilderness	Great Gulf Wilderness; Presidential Range - Dry River Wilderness	44.31, -71.22	New Hampshire
LYBR1 Lye Brook Wilderness	Lye Brook Wilderness	43.15, -73.13	Vermont
BRIG1 Brigantine National Wildlife Refuge	Brigantine National Wildlife Refuge	39.47, -74.45	New Jersey

http://www.vista.circa.colostate.edu/views/; http://vista.cira.colostate.edu/improve/

4.1 Calculation Methodology

In September 2003, EPA issued guidance for the calculation of natural background and baseline visibility conditions. The guidance provided a default method and described certain refinements that states might consider in order to tailor their estimates to any Class I areas not adequately represented by the default method. At that time, MANE-VU calculated natural visibility for each of the MANE-VU Class I Areas using the default method for the 20 percent best and 20 percent worst visibility days. MANE-VU also evaluated ways to refine the estimates. Potential refinements included 1) increasing the multiplier used to calculate impairment attributed to carbon, 2) adjusting the formula used to calculate the 20 percent best and worst visibility days, and 3) accounting for visibility impairment caused by sea salt at coastal sites. However, MANE-VU found that these refinements did not significantly improve the accuracy of the estimates, and MANE-VU states desired a consistent approach to visibility assessment. Therefore, default estimates were used with the understanding that this methodology would be reconsidered upon demonstrated improvements in the science.

Once the technical analysis of visibility conditions was complete, MANE-VU provided an opportunity to comment to federal agencies and stakeholders. The proposed approach to visibility assessment was posted on the MANE-VU website on March 17, 2004, and a stakeholder briefing was held on the same day. Comments were received from the Electric Power Research Institute (EPRI), the Midwest Ozone Group (MOG), the Appalachian Mountain Club, the National Parks Conservation Association, the National Park Service, and the US Forest Service.

Several comments supported the proposed approach in general; other comments were divided among four main topics: 1) the equation used to calculate visibility, 2) the statistical technique used to estimate the 20 percent best and worst visibility days, 3) the inclusion of transboundary effects and fires, and 4) the timing as to when new information should be included. All comments were reviewed and summarized by MANE-VU; and air directors were briefed on comments, proposed response options, and implications. Attachment J provides a compilation of comments received and a summary of stakeholders' comments.

MANE-VU's position on natural background conditions was presented in a report issued in June 2004 (see Attachment K, "Natural Background Visibility Conditions: Considerations and Proposed Approach to the Calculation of Natural Background Visibility Conditions at MANE-VU Class I Areas," June 10, 2004). The report stated, "Refinements to other aspects of the default method (e.g., refinements to the assumed distribution or treatment of Rayleigh extinction, inclusion of sea salt, and improved assumptions about the chemical composition of the organic fraction) may be warranted prior to submission of SIPs depending on the degree to which scientific consensus is formed around a specific approach…"

In 2006, the IMPROVE Steering Committee adopted an alternative reconstructed extinction equation to revise certain aspects of the default method. The scientific basis for these revisions was well understood, and the Committee determined that the revisions improved the performance of the equation at reproducing observed visibility at Class I sites.

In 2006, MANE-VU conducted an assessment of the default and alternative approaches for calculation of baseline and natural background conditions at MANE-VU Class I Areas. Based on that assessment, in December 2006, MANE-VU recommended adoption of the alternative reconstructed extinction equation for use in the regional haze SIPs. (See Attachment L, "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," December 2006.) MANE-VU will continue to participate in further research efforts on this topic and will reconsider the calculation methodology as scientific understanding evolves.

4.2 MANE-VU Baseline Visibility

The IMPROVE program has calculated the 20 percent best and 20 percent worst baseline (2000-2004) and natural visibility conditions using the EPA-approved alternative method described above for each MANE-VU Class I Area. The data are posted on the Visibility Information Exchange Web System (VIEWS) operated by the regional planning organizations. The information can be accessed at http://vista.cira.colostate.edu/views/) and is summarized in Table 4.2 below. Displayed are the five-year average baseline visibility values for the period 2000-2004, natural visibility levels, and the difference between baseline and natural visibility values for each of the MANE-VU Class I Areas. The difference columns (best and worst) are of particular interest because they describe the magnitude of visibility impairment attributable to manmade emissions, which are the focus of the Regional Haze Rule.

The five-year averages for 20 percent best and worst visibility were calculated in accordance with 40 CFR 51.308(d)(2), as detailed in NESCAUM's Baseline and Natural Background document found in Attachment L.

Table 4.2: Summary of Baseline Visibility and Natural Visibility Conditions for the 20 Percent Best and 20 Percent Worst Visibility Days at MANE-VU Class I Areas

Class I Area(s)	2000-2004 Baseline (deciviews)		Natural Conditions (deciviews)		Difference (deciviews)	
	Best 20%	Worst 20%	Best 20%	Worst 20%	Best 20%	Worst 20%
Acadia National Park	8.8	22.9	4.7	12.4	4.1	10.5
Moosehorn Wilderness and Roosevelt Campobello International Park	9.2	21.7	5.0	12.0	4.1	9.7
Great Gulf Wilderness and Presidential Range - Dry River Wilderness [10]	7.7	22.8	3.7	12.0	3.9	10.8
Lye Brook Wilderness	6.4	24.5	2.8	11.7	3.6	12.7
Brigantine Wilderness	14.3	29.0	5.5	12.2	8.8	16.8

Source: VIEWS (http://vista.circa.colostate.edu/views/), prepared on 6/22/2007

4.3 New Hampshire Class I Areas – Baseline Visibility

As indicated in the table above, the 2001-2004 baseline visibility for the Great Gulf and Presidential Range - Dry River Wilderness Class I areas was 7.7 deciviews for the 20 percent best visibility days and 22.8 deciviews for the 20 percent worst visibility days. These are average values based on data collected at the Great Gulf (GRGU1) IMPROVE monitoring site. As described in Section 5, Monitoring Strategy of this SIP, New Hampshire accepts designation of this monitoring site as representative of the Great Gulf and Presidential Range - Dry River Wilderness Areas in accordance with 40 CFR 51.308(d)(2)(i). (The two wilderness areas are close enough together that a single monitor suffices.)

Tables 4.3 lists the baseline visibility for the 20 percent best and 20 percent worst visibility days for each year of the period 2000-2004, from which the valid four-year average values in Table 4.2 were calculated. The averages were determined in accordance with 40 CFR 51.308(d)(2), as detailed in the NESCAUM Baseline and Natural Background document found in Attachment L of this SIP. The deciview visibility values for best and worst days were obtained from data included in Attachment L.

[10] Deciview values based on 4-year average for 2001-2004 (data collection in 2000 was for summer only).

Table 4.3: Baseline Visibility for the 20 Percent Best Days and 20 Percent Worst Days During 2000-2004 in New Hampshire Class I Areas

Class I Area(s)	Year	Baseline Visibility (deciviews)		Note
		20% Best	20% Worst	
Great Gulf Wilderness and Presidential Range - Dry River Wilderness	2000	7.4	20.0	11
	2001	8.3	23.3	
	2002	7.8	24.8	
	2003	6.9	21.6	
	2004	7.7	21.6	
	Average	7.7	22.8	12

Source: VIEWS (http://vista.circa.colostate.edu/views)

4.4 New Hampshire Class I Areas – Natural Background

Natural background refers to the visibility conditions that existed before human activities affected air quality in the region. Consistent with the stated visibility goals of the Clean Air Act, natural background is identified as the visibility target to be reached by 2064 in each Class I area.

The Great Gulf and Presidential Range - Dry River Wilderness Class I areas have an estimated natural background visibility of 3.7 deciviews on the 20 percent best days and 12.0 deciviews on the 20 percent worst days. These best and worst 20 percent visibility values were calculated using the above-referenced EPA guidelines and approved alternative method described in NESCAUM's Baseline and Natural Background document (Attachment L).

[11] Approximate values, based on summer-only observations.

[12] Based on 4 valid years, 2001-2004

5. AIR MONITORING STRATEGY

In the mid-1980's, the Interagency Monitoring of Protected Visual Environments (IMPROVE) program was established to measure visibility impairment in mandatory Class I areas throughout the United States. The monitoring sites are operated and maintained through a formal cooperative relationship between the U.S. EPA, National Park Service, U.S. Fish and Wildlife Service, Bureau of Land Management, and U.S. Forest Service. In 1991, several additional organizations joined the effort: State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials (which have since merged under the name National Association of Clean Air Agencies), Western States Air Resources Council, Mid-Atlantic Regional Air Management Association, and Northeast States for Coordinated Air Use Management.

5.1 IMPROVE Program Objectives

The IMPROVE program provides scientific documentation of the visual air quality of America's wilderness areas and national parks. Many individuals and organizations – land managers; industry planners; scientists, including university researchers; public interest groups; and air quality regulators – use the data collected at IMPROVE sites to understand and protect the visual air quality resource in Class I areas. Major objectives of the IMPROVE program include the following:

- Establish current visibility and aerosol conditions in mandatory Class I areas;
- Identify chemical species and emission sources responsible for existing anthropogenic visibility impairment;
- Document long-term trends for assessing progress towards the national visibility goals;
- Provide regional haze monitoring for all visibility-protected federal Class I areas where practical, as required by EPA's Regional Haze Rule.

5.2 Monitoring Requirements

EPA's Regional Haze Rule establishes air monitoring requirements that affected states must meet to assess visibility impairment caused by regional haze in Class I areas. The following describes how New Hampshire is complying with specific sections of the rule:

- 40 CFR 51.308(d)(4) requires a monitoring strategy for measuring, characterizing, and reporting regional haze / visibility impairment that is representative of all mandatory Class I areas. (Note that this monitoring strategy must be coordinated with the additional requirements of 40 CFR 51.305, which is not applicable to New Hampshire.) New Hampshire's monitoring strategy relies on participation in the IMPROVE network and Visibility Information Exchange Web System (VIEWS). NHDES will evaluate the monitoring network periodically and make appropriate adjustments to it as necessary, consistent with the IMPROVE program objectives stated above. However, New Hampshire's commitment to following this strategy and providing continuing assessments of progress toward national visibility goals at mandatory Class I Areas will remain contingent on sufficient federal funding in support of monitoring program requirements and associated databases. In the event that existing funding sources are eliminated or curtailed, New Hampshire will consult with the FLMs on the most practicable course of action.

- 40 CFR 51.308(d)(4)(i) requires states to establish additional monitoring sites or equipment as needed to assess whether reasonable progress goals are being achieved toward visibility improvement at mandatory Class I areas. At this time, the current monitors are sufficient to make this assessment. New Hampshire's commitment to maintain the current level of monitoring, and to expand monitoring or analysis should such action become necessary, will remain contingent on federal funding assistance.

- 40 CFR 51.308(d)(4)(ii) requires each affected state to include procedures by which monitoring data and other information are used to determine the state's contribution of emissions to visibility impairment at mandatory Class I areas both within and outside the state. New Hampshire's estimated contributions are summarized in Subsection 2.1 of this SIP and are documented in a detailed technical analysis prepared by NESCAUM entitled, "Contributions to Regional Haze in the Northeast and Mid-Atlantic United States," August 2006 (Attachment B). The NESCAUM study used various tools and techniques to assess the contributions of individual states and regions to visibility degradation in Class I areas within and outside MANE-VU.

- 40 CFR 51.308(d)(4)(iv) requires a state to submit visibility monitoring data annually for each Class I area and, if possible, to provide the data in electronic format. The Federal Land Manager submits the data, and the data are posted on the VIEWS website.

- 40 CFR 51.308(d)(4)(v) requires a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in mandatory Class I areas within New Hampshire. Section 6, Emissions Inventory, addresses this requirement.

- 40 CFR 51.308(d)(4)(vi) requires that SIPs provide other elements, including reporting, recordkeeping, and other measures necessary to assess and report on visibility. While NHDES believes the current IMPROVE network is sufficient to adequately measure and report progress toward the regional haze goals set for New Hampshire's and other Class I areas, NHDES in the past has found additional monitoring information to be useful in assessing patterns of regional visibility and fine particle pollution. Examples of these data sources include:
  - The MANE-VU RAIN network, which provides continuous, speciated information on rural aerosol characteristics and visibility parameters;
  - The EPA CASTNET program, which has provided complementary rural fine particle speciation data at non-Class I sites;
  - The EPA Speciation Trends Network (STN), which provides speciated, urban fine particle data to help develop a comprehensive picture of local and regional sources;
  - State-operated rural and urban speciation sites using IMPROVE or Speciation Trends Network (STN) methods (the latter program comprising 54 monitoring stations located mainly in or near larger metropolitan areas); and
  - The Supersites program, which has undertaken special studies to expand knowledge of the processes that control fine particle formation and transport in the region.

Assuming that these resources will continue to be available and that fiscal realities will allow, New Hampshire will continue using these and other data sources for the purposes of understanding visibility impairment and documenting progress toward national visibility goals for Class I areas under the Regional Haze Rule.

5.3 Monitoring Sites for MANE-VU Class I Areas

IMPROVE monitoring sites have been established for each of the Class I areas in the region. The Great Gulf Wilderness and Presidential Range - Dry River Wilderness share a single monitoring site. Each of the other MANE-VU Class I Areas has its own monitoring site.

5.3.1 Acadia National Park, Maine

The IMPROVE monitor for Acadia National Park (ACAD1) is located at park headquarters, near Bar Harbor, Maine, at elevation 157 meters, latitude 44.38˚, and longitude -68.26˚. This monitor is operated and maintained by the National Park Service. New Hampshire considers the ACAD1 site as adequate for assessing reasonable progress toward visibility goals at Acadia National Park, and no additional monitoring sites or equipment are necessary at this time.

Figure 5.1: Map of Acadia National Park Showing Location of IMPROVE Monitor

Created by Tom Downs, MEDEP 4/17/07
http://www.maine.gov/dep/air/meteorology/images/Acadia.jpg

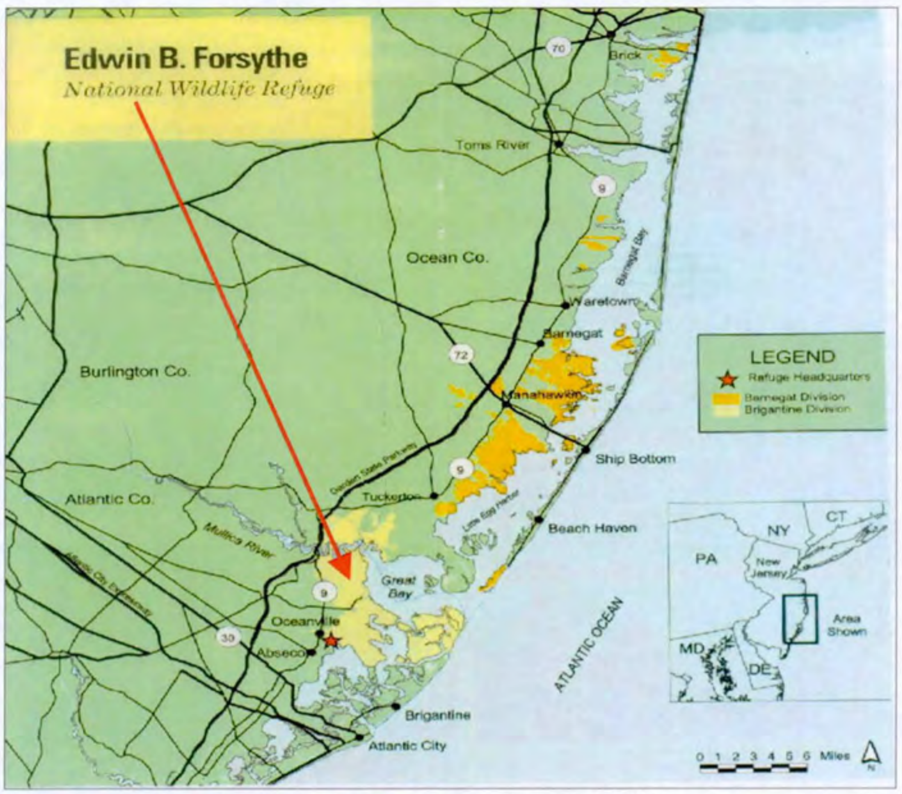
Figure 5.2: Acadia National Park on Clear and Hazy Days

http://www.hazecam.net/class1/acadia.html

5.3.2 Brigantine Wilderness, New Jersey

The IMPROVE monitor for the Brigantine Wilderness (BRIG1) is located at the Edwin B. Forsythe National Wildlife Refuge Headquarters in Oceanville, New Jersey, at elevation 5 meters, latitude 39.47˚, and longitude -74.45˚. This monitor is operated and maintained by the U.S. Fish & Wildlife Service. New Hampshire considers the BRIG1 site as adequate for assessing reasonable progress toward visibility goals at the Brigantine Wilderness, and no additional monitoring sites or equipment are necessary at this time.

Figure 5.3: Map of Edwin B. Forsythe National Wildlife Refuge



http://www.fws.gov/northeast/forsythe/MAP.htm

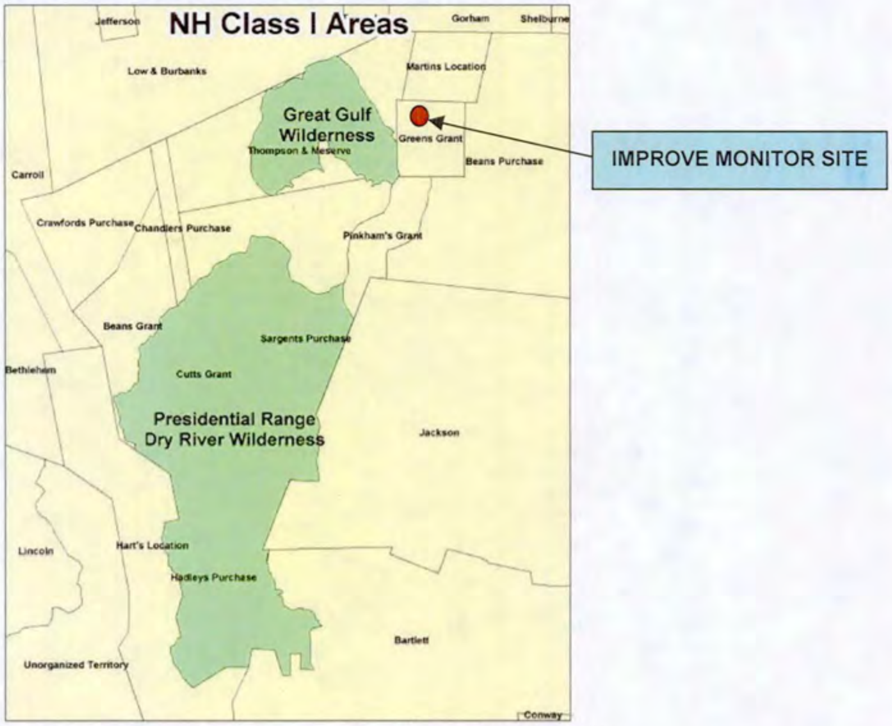
Figure 5.4: Brigantine Wilderness on Clear and Hazy Days

http://www.hazecam.net/class1/brigantine.html

5.3.3 Great Gulf Wilderness, New Hampshire

The IMPROVE monitor for the Great Gulf Wilderness (GRGU1) is located at Camp Dodge, in the mid-northern area of Greens Grant in the White Mountain National Forest. The monitor site lies just east and south of where Route 16 crosses the Greens Grant / Martins Location boundary, south of Gorham, New Hampshire, at elevation 454 meters, latitude 44.31˚, and longitude of -71.22˚. This monitor, which also represents the Presidential Range - Dry River Wilderness (see 5.3.4 below), is operated and maintained by the U.S. Forest Service. New Hampshire considers the GRGU1 site as adequate for assessing reasonable progress toward visibility goals at the Great Gulf Wilderness, and no additional monitoring sites or equipment are necessary at this time.

Figure 5.5: Map of Great Gulf and Presidential Range - Dry River Wilderness Areas Showing Location of IMPROVE Monitor



http://www.maine.gov/dep/air/meteorology/images/NHclass1.jpg

Figure 5.6: Great Gulf Wilderness on Clear and Hazy Days

http://www.wilderness.net

5.3.4 Presidential Range - Dry River Wilderness, New Hampshire

The IMPROVE monitor for the Presidential Range - Dry River Wilderness is also the monitor for Great Gulf Wilderness (GRGU1), as described above. New Hampshire considers the GRGU1 site as adequate for assessing reasonable progress toward visibility goals at the Presidential Range - Dry River Wilderness, and no additional monitoring sites or equipment are necessary at this time.

Figure 5.7: Presidential Range - Dry River Wilderness in Autumn

http://www.wilderness.net

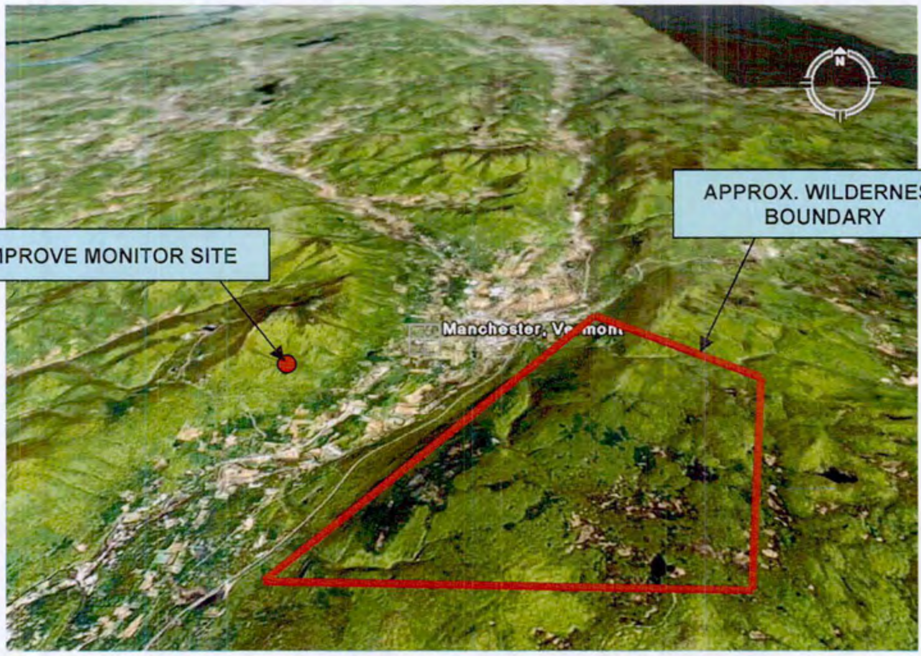
5.3.5 Lye Brook Wilderness, Vermont

The IMPROVE monitor for the Lye Brook Wilderness (LYBR1) is located on Mount Equinox at the windmills in Manchester, Vermont, at elevation 1015 meters, latitude 43.15°, and longitude of -73.13°. The monitor does not lie within the wilderness area but is situated on a mountain peak across the valley to the west of the wilderness area. The IMPROVE site and the Lye Brook Wilderness are at similar elevations. The monitor is operated and maintained by the U.S. Forest Service. New Hampshire considers the LYBR1 site as adequate for assessing reasonable progress toward visibility goals at the Lye Brook Wilderness, and no additional monitoring sites or equipment are necessary at this time.

Figure 5.8: Location of Lye Brook Wilderness IMPROVE Monitor

http://www.wilderness.net/index.cfm?fuse=NWPS&sec=stateView&state=NH&map=menhvt

Figure 5.9: Aerial View of Lye Brook Wilderness IMPROVE Monitoring Site



sources: GoogleEarth; and Paul Wishinski, Vermont DEC, Air Pollution Control Division

Figure 5.10: Lye Brook Wilderness on Clear and Hazy Days

http://www.hazecam.net/class1/lye.html

5.3.6 Moosehorn Wilderness, Maine

The IMPROVE monitor for the Moosehorn Wilderness (MOOS1) is located near McConvey Road, about one mile northeast of the National Wildlife Refuge Baring (ME) Unit Headquarters, at elevation 78 meters, latitude 45.13˚, and longitude -67.27˚. This monitor also represents the Roosevelt Campobello International Park in New Brunswick, Canada. The monitor is operated and maintained by the U.S. Fish & Wildlife Service. New Hampshire considers the MOOS1 site as adequate for assessing reasonable progress toward visibility goals at the Moosehorn Wilderness, and no additional monitoring sites or equipment are necessary at this time.

Figure 5.11: Map of the Baring and Edmunds Divisions of the Moosehorn National Wildlife Refuge Showing Location of IMPROVE Monitor

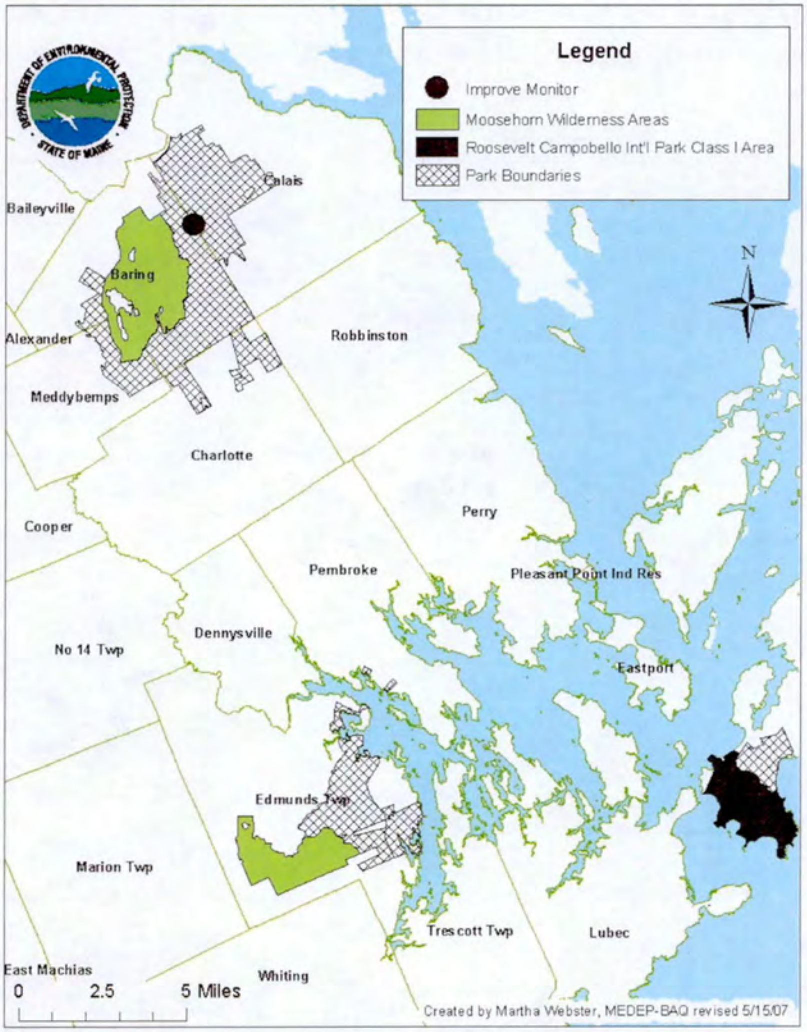


Figure 5.12: Moosehorn Wilderness on Clear and Hazy Days

http://www.hazecam.net/moosehorn.html

5.3.7 Roosevelt Campobello International Park, New Brunswick, Canada

The IMPROVE monitor for Roosevelt Campobello International Park is also the monitor for the Moosehorn Wilderness (MOOS1), as described above. New Hampshire considers the MOOS1 site as adequate for assessing reasonable progress toward visibility goals at Roosevelt Campobello International Park, and no additional monitoring sites or equipment are necessary at this time.

Figure 5.13: Map of Roosevelt Campobello International Park

http://www.maine.gov/dep/air/meteorology/images/rcip.jpg

Figure 5.14: Roosevelt Campobello International Park on Clear and Hazy Days

source: Chessie Johnson

6. EMISSIONS INVENTORY

40 CFR 51.308(d)(4)(v) of EPA's Regional Haze Rule requires a statewide emissions inventory of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I area. The inventory must include emissions for a baseline year, future (projected) year, and the most recent year for which high-quality data are available. New Hampshire's baseline year, 2002, is also the most recent year for which data are available. The pollutants inventoried by New Hampshire include nitrogen oxides (NO_X), sulfur dioxides (SO_2), volatile organic compounds (VOCs), fine particles (particulate matter less than 2.5 micrometers in diameter, or $PM_{2.5}$), coarse particles (particulate matter less than 10 micrometers in diameter, or PM_{10}), and ammonia (NH_3). The following source categories were included in New Hampshire's emissions inventory: stationary point sources, stationary area sources, on-road mobile sources, non-road mobile sources, and biogenic sources. These emissions categories are discussed further in Subsection 7.3, Model Platforms.

6.1 Baseline and Future-Year Emissions Inventories for Modeling

40 CFR 51.308(d) (3) (iii) of EPA's Regional Haze Rule requires the State of New Hampshire to identify the baseline emissions inventory on which emission control strategies are founded. The baseline inventory is intended to be used for assessing progress in making emission reductions. In accordance with EPA's guidance memorandum "2002 Base Year Emission Inventory SIP Planning: 8-hour Ozone, $PM_{2.5}$, and Regional Haze Programs," November 18, 2002, all of the MANE-VU states are using 2002 as the baseline year for regional haze.

Previously, on July 5, 2006, New Hampshire submitted its 2002 baseline inventory to EPA to meet its implementation planning obligations under the 8-hour ozone program. It should be noted, however, that emissions inventories are not static documents, but are constantly revised and updated to reflect the input of better emissions estimates as they become available. With contractor assistance, MARAMA developed a 2002 baseline modeling inventory using the inventories that New Hampshire and other states submitted to EPA to meet their SIP obligations and the requirements of the Consolidated Emissions Reporting Rule (CERR). To create the 2002 baseline inventory for modeling, MARAMA and its contractor quality-assured and augmented states' inventories and generated the necessary input files for the emissions processing model. As described in Part 6.1.1 below, work on this effort underwent several versions. Therefore, the 2002 baseline emissions summarized in this document may differ slightly from New Hampshire's original 2002 baseline inventory submittal.

Future-year inventories for 2009, 2012, and 2018 were projected from the 2002 base year. These future-year emissions inventories include emissions growth due to projected increases in economic activity as well as emissions reductions expected from the implementation of control measures. While the 2009 and 2012 emissions projections were originally developed in support of New Hampshire's and other states' ozone attainment demonstrations, the inventory for 2018 (the year targeted by the Regional Haze Rule) was developed for the specific purposes of regional haze SIP planning. Therefore, although the 2009 and 2012 projected inventories are mentioned in subsequent sections, only the 2002 baseline inventory and 2018 projected inventory are described below in Subsection 6.4, Summary of Emissions Inventories.

Accurate baseline and future-year emissions inventories are crucial to the analyses required for the regional haze SIP process. These emissions inventories were used to drive the air quality modeling simulations undertaken to assess the visibility improvements that would result from possible control measures. Air quality modeling was also used to perform a pollution apportionment, which evaluates the contribution to visibility impairment by geographic region and emission source sector.

To be compatible with the air quality modeling simulations, the baseline and future-year emissions inventories were processed with the Sparse Matrix Operator Kernel Emissions (SMOKE) emissions pre-processor for subsequent input into the CMAQ and REMSAD air quality models described in Subsection 7.3. Further description of the base and future-year emissions inventories is provided below.

6.1.1 Baseline Inventory (2002)

The starting point for the 2002 baseline emissions inventory was the 2002 inventory submittals that were made to EPA by state and local agencies as part of the Consolidated Emissions Reporting Rule (CERR). With contractor assistance (E.H. Pechan & Associates, Inc.,), MANE-VU then coordinated and quality-assured the 2002 inventory data, and prepared it for input into the SMOKE emissions model. The 2002 emissions from non-MANE-VU areas within the modeling domain were obtained from other Regional Planning Organizations for their corresponding areas. These Regional Planning Organizations included the Visibility Improvement State and Tribal Association of the Southeast (VISTAS), the Midwest Regional Planning Organization (MRPO), and the Central Regional Air Planning Association (CenRAP).

The 2002 baseline inventory went through several iterations. Work on Version 1 of the 2002 MANE-VU inventory began in April 2004, and the final inventory and SMOKE input files were completed during January 2005. Work on Version 2 (covering the period of April through September 2005) involved incorporating revisions requested by some MANE-VU state/local agencies on the point, area, and on-road categories. Work on Version 3 (covering the period from December 2005 through April 2006) included additional revisions to the point, area, and on-road categories as requested by some states. Thus, the Version 3 inventory for point, area, and on-road sources was built upon Versions 1 and 2. This work also included development of the biogenic inventory. In Version 3, the non-road inventory was completely redone because of changes that EPA made to the NONROAD2005 non-road mobile emissions model.

Version 3 of the MANE-VU 2002 baseline emissions inventory was used in the regional air quality modeling simulations. Further description of the data sources, methods, and results for this version of the 2002 baseline inventory is presented in E.H. Pechan & Associates, Inc., "Technical Support Document for 2002 MANE-VU SIP Modeling Inventories, Version 3, November 20, 2006, also known as the Baseline Emissions Report (Attachment M).
Emissions inventory data files are available on the MARAMA website at:
http://www.marama.org/visibility/EI_Projects/index.html.

6.1.2 Future-Year Emissions Inventories

Future-year emissions inventories are provided in MACTEC's technical support document, "Development of Emissions Projections for 2009, 2012, and 2018 for NonEGU Point, Area, and Nonroad Sources in the MANE-VU Region," Final Report, February 28, 2007, also known as the Emission Projections Report (Attachment N). This document describes the data sources, methods, and modeling results for three future years, five emission source sectors, two emission control scenarios, seven pollutants, and eleven states plus the District of Columbia. The following summarizes the basic framework of the future-year inventories that were developed:

- ***Projection years*:** 2009, 2012, and 2018;
- ***Emission source sectors*:** point-source electric generating units (EGUs), point-source non-electric generating units (non-EGUs), area sources, non-road mobile sources, and on-road mobile sources.
- ***Emission control scenarios*:**
  - A combined on-the-books/on-the-way (OTB/OTW) control strategy accounting for emission control regulations already in place as of June 15, 2005, as well as some emission control regulations that are not yet finalized but are expected to achieve additional emission reductions by 2009; and
  - A beyond-on-the-way (BOTW) scenario to account for anticipated Phase 1 implementation of a low-sulfur fuel strategy for non-EGU sources and controls from potential new regulations that may be necessary to meet attainment and other regional air quality goals, mainly for ozone.
  - An updated scenario (sometimes referred to as "best-and-final") to account for additional potentially reasonable control measures. For the MANE-VU region, these include: SO_2 reductions at a set of 167 EGUs which were identified as contributing to visibility impairment at northeast Class I areas; anticipated Phase 2 implementation of a low-sulfur fuel strategy for non-EGU sources; and implementation of a Best Available Retrofit Technology (BART) strategy for BART-eligible sources not controlled under other programs.

  (Note: Refer to Section 11, Long-Term Strategy, for detailed descriptions of specific control strategies.)
- ***Pollutants*:** ammonia, carbon monoxide (CO), oxides of nitrogen (NO_X), sulfur dioxide (SO_2), volatile organic compounds (VOCs), fine particulate matter ($PM_{2.5}$, sum of filterable and condensable components), and coarse particulate matter (PM_{10}, sum of filterable and condensable components).
- ***States*:** Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont, plus the District of Columbia (all members of the MANE-VU region).

6.2 Emission Processor Selection and Configuration

The Sparse Matrix Operator Kernel Emissions (SMOKE) model was used to format the emissions inventories for use with the air quality models that are discussed in Subsection 7.3. SMOKE is primarily an emissions processing system, as opposed to a true emissions inventory preparation system, in which emissions estimates are simulated from "first principles." This means that, with the exception of mobile and biogenic sources, SMOKE's purpose is to provide an efficient, modern tool for converting emissions inventory data into the formatted emissions files required for a photochemical air quality model. The SMOKE emissions processing that was performed in support of the air quality modeling for regional haze is described further in Subsection 7.2.

6.3 Inventories for Specific Source Categories

There are five emission source classifications in the emissions inventory, as follows:

- Stationary point,
- Stationary area,
- Non-road mobile,
- On-road mobile, and
- Biogenic.

Stationary point sources are large sources that emit greater than a specified tonnage per year, as described below. ***Stationary area sources*** are those sources whose individual emissions are relatively small (i.e., dry cleaners, service stations, agricultural areas, fires, etc.), but because of the large number of these sources, their collective emissions are significant. ***Non-road mobile sources*** are equipment that can move but do not use the roadways (i.e., lawn mowers, construction equipment, railroad locomotives, marine vessels, aircraft, etc.). ***On-road mobile sources*** include automobiles, trucks, buses, and motorcycles that use the roadway system. ***Biogenic sources*** include the off-gassing of natural sources such as trees, crops, grasses, and natural decay of plants.

The subsections below give an overview of each of the source categories and the methods that were used to develop their corresponding baseline and future-year emissions estimates. All emissions data were prepared for modeling in accordance with EPA guidance.

6.3.1 Stationary Point Sources

Point source emissions are emissions from large individual sources. Generally, point sources have permits to operate, and their emissions are individually calculated based on source-specific parameters. Emissions estimates for point sources are usually made on a regular basis, and the largest point sources are inventoried annually. Sources with emissions greater than or equal to 100 tons per year (tpy) of a criteria pollutant, 10 tpy of a single hazardous air pollutant (HAP), or 25 tpy for total HAPs are considered to be major sources. Emissions from smaller point sources are also calculated individually but less frequently. Point sources are further subdivided into EGUs and non-EGUs.

6.3.1.1 Electric Generating Units (EGUs)

The base-year inventory for EGU sources were based on 2002 continuous emissions monitoring (CEM) data reported to EPA in compliance with the Acid Rain Program or 2002 state emissions inventory data. The CEM data provided actual hourly emission values used in the modeling of SO_2 and NO_X emissions from these large sources. See Chapter II, Section A.2.a.i of the "Technical Support Document for 2002 MANE-VU SIP Modeling Inventories," Version 3 (Attachment M) for a discussion of the quality assurance steps performed on the CEM data that were included in the 2002 baseline modeling inventory. Emissions of other pollutants (e.g., VOCs, CO, NH_3, and $PM_{2.5}$) were provided by the states in most instances.

Future-year inventories of EGU emissions for 2009, 2012 and 2018 were developed using ICF International's Integrated Planning Model (IPM®) to forecast growth in electric demand and replacement of older, less efficient and more polluting power plants with newer, more efficient and cleaner units. This effort was undertaken by an inter-RPO workgroup. While the output of the IPM model predicts that a certain number of older plants will be replaced by newer units to meet future electric growth and state-specific NO_X and SO_2 caps, New Hampshire did not directly rely on the closure of any particular plant in establishing the 2018 inventory upon which the reasonable progress goals were set.

The IPM model results do not provide a reliable basis upon which to predict EGU closures. Specific plant closures in the New Hampshire are addressed in Section 10, Reasonable Progress Goals. Preliminary modeling was performed with unchanged IPM 2.1.9 model results. However, prior to the most recent modeling, future-year EGU inventories were adjusted as follows:

- First, IPM predictions were reviewed by permitting and enforcement staff of the MANE-VU states. In many cases, staff believed that the IPM shutdown predictions were unlikely to occur. In particular, many oil-fired EGUs in urban areas were predicted to be shut down by IPM. Similar source information was solicited from states in both VISTAS and MRPO. As a result of this model validation, the IPM modeling output was adjusted before the most recent modeling to reflect staff knowledge of specific plant status in MANE-VU, VISTAS, and MRPO states. Where expected EGU operating status was contrary to what was predicted by IPM modeling, the future-year emissions inventory was adjusted to reflect the expected operation of those plants.

- Second, as a result of inter- and intra-RPO consultations, MANE-VU agreed to pursue certain emission control measures (see Section 3, Regional Planning). For EGUs, the agreed-upon approach was to pursue emission reductions from each of the top 167 stacks located in MANE-VU, MRPO, and VISTAS that contributed the most to visibility impairment at any Class I area in the MANE-VU region. This approach, known as the targeted EGU strategy, is further described in Section 11 of this SIP.

6.3.1.2 Non-EGU Point Sources

The primary basis for the 2002 baseline non-EGU emissions inventory was data reported by state and local agencies for the CERR. As described in Part 6.1.1, MANE-VU's contractor, E.H. Pechan & Associates (Pechan), coordinated the quality assurance of the inventory and prepared the necessary files for input into the SMOKE emissions model. Further information on the preparation of the MANE-VU 2002 baseline point source modeling emissions inventory can be found in Chapter II of the Baseline Emissions Report (Attachment M).

Projected non-EGU point source emissions were developed for the MANE-VU region by MACTEC Federal Programs, Inc. under contract to Mid-Atlantic Regional Air Management Association (MARAMA). The specific methodologies that were employed are described in Section 2 of the Emission Projections Report (Attachment N). MACTEC used state-supplied growth factor data, where available, to project future-year emissions. Where state-supplied data were not available, MACTEC used EPA's Economic Growth and Analysis System, Version 5.0 (EGAS 5.0) to develop applicable growth factors for the non-EGU component. MACTEC also incorporated the applicable federal and state emissions control programs to account for the expected emissions reductions that will take place under the OTB/OTW and BOTW scenarios.

6.3.2 Stationary Area Sources

Stationary area sources include sources whose individual emissions are relatively small but, because the number of sources is large, their collective emissions are significant. Some examples include dry cleaners, service stations, and residential heating. For each area source, emissions are estimated by multiplying an appropriate emission factor by some known indicator of collective activity, such as fuel usage, number of households, or population.

The area source emissions inventory submittals made for the CERR became the basis for the area source portion of the 2002 baseline inventory. MANE-VU's consultant, Pechan, prepared the area source modeling inventory using the CERR submittals as a starting point. Pechan quality-assured the inventory and augmented it with additional data, including MANE-VU-sponsored inventories for categories such as residential wood combustion and open burning. Details on the preparation of MANE-VU's 2002 baseline area source emissions inventory can be found in Chapter III of the Baseline Emissions Report (Attachment M).

In similar fashion, MACTEC prepared future-year area source emission projections for the MANE-VU region. The specific methodologies employed are described in Section 3 of the Emission Projections Report (Attachment N). MACTEC applied growth factors to the 2002 baseline area source inventory using state-supplied data, where available, or using the EGAS 5.0 growth factor model. MACTEC also accounted for the appropriate control strategies in the future year projections.

6.3.3 Non-Road Mobile Sources

Non-road mobile sources are equipment that can move but do not typically use the roadways, such as construction equipment, aircraft, railroad locomotives, and lawn & garden equipment. For the majority of non-road mobile sources, emissions are estimated using the EPA's NONROAD model. Aircraft, railroad locomotives, and commercial marine vessels are not included in the NONROAD model; and their emissions are estimated using applicable references and methodologies. Again, Pechan prepared the 2002 baseline modeling inventory using the state and local CERR submittals as a starting point. Details on the preparation of the 2002 baseline non-road inventory are described in Chapter IV of the Baseline Emissions Report (Attachment M).

Future-year non-road mobile source emissions were projected for the MANE-VU region by MACTEC. The methodologies employed are discussed in Section 4 of the Emission Projections Report (Attachment N). MACTEC used EPA's NONROAD2005 non-road vehicle emissions model as contained in EPA's National Mobile Inventory Model (NMIM). Since the calendar year is an explicit input into the NONROAD model, future-year emissions for non-road vehicles could be calculated directly for the applicable projection years. For the non-road vehicle types that are not included in the NONROAD model (i.e. aircraft, locomotives, and commercial marine vessels), MACTEC used the 2002 baseline inventory and the projected inventories that EPA developed for these categories for the Clean Air Interstate Rule (CAIR) to develop emission ratios and subsequent combined growth and control factors. Since the future years for the CAIR projections did not precisely match those required for the purposes of ozone, particulate matter, and regional haze analyses (i.e. 2009, 2012, and 2018), MACTEC used linear interpolation to develop factors for the required future years.

6.3.4 On-Road Mobile Sources

The on-road emissions source category consists of vehicles that are meant to travel on public roadways, including cars, trucks, buses, and motorcycles. The basic methodology used for on-road mobile source calculations is to multiply vehicle-miles-traveled (VMT) by emission factors developed using the EPA's MOBILE6 motor vehicle emission factors model. The on-road mobile category requires that SMOKE model inputs be prepared instead of the SMOKE/IDA emissions data format that is required by the other emission source categories. Therefore, for the 2002 baseline inventory, Pechan prepared the necessary VMT and MOBILE6 inputs in SMOKE format.

Projected on-road mobile source inventories were developed by NESCAUM for the MANE-VU region for ozone, particulate matter, and regional haze SIP purposes. As with the other emissions source categories, projected on-road mobile inventories were developed for calendar years 2009, 2012, and 2018. As part of this effort, MANE-VU member states were asked to provide VMT data and MOBILE6 model inputs for the applicable calendar years. Using the inputs supplied by the MANE-VU member states, NESCAUM compiled and generated the required SMOKE/MOBILE6 emissions model inputs. Further details regarding the on-road mobile source projections can be found in NESCAUM's "Technical Memorandum, Development of MANE-VU Mobile Source Projection Inventories for SMOKE/MOBILE6 Application," June 2006 (Attachment O).

6.3.5 Biogenic Emission Sources

For the purposes of the 2002 baseline modeling emissions inventory, biogenic emissions were calculated for the modeling domain by the New York State Department of Environmental Conservation (NYSDEC). NYSDEC used the Biogenic Emissions Inventory System (BEIS) Version 3.12 as contained within the SMOKE emissions processing model. Biogenic emissions estimates were made for CO, nitrous oxide (NO) and VOCs. Further details about the biogenic emissions processing can be found in NYSDEC's technical support document TSD-1c, "Emission Processing for the Revised 2002 OTC Regional and Urban 12 km Base Case Simulations," September 19, 2006 (Appendix P), and in Chapter VI of Pechan's "Technical Support Document for 2002 MANE-VU SIP Modeling Inventories," Version 3, November 20, 2006 (Appendix M). Biogenic emissions were assumed to remain constant for the future-years analysis – a reasonable approximation reflecting the expectation that most of the region will remain heavily forested for the duration of the planning period.

6.4 Summary of Emissions Inventories

New Hampshire's baseline and future-year emissions inventories are summarized in Tables 6.1 through 6.4, below. All values are reported in tons per year (tpy). The three different emissions inventories for 2018 represent the emission control scenarios described under the third bullet in Part 6.1.2 of this section.

Table 6.1: 2002 Emissions Inventory Summary for New Hampshire (tpy)

Emission Sector	VOC	NO_X	$PM_{2.5}$	PM_{10}	NH_3	SO_2
Point	1,599	9,759	2,938	3,332	74	46,560
Area	65,370	10,960	17,532	43,328	2,158	7,072
Mobile	16,762	33,283	562	814	1,447	777
Non-Road Mobile	22,376	9,912	965	1,058	9	891
Biogenic	141,894	482	--	--	--	--
TOTAL	248,001	64,396	21,997	48,532	3,688	55,300

Table 6.2: 2018 OTB/OTW Emissions Inventory Summary for New Hampshire (tpy)

Emission Sector	VOC	NO_X	$PM_{2.5}$	PM_{10}	NH_3	SO_2
Point	1,367	4,524	3,208	3,397	184	10,583
Area	64,368	12,430	18,316	49,801	2,789	7,421
Mobile	6,564	7,671	263	282	1,916	537
Non-Road Mobile	15,003	6,344	634	697	11	246
Biogenic	141,894	482	--	--	--	--
TOTAL	229,196	31,451	22,421	54,177	4,900	18,787

Table 6.3: 2018 BOTW Emissions Inventory Summary for New Hampshire (tpy)

Emission Sector	VOC	NO_X	$PM_{2.5}$	PM_{10}	NH_3	SO_2
Point	1,292	4,258	3,208	3,397	184	10,568
Area	62,650	12,180	18,087	49,544	2,789	3,118
Mobile	6,564	7,671	263	282	1,916	537
Non-Road Mobile	15,003	6,344	634	698	12	246
Biogenic	141,894	482	--	--	--	--
TOTAL	227,403	30,935	22,192	53,921	4,901	14,469

Table 6.4: 2018 Most Recent Emissions Inventory Summary for New Hampshire (tpy)

Emission Sector	VOC	NO_X	$PM_{2.5}$	PM_{10}	NH_3	SO_2
Point	1,291	4,258	3,208	3,397	184	11,849
Area	62,649	12,180	14,993	21,775	2,789	972
Mobile	6,564	7,671	263	282	1,916	537
Non-Road Mobile	15,003	6,344	634	697	11	246
Biogenic	141,894	482	--	--	--	--
TOTAL	227,401	30,935	19,098	26,151[13]	4,900	13,604

[13] An adjustment factor was applied during the processing of emissions data to restate fugitive particulate matter emissions. Grid models have been found to overestimate fugitive dust impacts when compared with ambient samples; therefore, an adjustment is typically applied to account for the removal of particles by vegetation and other terrain features. The summary emissions for PM_{10} in Table 6.4 reflect this adjustment. Comparable adjustments were not made to PM_{10} values listed in Tables 6.1 through 6.3.

7. AIR QUALITY MODELING

Air quality modeling to assess regional haze has been performed cooperatively between New Hampshire and its regional planning organization, MANE-VU, with major modeling being conducted by NESCAUM and screening modeling being conducted by NHDES. These modeling efforts include emissions processing, meteorological input analysis, and chemical transport modeling to perform regional air quality simulations for calendar year 2002 and several future periods, including the primary target date, 2018, for this SIP. Modeling was conducted in order to assess contributions from upwind areas as well as New Hampshire's contribution to Class I areas in downwind states. Further, the modeling evaluated visibility benefits of specific control measures being considered to achieve reasonable progress goals and establish a long-term emissions management strategy for MANE-VU Class I Areas.

Several modeling tools were utilized for these analyses:

- The Fifth-Generation Pennsylvania State University/National Center for Atmospheric Research (NCAR) Mesoscale Model (MM5) was used to derive the required meteorological inputs for the air quality simulations.
- The Sparse Matrix Operator Kernel Emissions (SMOKE) emissions modeling system was used to process and format the emissions inventories for input into the air quality models.
- The Community Mesoscale Air Quality model (CMAQ) was used for the primary SIP modeling.
- The Regional Model for Aerosols and Deposition (REMSAD) was used during contribution apportionment.
- The California Puff Model (CALPUFF) was used to assess the contribution of individual states' emissions to sulfate levels at selected Class I receptor sites.
- The CALGRID photochemical grid model was used to perform screening-level analyses of emission control strategies.

Each of these tools has been evaluated and found to perform adequately. The SIP-pertinent modeling underwent full performance testing, and the results were found to meet the specifications of EPA modeling guidance.

For more details on the regional haze modeling, refer to the NESCAUM report, "MANE-VU Modeling for Reasonable Progress Goals: Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G). The detailed modeling approach for the most recent 2018 projections can be found in NESCAUM's "2018 Visibility Projections," May 13, 2008 (Attachment Q).

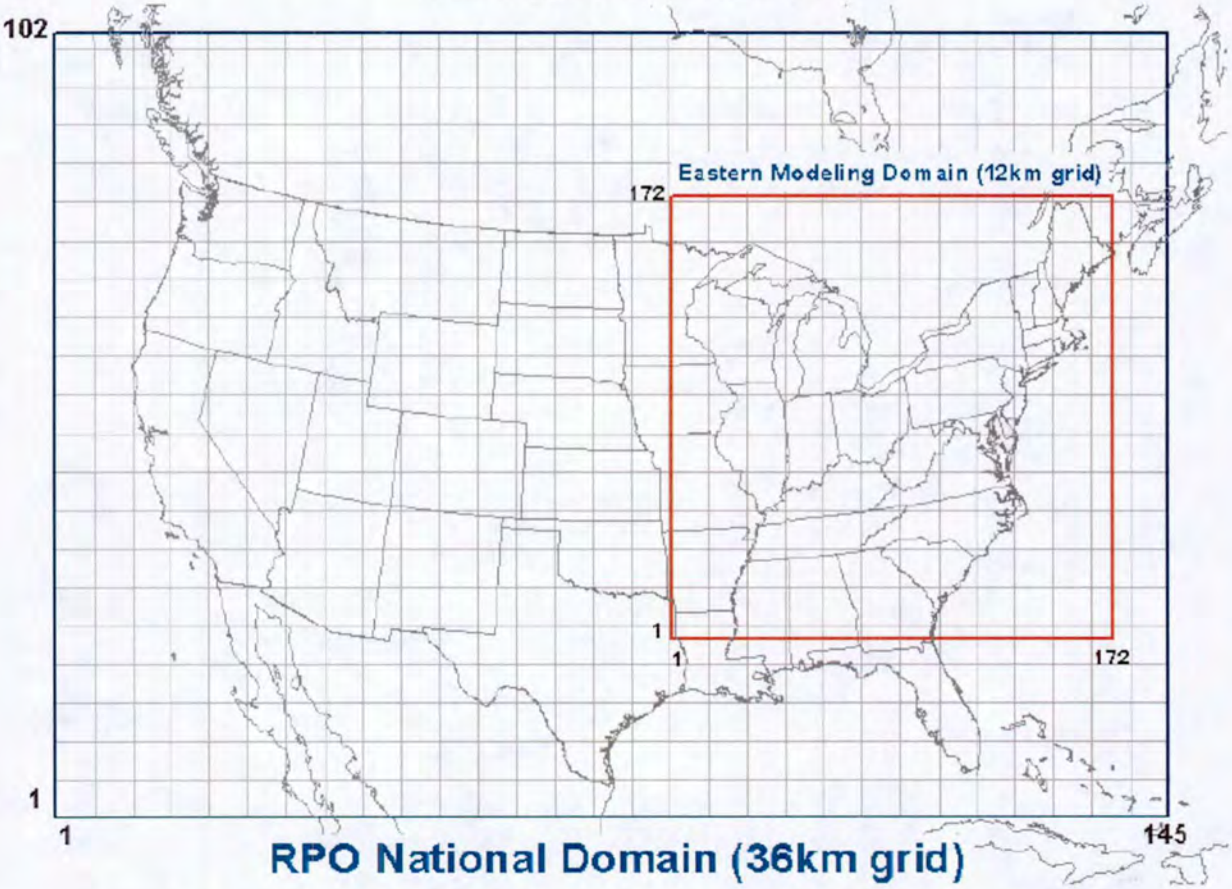
7.1 Meteorology

The meteorological inputs for the air quality simulations were developed by the University of Maryland (UMD) using the MM5 meteorological modeling system. Meteorological inputs were generated for 2002 to correspond with the baseline emissions inventory and analysis year. The MM5 simulations were performed on a nested grid (Figure 7.1). The modeling domain is composed of a 36-km, 145 x 102 continental grid and a nested 12-km, 172 x 172 grid encompassing the eastern United States and parts of Canada. In cooperation with the New York State Department of Conservation (NYSDEC), an assessment was made for the period of May-September 2002 to compare the MM5 predictions with observations from a variety of data sources, including:

- Surface observations from the National Weather Service and the Clean Air Status and Trends Network (CASTNET),
- Wind-profiler measurements from the Cooperative Agency Profilers (CAP) network,
- Satellite cloud image data from the UMD Department of Atmospheric and Oceanic Science, and
- Precipitation data from the Earth Observing Laboratory at NCAR.

Further details regarding the MM5 meteorological processing and the modeling domain can be found in NYSDEC's technical support document TSD-1a, "Meteorological Modeling Using Penn State/NCAR 5th Generation Mesoscale Model (MM5)," February 1, 2006 (Attachment R), and in the NESCAUM report, "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," November 27, 2007 (Attachment G).

Figure 7.1: Modeling Domains Used in MANE-VU Air Quality Modeling Studies with CMAQ



Note: Outer (blue) domain is 36-km grid. Inner (red) domain is 12-km grid. Gridlines are shown at 180-km intervals (5×5 36-km cells and 15×5 12-km cells).

7.2 Data Preparations

Emissions data were prepared for input into the CMAQ and REMSAD air quality models using the SMOKE emissions modeling system. SMOKE supports point, area, mobile (both on-road and non-road), and biogenic emissions. The SMOKE emissions modeling system uses flexible processing to apply chemical speciation as well as temporal and spatial allocation to the emissions inventories. SMOKE incorporates the Biogenic Emission Inventory System (BEIS) and EPA's MOBILE6 motor vehicle emission factor model to process biogenic and on-road mobile emissions, respectively. Vector-matrix multiplication is used during the final processing step to merge the various emissions components into a single model-ready emissions file. Examples of processed emissions outputs are shown in Figure 7.2.

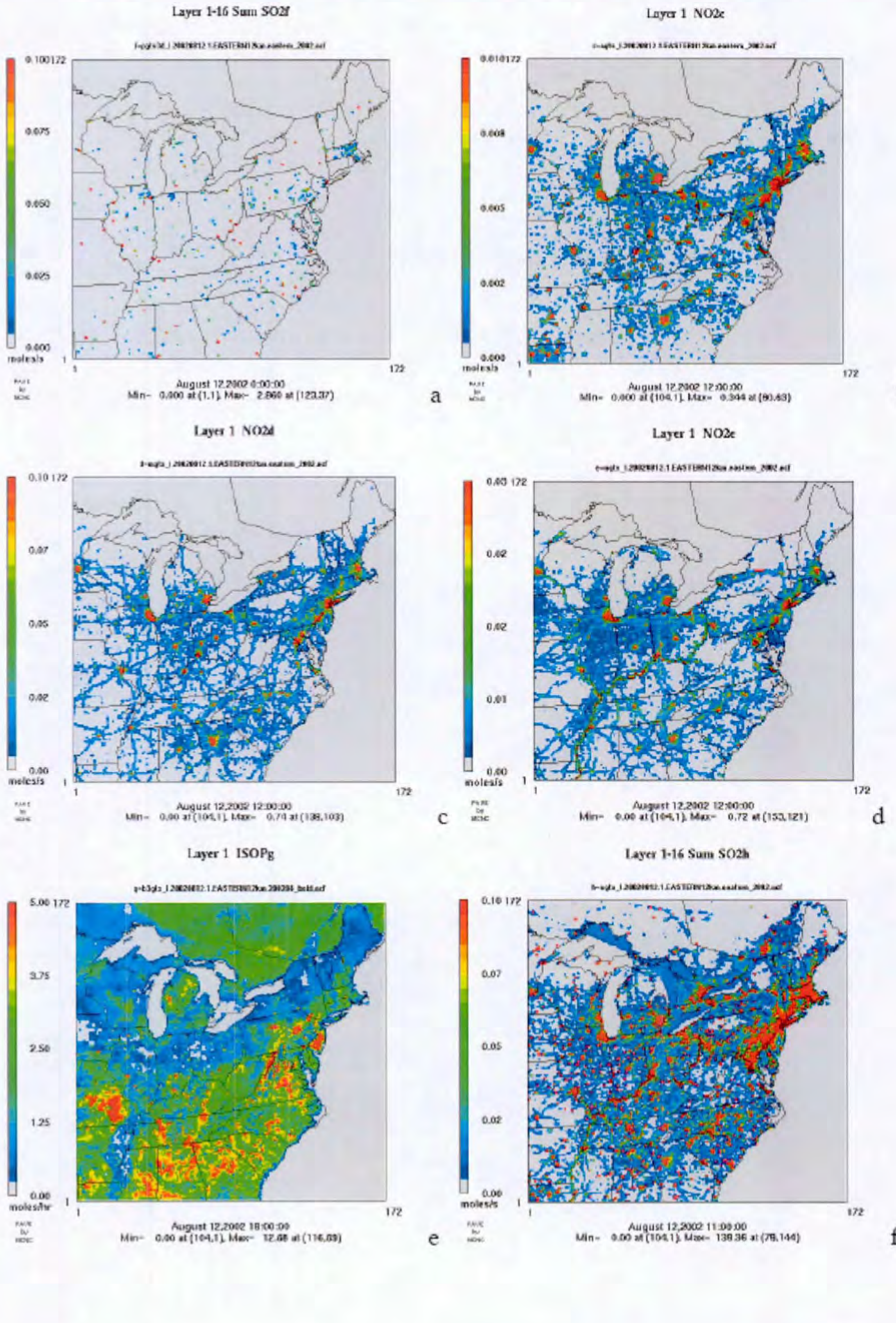
Further details on the SMOKE processing conducted in support of the air quality simulations is provided in NYSDEC's technical support document TSD-1c, "Emission Processing for the Revised 2002 OTC Regional and Urban 12 km Base Case Simulations," September 19, 2006 (Attachment P), and in NESCAUM's report, "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G). Additional details on the emissions inventory preparation can be found in Section 6 of this report.

7.3 Model Platforms

Two regional-scale air quality models, CMAQ and REMSAD, were used for the air quality simulations that directly supported the regional haze SIP effort. CMAQ was developed by EPA and was used to perform the primary SIP-related modeling. The CMAQ modeling simulations were also an important tool for the 8-hour ozone SIP process. REMSAD was developed by ICF Consulting/Systems Applications International with support from EPA. REMSAD was used by NESCAUM to perform a source apportionment (contribution assessment) analysis. All of the air quality simulations that were used in the SIP efforts were performed on the 12-km eastern modeling domain shown in Figure 7.1, above.

NYSDEC performed an extensive model performance analysis to evaluate CMAQ model predictions against observations of ozone, $PM_{2.5}$, and other pollutant species. This model performance evaluation is described in detail in NYSDEC's technical support document TSD-1e, "CMAQ Model Performance and Assessment, 8-Hr OTC Ozone Modeling," February 23, 2006 (Attachment S). A model performance evaluation for $PM_{2.5}$ species, aerosol extinction coefficient, and the haze index is provided in NESCAUM's report, "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G).

Figure 7.2: Examples of Processed Model-Ready Emissions: (a) SO_2 from Point, (b) NO_2 from Area, (c) NO_2 from On-Road, (d) NO_2 from Non-Road, (e) Isoprene from Biogenic, and (f) SO_2 from all Source Categories



7.3.1 CMAQ

The CMAQ air quality simulations were performed cooperatively among five modeling centers: NYSDEC, the New Jersey Department of Environmental Protection (NJDEP) in association with Rutgers University, the Virginia Department of Environmental Quality (VADEQ), UMD, and NESCAUM. NYSDEC also performed an annual 2002 CMAQ simulation on the 36-km domain shown in Figure 7.1; this simulation was used to derive the boundary conditions for the inner 12-km eastern modeling domain. Boundary conditions for the 36-km simulations were obtained from a run of the GEOS-Chem (Goddard Earth Observing System) global chemistry transport model that was performed by researchers at Harvard University. The technical options that were used in performing the CMAQ simulations are described in detail in NYSDEC's technical support document TSD-1d, "8hr Ozone Modeling Using the SMOKE/CMAQ System," February 1, 2006 (Attachment T). Further technical details regarding the CMAQ model and its execution are also provided in NESCAUM's report, "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G).

7.3.2 REMSAD

The REMSAD modeling simulations were used to produce the contribution assessment required by the Regional Haze Rule. REMSAD's species tagging capability makes it an important tool for this purpose. The REMSAD model simulations were performed on the same 12-km eastern modeling domain as shown in Figure 7.1. NESCAUM's report, "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G), further describes the REMSAD model and its application to the regional haze SIP efforts.

7.3.3 CALGRID

In addition to the SIP-quality modeling platforms described above, another modeling platform was developed for use as a screening tool to evaluate additional control strategies or to perform sensitivity analyses. The CALGRID model was selected as the basis for this platform. CALGRID is a grid-based photochemical air quality model that is designed to be run in a Windows environment. In order to make the CALGRID model the best possible tool to supplement the SIP-quality CMAQ and REMSAD modeling, the current version of the CALGRID platform was set up to be run with the same set of inputs as the SIP-quality models. The CALGRID air quality simulations were run on the same 12-km eastern modeling domain that was used for CMAQ and REMSAD. This model's performance was comparable to the performance of the already evaluated CMAQ and REMSAD models and was thus determined to perform adequately.

Conversion utilities were developed to reformat the meteorological inputs, the boundary conditions, and the emissions data for use with the CALGRID modeling platform. Pre-merged SMOKE emissions files were obtained from the modeling centers and reformatted for input into Emission Processor version 6 (EMSPROC6), the emissions pre-processor for the CALGRID modeling system. EMSPROC6 allows the CALGRID user to adjust emissions temporally, geographically, and by emissions category for control strategy analysis. The pre-merged SMOKE files that were obtained from the modeling centers were broken down into the biogenic, point, area, non-road, and on-road emissions categories. These files by component were then converted for use with EMSPROC6, thus giving CALGRID users the flexibility to analyze a wide variety of emissions control strategies. Additional information on the CALGRID modeling platform can be found in NHDES' "Modeling Protocol for the OTC CALGRID Screening-Level Modeling Platform for the Evaluation of Ozone," May 23, 2007 (Attachment U).

7.3.4 CALPUFF

CALPUFF is a non-steady-state Lagrangian puff model that simulates the dispersion, transport, and chemical transformation of atmospheric pollutants. Two parallel CALPUFF modeling platforms were developed by the Vermont Department of Environmental Conservation (VTDEC) and the Maryland Department of the Environment (MDE). The VTDEC CALPUFF modeling platform utilized meteorological observation data from the National Weather Service (NWS) to drive the CALMET meteorological model. The MDE platform utilized the same MM5 meteorological inputs that were used in the modeling done in support of the ozone and regional haze SIPs. These two platforms were run in parallel to evaluate individual states' contributions to sulfate levels at Northeast and Mid-Atlantic Class I areas. The CALPUFF modeling effort is described in detail in NESCAUM's report, "Contributions to Regional Haze in the Northeast and Mid-Atlantic United States," August 2006 (Attachment B).

References

Center for Environmental Modeling for Policy Development, University of North Carolina at Chapel Hill. *Sparse Matrix Operator Kernel Emissions (SMOKE) Model.* http://www.smoke-model.org/index.cfm.

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8. UNDERSTANDING THE SOURCES OF HAZE-CAUSING POLLUTANTS

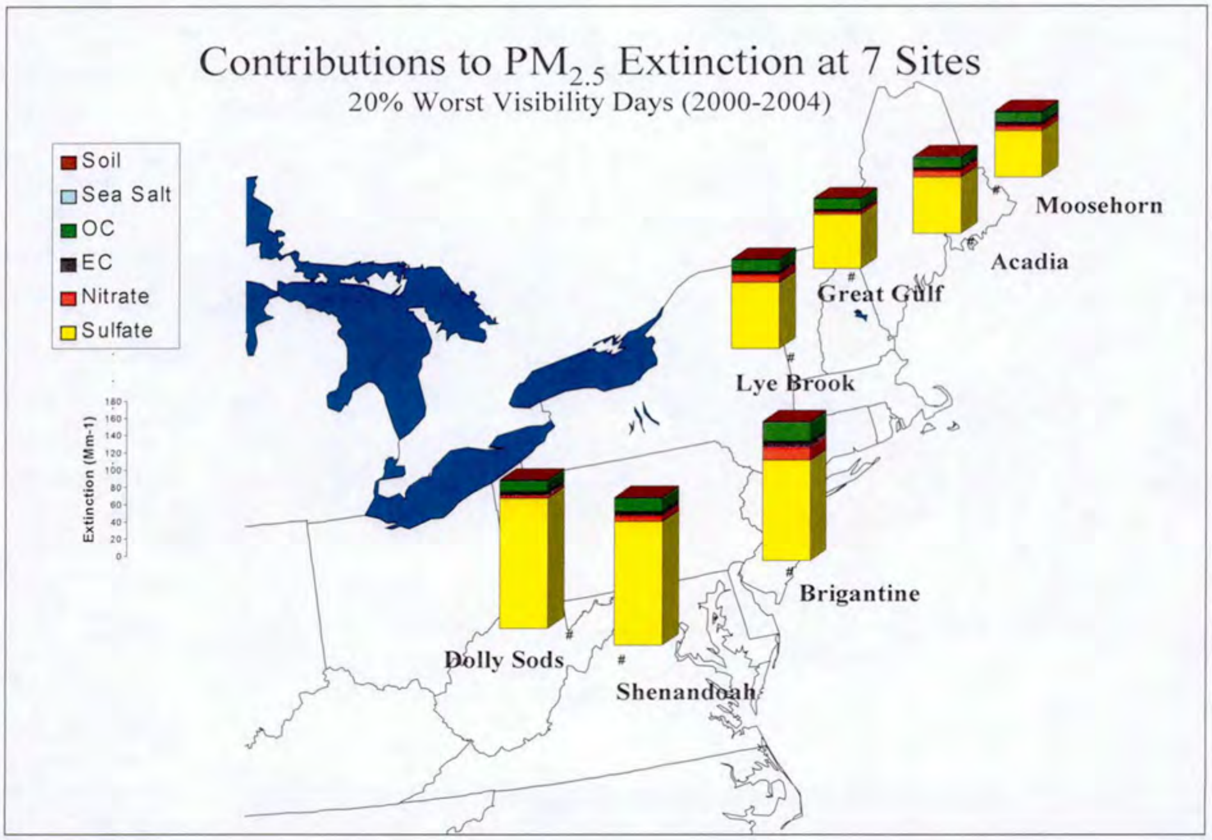
This section explores the origins, quantities, and roles of visibility-impairing pollutants emitted in the eastern United States and Canada that contribute significantly to regional haze at MANE-VU's mandatory Class I areas.

8.1 Fine-Particle Pollutants

The pollutants primarily responsible for fine particle formation, and thus contributing to regional haze, include SO_2, NO_X, VOCs, NH_3, PM_{10}, and $PM_{2.5}$. The MANE-VU Contribution Assessment (Attachment B), finalized in August 2006, reflects a conceptual model in which sulfate emerges as the most important single constituent of haze-forming fine particle pollution and the principle cause of visibility impairment across the Northeast region. Sulfate alone accounts for anywhere from ½ to ⅔ of total fine particle mass on the 20 percent haziest days at MANE-VU Class I Areas. This translates to about ⅔ to ¾ of visibility extinction on those days.

Visibility extinction is a measure of the ability of particles to scatter and absorb light. Extinction is expressed in units of inverse mega-meters (Mm^{-1}). Figure 8.1 shows the dominance of sulfate in visibility extinction calculated from 2000-2004 baseline data for seven Northeast Class I Areas.

Figure 8.1: Contributions to $PM_{2.5}$ Extinction at Seven Class I Areas



Given the dominant role of sulfate in the formation of regional haze in the Northeast and Mid-Atlantic Regions, MANE-VU concluded that an effective emissions management approach would rely heavily on broad-based regional SO_2 control measures in the eastern United States. The focus on SO_2 as MANE-VU's first priority makes sense not only because of its dominant role in regional haze but also because its emission sources are well understood. Moreover, the control measures needed for SO_2 emission reductions are readily available, cost-effective, and could be implemented quickly. On the basis of the scientific evidence, it is apparent that the bulk of haze-causing pollution can be eliminated by pursuing SO_2 emission controls.

Organic carbon was found to be the next largest contributor to haze after sulfate. In comparison with sulfate, the emission sources of organic carbon, are diverse, variable, more diffuse, and less well understood; and the problem of controlling organic carbon emissions is exceedingly complex. For these reasons, MANE-VU considered organic carbon to be the subject of possible future control measures but not a specific target pollutant in the initial strategy to mitigate regional haze.

8.2 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 and nearby Class I areas. Based on estimates obtained by several evaluation methods, emissions that originated within MANE-VU states contributed approximately one-fourth of the total sulfate aerosol recorded at New Hampshire's Class I areas in 2002. More specifically, four different estimation methods yielded the following contribution ranges: MANE-VU, 21-28 percent; MRPO, 20-27 percent; VISTAS, 12-18 percent; CenRAP, 2-5 percent; Canada, 7-19 percent; and all other regions, 23-24 percent (see Tables 8.1, 8.2, 8.3, and 8.5 of the Contribution Assessment for details).

It should be pointed out that the listed values for VISTAS, CenRAP, and Canada understate the actually percentage contributions from those regions because they count only emissions originating within the modeling domain (see Figure 7.1). Actual contributions, especially in the case of CenRAP, would be considerably higher than stated. Differences between actual and stated values are lumped into "Other."

These findings highlight the importance of emissions from outside MANE-VU to visibility impairment inside the region. Note that, although there is some variation in the contribution estimates among the different assessment methods employed, there is a general consistency of results from one method to another.

Table 8.1 displays the results of just one of the methods used (the REMSAD model) to assess state-by-state and regional contributions to annual sulfate impacts in nine Class I areas.

Table 8.1: Percent Contributions (Mass Basis) of Individual MANE-VU States and Other Regions to Total Annual Sulfate Impacts at Northeast Class I Areas (REMSAD)

Contributing State or Region	Mandatory Class I Area						
	Acadia ME	Brigantine NJ	Dolly Sods WV	Great Gulf & Presidential Range - Dry River, NH	Lye Brook VT	Moosehorn & Roosevelt Campobello ME	Shenandoah VA
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
MRPO	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
CenRAP	0.88	1.12	1.58	1.65	1.67	0.82	1.48
Canada	8.69	7.11	3.90	14.84	12.43	7.85	4.75
Other	33.79	16.78	12.70	23.54	18.99	44.17	12.48

Note: Indicated percent contributions from, VISTAS, CenRAP, and Canada apply only to those portions lying within the modeling domain (see Figure 7.1). Actual contributions, especially from CenRAP, would be higher than stated.

Source: Table 8-1 of the MANE-VU Contribution Assessment

Figures 8.2 and 8.3, also borrowed from the Contribution Assessment, illustrate another method for identifying and ranking states' contributions to sulfate at Class I areas using the 2002 data. This simple technique for deducing the relative impact of emissions from specific point sources on specific receptor sites involves calculating the ratio of annual emissions (Q) to source-receptor distance (d). The ratio (Q/d) is then multiplied by a factor to account for the frequency effect of prevailing winds. The use of this technique is explained in the Contribution Assessment (see pages 4-12 to 4-17 of Attachment B).

Figure 8.2: Ranked Sulfate Contributions to Northeast Class I Receptors Based on Q/d Method (Mass Basis), by Location of Origin

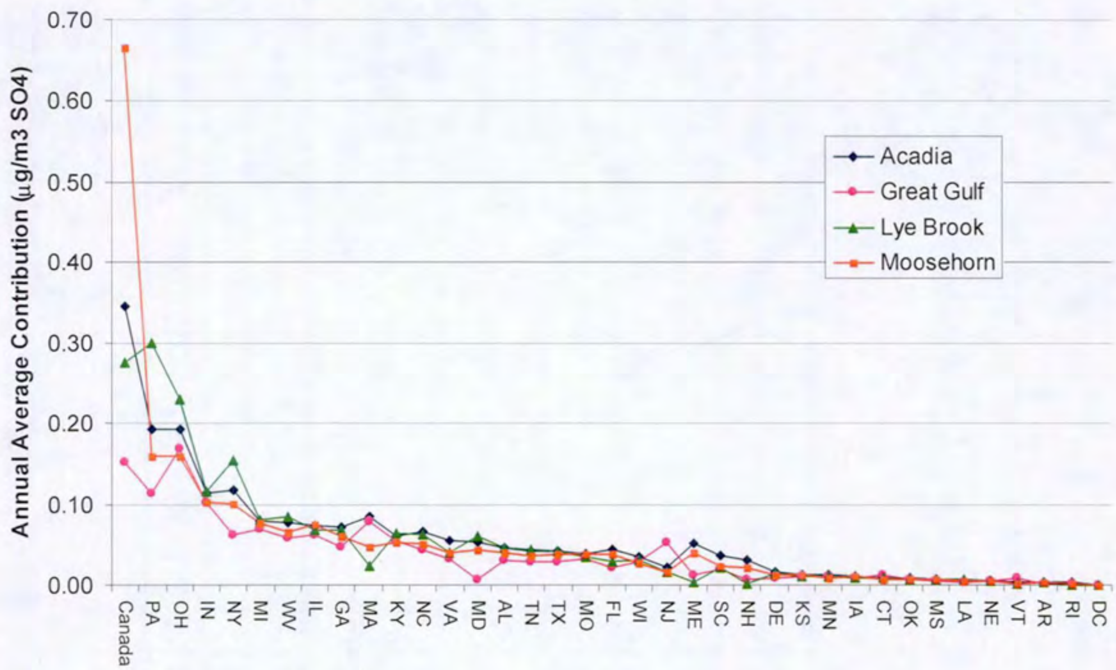
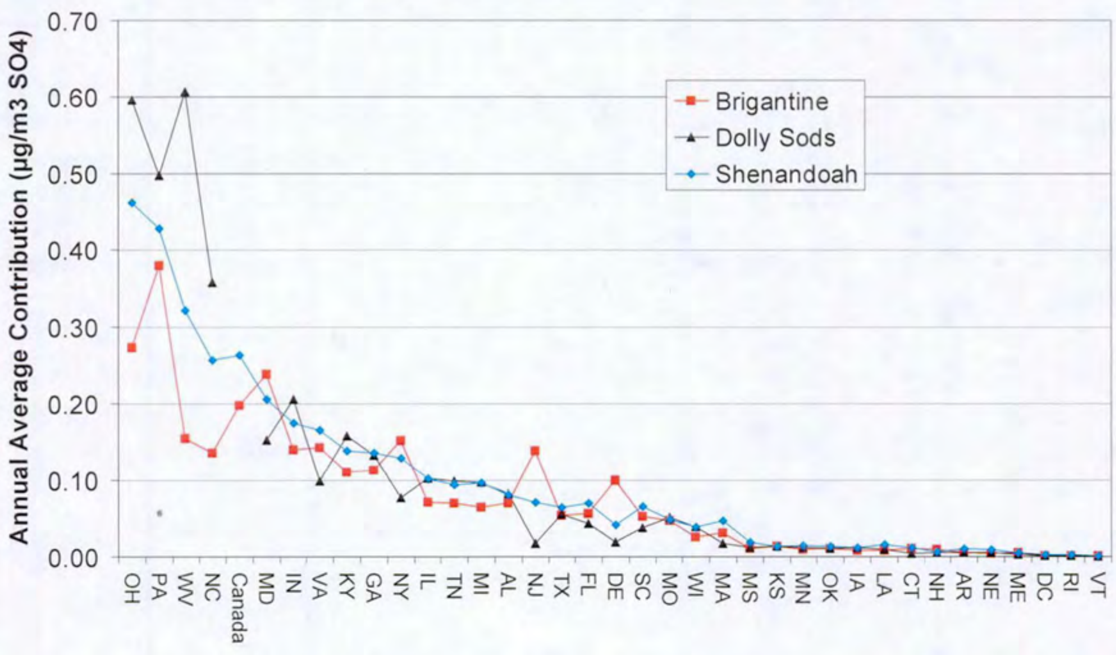


Figure 8.3: Ranked Sulfate Contributions to Mid-Atlantic Class I Receptors Based on Q/d Method (Mass Basis), by Location of Origin



The first of the Q/d plots covers the four northern Class I areas with IMPROVE monitoring in MANE-VU. The second covers one Class I area in the southern part of MANE-VU and two neighboring Class I areas in the VISTAS region. Observe, again, the comparative importance of emissions from Canada and from states outside the MANE-VU region.

The ranking of emission contributions to visibility impairment in the MANE-VU Class I Areas by methods such as these has direct relevance to the consultation process described previously in Section 3, Regional Planning and Consultation. Using results from the REMSAD model, MANE-VU applied the following three criteria to identify states and regions for the purposes of consultation on regional haze:

1. Any state/region that contributed 0.1 $\mu g/m^3$ sulfate or greater on the 20 percent worst visibility days in the base year (2002),
2. Any state/region that contributed at least 2 percent of total sulfate observed on the 20 percent worst visibility days in 2002, and
3. Any state/region among the top ten contributors on the 20 percent worst visibility days in 2002.

For the purposes of deciding how broadly to consult, the MANE-VU States settled on the second of the three criteria: any state/region that contributed at least 2 percent of total sulfate observed on the 20 percent worst visibility days in 2002.

In Figures 8.4 through 8.10, below, states and regions meeting the three listed criteria are identified graphically for seven Class I areas: Shenandoah and Dolly Sods are Class I areas in the VISTAS region that are impacted by emissions from MANE-VU states; the other five Class I areas are in MANE-VU. Note that the IMPROVE monitor at Great Gulf also represents the Presidential Range - Dry River Wilderness, and the IMPROVE monitor at Moosehorn also represents Roosevelt Campobello International Park.

Each figure has the following components:

- On the left is a single bar graph of the IMPROVE-monitored $PM_{2.5}$ mass concentration ($\mu g/m^3$) by constituent species for the baseline years 2000-2004. The yellow, bottom portion of the bar represents the measured sulfate concentration.
- The middle component of each figure provides a bar graph of the 2002 total sulfate contribution of each state or region as estimated by REMSAD.
- Finally, the right segment contains three maps showing which states meet the criteria described above.

Connecticut, Rhode Island, Vermont, and the District of Columbia were not identified as being among the political or regional units contributing at least 2 percent of sulfate at any of the seven Class I areas. However, as participants in MANE-VU, those entities have agreed to pursue adoption of regional control measures aimed at visibility improvement on the haziest days and prevention of visibility degradation on the clearest days.

Figure 8.4: Modeled 2002 Contributions to Sulfate at Great Gulf, by State

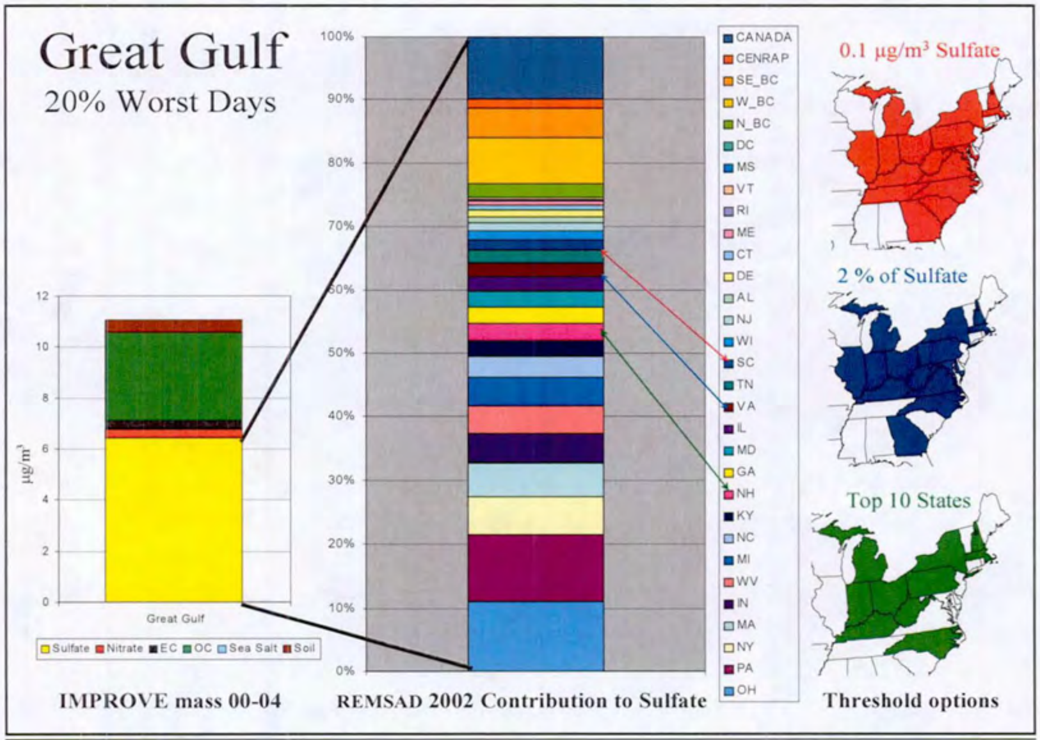


Figure 8.5: Modeled 2002 Contributions to Sulfate at Brigantine, by State

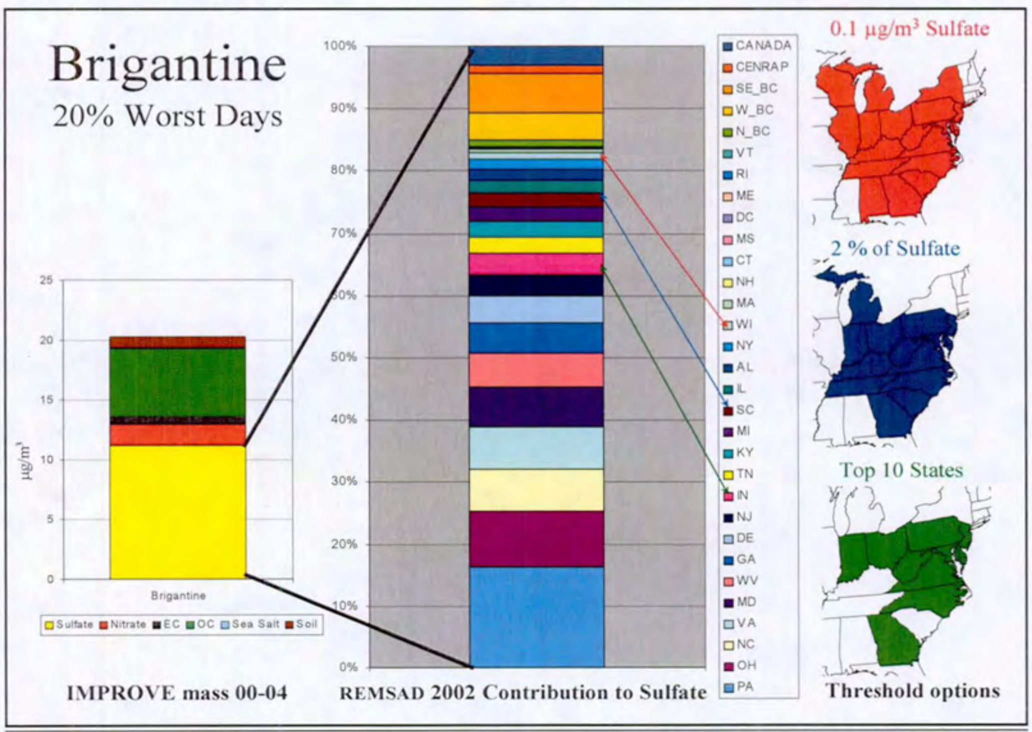


Figure 8.6: Modeled 2002 Contributions to Sulfate at Lye Brook, by State

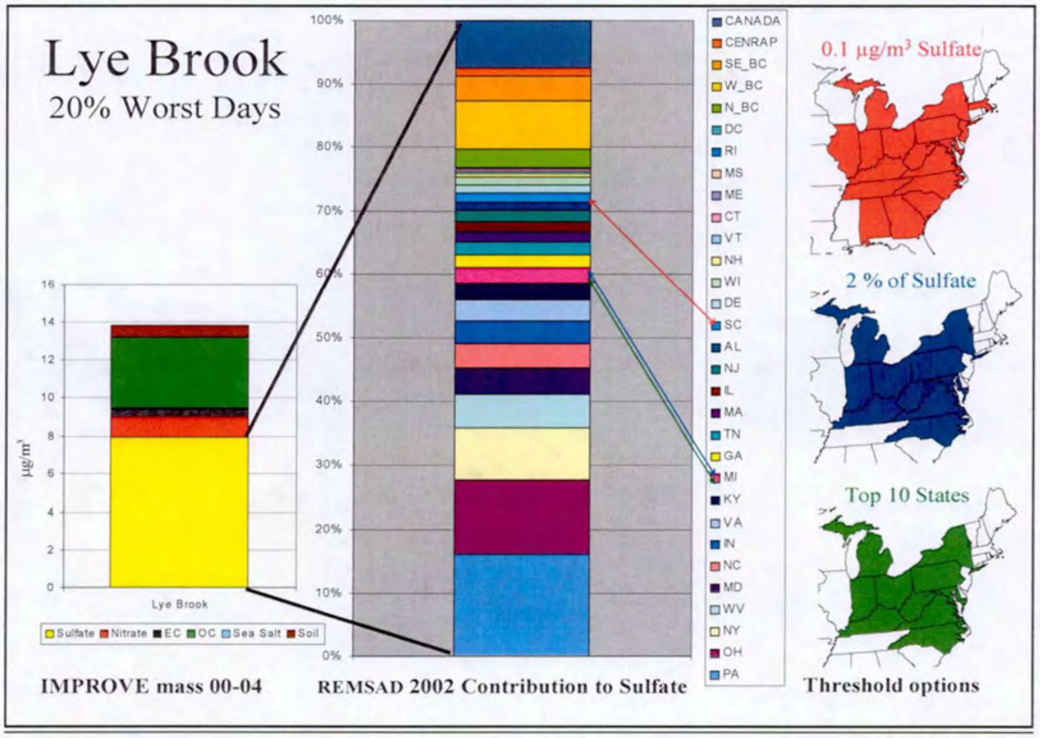


Figure 8.7: Modeled 2002 Contributions to Sulfate at Acadia, by State

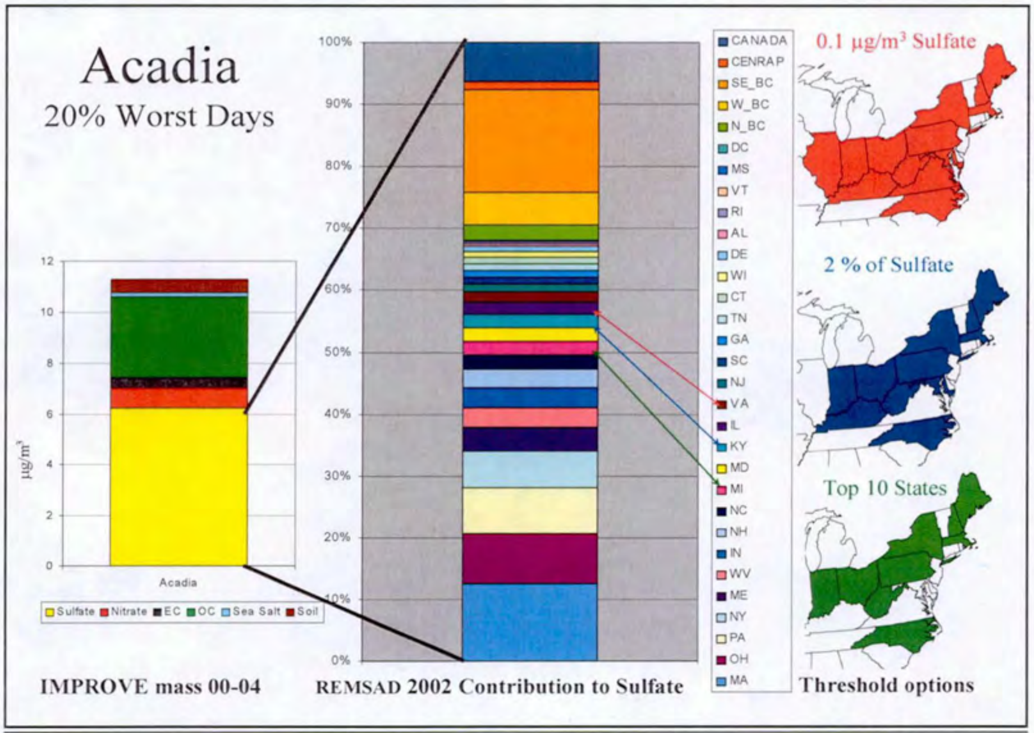


Figure 8.8: Modeled 2002 Contributions to Sulfate at Moosehorn, by State

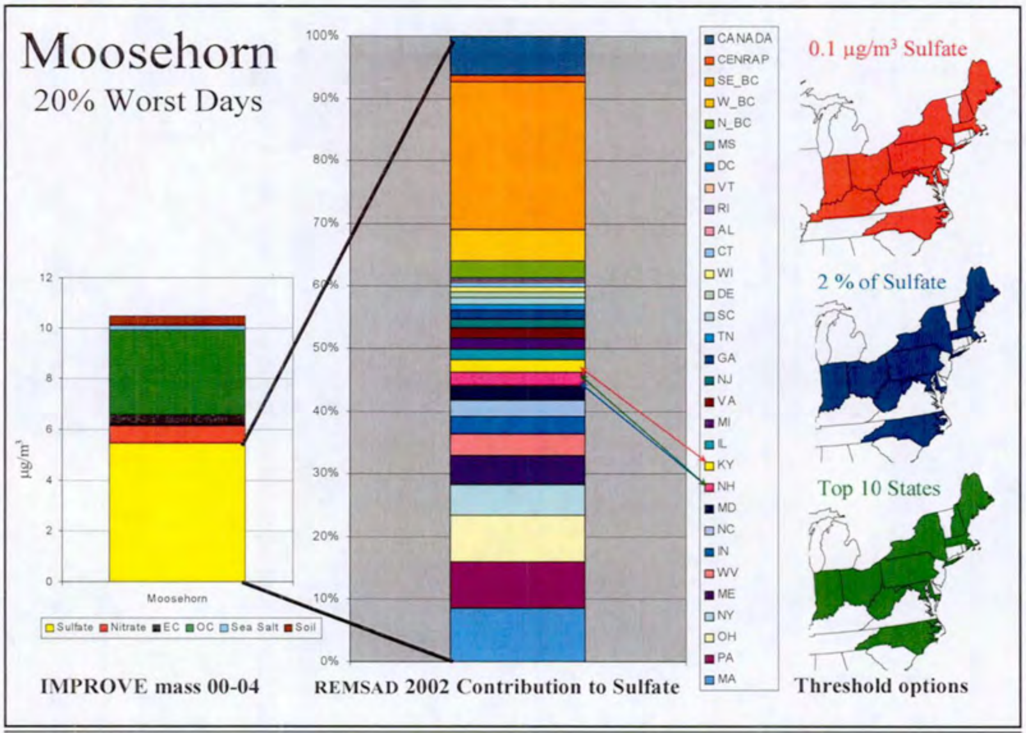


Figure 8.9: Modeled 2002 Contributions to Sulfate at Shenandoah, by State

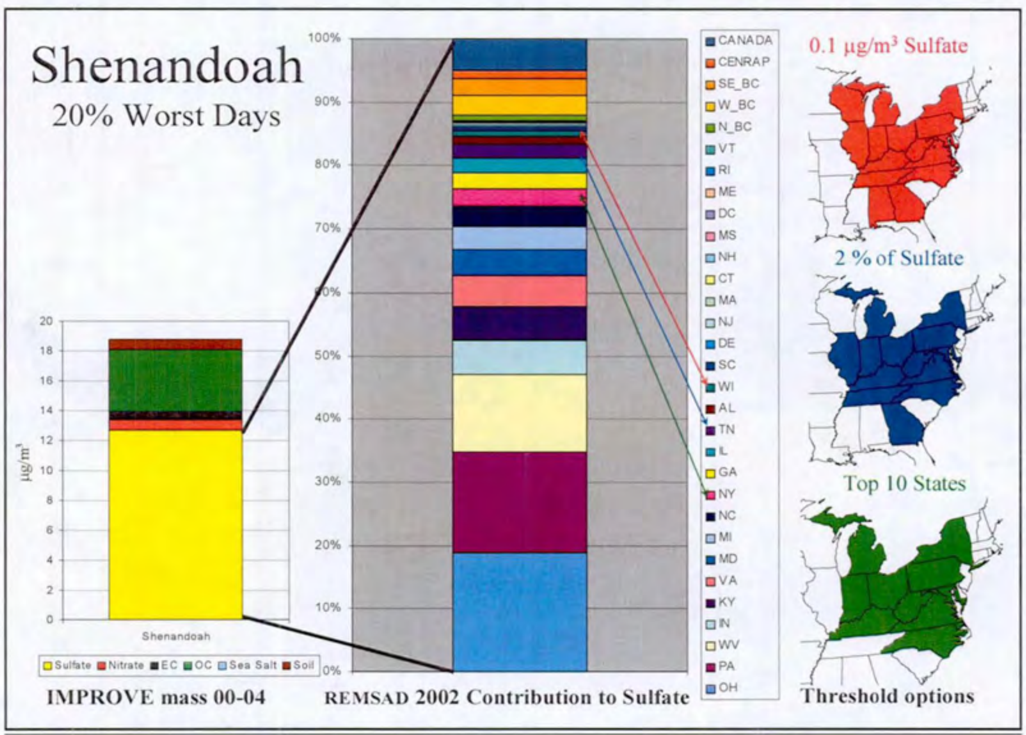
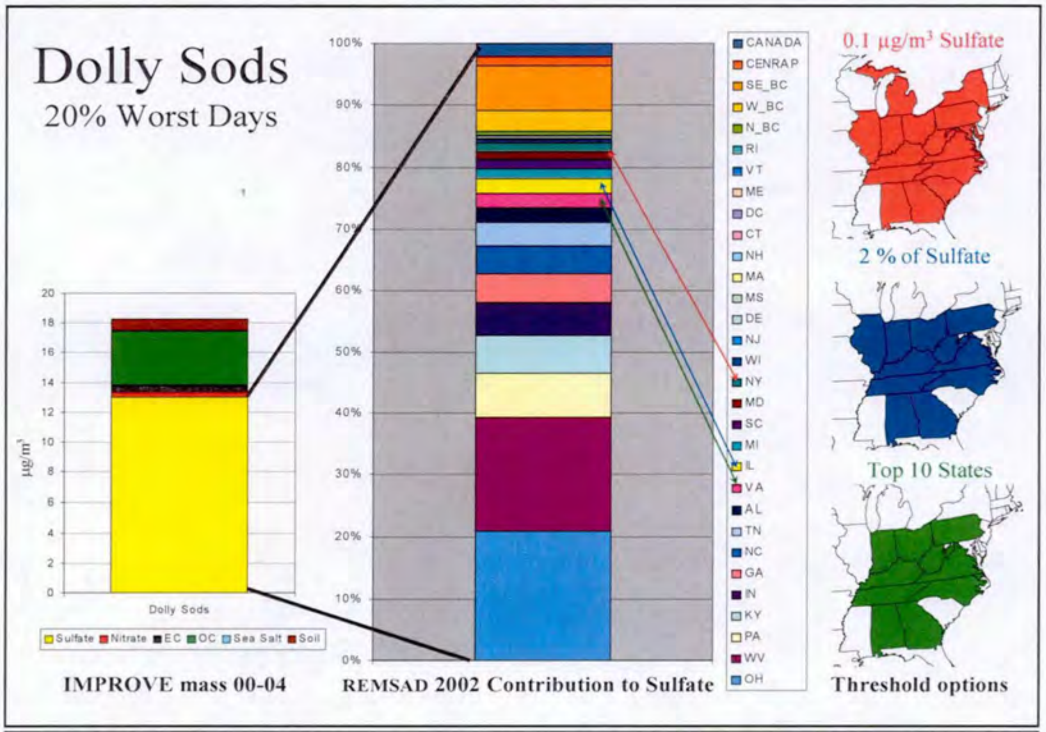


Figure 8.10: Modeled 2002 Contributions to Sulfate at Dolly Sods, by State



8.3 Emission Sources and Characteristics

As previously mentioned, the major pollutants responsible for regional haze are SO_2, NO_X, VOCs, NH_3, PM_{10}, and $PM_{2.5}$. The following is a description of the sources (e.g., point, area, and mobile) and characteristics of pollutant emissions contributing to haze in the eastern United States. Emissions data and graphics presented for the purposes of this section are taken from the MANE-VU 2002 Baseline Emissions Inventory, Version 2.0 (note that the more recent MANE-VU 2002 Baseline Emissions Inventory, Version 3.0, released in April 2006, has superseded Version 2.0 for modeling purposes). Although the emissions inventory database also includes carbon monoxide (CO), this primary pollutant is not considered here because it does not contribute to regional haze.

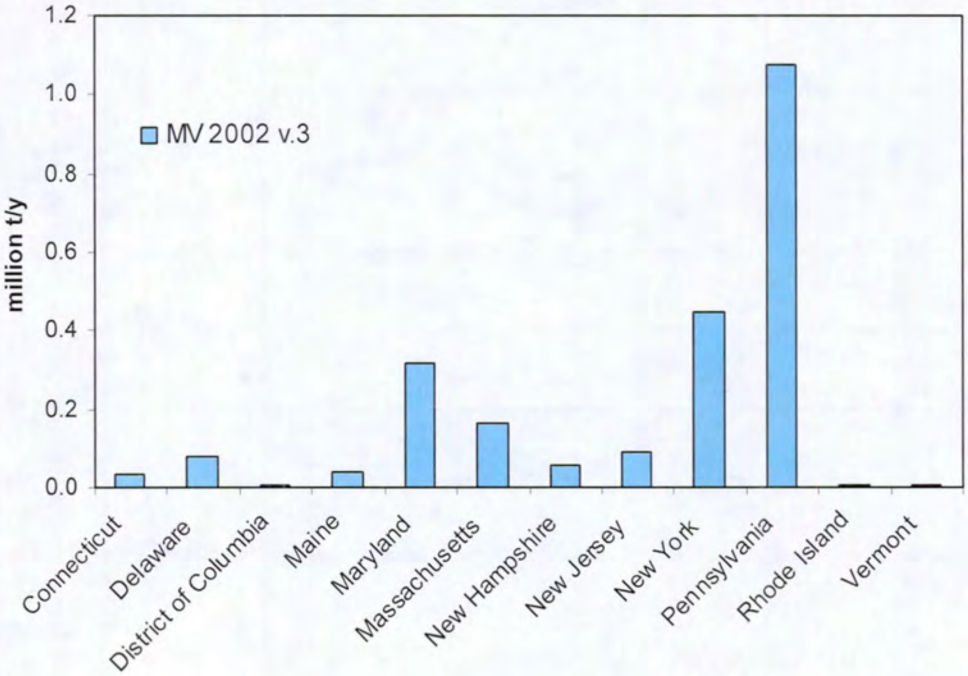
8.3.1 Sulfur Dioxide (SO_2)

SO_2 is the primary precursor pollutant for sulfate particles. Sulfate particles commonly account for more than 50 percent of particle-related light extinction at northeastern Class I areas on the clearest days and for as much as 80 percent or more on the haziest days. Hence, SO_2 emissions are an obvious target of opportunity for reducing regional haze in the eastern United States. Combustion of coal and, to a lesser extent, of certain petroleum products accounts for most anthropogenic SO_2 emissions. In fact, in 1998, a single source category – coal-burning power plants – was responsible for two-thirds of total SO_2 emissions nationwide (NESCAUM, 2001a).

Figure 8.11 shows SO_2 emissions in the MANE-VU states as extracted from the 2002 MANE-VU inventory (MARAMA, 2005). Most states in the region showed declines in annual SO_2 emissions through 2002 compared with those from previous inventories.

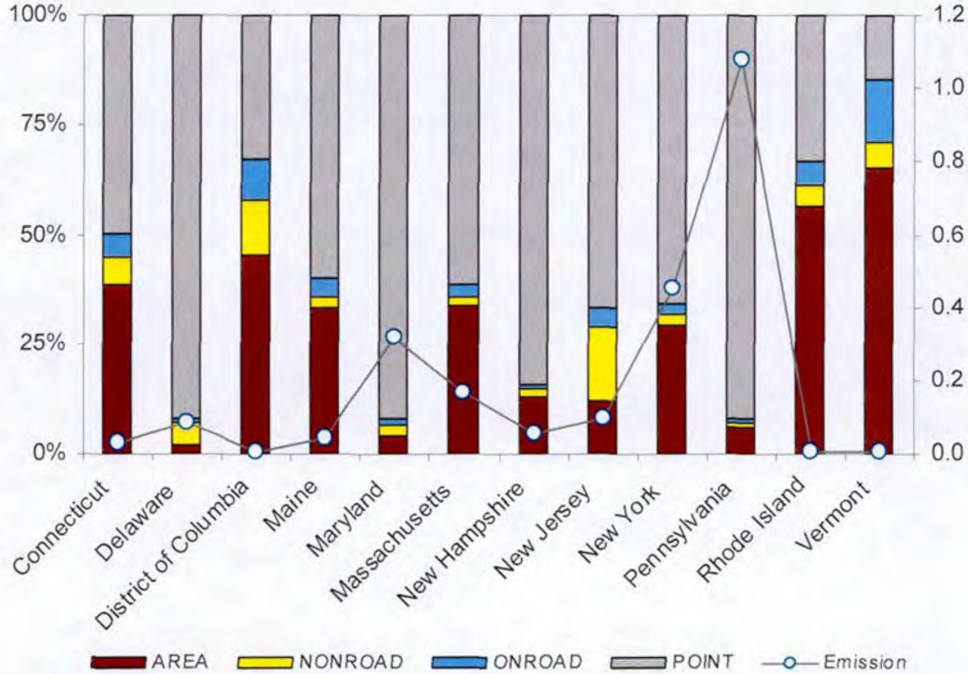
This decline can be attributed in part to implementation of Phase 2 of the Acid Rain Program, which in 2000 further reduced allowable emissions below Phase 1 levels and extended emission limits to a greater number of power plants.

Figure 8.11: Annual Sulfur Dioxide (SO_2) Emissions, by State



The bar graph in Figure 8.12 displays the percentage contributions from different emission source categories to annual SO_2 emissions in the MANE-VU states in 2002. The chart shows that point sources – consisting mainly of stationary combustion sources for generating electricity, industrial power, and heat – dominate SO_2 emissions in the region. Smaller stationary combustion sources, referred to collectively as area sources, are another important source category in the MANE-VU states. These include smaller industrial, commercial, and institutional boilers as well as residential heating sources. By contrast, on-road and non-road mobile sources make a relatively minor contribution to overall SO_2 emissions in the region (NESCAUM, 2001a).

Figure 8.12: 2002 Sulfur Dioxide (SO_2) Emissions, by State
Bar Graph = Percentage Fractions of Four Source Categories
Line Graph = Total Annual Emissions (10^6 tpy)



8.3.2 Volatile Organic Compounds (VOC)

Existing emissions inventories generally refer to volatile organic compounds (VOCs) as hydrocarbons whose volatility and reactivity in the atmosphere make them particularly important to ozone formation. From a regional haze perspective, there is less concern with the volatile organic gases emitted directly to the atmosphere than with the secondary organic aerosols (SOAs) that VOCs form after undergoing condensation and oxidation. Thus the VOC inventory category is of interest primarily because of the organic carbon component of $PM_{2.5}$.

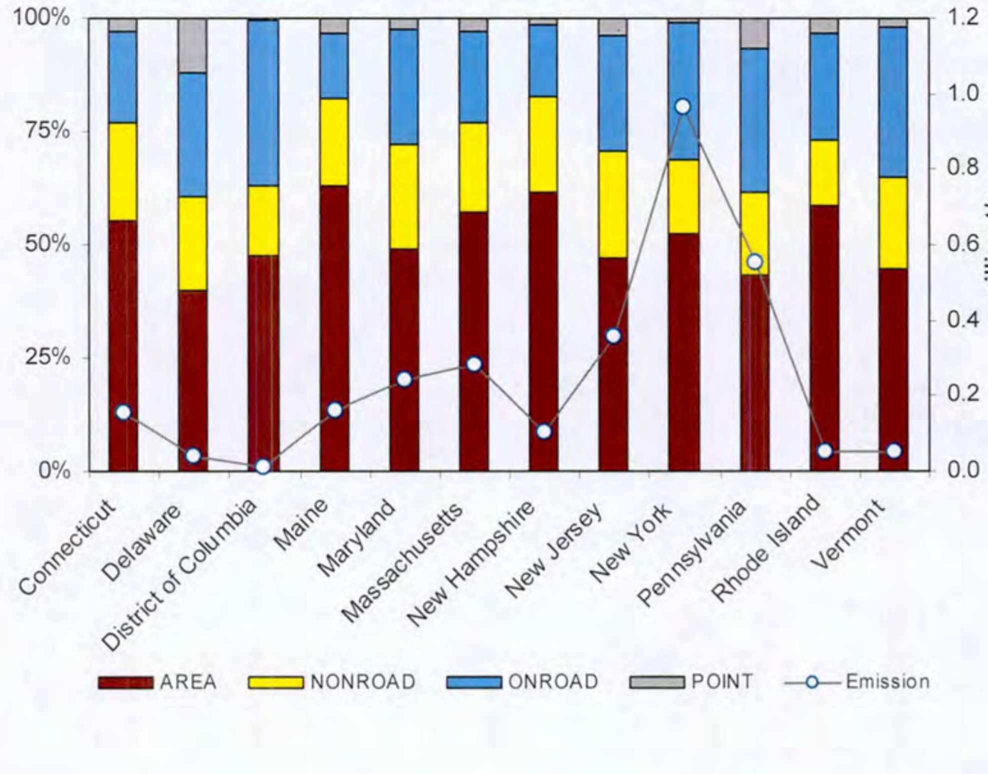
After sulfate, organic carbon generally accounts for the next largest share of fine particle mass and particle-related light extinction at northeastern Class I sites. The term organic carbon encompasses a large number and variety of chemical compounds that may be emitted directly from emission sources as components of primary PM or that may form in the atmosphere as secondary pollutants. The organic carbon present at Class I areas includes a mix of species, including pollutants originating from anthropogenic (i.e., manmade) sources as well as biogenic hydrocarbons emitted by vegetation. Recent efforts to cut back on manmade organic carbon emissions have been undertaken mainly for the purpose of reducing summertime ozone formation in urban centers. Future efforts to make further reductions in organic carbon emissions may be driven by programs that address fine particles and visibility.

Understanding the source regions and transport dynamics for organic carbon in MANE-VU and nearby Class I areas is likely to be more complex than for sulfate. This complexity derives from the large number and diversity of organic carbon species, the wide variation in their transport characteristics, and the fact that a given species may undergo numerous complex chemical reactions in the atmosphere. Thus, the organic carbon contribution to visibility impairment at most Class I areas in the region is likely to include manmade pollution from nearby sources, manmade pollution transported from a distance, and biogenic emissions – especially terpenes from coniferous forests.

As shown in Figure 8.13, the VOC inventory is dominated by mobile (on- and off-road) sources and area sources. Mobile sources of VOCs include evaporative emissions from transportation fuels and exhaust emissions from gasoline passenger vehicles and diesel-powered, heavy-duty vehicles. VOC emissions may also originate from a variety of area sources (including those that use organic solvents, architectural coatings, and dry cleaning fluids) as well as from some point sources (e.g., industrial facilities and petroleum refineries).

Biogenic VOCs (not included in Figure 8.13) may play an important role within the rural settings typical of Class I areas. The oxidation of hydrocarbon molecules containing seven or more carbon atoms is generally the most significant pathway for the formation of light-scattering organic aerosol particles (Odum et al., 1997). Smaller reactive hydrocarbons that may contribute significantly to urban smog (ozone) are less likely to play a role in organic aerosol formation, although it is noted that high ozone levels can have an indirect effect on visibility by promoting the oxidation of other available hydrocarbons, including biogenic emissions (NESCAUM, 2001a). In short, further work is needed to characterize the organic carbon contribution to regional haze in the MANE-VU states and to develop emissions inventories that will be of greater value for visibility planning purposes. As pointed out in Subsection 8.1, above, organic carbon could be the subject of future control measures to mitigate regional haze but is not the focus of initial planning.

Figure 8.13: 2002 Volatile Organic Carbon (VOC) Emissions, by State
Bar Graph = Percentage Fractions of Four Source Categories
Line Graph = Total Annual Emissions (10^6 tpy)



8.3.3 Oxides of Nitrogen (NO_X)

NO_X emissions contribute to visibility impairment in the eastern U.S. by forming light-scattering nitrate particles. Nitrate generally accounts for a substantially smaller fraction of fine particle mass and related light extinction than sulfate and organic carbon at northeastern Class I areas. Notably, nitrate may play a more important role in urban settings and in the wintertime. In addition, NO_X may have an indirect effect on summertime visibility by virtue of its role in the formation of ozone, which in turn promotes the formation of secondary organic aerosols (NESCAUM, 2001a).

Since 1980, nationwide emissions of NO_X from all sources have shown little change. Emissions increased by 2 percent between 1989 and 1998 (EPA, 2000a). To a large extent, increases from the industrial and transportation sectors have been offset by emission reductions from power plant combustion sources implemented during the same time period. Figure 8.14 shows NO_X emissions in 2002 for each state in the MANE-VU region. In the several years just prior to 2002, most MANE-VU states experienced declining NO_X emissions.

Mobile sources and power plants generally dominate state and national NO_X emissions inventories. Nationally, power plants account for more than one-quarter of all NO_X emissions, amounting to over six million tons annually. The electric sector plays an even larger role in parts of the industrial Midwest, where power plants contribute significantly to NO_X emissions. By contrast, mobile sources dominate the NO_X inventories for more urbanized MANE-VU states, as shown in Figure 8.15. In these states, on-road mobile sources (i.e., highway vehicles) represent the largest NO_X source category. Emissions from non-road (i.e., off-highway) mobile sources, primarily diesel-powered engines, also make up a substantial fraction of the inventory.

Figure 8.14: Annual Nitrogen Oxide (NO_X) Emissions, by State

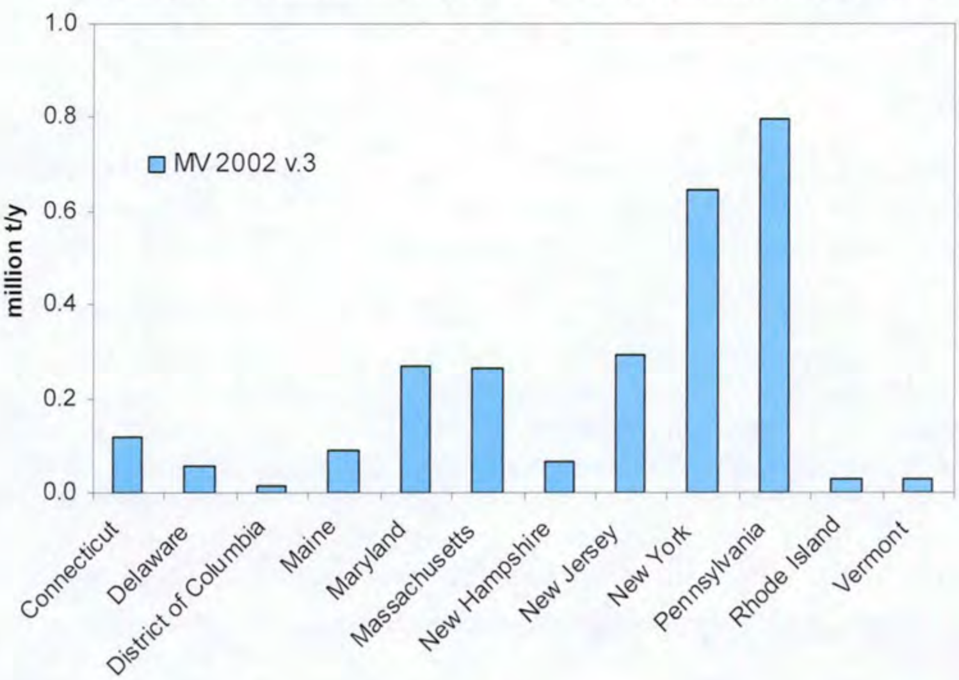
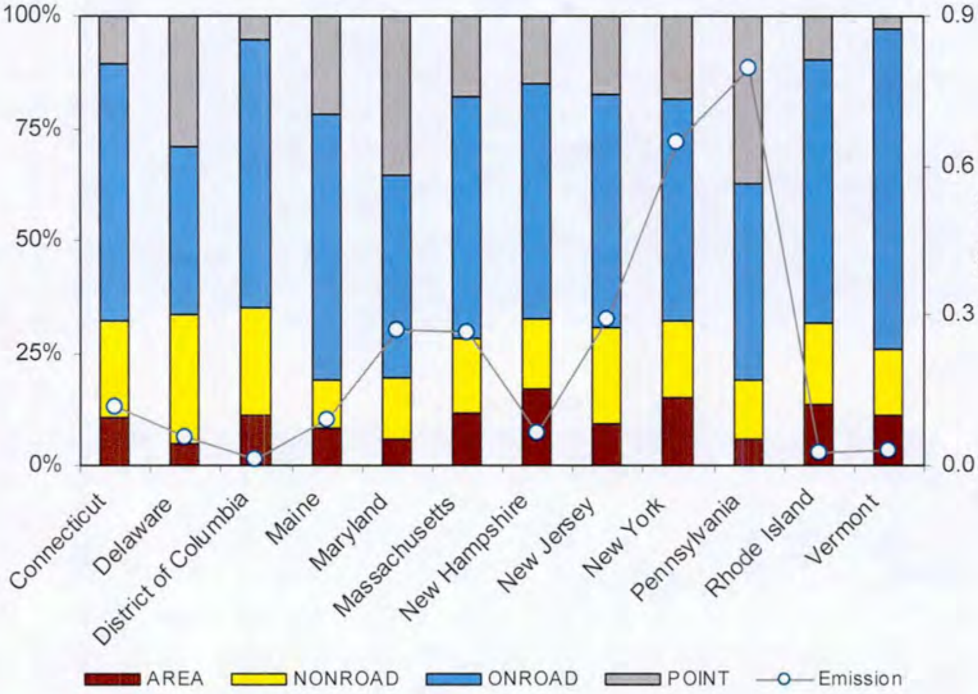


Figure 8.15: 2002 Nitrogen Oxide (NO_X) Emissions, by State
Bar Graph = Percentage Fractions of Four Source Categories
Line Graph = Total Annual Emissions (10^6 tpy)



8.3.4 Primary Particulate Matter (PM_{10} and $PM_{2.5}$)

Directly emitted, or "primary," particles (as distinct from secondary particles that form in the atmosphere through chemical reactions involving precursor pollutants such as SO_2 and NO_X) can also contribute to regional haze. For regulatory purposes, a distinction is made between particulate matter (PM) with an aerodynamic diameter less than or equal to 10 micrometers (PM_{10}) and smaller particles with an aerodynamic diameter less than or equal to 2.5 micrometers ($PM_{2.5}$).

Figures 8.16 and 8.17 show PM_{10} and $PM_{2.5}$ emissions, respectively, for the MANE-VU states as reported for the 2002 base year. Most states showed a steady decline in annual PM_{10} emissions in the years leading up to the 2002 inventory. By contrast, emission trends for primary $PM_{2.5}$ were more variable.

Crustal sources are significant contributors of primary PM emissions. This category includes fugitive dust emissions from construction activities, paved and unpaved roads, and agricultural tilling. Typically, monitors estimate PM_{10} emissions from these types of sources by measuring the horizontal flux of particulate mass at a fixed downwind sampling location within perhaps 10 meters of a road or field. Comparisons between estimated emission rates for fine particles using these types of measurement techniques and observed concentrations of crustal matter in the ambient air at downwind receptor sites suggest that physical or chemical processes remove a significant fraction of crustal material relatively quickly. As a result, it rarely entrains into layers of the atmosphere where it can be transported to downwind receptor locations. Because of this discrepancy between estimated emissions and observed ambient concentrations, modelers typically reduce estimates of total $PM_{2.5}$ emissions from all crustal sources by applying a factor of 0.15 to 0.25 to the total $PM_{2.5}$ emissions before including them in modeling analyses.

Figure 8.16: Primary Coarse Particle (PM_{10}) Emissions, by State

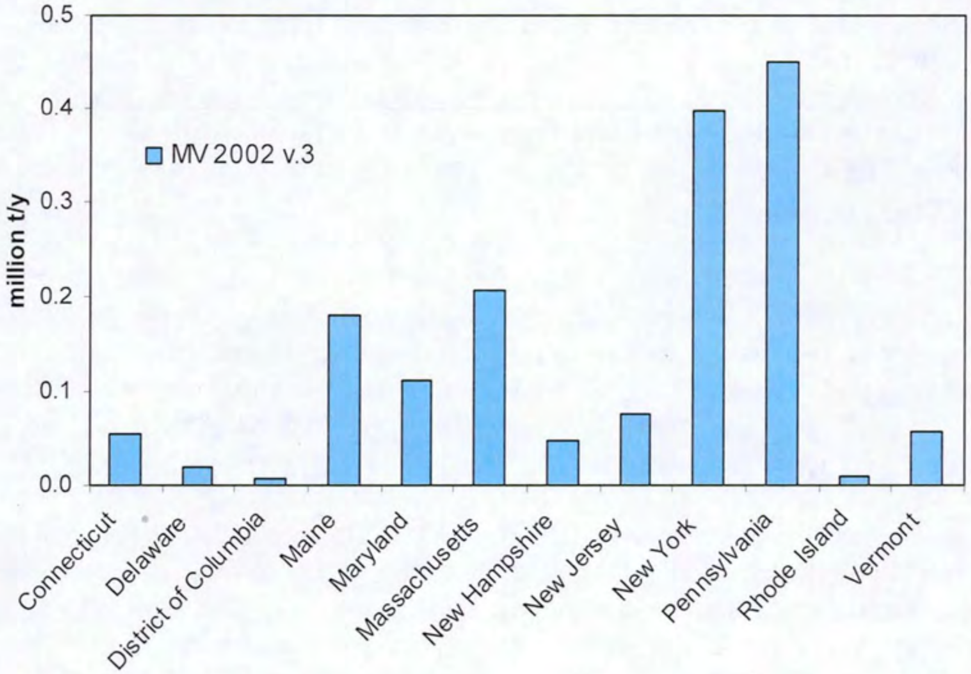
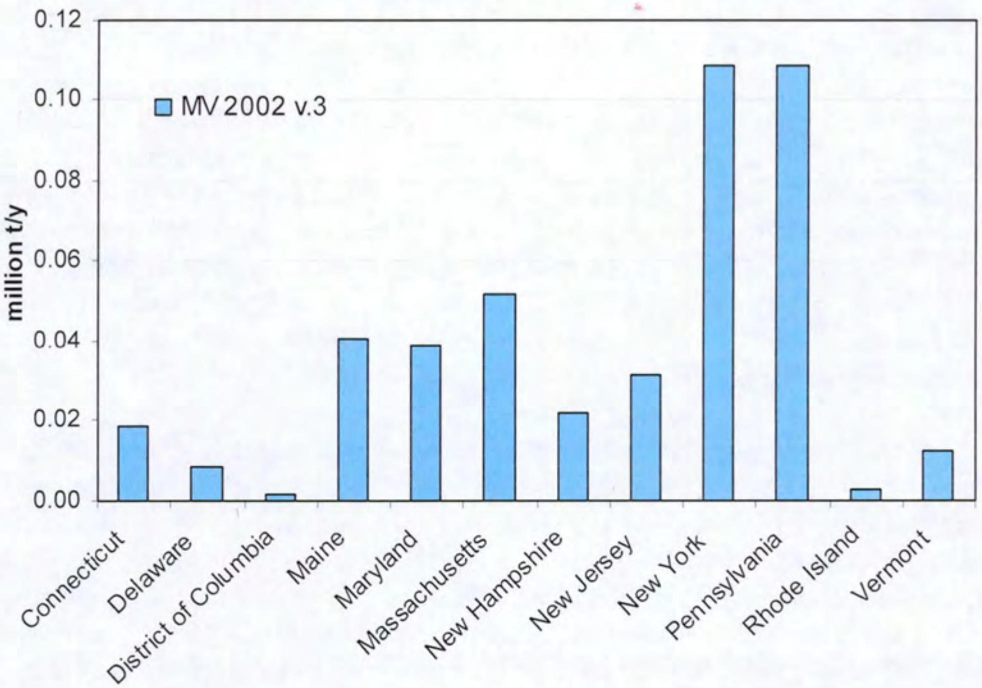


Figure 8.17: Primary Fine Particle ($PM_{2.5}$) Emissions, by State



From a regional haze perspective, crustal material generally does not play a major role. On the 20 percent best visibility days during the baseline period (2000-2004), crustal PM accounted for six to eleven percent of particle-related light extinction at MANE-VU Class I sites. On the 20 percent worst visibility days, however, crustal material generally plays a much smaller role, ranging from two to three percent visibility extinction, than other haze-forming pollutants. Moreover, the crustal fraction includes materials of natural origin, such as soil or sea salt, that is not targeted under the Regional Haze Rule. Of course, the crustal fraction can be influenced by construction, agricultural practices, and road maintenance (including wintertime salting). Thus, to the extent that these types of activities are found to affect visibility at Northeastern Class I areas, control measures to reduce coarse and fine particulate matter deriving from crustal material may prove beneficial and are within the purview of EPA or state agencies.

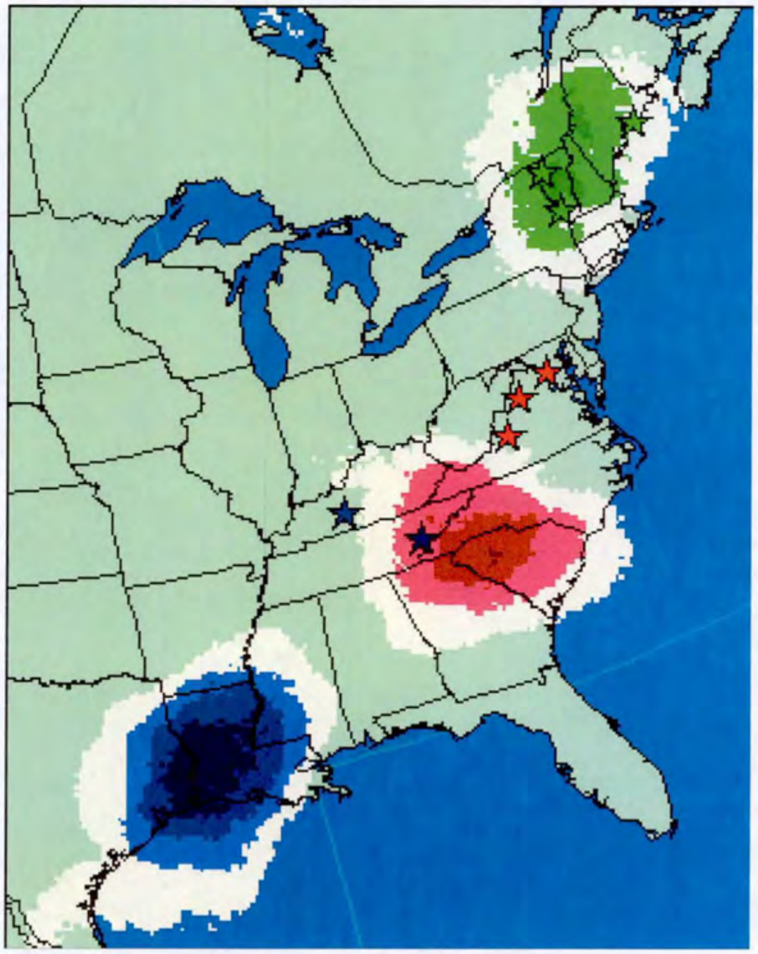
Experience from the western United States, where the crustal component has played a more significant role in overall particulate levels, may be applicable to the extent that it is relevant to the situation in the eastern states. In addition, a few areas in the Northeast, such as New Haven, Connecticut, and Presque Isle, Maine, have had some experience with the control of dust and road-salt stemming from regulatory obligations related to their past non-attainment status with respect to the NAAQS for PM_{10}.

Current emissions inventories for the entire MANE-VU area indicate that residential wood combustion represents 25 percent of primary fine particle emissions in the region. This finding implies that rural sources can play an important role as well as contributions from the region's many populous urban areas. An important consideration in this regard is that residential wood combustion occurs mainly in the winter months, while managed or prescribed burning activities occur largely in other seasons. The latter category includes agricultural field-burning, prescribed burning of forested areas, and miscellaneous burning activities such as construction waste burning. Particulate emissions from many of these sources can be managed by limiting allowed burning activities to times when favorable meteorological conditions can efficiently disperse the emissions.

Although data are currently lacking, New Hampshire and other MANE-VU states are concerned about the growing use of residential wood stoves by homeowners seeking alternatives to petroleum-based fuels for home heating. Recent, localized problems with smoke emissions from outdoor wood boilers (wood-fired hydronic heaters) prompted the New Hampshire legislature, in August 2008, to pass a law that tightens requirements on the sale, installation, and use of these devices. NHDES will keep close watch on smoke emissions from the residential sector to determine whether additional control measures on this source category may be necessary in the next few years.

Figure 8.18, taken from Appendix B of the MANE-VU Contribution Assessment, represents the results of source apportionment and trajectory analyses on wood smoke in the area extending from the Gulf States to the Northeast. The green-highlighted portion of the map depicts the wood smoke source region in the Northeast states. The stars on the map represent air monitor sites (including those at several Class I areas) whose data sets were determined to be useful to the modeling analysis. Although New Hampshire's Great Gulf Wilderness was not specifically analyzed, it is believed that the green portion of the map adequately characterizes the wood smoke source region in the vicinity of this Class I area.

Figure 8.18: Wood Smoke Source Regional Aggregations



Northeast: ACAD, PMRC, LYBR
Mid-Atlantic: WASH, SHEN, JARI
Southeast: GRSM, MACA

MANE-VU's "Technical Support Document on Agricultural and Forestry Smoke Management in the MANE-VU Region," September 1, 2006 (Attachment V), concluded that fire from land management activities was not a major contributor to regional haze in MANE-VU Class I Areas, and that the majority of emissions from fires were from residential wood combustion.

Figures 8.19 and 8.20 show that area sources dominate primary PM emissions. (EPA's National Emissions Inventory categorizes residential wood combustion and some other combustion sources as area sources.) The relative contribution of point sources is larger in the primary $PM_{2.5}$ inventory than in the primary PM_{10} inventory because the crustal component of particulate emissions (consisting mainly of larger, or coarse, particles) contributes more to overall PM_{10} levels than to $PM_{2.5}$ levels. At the same time, pollution control equipment commonly installed at large point sources is usually more efficient at capturing coarse particle emissions.

Figure 8.19: 2002 Primary Coarse Particle (PM_{10}) Emissions, by State
Bar Graph = Percentage Fractions of Four Source Categories
Line Graph = Total Annual Emissions (10^6 tpy)

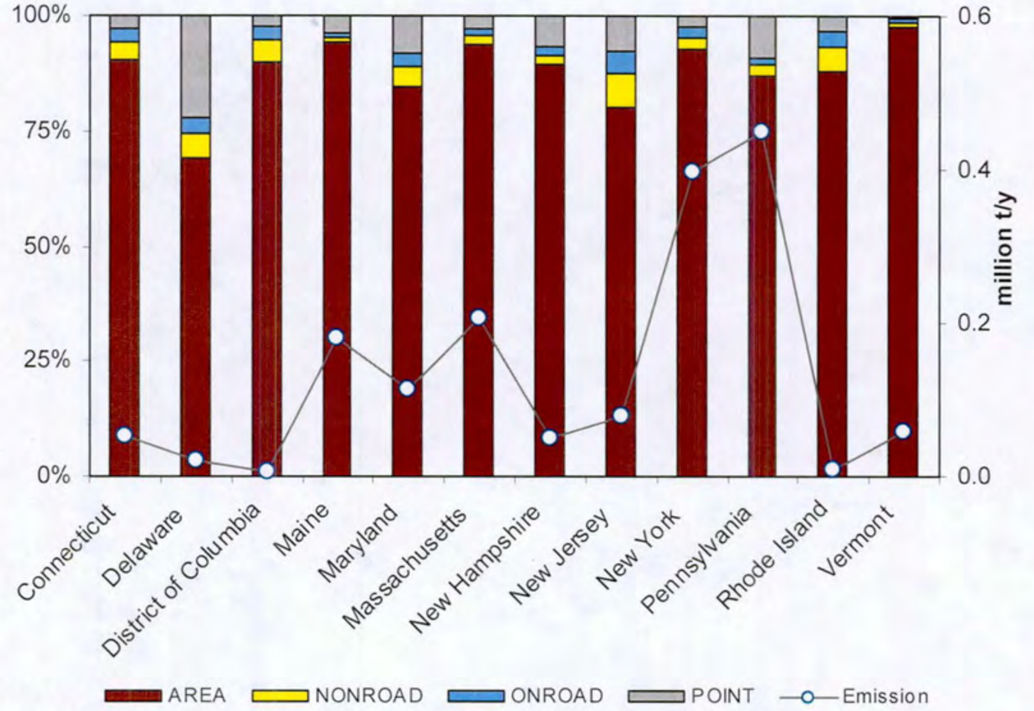
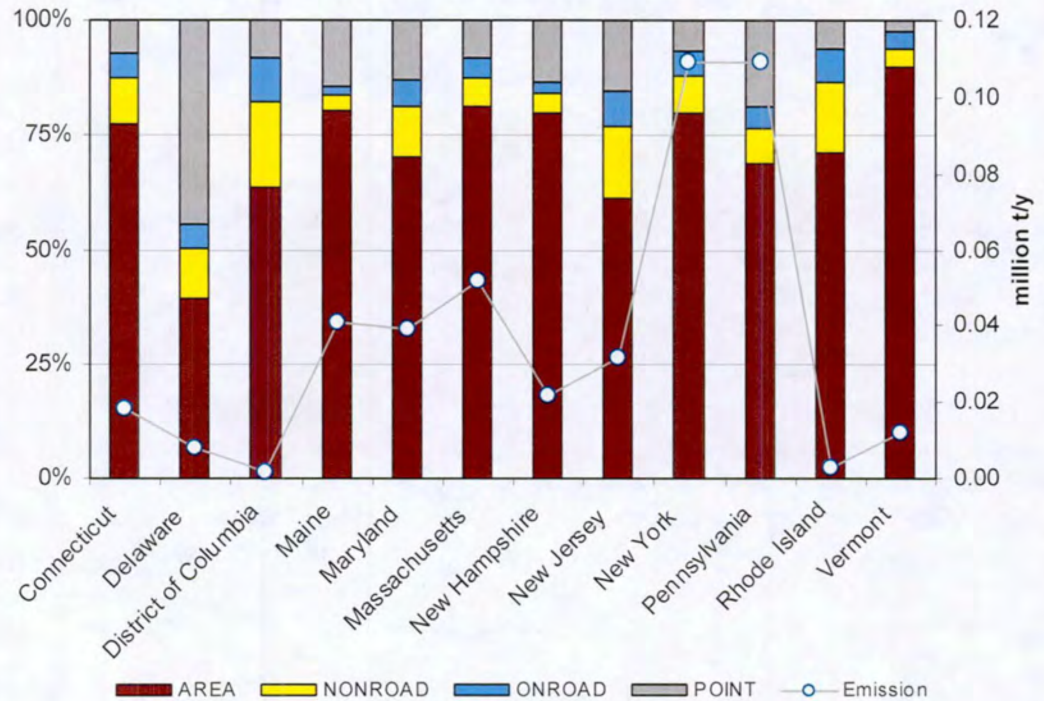


Figure 8.20: 2002 Primary Fine Particle ($PM_{2.5}$) Emissions, by State
Bar Graph = Percentage Fractions of Four Source Categories
Line Graph = Total Annual Emissions (10^6 tpy)



8.3.5 Ammonia Emissions (NH_3)

Because ammonium sulfate ($(NH_3)_2SO_4$) and ammonium nitrate (NH_3NO_3) are significant contributors to atmospheric light scattering and fine particle mass, knowledge of ammonia emission sources is important to the development of effective regional haze reduction strategies. According to 1998 estimates, livestock agriculture and fertilizer use accounted for approximately 86 percent of all ammonia emissions to the atmosphere (EPA, 2000b). However, improved ammonia inventory data are needed as inputs to the photochemical models used to simulate fine particle formation and transport in the eastern United States. States were not required to include ammonia in their emissions data collection efforts until fairly recently (see the Consolidated Emissions Reporting Rule, 67 CFR 39602, June 10, 2002). Therefore, emissions data for ammonia do not exist at the same level of detail or reliability as exists for other pollutants.

Ammonium ion (formed from ammonia emissions to the atmosphere) is an important constituent of airborne particulate matter, typically accounting for 10–20 percent of total fine particle mass. Reductions in ammonium ion concentrations can be instrumental to controlling regional haze because such reductions yield proportionately greater reductions in fine particle mass. Ansari and Pandis (1998) showed that a 1 $\mu g/m^3$ reduction in ammonium ion could result in up to a 4 $\mu g/m^3$ reduction in fine particulate matter. Decision makers, however, must weigh the benefits of ammonia reduction against the significant role it plays in neutralizing acidic aerosol.[14]

To address the need for improved ammonia inventories, MARAMA, NESCAUM, and EPA funded researchers at Carnegie Mellon University (CMU) in Pittsburgh to develop a regional ammonia inventory (Davidson et al., 1999). This study focused on three issues with respect to current emission estimates: 1) a wide range of ammonia emission factors, 2) inadequate temporal and spatial resolution of ammonia emissions estimates, and 3) a lack of standardized ammonia source categories.

The CMU project established an inventory framework with source categories, emission factors, and activity data that are readily accessible to the user. With this framework, users can obtain data in a variety of formats[15] and can make updates easily, allowing additional ammonia sources to be added or emission factors to be replaced as better information becomes available (Strader et al., 2000; NESCAUM, 2001b).

Figures 8.21 and 8.22 show estimated ammonia emissions for the MANE-VU states in 2002. Area and on-road mobile sources dominate the ammonia inventory data. Specifically, emissions from agricultural sources and livestock production account for the largest share of estimated ammonia emissions in the MANE-VU region, except in the District of Columbia. The two other sources contributing significant emissions are wastewater treatment systems and gasoline exhaust from highway vehicles.

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[14] SO_2 reacts in the atmosphere to form sulfuric acid (H_2SO_4). Ammonia can partially or fully neutralize this strong acid to form ammonium bisulfate or ammonium sulfate. If planners focus future control strategies on ammonia and do not achieve corresponding SO_2 reductions, fine particles formed in the atmosphere will be substantially more acidic than those presently observed.

[15] For example, the user will have the flexibility to choose the temporal resolution of the output emissions data or to spatially attribute emissions based on land-use data.

Figure 8.21: Ammonia (NH_3) Emissions, by State

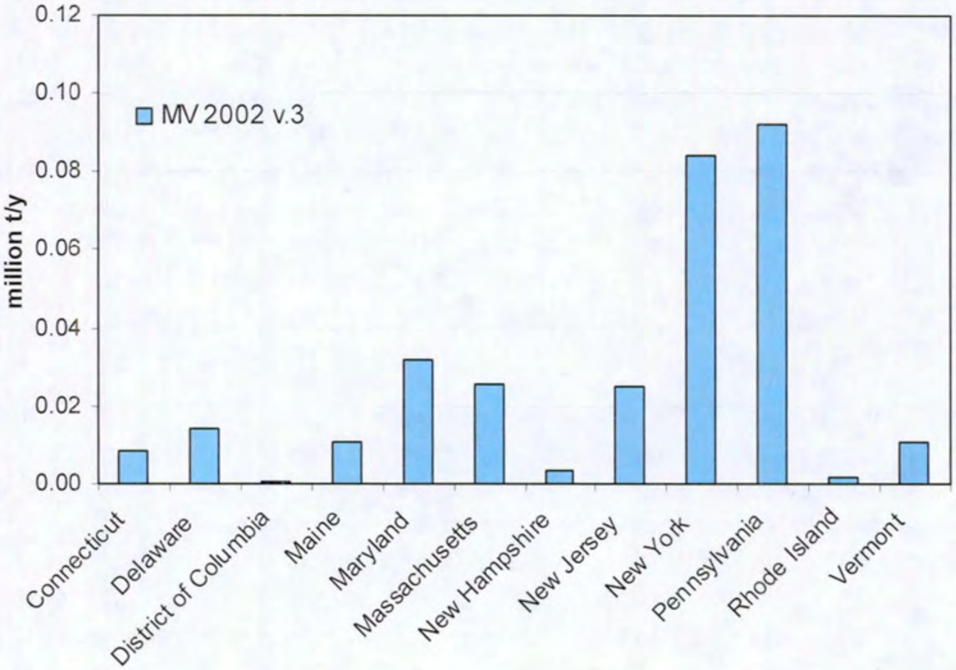
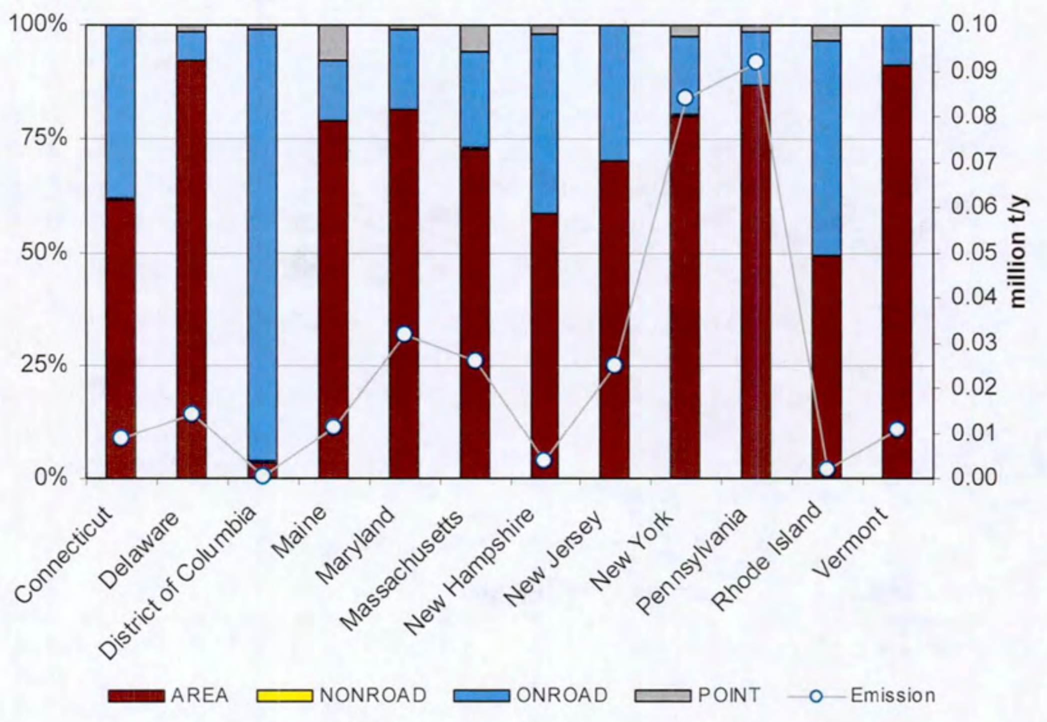


Figure 8.22: 2002 Ammonia (NH_3) Emissions, by State
Bar Graph = Percentage Fractions of Four Source Categories
Line Graph = Total Annual Emissions (10^6 tpy)



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9. BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

In the Regional Haze Rule, EPA included provisions for reducing emissions of visibility-impairing pollutants from large sources that, because of their age, were exempted from new source performance standards (NSPS) established under the Clean Air Act. These provisions, known as Best Available Retrofit Technology, or BART, are published in 40 CFR 51.308(e).

Under this part of the rule, New Hampshire is required to submit an implementation plan containing emission limitations representing Best Available Retrofit Technology and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I area. This requirement applies unless New Hampshire demonstrates that an emissions trading program or other alternative will achieve greater reasonable progress toward natural visibility conditions. New Hampshire, with the help of the MANE-VU Regional Planning Organization, has developed a strategy meeting the requirements of BART. This section of the SIP specifically addresses how New Hampshire's plan satisfies BART requirements. A more general description of BART implementation within MANE-VU is presented later in Part 10.2.2 of Section 10, Reasonable Progress Goals.

The BART provisions of the Regional Haze Rule require states to develop an inventory of sources within each state that would be eligible for BART controls. The rule also:

- Outlines methods to determine whether a source is "reasonably anticipated to cause or contribute to haze,"
- Defines the methodology for conducting BART control analysis,
- Provides presumptive performance levels for electricity generating units (EGUs) greater than 200 MW at fossil-fuel-fired power plants larger than 750 megawatts (all BART-eligible EGUs in New Hampshire are below this size); and
- Provides a justification for the use of the Clean Air Interstate Rule (CAIR) as meeting BART requirements for CAIR-affected electrical generating units (EGUs). (Note: With the remand of CAIR and its replacement with the proposed Transport Rule, EPA's previous determination of regulatory equivalency is invalid. New Hampshire has always held that, because the old CAIR requirements were not source-specific, they should not, in the general case, be considered equivalent to BART requirements, which *are* source-specific.)

Beyond the specific elements listed above, EPA has allowed the states a great deal of flexibility in implementing the BART program. Because of the collective importance of BART sources to the management of regional haze, the MANE-VU Board decided, in June 2004, that a BART determination would be made by the member states for each BART-eligible source, without exception. **Consequently, New Hampshire has completed a BART analysis on all BART-eligible sources in the state.** This process includes consideration of the available technology, potential improvements in visibility, and other factors described later in this section.

9.1 BART Applicability

The BART requirements pertain to large facilities in each of 26 source categories that meet certain criteria, including industrial boilers, pulp and paper mills, cement kilns, and other large stationary sources. The BART program applies to units installed and operated between 1962 and 1977 with the potential to emit more than 250 tons per year of a visibility-impairing pollutant. Each BART-eligible unit must undergo a case-by-case analysis to determine whether new emission restrictions are appropriate to limit the unit's impact on visibility at Class I areas.

9.2 BART-Eligible Sources in New Hampshire

A list of New Hampshire's BART-eligible sources is presented in Table 9.1. These sources were identified using the methodology contained in 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule, adopted July 6, 2005.

Table 9.1: BART-Eligible Sources in New Hampshire

MANE-VU BART ID	Source and Unit	BART Pollutants	Location
NH1	Public Service of New Hampshire Merrimack Station Unit MK2 320-MW EGU	SO_2 NO_X PM	Bow, NH
NH2	Public Service of New Hampshire Newington Station Unit NT1 400-MW EGU	SO_2 NO_X PM	Newington, NH

Note: Both BART-eligible sources are located at power plants smaller than the 750-MW minimum size for which EPA has provided presumptive performance levels.

9.2.1 Cap-Outs and Shutdowns

Many facilities in the MANE-VU region are relatively small emission sources with potential emissions exceeding the BART applicability threshold of 250 tons per year of haze-causing pollutants but whose actual emissions are well below 250 tons in any year. Some of these facilities may have accepted an enforceable permit limitation restricting their emissions to less than 250 tons per year. Any otherwise BART-eligible facility may be allowed to "cap-out" of BART by accepting enforceable permit limits. In addition, some BART-eligible facilities within the region may have permanently shut down. **In New Hampshire, no BART-eligible facilities capped out or permanently shut down to avoid BART.**

9.2.2 Small Source Exemptions

As provided in 40 CFR 51.308(e)(1)(ii)I of the Regional Haze Rule, a state is not required to make a BART determination for either SO_2 or NO_X if a BART-eligible source has the potential to emit less than 40 tons per year of these pollutants, or for PM_{10} if a BART-eligible source emits less than 15 tons per year of this pollutant. **No BART-eligible sources in New Hampshire have been exempted from the BART determination process.**

9.2.3 Large Electrical Generating Units

Under 40 CFR 51.308(e)(1)(ii)(B), the determination of BART for large EGUs at fossil-fuel-fired power plants having a total generating capacity greater than 750 megawatts must follow the guidelines presented in 40 CFR Part 51, Appendix Y. This part of the rule defines the process for making BART determinations on a case-by-case basis. (States are not required to use this process when making BART determinations for other types of sources.) **Because all BART-eligible EGUs in New Hampshire are installed at power plants smaller than 750**

MW, they are not subject to the guidelines of 40 CFR Part 51, Appendix Y. However, as discussed in Subsection 9.4 below, NHDES has conducted a source-specific BART analysis using the Appendix Y guidelines for each of these EGUs.

9.3 Determination of BART Requirements for BART-Eligible Sources and Analysis of Best Retrofit Technologies

40 CFR 51.308(e)(1)(ii)(A) requires that, for each BART-eligible source within the state, any BART determination must be based on an analysis of the best system of continuous emission control technology available and the associated emission reductions achievable. In addition to considering available technologies, this analysis must evaluate five specific factors for each source:

1. The costs of compliance,
2. The energy and non-air quality environmental impacts of compliance,
3. Any existing pollution control technology in use at the source,
4. The remaining useful life of the source, and
5. The degree of visibility improvement which may reasonably be anticipated from the use of BART.

NESCAUM examined, from a regional perspective, the various options available to MANE-VU states for meeting these requirements. The findings are contained in the NESCAUM report "Five-Factor Analysis of BART Eligible Sources: Survey of Options for Conducting BART Determinations," June 1, 2007 (Attachment W).

9.3.1 BART Determinations and Required Control Levels

NHDES has performed BART determinations for all BART-eligible sources in New Hampshire. The BART level of control for each source was taken to be that level of continuous emission reductions that would be achieved by installation of the best retrofit system, after considering the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

For its BART determinations on each BART-eligible source, NHDES used the method in 40 CFR Part 51, Appendix Y, Guidelines for BART Determinations under the Regional Haze Rule. Detailed BART analyses for New Hampshire's two BART sources, PSNH Merrimack Station Unit MK2 and PSNH Newington Station Unit NT1, are presented in Attachment X. The application of BART to these two sources yields estimated emission reductions from the 2002 baseline year in the following amounts:

- Approximately 22,000 tons per year of sulfur dioxide,
- Approximately 100+ tons per year of nitrogen oxides, and
- No additional reduction in particulate matter (existing controls = BART).

Tables 9.2 and 9.3 summarize the BART determinations for the two BART-eligible sources in New Hampshire for the visibility-impairing pollutants SO_2, NO_X, and PM. Included in these tables are the baseline and BART control levels, BART emission limits, and annual emissions before and after BART implementation.

Table 9.2: Emission Reductions Resulting from BART Controls at PSNH Merrimack Station Unit MK2

Pollutant	BART Controls	Baseline Capacity Factor (%)	2002 Baseline Emissions (tpy)	Baseline Control Level (%)	BART Control Level (%)	BART Emission Limit	Est. 2002 Emissions after BART (tpy)	Est. 2002 Emission Reductions (tpy)
SO_2	Flue gas desulfurization (FGD) (July 1, 2013)	72	20,902	40 [16]	90 [17] (as initially modeled)	10% of uncontrolled SO_2 emissions, calendar monthly avg.	2,090	18,812
NO_X	Selective catalytic reduction (SCR) (existing)	72	2,871	85	85 (same as baseline)	0.30 lb/MMBtu, 30-day rolling average	2,871	122[18]
PM	Two electrostatic precipitators (ESPs) in series (existing)	72	210	99	99 (same as baseline)	0.08 lb/MMBtu total suspended particulate (TSP) [19]	210	0

Table 9.3: Emission Reductions Resulting from BART Controls at PSNH Newington Station Unit NT1

Pollutant	BART Controls	Baseline Capacity Factor (%)	2002 Baseline Emissions (tpy)	Baseline Control Level (%)	BART Control Level (%)	BART Emission Limit	Est. 2002 Emissions after BART (tpy)	Est. 2002 Emission Reductions (tpy)
SO_2	SO_2 emission limitation (July 1, 2013)	19 [20]	5,226	0	67 [21]	0.50 lb/MMBtu, 30-day rolling average	1,742	3,484 [22]
NO_X	Low-NOx burners, overfire air, and water injection (existing)	19	943	33 [23]	33 (same as baseline)	0.35 lb/MMBtu (oil) and 0.25 lb/MMBtu (oil/gas), daily avg. (= RACT limit)	943	0
PM	ESP (existing)	19	196	42 / 93 [24]	42 / 93 (same as baseline)	0.22 lb/MMBtu total suspended particulate (TSP)	196	0

[16] The 40% baseline level of control for Unit MK2 is based on a switch to a lower-sulfur coal that occurred in 1994.

[17] For modeling purposes, a control level of 90% from baseline 2002 SO_2 emissions has been applied as a conservative estimate of expected performance. The actual rate of reduction from baseline 2002 emissions will vary, depending on the sulfur content of coal used in future years. Unit MK2 will continue to be subject to Title V operating permit conditions that limit coal sulfur content to 2.0 lb/MMBtu gross heat content and that require SO_2 emissions to be controlled to no more than 10 percent of the uncontrolled SO_2 emission rate (i.e., 90% SO_2 removal).

[18] Estimated emission reductions from baseline that would occur with existing controls and a revised emission limit of 0.30 lb/MMBtu.

[19] This revised emission limit will simultaneously apply to Unit MK1 (not a BART-eligible source).

[20] The current Title V operating permit for PSNH Newington Station limits the annual capacity factor for Unit NT1 to 66.2%. This capacity factor limit is expressed as a restriction on the maximum annual heat input rating for the unit.

[21] Minimum expected reduction based on 100% use of residual fuel oil at 0.4% actual sulfur content, or a 50:50 ratio (Btu basis) of natural gas to residual fuel oil at 0.8% actual sulfur content. The reduction in maximum permitted SO_2 emissions is 75%.

[22] Additional emission reductions beyond the stated value may occur with a switch to 0.5% low-sulfur oil upon implementation of MANE-VU's low-sulfur oil strategy by no later than 2018.

[23] The baseline level of NO_X control was calculated by comparing emission test results from October 1992 (0.371 lb/MMBtu) to test results from 2001 (0.249 lb/MMBtu) after a number of NO_X reduction projects were completed on Unit NT1.

[24] The lower value is based on a 2001 stack test value of 0.058 lb/MMBtu and an AP42 uncontrolled emission factor of 0.103 lb/MMBtu. The higher value is the stated efficiency under normal operating conditions from a 1971 Buell Envirotech Corp. performance specification for this unit; maximum efficiency under design conditions is stated as 98 percent.

In Table 9.2, the BART control level for sulfur dioxide, for PSNH Merrimack station Unit MK2, is stated as 90 percent. This control level is based on implementation of New Hampshire statute RSA 125-O, Multiple Pollutant Reduction Program, which requires installation and operation of a flue gas desulfurization, or scrubber, system on both units at this facility. Because the scrubber will be optimized for mercury emission reductions, Unit MK2 may not experience the typical SO_2 removal efficiency of 95 percent associated with new FGD technology. Consequently, a more conservative SO_2 control level of 90 percent (minimum) was established as an operating condition in the facility's air permit. (The Multiple Pollutant Reduction Program requires the scrubber to operate at a sustained control level of 80 percent or greater for mercury emission reductions.) The required SO_2 control level effectively means that actual SO_2 emission reductions must *exceed* 90 percent on average.

The modest reduction in NOx emissions for Unit MK2 would result from operational changes with existing control equipment. These changes would be necessary to ensure compliance with a BART performance level of 0.30 lb/MMBtu, which is lower than the current effective emission limit of 0.37 lb/MMBtu.

In Table 9.3, for PSNH Newington Station Unit NT1, the BART control level for sulfur dioxide is based on an emission limitation of 0.50 lb/MMBtu, applicable to all fuels and fuel mixtures. (The boiler can be fired with either natural gas or liquid fuel (i.e., residual fuel oil or biofuel), or it can be co-fired with both types of fuel at the same time.) Note that SO_2 emissions from this unit may be further reduced with the planned introduction of 0.5-percent-sulfur residual fuel oil by 2018 upon implementation of MANE-VU's low-sulfur oil strategy (contingent on fuel availability and cost). See Parts 10.2.3 and 11.4.2 of this SIP for a detailed description of this control measure.

9.3.2 Visibility Improvements Resulting from BART

To assess the degree of visibility improvement associated with the implementation of BART controls, NHDES conducted a set of CALPUFF modeling runs for the New Hampshire BART-eligible sources under controlled and uncontrolled conditions. Results were tabulated for the average of the 20% best visibility (about 11.7 to 12.4 dv) and the 20% worst visibility (about 22.8 dv) modeled days at each nearby Class I area. The BART guidelines suggest that models be used in a "relative" way to estimate the expected visibility benefits of BART controls. NHDES normalized the CALPUFF modeling results, calculated predicted visibility extinctions, and then applied predicted extinctions to a best-fit equation to the actual observed extinction-to-deciview relationship measured at Acadia NP, Great Gulf NWR, and Lye Brook NWR. Thus, CALPUFF was applied in a relative way using real data as the basis. The CALPUFF-predicted visibility benefits from BART controls on the 20% best and 20% worst visibility days are shown in Tables 9-4 and 9-5 for New Hampshire's two BART facilities, Unit MK2 at PSNH Merrimack Station and Unit NT1 at PSNH Newington Station.

Further description of the assessment of visibility impacts from these two BART sources may be found in the detailed BART analyses presented in Attachment X.

Table 9-4. CALPUFF Modeling Results for Merrimack Station Unit MK2: Visibility Improvements from BART Controls

On the 20% Best Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	90% with FGD	1.07	0.83	**0.17**
NOx	Additional 25% with SCR upgrade	0.21	0.18	**0.10**
PM	90% with upgraded controls	0.16	0.12	**0.03**
On the 20% Worst Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	90% with FGD	**0.26**	**0.20**	0.03
NOx	Additional 25% with SCR upgrade	**0.07**	**0.06**	0.03
PM	90% with upgraded controls	**0.07**	**0.05**	<0.01*

* below sensitivity limit of model

Note: Values in **boldface** are considered as having greater validity in the modeling estimation of maximum visibility benefits from BART controls.

Table 9-5. CALPUFF Modeling Results for Newington Station Unit NT1: Visibility Improvements from BART Controls

On the 20% Best Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	FGD (90% sulfur reduction*)	0.57	0.45	0.09
	1.0%-S residual fuel oil (50% sulfur reduction*)	0.30	0.24	0.05
	0.5%-S residual fuel oil (75% sulfur reduction*)	0.46	0.36	0.07
	0.3%-S residual fuel oil (85% sulfur reduction*)	0.52	0.40	0.08
	0.50 lb SO_2/MMbtu (77% sulfur reduction*)	0.47	0.37	0.08
	Switch from 0.50 lb SO_2/MMbtu emission limit to 0.3%S residual fuel oil	*<0.05*	*0.03*	*<0.01****
NOx	SNCR (25% NOx reduction**)	0.11	0.10	0.04
	SCR (78% NOx reduction**)	0.34	0.30	0.12
PM	Baghouse (85% PM reduction**)	0.05	0.04	0.01
On the 20% Worst Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	FGD (90% sulfur reduction*)	**0.13**	**0.10**	<0.01***
	1.0%-S residual fuel oil (50% sulfur reduction*)	**0.07**	**0.06**	<0.01***
	0.5%-S residual fuel oil (75% sulfur reduction*)	**0.11**	**0.09**	0.01
	0.3%-S residual fuel oil (85% sulfur reduction*)	**0.13**	**0.10**	0.01
	0.50 lb SO_2/MMbtu (77% sulfur reduction*)	**0.11**	**0.09**	0.01
	Switch from 0.50 lb SO_2/MMbtu emission limit to 0.3%S residual fuel oil	***0.01***	***0.01***	*<0.01****
NOx	SNCR (25% NOx reduction**)	**0.04**	**0.03**	0.01
	SCR (78% NOx reduction**)	**0.11**	**0.10**	0.03
PM	Baghouse (85% PM reduction**)	**0.02**	**0.02**	<0.01***

* from maximum permitted level
** from baseline level with existing controls
*** below sensitivity limit of model

Note: Values in **boldface** are considered as having greater validity in the modeling estimation of maximum visibility benefits from BART controls.

NHDES also used the CALGRID photochemical model to perform a screening-level analysis of the anticipated effects of BART controls at New Hampshire's two BART-eligible sources (see Part 7.3.3 for a description of the CALGRID modeling platform). Separate CALGRID modeling runs were conducted to examine the effects of selected emission control measures on each of these sources. One run assessed the effects of installing scrubber technology on Merrimack Station Unit MK2. The second run assessed the effects of switching to lower-sulfur residual fuel oil for Newington Station Unit NT1. Both simulations were performed for the full summer modeling episode (May 15 to September 15, 2002) and used the 2018 BOTW emissions inventory scenario as a baseline (see Part 6.1.2 for a description of all future-year emissions inventories). The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutant within the region. NHDES post-processed the modeled concentration reductions to estimate the corresponding visibility improvements at Class I areas.

Based on the CALGRID modeling results, the installation of scrubber technology on Merrimack Station Unit MK2 is expected to reduce maximum predicted 24-hour average SO_2 concentration impacts by up to 21 $\mu g/m^3$ (8 ppb by volume) and maximum predicted 24-hour average $PM_{2.5}$ concentration impacts by up to 1 $\mu g/m^3$. The largest modeled pollutant concentration reductions occur within a 50-kilometer radius of the facility, an area which does not contain any federal Class I areas. For the affected Class I areas (located 100 to 500 kilometers away), reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, are expected to yield a nominal improvement in visibility (about 0.1 deciview) on direct-impact hazy days.

For Newington Station Unit NT1, switching to lower-sulfur residual fuel oil is expected to reduce maximum predicted 24-hour average SO_2 concentration impacts by 2 $\mu g/m^3$ and maximum predicted 24-hour average $PM_{2.5}$ concentration impacts by 0.1 $\mu g/m^3$. At the affected Class I areas, reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, would yield negligible visibility improvement, according to the CALGRID modeling results.

9.4 Alternatives to BART for Any Source

40 CFR 51.308(e)(1)(v)(2) of the Regional Haze Rule provides that a state may opt to implement an emissions trading program or other alternative measure rather than require sources subject to BART to install, operate, and maintain BART. In such case, the state must demonstrate that the emissions trading program or other alternative measure will achieve greater reasonable progress than would be achieved through the installation and operation of BART. To make this demonstration, the state must submit an implementation plan containing the elements listed in the above-referenced part of the rule.

New Hampshire does not support the provisions of the BART rule that allow emissions trading programs or other alternative measures because they are not likely to yield visibility improvements equivalent to those that would accrue from source-specific BART controls. **Consequently, NHDES does not propose to use alternative measures for BART-eligible sources in New Hampshire.**

9.5 BART Enforceable Provisions and Implementation Schedule

The enforceable provisions and compliance schedule for BART are summarized in Tables 9-6 and 9-7 for New Hampshire's two BART-eligible sources. The BART control measures will be enforceable through a combination of existing permit conditions and administrative rules, including a newly adopted administrative rule Env-A 2300, Mitigation of Regional Haze (see Attachment GG).

40 CFR 51.308(e)(1)(iv) requires that BART must be in operation for each applicable source no later than five years after SIP approval. New Hampshire is requiring all BART-eligible sources to install and operate BART controls as expeditiously as practicable but in no case later than July 1, 2013.

40 CFR 51.308(e)(1)(v) requires that each source subject to BART maintain the required control equipment and establish procedures to ensure such equipment is properly operated and maintained. New Hampshire will meet this requirement by including in the Title V operating permit for each BART-eligible source provisions to ensure proper operation and maintenance of the control equipment. Note that, because New Hampshire does not have a merged construction permitting and Title V permitting program, requirements related to BART first need to be placed into a state temporary permit (i.e., construction permit) before they can be incorporated subsequently into a federal Title V operating permit.

Table 9-6: BART Enforceable Provisions and Compliance Schedule for PSNH Merrimack Station Unit MK2

Pollutant	BART Controls / Emission Limitations	Regulatory Citations*	Compliance Date
SO_2	Fuel sulfur limits (existing); Flue gas desulfurization (FGD), with required SO_2 percent reduction set at maximum sustainable rate, but not less than 90% as a calendar monthly average	Administrative Rule Env-A 1606.01, Maximum Sulfur Content Allowable in Coal; Temporary permit for FGD system (TP-0008); Proposed Title V operating permit (TV-0055);	FGD: July 1, 2013
NO_X	SCR (existing); NOx emission limit of 0.30 lb/MMBtu, 30-day rolling average	Proposed Title V operating permit (TV-0055); Administrative Rule Env-A 2300, Mitigation of Regional Haze	Rule: July 1, 2013
PM	Two ESPs in series (existing) TSP emission limit of 0.08 lb/MMBtu	Proposed Title V operating permit (TV-0055); Administrative Rule Env-A 2300, Mitigation of Regional Haze	Rule: July 1, 2013

Table 9-7: BART Enforceable Provisions and Compliance Schedule for PSNH Newington Station Unit NT1

Pollutant	BART Controls / Emission Limitations	Regulatory Citations*	Compliance Date
SO_2	SO_2 emission limit of 0.50 lb/MMBtu, 30-day rolling average, applicable to any fuel type or mix	Administrative Rule Env-A 2300, Mitigation of Regional Haze	Rule: July 1, 2013
NO_X	Low-NOx burners, overfire air, and water injection (existing); NOx emission limits of 0.35 lb/MMBtu with oil and 0.25 lb/MMBtu with oil/gas, 24-hour calendar day average	Title V operating permit (TV-OP-054)	N.A. (Existing controls are BART)
PM	Electrostatic precipitator (existing); TSP emission limit of 0.22 lb/MMBtu	Title V operating permit (TV-OP-054)	N.A. (Existing controls are BART)

*Applicable permits and rules are available in Attachments FF through II.

10. REASONABLE PROGRESS GOALS

40 CFR 51.308 (d)(1) of the Regional Haze Rule requires New Hampshire to establish, for each Class I area within the state, reasonable progress goals (RPG) toward achieving natural visibility conditions. On June 1, 2007, the U.S. Environmental Protection Agency (EPA) released final guidance to be used by states in setting reasonable progress goals. The goals must provide for visibility improvement on the days of greatest visibility impairment and ensure no visibility degradation on the days of least visibility impairment for the duration of the State Implementation Plan (SIP) period.

As provided in 40 CFR 51.308 (d)(1)(iv), the state must consult with other states in the setting of reasonable progress goals. The rule states:

> "In developing each reasonable progress goal, the State must consult with those States which may reasonably be anticipated to cause or contribute to visibility impairment in the mandatory Class I Federal area. In any situation in which the State cannot agree with another such State or group of States that a goal provides for reasonable progress, the State must describe in its submittal the actions taken to resolve the disagreement. In reviewing the State's implementation plan submittal, the Administrator will take this information into account in determining whether the State's goal for visibility improvement provides for reasonable progress towards natural visibility condition."

New Hampshire consulted with states found to contribute to visibility impairment at New Hampshire's Class I areas and with states that requested consultation with New Hampshire regarding visibility conditions at their Class I areas. In particular, New Hampshire worked closely with the other MANE-VU states to ensure consistency of approach in setting reasonable progress goals. **Accordingly, New Hampshire agrees with the reasonable progress goals established by Maine, Vermont, and New Jersey.** A description of the consultation process is found under Section 3, Regional Planning and Consultation.

The Regional Haze Rule also requires each Class I state to consider four factors in setting reasonable progress goals: cost, time needed for compliance, energy and non-air quality environmental impacts, and remaining useful life. In addition, the state must show that it considered the uniform rate of improvement and the emission reduction measures needed to achieve it for the period covered by the implementation plan. If the state proposes a rate of progress slower than the uniform rate of progress, the state must assess the number of years it would take to attain natural conditions if visibility improvement continues at the rate proposed.

10.1 Calculation of Uniform Rate of Progress

As a benchmark to aid in developing reasonable progress goals, MANE-VU compared baseline visibility conditions to natural visibility conditions at each MANE-VU Class I area. The difference between baseline and natural visibility conditions for the 20 percent worst days was used to determine the uniform rate of progress that would be needed during each implementation period in order to attain natural visibility conditions by 2064. Table 10.1 presents baseline visibility, natural visibility, and required uniform rate of progress for each MANE-VU Class I area. Visibility values are expressed in deciviews (dv), where each single-unit deciview decrease would represent a barely perceptible improvement in visibility.

Table 10.1: Uniform Rate of Progress Calculation (all values in deciviews)

Class I Area	2000-2004 Baseline Visibility (20% Worst Days)	Natural Visibility (20% Worst Days)	Total Improvement Needed by 2018	Total Improvement Needed by 2064	Uniform Annual Rate of Improvement
Acadia National Park	22.9	12.4	2.4	10.5	0.174
Moosehorn Wilderness and Roosevelt Campobello International Park	21.7	12.0	2.3	9.7	0.162
Great Gulf Wilderness and Presidential Range - Dry River Wilderness	22.8	12.0	2.5	10.8	0.180
Lye Brook Wilderness	24.5	11.7	3.0	12.8	0.212
Brigantine Wilderness	29.0	12.2	3.9	16.8	0.280

Note: Both natural conditions and baseline visibility for the 5-year period from 2000 through 2004 were calculated in conformance with an alternative method recommended by the IMPROVE Steering Committee.[25]

The reasonable progress goals established for MANE-VU's Class I Areas, described later in Subsection 10.3, are expected to provide visibility improvements in excess of the uniform rates of progress shown above.

10.2 Identification of (Additional) Reasonable Control Measures

New Hampshire and the other MANE-VU states have identified specific emission control measures – beyond those which individual states or RPOs had already made commitments to implement – that would be reasonable to undertake as part of a concerted strategy to mitigate regional haze. The proposed additional control measures were incorporated into the regional strategy adopted by MANE-VU on June 20, 2007, to meet the reasonable progress goals established in this SIP. The basic elements of this strategy are described in the New Hampshire/MANE-VU "Ask" (see Part 3.2.2 under Section 3, Regional Planning and Consultation). States targeted for coordinated actions toward achieving these goals include all of the MANE-VU states plus Georgia, Illinois, Indiana, Kentucky, Michigan, North Carolina, Ohio, South Carolina, Tennessee, Virginia, and West Virginia.[26]

In addition to including proposed emission controls in the eastern United States, MANE-VU determined that it was reasonable to include anticipated emission reductions in Canada in the modeling used to set reasonable progress goals. This determination was based on evaluations conducted before and during the consultation process (see description of relevant consultations in Part 3.2.1). Specifically, the modeling accounts for six coal-burning electric generating

[25] "Baseline and Natural Visibility Conditions, Considerations and Proposed Approach to the Calculation of Baseline and Natural Visibility Conditions at MANE-VU Class I Areas," NESCAUM, December 2006.

[26] In addition, Vermont identified at least one source in Wisconsin as a significant contributor to visibility impairment at the Lye Brook Wilderness Class I Area.

units (EGUs) in Canada having a combined output of 6,500 MW that are scheduled to be shut down and replaced by nine natural gas turbine units equipped with selective catalytic reduction (SCR) by 2018.

The process of identifying reasonable measures and setting reasonable progress goals is described in the subsections which follow. Further elaboration on the reasonable measures which make up the New Hampshire/MANE-VU long-term strategy is provided in Section 11 of this SIP. Under this plan, the affected states will have a maximum of 10 years to implement reasonable and cost-effective control measures to reduce primarily SO_2 and NO_X emissions. For a description of how proposed emission control measures were modeled to estimate resulting visibility improvements, see Subsection 10.4, Visibility Affects of (Additional) Reasonable Control Measures.

10.2.1 Rationale for Determining Reasonable Controls

40 CFR 51.308(d)(1)(i)(A) of EPA's Regional Haze Rule requires that, in establishing reasonable progress goals for each Class I area, the state must consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources. The SIP must include a demonstration showing how these factors were taken into consideration in setting the RPGs. These factors are sometimes termed the "four statutory factors," since their consideration is required by the Clean Air Act.

Early Focus on SO_2: MANE-VU conducted a Contribution Assessment (Attachment B) and developed a conceptual model that showed the dominant contributor to visibility impairment at all MANE-VU Class I areas during all seasons in the base year was particulate sulfate formed from emissions of SO_2. While other pollutants, including organic carbon, will need to be addressed in order to achieve the national visibility goals, MANE-VU's contribution assessment suggested that an early emphasis on SO_2 would yield the greatest near-term benefit. Therefore, it is reasonable to conclude that the additional measures considered in setting reasonable progress goals require reductions in SO_2 emissions.

Contributing Sources: The MANE-VU Contribution Assessment indicates that emissions from within MANE-VU in 2002 were responsible for approximately 25 percent of the sulfate at MANE-VU Class I Areas. Sources in the Midwest and Southeast regions were responsible for about 15 to 25 percent each. Point sources dominated the inventory of SO_2 emissions. Therefore, MANE-VU's long-term strategy includes additional measures to control sources of SO_2 both within the MANE-VU region and in other states that were determined to contribute to regional haze at MANE-VU Class I Areas.

The Contribution Assessment documented the source categories most responsible for visibility degradation at MANE-VU Class I Areas. As described in Section 11, Long-Term Strategy, there was a collaborative effort between the Ozone Transport Commission and MANE-VU to evaluate a large number of potential control measures. Several measures that would reduce SO_2 emissions were identified for further study.

Four-Factor Analysis: These efforts led to production of the MANE-VU report by MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007, otherwise known as the Reasonable Progress Report (Attachment Y). This report provides an analysis of the four statutory factors for five major source categories: electrical generating units (EGUs); industrial, commercial, and institutional (ICI) boilers; cement and lime kilns; heating oil combustion; and residential wood combustion. Table 10.2 summarizes the results of MANE-VU's four-factor analysis for the source categories considered.

Table 10.2: Summary of Results from Four-Factor Analysis of Different Source Categories

Source Category	Primary Regional Haze Pollutant	Control Measure(s)	Average Cost in 2006 dollars (per ton of pollutant reduction)	Compliance Timeframe	Energy and Non-Air Quality Environmental Impacts	Remaining Useful Life
Electric Generating Units	SO_2	Switch to a low-sulfur coal (generally <1% sulfur); switch to natural gas (virtually 0% sulfur); coal cleaning; flue gas desulfurization (FGD), including wet, spray-dry, or dry.	\$775-\$1,690 based on IPM® v.2.1.9 * \$170-\$5,700 based on available literature	2-3 years following SIP submittal	Fuel supply issues, possible permitting issues, reduced electricity production capacity, wastewater issues	50 years or more
Industrial, Commercial, Institutional Boilers	SO_2	Switch to a low-sulfur coal (generally <1% sulfur); switch to natural gas (virtually 0% sulfur); switch to a lower-sulfur oil; coal cleaning; combustion controls; flue gas desulfurization (FGD), including wet, spray-dry, or dry.	\$130-\$11,000 based on available literature; dependent on size.	2-3 years following SIP submittal	Fuel supply issues, potential permitting issues, control device energy requirements, wastewater issues	10-30 years
Cement and Lime Kilns	SO_2	Fuel switching; flue gas desulfurization (FGD), including wet, spray-dry, or dry; advanced flue gas desulfurization (FGD).	\$1,900-\$73,000 based on available literature; dependent on size.	2-3 years following SIP submittal	Control device energy requirements, wastewater issues	10-30 years
Heating Oil	SO_2	Switch to lower-sulfur fuel (varies by state)	\$550-\$750 based on available literature; high degree of uncertainty with this cost estimate	Currently feasible; capacity issues may influence timeframe for implementation of new fuel standards	Increased furnace/boiler efficiency, reduced furnace/boiler maintenance requirements	18-25 years
Residential Wood Combustion	PM	State implementation of NSPS, ban on resale of uncertified devices, installer training certification or inspection program, pellet stoves, EPA Phase II certified RWC devices, retrofit requirement, accelerated changeover requirement or inducement	\$0-\$10,000 based on available literature	Several years, depending on mechanism for emission reductions	Increased efficiency of combustion device, reduced greenhouse gas emissions	10-15 years

* Integrated Planning Model® CAIR versus CAIR plus analysis conducted for MARAMA/MANE-VU by ICF Consulting, L.L.C.

The MANE-VU states reviewed the four-factor analyses presented in the Reasonable Progress Report, consulted with one another about possible control measures, and concluded by adopting the statements known as the MANE-VU Ask. These statements identify the control measures that would be pursued toward improving visibility in the region. The following discussions focus on the four basic control strategies chosen by MANE-VU and included in the modeling to establish the reasonable progress goals:

1. Best Available Retrofit Technology (BART),
2. Low-sulfur fuel oil requirements,
3. Emission reductions from specific EGUs, and
4. Additional measures determined to be reasonable.

10.2.2 Best Available Retrofit Technology Controls

The MANE-VU states have identified approximately 100 BART-eligible sources of all types, including EGUs, in the region. Most of these facilities are already controlling emissions in response to other federal or state air programs or are likely to install emission controls under new programs. A complete compilation of BART-eligible sources in the MANE-VU region is available in Appendix A of MANE-VU's "Assessment of Control Technology Options for BART-Eligible Sources," March 2005, also known as the BART Report (Attachment Z).

To assess the benefits of implementing BART in the MANE-VU region, NESCAUM estimated emission reductions for twelve BART-eligible sources in MANE-VU states that would probably be controlled as a result of BART requirements alone. These sources include one EGU and eleven non-EGUs. The affected sources were identified by a survey of states' staff members, who furnished data on the potential control technologies and expected control levels for these sources under BART implementation. The twelve (non-EGU) sources are listed in Table 10.3 along with their 2002 baseline and 2018 estimated emissions. Information on these sources was incorporated into the 2018 emissions inventory projections that were used in the modeling to set reasonable progress goals.

Table 10.3: Estimated Emissions from BART-Eligible Facilities in MANE-VU States (Non-EGU Facilities Likely to be Controlled as a Result of BART Alone)

State	Facility Name	Unit Name	SCC Code	Plant ID (MANE-VU Inventory)	Point ID (MANE-VU Inventory)	Facility Type	2002 SO_2 Emissions (tons)	2018 SO_2 Emissions (tons)
MD	EastAlco Aluminum	28	30300101	021-0005	28	Metal Production	1,506	1,356
MD	Eastalco Aluminum	29	30300101	021-0005	29	Metal Production	1,506	1,356
MD	Lehigh Portland Cement	39	30500606	013-0012	39	Portland Cement	9	8
MD	Lehigh Portland Cement	16	30500915	021-0003	16	Portland Cement	1,321	1,189
MD	Lehigh Portland Cement	17	30500915	021-0003	17	Portland Cement	9,76	8,78
MD	Westvaco Fine Papers	2	10200212	001-0011	2	Paper and Pulp	8,923	1,338
ME	Wyman Station	Boiler 3	10100401	2300500135	004	EGU	616	308
ME	SAPPI Somerset	Power Boiler 1	10200799	2302500027	001	Paper and Pulp	2,884	1,442
ME	Verso Androscoggin LLC	Power Boiler 1	10200401	2300700021	001	Paper and Pulp	2,964*	1,482
ME	Verso Androscoggin LLC	Power Boiler 2	10200401	2300700021	002	Paper and Pulp	3,086*	1,543
NY	Kodak Park Division	U00015	10200203	8261400205	U00015	Chemical Manufacturer	2,3798	1,4216
NY	Lafarge Building Materials, Inc	41000	30500706	4012400001	041000	Portland Cement	14,800	4,440

Note: Many additional sources in MANE-VU are BART-eligible but are expected to be controlled as a result of other emission reduction programs (e.g., state-specific multi-pollutant programs).

*Data for 1999 baseline year.

***Best Available Retrofit Technology is Reasonable*:** BART controls are part of the strategy for improving visibility at MANE-VU Class I Areas. MANE-VU prepared reports to provide states with information about available control technologies (e.g., MANE-VU's BART Report referenced above), estimated cost ranges, and other factors associated with those controls. The reasonable progress goals established in this regional haze SIP assume that states whose emissions affect Class I areas in New Hampshire and elsewhere in MANE-VU will make determinations demonstrating the reasonableness of BART controls for sources in their states.

10.2.3 Low-Sulfur Fuel Strategy

The MANE-VU region, especially the Northeast, is heavily reliant on distillate oil for home space heating, with more than 4 million gallons used, according to 2006 estimates from the Energy Information Administration[27]. Likewise, the heavier residual oils are widely used by non-EGU sources and, to a lesser extent, the EGU sector. The sulfur content of distillate fuels currently averages above 2,000 ppm (0.2 percent). Although the sulfur content of residual oils varies by source and region, it can exceed 2.0 percent. Combustion of distillate and residual fuel in the MANE-VU states resulted in SO_2 emissions totaling approximately 380,000 tons in 2002.

As the second component of MANE-VU's long-term strategy, the member states agreed to pursue measures that would require the sale and use of fuel oils having reduced sulfur content. This strategy would be implemented in two phases:

- Phase 1 would require reducing the sulfur content in distillate (#1 and # 2) fuel oils from current levels of 2,000 to 2,300 ppm (0.20 to 0.23 percent) to a maximum of 500 ppm (0.05 percent) by weight. It would also restrict the sale of heavier blends of residual (# 4, #5, and # 6) fuel oils that have sulfur content greater than 2,500 ppm (0.25 percent) and 5,000 ppm (0.5 percent) by weight, respectively.
- Phase 2 would require further reducing the sulfur content of the distillate fraction from 500 ppm (0.05 percent) to 15 ppm (0.015 percent) while keeping the sulfur limits on residual oils at first-phase levels.

The two phases are to be introduced in sequence with slightly different timing for an inner zone of MANE-VU states[28] and the remainder of MANE-VU states. While all MANE-VU states have agreed to pursue implementation of both phases to full effect by the end of 2018, it is possible that not every state can make a firm commitment to these measures today. They are included in the modeling because they are reasonably expected to be adopted by 2018. States are expected to review the situation by the time of the first regional haze SIP progress report in 2013 and to seek alternate, equivalent reductions if necessary.

Reductions in sulfur dioxide emissions will occur as a direct consequence of the low-sulfur fuel strategy. For both phases combined, it is estimated that SO_2 emissions in the MANE-VU region will decline from 2002 levels by 168,222 tons per year for combustion of light distillates and by 42,875 tons per year for combustion of the heavier fuels. Together, these reductions represent a 35 percent decrease in the projected 2018 SO_2 emissions inventory for non-EGU sources in the region.

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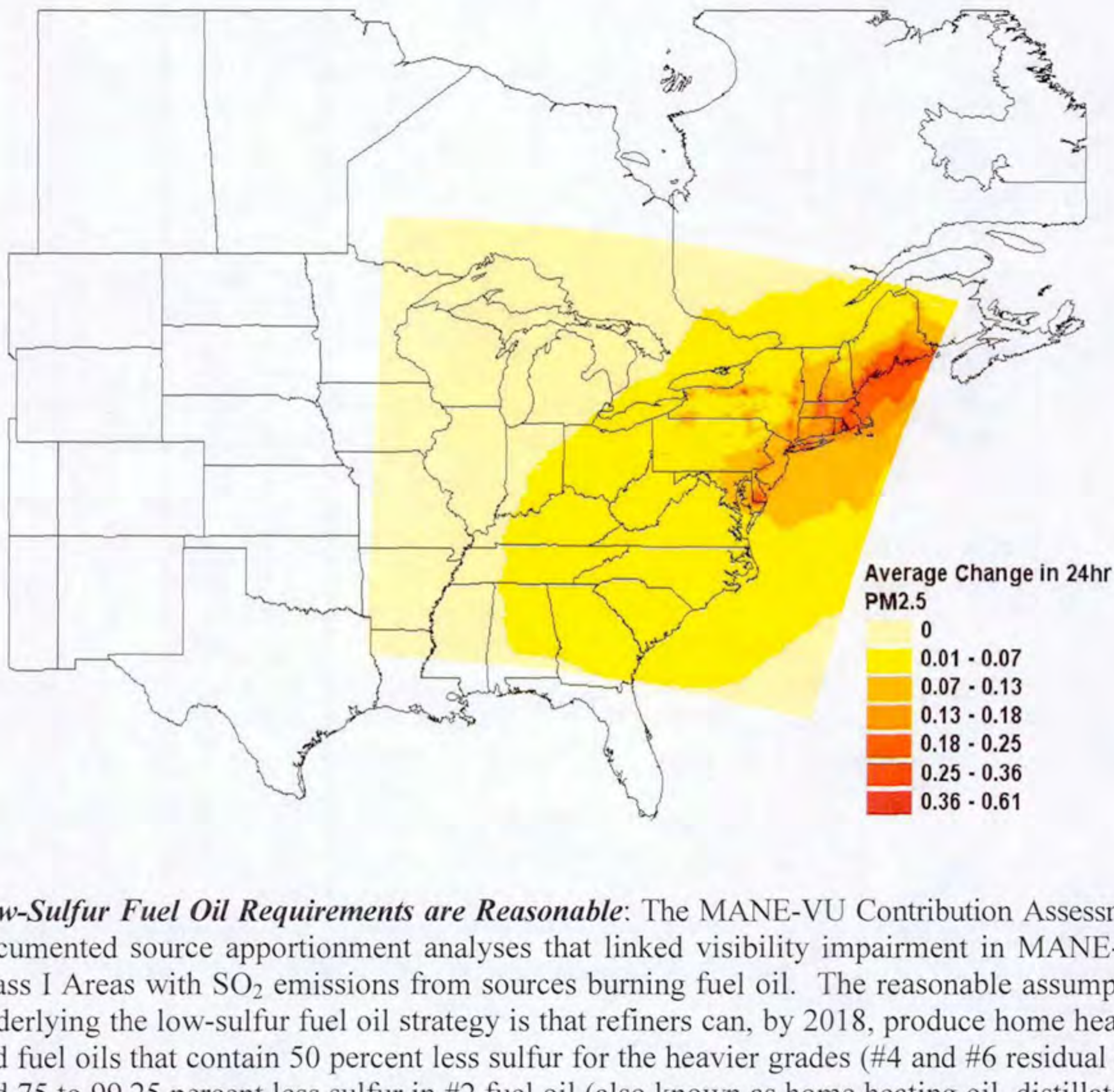
[27] U.S. Department of Energy, EIA, Table F3a, at http://www.eia.doe.gov/emeu/states/sep_fuel/html/fuel_use_df.html.

[28] The inner zone includes New Jersey, Delaware, New York City, and possibly portions of eastern Pennsylvania.

NESCAUM analyzed the two program phases separately for MANE-VU, but it is the combined benefit of implementing both phases that is relevant to the question of visibility improvement by 2018. To estimate the effects of the low-sulfur fuel strategy, MANE-VU applied the expected sulfur dioxide emission reductions to all non-EGU sources burning #1, #2, #4, #5, or #6 fuel oil. These emission reductions would result directly from the lowering of fuel sulfur content from original levels to 0.015 percent for #1 and #2 oil, to 0.25 percent for #4 oil, and to 0.5 percent for #5 and #6 oil.

The reduction in SO_2 emissions by 2018 will yield corresponding reductions in sulfate aerosol, the main culprit in fine-particle pollution and regional haze. The full benefit of MANE-VU-s low-sulfur fuel strategy is represented in Figure 10.1, which displays the estimated average reductions in 24-hr $PM_{2.5}$ concentration as calculated by the CMAQ model for the combined first and second phases of the program.

Figure 10.1: Average Change in 24-hr $PM_{2.5}$ Due to Low-Sulfur Fuel Strategy (Phases 1 and 2 Combined) Relative to OTB/OTW (values in $\mu g/m^3$)



Low-Sulfur Fuel Oil Requirements are Reasonable: The MANE-VU Contribution Assessment documented source apportionment analyses that linked visibility impairment in MANE-VU Class I Areas with SO_2 emissions from sources burning fuel oil. The reasonable assumption underlying the low-sulfur fuel oil strategy is that refiners can, by 2018, produce home heating and fuel oils that contain 50 percent less sulfur for the heavier grades (#4 and #6 residual oil), and 75 to 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 consumer.

<u>Four-Factor Analysis – Low-Sulfur Fuel Oil Strategy</u>: The MANE-VU Reasonable Progress Report discussed the four factors as they apply to low-sulfur fuel use for ICI boilers and residential heating systems. MANE-VU's Reasonable Progress Report identified switching to a lower-sulfur fuel oil as an available SO_2 control option that would achieve 50 to 90 percent reductions in SO_2 emissions from ICI Boilers. The report also noted that home heating oil use generates an estimated 100,000 tons of SO_2 emissions in the Northeast each year and that SO_2 emissions would decline in proportion to reductions in fuel sulfur content. The following discussion summarizes information concerning the four factors for the low-sulfur fuel strategy.

1) Low-Sulfur Fuel Oil Strategy – Costs of Compliance: The MANE-VU Reasonable Progress report noted that because of requirements for motor vehicle fuels, refineries have already performed the capital investments required for the production of low-sulfur diesel (LSD) and ultra-low sulfur diesel (ULSD). The report estimated a cost per ton of SO_2 removed by switching to lower-sulfur fuel would range from $554 to $734 per ton (converted from 2001 to 2006 dollars using a conversion factor of 1.1383). In some seasons and some locations, low-sulfur diesel is actually cheaper than regular diesel fuel. (See Chapter 8 of the Reasonable Progress Report.)

The sulfur content of #4 and #6 fuels can also be cost-effectively reduced. Residual oil is essentially a byproduct of the refining process and is produced in several grades that can be blended to meet a specified fuel sulfur content limit. New York Harbor residual fuel prices for the week ending March 21, 2008, ranged from a low of $71.38 a barrel for 2.0 and 2.2 percent sulfur fuel to a high of $91.38 per barrel for 0.3 percent sulfur fuel.[29]

While the costs of achieving the projected emissions reductions with the low-sulfur fuel strategy are somewhat uncertain, they are believed to be reasonable in comparison with the costs of controlling other sectors. Some MANE-VU states are proceeding with low-sulfur oil requirements much sooner than 2018; however, all of the MANE-VU states concur that a low-sulfur oil strategy is both reasonable and achievable within the MANE-VU region by no later than 2018. MANE-VU has concluded that the cost of requiring the use of lower-sulfur fuels is reasonable.

2) Low-Sulfur Fuel Oil Strategy – Time Necessary for Compliance: MANE-VU's Reasonable Progress Report indicated that furnaces and boilers would not have to be retrofit and would not require expensive control technologies to burn ULSD distillate fuel oil. Therefore, the time necessary for compliance would be determined by the availability of the fuel.

The MANE-VU Reasonable Progress Report notes that, on a national scale, more ULSD is produced than both LSD and high-sulfur fuel, and concludes that the United States has the infrastructure to produce adequate stocks of these fuels. NESCAUM's report, "Low Sulfur Heating Oil in the Northeast States: An Overview of Benefits, Costs, and Implementation Issues," December 2005 (Attachment AA) observes that the federal rules for heavy duty highway diesel fuel are flexible, so that if there is a shortage of 15 ppm fuel, the 15 to 500 ppm fuel could be used to relieve the shortage. With this flexibility, the report concludes that

[29] During this same period, low-pour (low-temperature, reduced viscosity) residual fuel oil with a 0.5 percent sulfur content sold for $80.83 per barrel. Residual oil with a fuel sulfur content limit of 0.7 percent and 1.0 percent traded at $75.13 and $72.63, respectively.

the likelihood of a fuel shortage in the short term due to use of ULSD for heating oil is diminished. The volatile nature of heating supply and demand presents unique challenges to the fuel oil industry. The success of a low-sulfur fuel oil program is predicated on meeting these challenges. The Northeast states are consulting with fuel suppliers and assessing a variety of business strategies and regulatory approaches that could be used to minimize any potential adverse supply and price impacts that could result from a regional 500 ppm sulfur standard for heating oil. Suppliers can increase pre-season reserves of low-sulfur product. Blending domestically produced biodiesel into heating oil offers opportunity to reduce imports, stabilize supplies and minimize supply-related price spikes.

Potential supply disruptions and price spikes for residual fuels are a particular concern for several northern MANE-VU states. Maine, New Hampshire, and Massachusetts receive a significant percentage of their residual fuel supplies from offshore sources during the winter months, when barge traffic from New York Harbor is interrupted because of severe weather. At these times, residual oil is often imported directly from foreign sources (e.g., Venezuela and Russia), and stakeholders have expressed concerns that the supply of low-sulfur residual fuels may be insufficient to satisfy demand during these periods. While the potential for disruptions in the supply of residual fuels is greater than that for distillate oil, these disruptions would affect only a limited number of states during extreme weather events.

MANE-VU has identified several mechanisms that could be implemented to address disruptions, including seasonal averaging and emergency waivers. A seasonal averaging approach would reduce potential supply constraints by allowing the use of higher-sulfur fuel during periods of peak demand (and limited supply), and then requiring the increased sulfur content of these fuels to be offset through the use of a lower-sulfur fuel at other times. This approach would provide regulatory certainty and greater flexibility during the winter months when fuel supplies may be subject to weather-related disruptions, but at a cost of increased recordkeeping and compliance monitoring. Since many states already have statutory authority to waive fuel sulfur limits in an emergency, states could also utilize their discretionary powers to address short-term supply disruptions.

Although New Hampshire does not intend to use seasonal averaging, the state would reserve the option of pursuing an emergency waiver in a fuel supply disruption and would follow EPA's established procedures for fuel waivers. As described on the agency's fuel waivers website at http://www.epa.gov/compliance/resources/faqs/civil/fuelwaiver.html, EPA, with the concurrence of the Department of Energy, may temporarily waive a fuel or fuel additive requirement if doing so will alleviate the fuel supply emergency. Clean Air Act Section 211(c)(4)(C), which authorizes fuels waivers, specifies the criteria for granting a fuel waiver and the conditions that must be included in a fuel waiver. In the case of an emergency disruption of low-sulfur fuel supplies, NHDES would seek a short-term emergency waiver on fuel sulfur content. To the extent feasible, it would be the intent of any such waiver to moderate the degree of visibility degradation resulting from temporary use of higher-sulfur fuels in a supply disruption. The details would be worked out in response to the particulars of the emergency situation at the time of any waiver request.

To implement the low-sulfur fuel oil strategy, New Hampshire and the other MANE-VU states propose a phase-in of the required use of lower-sulfur fuels by 2018, allowing adequate time to achieve the strategy's full effect.

3) Low-Sulfur Fuel Oil Strategy – Energy and Non-Air Quality Environmental Impacts of Compliance: According to MANE-VU's Reasonable Progress Report, reducing the sulfur content of fuel oil would have a variety of beneficial consequences for boilers and furnaces using this fuel. Low-sulfur distillate fuel is cleaner burning and emits less particulate matter, thereby reducing the rate of fouling of heating units and allowing longer time intervals between cleanings. The MANE-VU report cites a study by the New York State Energy Research and Development Authority (NYSERDA) that showed that boiler deposits are reduced by a factor of two by lowering the fuel sulfur content from 1,400 ppm to 500 ppm. The use of low-sulfur oil could extend the useful life of a source by reducing the maintenance required because low-sulfur oil is less damaging to the combustion equipment.

The report also notes that decreasing sulfur levels in fuel would enable manufacturers to develop more efficient furnaces and boilers by using more advanced condensing equipment that recovers energy normally lost to the heating of water vapor in the exhaust gases. In addition, SO_2 controls would have beneficial environmental impacts by reducing acid deposition and helping to decrease ambient concentrations of $PM_{2.5}$. Reductions in $PM_{2.5}$ resulting from use of low-sulfur fuels could help nonattainment areas meet health-based National Ambient Air Quality Standards.

4) Low-Sulfur Fuel Oil Strategy – Remaining Useful Life of Any Potentially Affected Sources: Residential furnaces and boilers have finite life spans, but they do not need to be replaced to burn low- or ultra-low-sulfur fuel oil. The Energy Research Center estimates that the average life expectancy of a residential heating oil boiler is 20-25 years. As noted above, use of low-sulfur fuel is less damaging to equipment and could therefore extend the useful life of an oil-fired residential furnace or boiler.

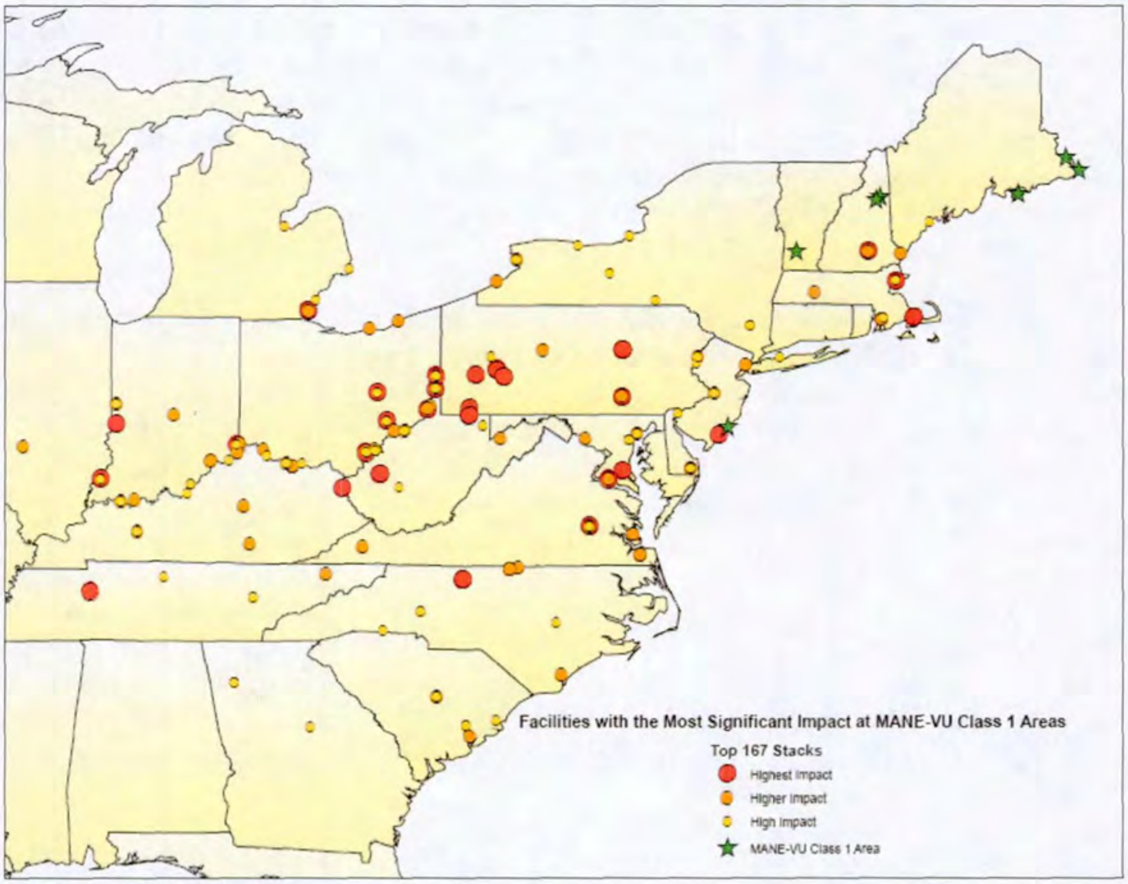
Available information on the remaining useful life of ICI boilers indicates a wide range of life expectancies, depending on unit size, capacity factor, and level of maintenance performed. (Capacity factor is defined as the actual amount of energy a boiler generates in one year divided by the total amount it could generate if it ran full time at full capacity.) The typical life expectancy of an ICI boiler ranges from 10 years to more than 30 years. As in the case of residential units, use of lower-sulfur fuels could extend the life span of an ICI boiler.

10.2.4 Targeted EGU Strategy for SO_2 Reduction

Electrical generating units (EGUs) are the single largest sector contributing to visibility impairment at MANE-VU's Class I Areas. SO_2 emissions from power plants continue to dominate the emissions inventory. Sulfate formed through atmospheric processes from SO_2 emissions are responsible for over half the mass and approximately 70-80 percent of visibility extinction on the days of worst visibility (see NESCAUM's Contribution Assessment, Attachment B).

To ensure that EGU control measures are targeted at those units having the greatest impact on visibility at MANE-VU Class I Areas, a CALPUFF modeling analysis was conducted to identify the individual sources responsible for the highest contributions to visibility degradation. Accordingly, MANE-VU developed lists of the 100 EGU emission points (stacks) having the largest impacts at each MANE-VU Class I Area during 2002. The combined list for all seven MANE-VU Class I Areas identified a total of 167 distinct emission points. These 167 stacks are spread across the Northeast, Southeast, and Midwest (Figure 10.2).

Figure 10.2: Location of 167 EGU Stacks Contributing the Most to Visibility Impairment at MANE-VU Class I Areas

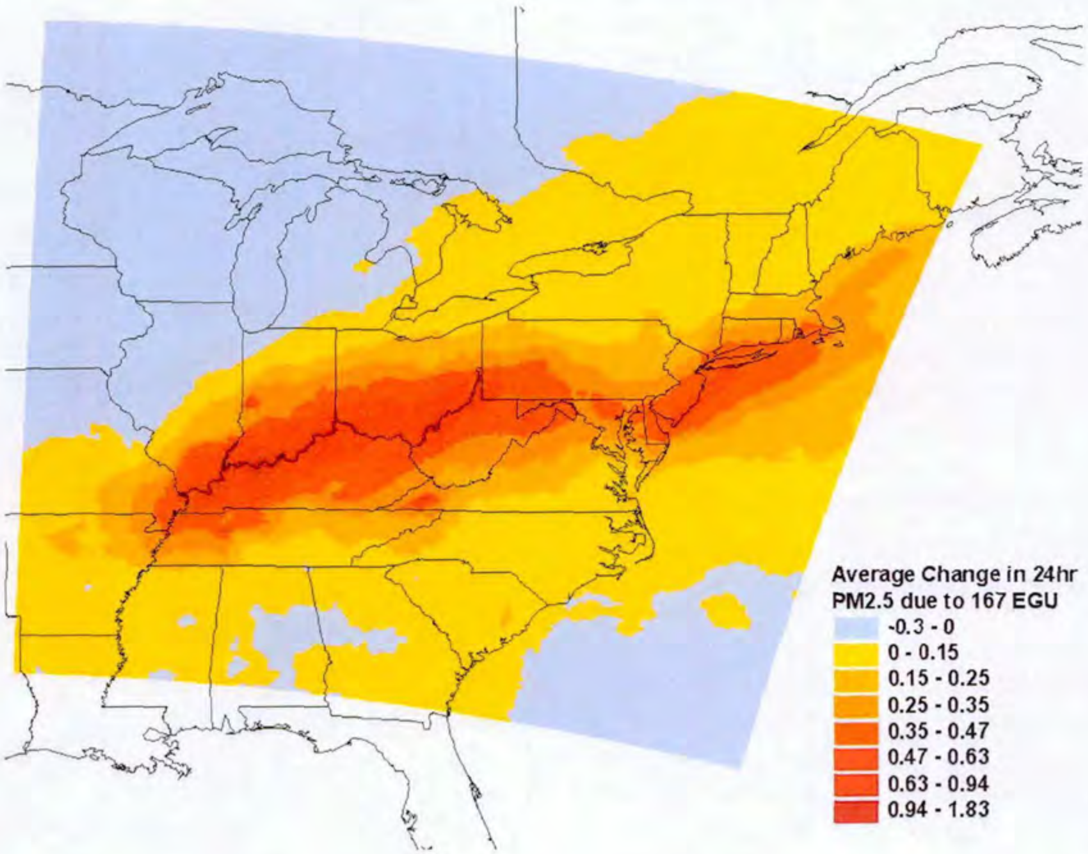


Note: Some facilities have more than one stack.

After consultations with its member states and with other RPOs, MANE-VU requested a 90-percent reduction in SO_2 emissions from the top 167 stacks by no later than 2018 (see the MANE-VU "Ask"). NESCAUM's preliminary modeling for MANE-VU showed that SO_2 emission reductions of this magnitude from the targeted facilities would produce substantial improvements in ambient 24-hour $PM_{2.5}$ concentrations. Assuming a control level equal to 10 percent of the 2002 baseline emissions (i.e., 90-percent emission reduction), NESCAUM used CMAQ to model sulfate concentrations in 2018 after implementation of controls. The modeled sulfate values were then converted to estimates of $PM_{2.5}$ concentration. Figure 10.3 displays the predicted average change in 24-hr $PM_{2.5}$.

The map illustrates the reductions in fine-particle pollution in the Eastern U.S. that would result from implementation of the targeted EGU strategy for SO_2. Improvements in $PM_{2.5}$ levels would occur throughout the MANE-VU region and portions of the VISTAS and MRPO regions, especially along the Ohio River Valley.

Figure 10.3: Preliminary Estimate of Average Change in 24-hr $PM_{2.5}$ Resulting from a 90-Percent Reduction in SO_2 Emissions from the Top 167 EGU Stacks Affecting MANE-VU Class I Areas



Although the reductions would be both advantageous and potentially large, MANE-VU determined, after further consultation with affected states, that it was unreasonable to expect that the full 90-percent reduction in SO_2 emissions would be achieved by 2018. Therefore, additional modeling was conducted to assess the more realistic scenario in which emissions would be controlled by the individual facilities and/or states to levels already projected to take place by that date. At some facilities, the actual emission reductions are anticipated to be greater or less than the 90 percent benchmark. For details, see Alpine Geophysics' report for MARAMA entitled, "Documentation of 2018 Emissions from Electric Generating Units in the Eastern United States for MANE-VU's Regional Haze Modeling," Final Report, August 16, 2009 (Attachment H).

***Targeted EGU SO_2 Reduction Strategy Controls are Reasonable*:** MANE-VU identified specific EGU stacks that were significant contributors to visibility degradation at MANE-VU Class I Areas in 2002. The CALPUFF modeling analyses identifying potentially significant contributing sources are documented in the Contribution Assessment. MANE-VU obtained information about existing and planned controls on emissions from those stacks. These analyses and information on proposed EGU controls are presented in MANE-VU's Reasonable Progress Report and the Contribution Assessment as well as in Section 6, Emissions Inventory, and Section 11, Long-Term Strategy section of this SIP.

Based on information gathered from the states and regional planning organizations, MANE-VU anticipated that emissions from many of the targeted EGU stacks would be subject to EPA's Clean Air Interstate Rule (CAIR). However, because CAIR – recently remanded and scheduled for replacement – was a cap-and-trade program, it was not possible to predict with certainty which of the 167 stacks would actually be controlled under CAIR in 2018.

Four-Factor Analysis – Targeted EGU SO_2 Reduction Strategy: The following discussion addresses each of the four factors with respect to the strategy of controlling specific EGUs. Information is taken primarily from the MANE-VU Reasonable Progress Report (Attachment Y) and MANE-VU BART Report (Attachment Z).

1) Targeted EGU SO_2 Reduction Strategy – Costs of Compliance: Technologies to control the precursors of regional haze are commercially available today. Because EGUs are the most significant stationary source of SO_2, NO_X, and PM, they have been subject to extensive federal and state regulations to control all three pollutants. The technical feasibility of control technologies has been successfully proven for a substantial number of small (e.g., 100 MW) to very large (over 1,000 MW) boilers burning different types of coal. Over the last few years, the cost data clearly indicate that many technologies provide substantial and cost-effective emission reductions.

Both wet and dry scrubbers are in wide commercial use in the U.S. for controlling SO_2 emissions from coal-fired power plants. The capital costs for new or retrofit wet or dry scrubbers are higher than the capital costs for NO_X and PM controls. The MANE-VU BART report found that the capital costs of scrubbers ranged from \$180/kW for large units (greater than 600 MW) to as high as \$350/kW for small units (200 to 300 MW). Typical costs were in the range of 200 to 500 dollars per ton of SO_2 removed, but rose steeply for small units burning lower-sulfur coal and operating at low capacity factors. (See pages 2-22 through 2-25 of the BART Report, Attachment Z).

The MANE-VU Reasonable Progress Report (Attachment Y) reviewed options for controlling coal-fired EGU boilers, including switching to lower-sulfur coal, switching to natural gas, coal cleaning, and flue gas desulfurization (FGD). The most effective control option (but not necessarily appropriate for all installations) is FGD, which can achieve up to 95 percent reduction in SO_2 emissions. The costs of different technologies vary considerably among units and were estimated to range from as low as \$170/ton to as high as \$5,700/ton.

Table 10.4 summarizes the estimated costs of controlling SO_2 emissions, expressed in dollars per ton of SO_2 removed.

Table 10.4: Estimated Cost Ranges for SO_2 Control Options for Coal-Fired EGU Boilers (2006 dollars per ton of SO_2 removed)

Technology	Description	Performance	Cost Range (2006 dollars/ton of SO_2 Reduced)
Switch to a Low Sulfur Coal (generally <1% sulfur)	Replace high-sulfur bituminous coal combustion with lower-sulfur coal	50-80% reduction in SO_2 emissions by switching to a lower-sulfur coal	Potential reduction in coal costs, but possibly offset by expensive retrofits and loss of boiler efficiency
Switch to natural gas (virtually 0% sulfur)	Replace coal combustion with natural gas	Virtually eliminate SO_2 emissions by switching to natural gas	Unknown – cost of switch is currently uneconomical due to price of natural gas
Coal Cleaning	Coal is washed to remove some of the sulfur and ash prior to combustion	20-25% reduction in SO_2 emissions	2-15% increase in fuel costs based on current prices of coal
Flue Gas Desulfurization (FGD) – Wet	SO_2 is removed from flue gas by dissolving it in a lime or limestone slurry. (Other alkaline chemicals are sometimes used)	30-95%+ reduction in SO_2 emissions	\$570-\$5,700 for EGUs <1,200 MW \$330-\$570 for EGUs >1,200 MW
Flue Gas Desulfurization (FGD) – Spray Dry	A fine mist containing lime or other suitable sorbent is injected directly into flue gas	60-95%+ reduction in SO_2 emissions	\$570-\$4,550 for EGUs <600 MW \$170-\$340 for EGUs >600 MW
Flue Gas Desulfurization (FGD) –Dry	Powdered lime or other suitable sorbent is injected directly into flue gas	40-60% reduction in SO_2 emissions	\$250-\$850 for EGUs ~300 MW

Table references:

1. EIA website accessed on 2/20/07: http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html
2. EIA website accessed on 2/20/07: http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html
3. STAPPA-ALAPCO. *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*; March 2006.

To predict future emissions and further evaluate the costs of emission controls for electric generating units, MANE-VU and other RPOs have followed the example of the US Environmental Protection Agency (EPA) in using the Integrated Planning Model (IPM®), an integrated economic and emissions model for EGUs. This model projects electricity supplies based on various assumptions while at the same time developing least-cost solutions to electrical generating needs within specified emissions targets. IPM also provides estimates of the costs of complying with various policy requirements.

EPA developed IPM version 2.1.9 and used this model to evaluate the impacts of CAIR and the Clean Air Mercury Rule (CAMR). (Note that CAMR was vacated by the federal courts and is no longer in effect.) Recently, EPA updated their input data and developed IPM v.3.0. However, because of time constraints, all MANE-VU runs were based on EPA IPM v.2.1.9 with changes made to the input assumptions.

The RPOs collaborated with one another to update the inputs to IPM v.2.1.9 using more current data on the EGUs and more realistic fuel prices. The resulting IPM run is called VISTAS PC_1f. This IPM run serves as the basis for regional air quality modeling for ozone and haze SIPs in MANE-VU and the OTC.

MANE-VU, through MARAMA, contracted with the consulting firm ICF Resources, L.L.C. to prepare two new IPM runs, as documented in "Comparison of CAIR and CAIR Plus Proposal using the Integrated Planning Model (IPM®)," Final Draft Report, May 30, 2007 (Attachment BB). The first run, known as the MARAMA CAIR Base Case run (also known as MARAMA_5c), was based on the VISTAS PC_1f run and underlying EPA IPM v.2.1.9 with some updated information on fuel prices, control constraints, etc. The second run, called the MARAMA CAIR Plus run (also known as MARAMA_4c), was similarly based on VISTAS PC_1f run and the underlying EPA IPM v.2.1.9. The MARAMA CAIR Plus run included updated information used in the VISTAS run but assumed lower NO_X emission caps and higher SO_2 retirement ratios.

Based on the modeling results, MANE-VU estimates that the marginal cost of SO_2 emission reductions (the cost of reducing one additional ton of emissions) ranges from $640/ton in 2008 to $1,392/ton in 2018 (see Table 6, "Allowance Prices (Marginal Costs) of Emissions Reductions…," in Attachment BB).

Costs will vary for individual plants to reduce emissions by 90 percent, as recommended in the New Hampshire/MANE-VU Ask. However, this strategy provides states with flexibility to pursue controls on specific sources as appropriate and to control emissions from alternative sources, if necessary, to meet the 90 percent target established in the Ask.

Given the importance of SO_2 emissions from specific EGUs to visibility impairment in MANE-VU Class I Areas, the MANE-VU Commissioners, after weighing all factors – the availability of technology to reduce emissions, the estimated costs of controls, the costs of alternative measures, the flexibility to achieve alternative reductions if necessary, etc. – concluded that the costs of the targeted EGU strategy are reasonable. New Hampshire agrees with this conclusion.

2) Targeted EGU SO_2 Reduction Strategy – Time Necessary for Compliance: MANE-VU's Reasonable Progress Report indicates that, generally, sources are given a 2- to 4-year phase-in period to comply with new rules. Under Phase I of the NO_X SIP call, EPA provided a compliance date of about 3½ years from the SIP submittal date. Most MACT standards allow a 3-year compliance period. Under Phase II of the NO_X SIP Call, EPA provided for 2-year compliance period from the SIP submittal date. New Hampshire concludes that there is more than sufficient time between 2008 and 2018 for affected states to adopt requirements and for affected sources to install necessary controls.

3) Targeted EGU SO_2 Reduction Strategy – Energy and Non-Air Quality Environmental Impacts of Compliance: The MANE-VU Reasonable Progress Report identified several energy and non-air quality impacts from additional EGU controls. Large-scale fuel switching could potentially impact fuel supplies. Flue gas desulfurization systems may generate wastewater and sludge (which is sometimes recycled as a useful byproduct). On the other hand, SO_2, NO_X, and ammonia controls would have beneficial environmental impacts by reducing acid deposition and nitrogen deposition to water bodies and natural land areas. Emission reductions for these pollutants would also produce decreases in ambient levels of $PM_{2.5}$ and result in corresponding health benefits. Similarly, mercury emissions may be reduced by the addition of controls for other pollutants. New Hampshire concludes that the energy and non-air quality impacts of additional EGU controls are reasonable.

4) Targeted EGU SO_2 Reduction Strategy – Remaining Useful Life of Any Potentially Affected Sources: As noted in the MANE-VU Reasonable Progress Report, remaining useful life estimates of EGU boilers indicate a wide range of operating lifetimes, depending on unit size, capacity factor, and level of maintenance performed. Typical life expectancies range to 50 years or more. Additionally, implementation of air pollution regulations over the years has necessitated emission control retrofits that have increased the expected life spans of many EGUs. The lifetime of an EGU may be extended through repair, re-powering, or other strategies if the unit is more economical to run than to replace with power from other sources. Extending facility lifetime may be particularly likely for a unit serving an area with limited transmission capacity to bring in other power.

10.2.5 Non-EGU SO_2 Emissions Reduction Strategy for Non-MANE-VU States

In addition to the measures described above (i.e., BART, low-sulfur fuel, and targeted EGU controls), New Hampshire asked states in neighboring regional planning organizations to consider further non-EGU emission reductions comparable to those achieved by MANE-VU states through application of MANE-VU's low-sulfur fuel strategy. Previous modeling indicated that the MANE-VU low-sulfur fuel strategy would achieve a greater than 28-percent reduction in non-EGU SO_2 emissions by 2018. After consultation with other states and consideration of comments received, MANE-VU decided to include, in the latest modeling for the VISTAS and MRPO regions, implementation of control measures capable of achieving SO_2 emission reductions equivalent to MANE-VU's 28-percent reduction in non-EGU SO_2 emissions in 2018.

To model the effects of this strategy on visibility at MANE-VU Class I Areas, MANE-VU had to make reasonable assumptions about where the requested emission reductions would occur in the VISTAS and MRPO states without knowing precisely how those reductions would be realized. As a way to represent approximately a 28-percent reduction in non-EGU SO_2 emissions, the following reductions were modeled:

- For control measures in VISTAS and MRPO states:
  - Coal-fired ICI boilers: SO_2 emissions were reduced by 60 percent.
  - Oil-fired ICI boilers: SO_2 emissions were reduced by 75 percent.
  - ICI boilers lacking fuel specification: SO_2 emissions were reduced by 50 percent.
- For additional controls *only* in the VISTAS states: SO_2 emissions from other oil-fired area sources were reduced by 75 percent (based on the same SCCs identified in MANE-VU's oil strategies list).

This modeling scenario represents just one example of realistic strategies that states outside of MANE-VU could employ to meet the non-EGU SO_2 emissions reductions requested by MANE-VU.

New Hampshire acknowledges that a number of non-MANE-VU states have not included, or may not include, the requested 28-percent reduction in non-EGU SO_2 emissions in their State Implementation Plans at the present time. New Hampshire expects these states to revisit the MANE-VU Ask in the course of future regional haze SIP revisions and to make commitments to this request where feasible. NHDES will continue to monitor other states' actions with respect to regional haze planning. In time, actual reductions could turn out to be greater or less than the MANE-VU Ask. If necessary, New Hampshire will adjust its reasonable progress goals and long-term strategy at a later date to be consistent with programs implemented by the non-MANE-VU states. Any such adjustments would be incorporated into New Hampshire's first regional haze SIP revision in 2013.

***Non-EGU SO_2 Emission Reduction Measures Outside MANE-VU are Reasonable*:** After EGUs, ICI boilers are the next largest class of SO_2 emitters. ICI boilers are thus a logical choice among non-EGU sources for consideration of additional SO_2 control measures.

ICI Boiler Control Options: Air pollution reduction and control technologies for ICI boilers have advanced substantially over the past 25 years. However, according to a 1998 survey of industrial boilers by EPA (2004), only 2 percent of gas-fired boilers and 3 percent of oil-fired boilers had installed any kind of air pollution control device. A larger percentage of coal-fired boilers had installed air pollution controls: specifically, 47 percent had installed some type of control device, mainly to control particulate matter (PM). Post-combustion SO_2 controls were used by less than one percent of industrial boilers in 1998, with the exception of boilers firing petroleum coke (2 percent of boilers using this fuel had acid scrubbers). A small percentage of industrial boilers had combustion controls in place in 1998, although additional low-NO_X firing systems may have been installed since that date.

Almost all SO_2 emission control technologies fall into the category of reducing SO_2 after its formation as opposed to minimizing its formation during combustion. The method of SO_2 control appropriate for any individual ICI boiler is dependent upon the type of boiler, type of fuel, capacity utilization, and the types and staging of other air pollution control devices. However, cost-effective emission reduction technologies for SO_2 are available and are effective in reducing emissions from the exhaust gas stream of ICI boilers. Post-combustion SO_2 control is accomplished by reacting the SO_2 in the gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use, depending on the particular technology. SO_2 reduction technologies are commonly referred to as flue gas desulfurization (FGD) and are usually described in terms of the process conditions (wet versus dry), byproduct utilization (throwaway versus saleable) and reagent utilization (once-through versus regenerable).

The exceptions to the nearly universal use of post-combustion controls are found in fuel switching, coal cleaning, and fluidized bed boilers, in which limestone is added to the fuel in the combustion chamber. Both pre- and post-combustion SO_2 emission control alternatives for ICI boilers are outlined in Table 10.5. Further description of these technology options is available in Chapter 4 of the MANE-VU Reasonable Progress Report (Attachment Y).

The SO_2 removal efficiency of these controls varies from 20 to 99+ percent depending on the fuel type and control technology. For coal-fired boilers, options include switching to low-sulfur coal, coal cleaning, wet FGD, dry FGD, and spray dryers. The overall SO_2 reductions vary from a low of 20 to 25 percent for fuel switching to a high of 60 to 95 percent for wet FGD and spray dry FGD. The majority of control strategies, however, are capable of achieving a 60 percent or greater reduction. Thus, assuming that coal-fired ICI boilers adopt varying levels of controls, with most choosing a 50- to 70- percent reduction strategy and fewer choosing either the 20-percent or the 90-percent reduction strategy, the region-wide average would be likely to fall in the vicinity of a 60- percent reduction in SO_2 emissions. This assumption is validated by data showing that wet FGD systems represent 85 percent of the FGD systems in use in the United States and that these systems have an average SO_2

removal efficiency of 78 percent. MANE-VU's modeling of a 60-percent reduction in SO_2 emission from coal-fired ICI boilers is therefore reasonable.

Table 10.5: Available SO_2 Control Options for ICI Boilers

Technology	Description	Applicability	Performance
Switch to a Low Sulfur Coal (generally <1% sulfur)	Replace high-sulfur bituminous coal combustion with lower-sulfur coal	Potential control measure for all coal-fired ICIs currently using coal with high sulfur content	50-80% reduction in SO_2 emissions by switching to a lower-sulfur coal
Switch to Natural Gas (virtually 0% sulfur)	Replace coal combustion with natural gas	Potential control measure for all coal-fired ICIs	Virtually eliminate SO_2 emissions by switching to natural gas
Switch to a Lower Sulfur Oil	Replace higher-sulfur residual oil with lower-sulfur distillate oil. Alternatively, replace medium sulfur distillate oil with ultra-low sulfur distillate oil	Potential control measure for all oil-fired ICIs currently using higher sulfur content residual or distillate oils	50-80% reduction in SO_2 emissions by switching to a lower-sulfur oil
Coal Cleaning	Coal is washed to remove some of the sulfur and ash prior to combustion	Potential control measure for all coal-fired ICI boilers	20-25% reduction in SO_2 emissions
Combustion Control	A reactive material, such as limestone or bi-carbonate, is introduced into the combustion chamber along with the fuel	Applicable to pulverized coal-fired boilers and circulating fluidized bed boilers	40%-85% reductions in SO_2 emissions
Flue Gas Desulfurization (FGD) - Wet	SO_2 is removed from flue gas by dissolving it in a lime or limestone slurry. (Other alkaline chemical are sometimes used)	Applicable to all coal-fired ICI boilers	30-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) - Spray Dry	A fine mist containing lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	60-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) - Dry	Powdered lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	40-60% reduction in SO_2 emissions

For oil-fired boilers, options include switching to a lower-sulfur fuel (e.g., oil or natural gas), dry FGD, and spray dryers. The overall SO_2 reductions vary from a low of 40 to 60 percent for dry FGD to a high of 60 to 95 percent for spray dry FGD. For comparison, the MANE-VU low-sulfur fuel strategy assumes a 50- to 90- percent reduction in SO_2 emissions from oil-fired ICI boilers. Assuming a normal distribution of control strategies chosen by the sources, MANE-VU's modeling of an average 75-percent reduction in SO_2 emission from oil-fired ICI boilers is reasonable.

For ICI boilers in which a fuel was not specified, a 50-percent reduction in SO_2 emissions was assumed. ICI boilers in this category include those outside the MANE-VU region for which the current inventory did not specify the type of fuel burned. Because a response from the MRPO was not received, this assumption also encompasses some of the uncertainty regarding the implementation of MANE-VU's non-EGU Ask. Given the paucity of data, a lower reduction in SO_2 emissions (50 percent) was assumed for this category than for coal- or oil-fired ICI boilers. Implementation of one or more of the suggested SO_2 control options to achieve, on average, a 50-percent reduction in SO_2 emissions at these sources is a reasonable assumption.

For emissions from other area oil-combustion sources in the VISTAS region, an SO_2 reduction of 75 percent was assumed. This reduction is equal to the reduction that would result from implementing the MANE-VU low-sulfur fuel strategy for this sector. The four-factor analysis for the low-sulfur fuel strategy was described in Part 10.2.3 of this section.

Four-Factor Analysis – Non-EGU SO_2 Emission Reduction Measures Outside MANE-VU: Based on the survey of available technologies outlined above and the four-factor analyses summarized below, MANE-VU concludes that each of the strategies assumed for modeling purposes to meet the New Hampshire/MANE-VU Ask of a 28-percent reduction in non-EGU SO_2 emissions is reasonable. States should have no difficulty in meeting this benchmark in light of the control efficiencies that are attainable at reasonable costs with retrofit technologies that are available for ICI boilers today.

1) Non-EGU SO_2 Emission Reduction Measures outside MANE-VU – Costs of Compliance: Industrial boilers have a wider range of sizes than EGUs and often operate over a wider range of capacities. Thus, cost estimates for the same technologies will generally span a relatively larger range, and costs for an individual boiler will depend on the capacity of the boiler and typical operating conditions. In general, cost-effectiveness increases as boiler size and capacity factor (a measure of boiler utilization) increases.

MANE-VU's Reasonable Progress Report (Attachment Y) provides emission control cost estimates for ICI boilers in the range of \$130 to \$11,000 per ton of SO_2 removed, a very wide spread due to the variability of sources and control options in this category. All costs presented below for emission controls on ICI boilers are borrowed from this report. Dollar amounts originated from EPA publications cited in the report and are restated in 2006 dollars using appropriate adjustment factors found at www.inflationdata.com.

◊ *Cost of Fuel Switching*: Although fuel switching can be a very effective means of controlling SO_2 emissions (reductions of 50 to 99.9 percent are possible), burning low-sulfur fuel may not be technically feasible or economically practical as an SO_2 control option for every coal-fired boiler. Factors impacting applicability include the characteristics of the plant and the particular type of fuel change being considered. Additionally, switching to a lower-sulfur coal can affect fuel handling systems, boiler performance, PM control effectiveness, and ash handling systems. Oil-fired boilers switching to a lower-sulfur fuel of the same grade (e.g., switching from #6 fuel oil at 2.0% S to #6 fuel oil at 0.5% S) do not typically encounter these issues. (See Part 10.2.3 for a discussion of the costs and issues associated with switching to low-sulfur fuel oil.)

The costs of coal fuel switching, including substitution or blending with a low-sulfur coal, can be attributed to two main factors: the cost of low-sulfur coal compared to higher-sulfur coal (including consideration of the coal's heating value), and the cost of necessary boiler or coal-handling equipment modifications. Many plants will be able to switch from high-sulfur to low-sulfur bituminous coal without serious difficulty, but switching from bituminous to subbituminous coal may require potentially significant investments and modifications to an existing plant. Even if a lower-sulfur fuel is available, it may not be cost competitive if it must be supplied in small quantities or transported long distances from the supplier. It also may be more cost-effective to burn a higher-sulfur fuel supplied by nearby suppliers and to use a post-combustion control device.

Switching from coal combustion to natural gas combustion virtually eliminates SO_2 emissions. It is technically feasible to switch from coal to natural gas; but it is currently uneconomical to consider this option for large ICI boilers because of the required equipment modifications, the fuel quantities necessary, and the generally higher price of natural gas compared to coal.

◊ *Cost of Coal Cleaning*: The World Bank, an organization which assists with economic and technological needs in developing countries, reports that the cost of physically cleaning coal varies from \$1 to \$10 per ton of coal cleaned, depending on the coal quality, the cleaning process used, and the degree of cleaning desired. In most cases, the costs were found to be between \$1 and \$5 per ton of coal cleaned. Coal cleaning typically results in a 20- to 25-percent reduction in SO_2 emissions and increases the heating value of the fuel by a small amount.

◊ *Cost of Combustion Controls*: Dry sorbent injection (DSI) systems have lower capital and operation costs than post-combustion FGD systems because of the simplicity of the DSI design, lower water use needs, and smaller land area requirements. Table 10.6 presents the estimated costs of adding DSI-based SO_2 emission controls to ICI boilers for different boiler sizes, fuel types, and capacity factors.

Table 10.6: Estimated Costs of Dry Sorbent Injection (DSI) for ICI Boilers (2006 dollars)

Fuel	SO_2 Reduction (%)	Capacity Factor (%)	Cost-Effectiveness (\$/ton of SO_2 removed)		
			100 MMBtu/hr	250 MMBTU/hr	1,000 MMBTU/hr
2%-Sulfur Coal	40	14	4,686	3,793	2,979
		50	1,312	1,062	834
		83	772	624	490
3.43%-Sulfur Coal	40	14	2,732	2,212	1,737
		50	765	619	486
		83	450	364	286
2%-Sulfur Coal	85	14	2,205	1,786	1,402
		50	617	500	392
		83	363	294	231
3.43%-Sulfur Coal	85	14	1,286	1,040	818
		50	360	291	229
		83	212	171	134

Note: Data as compiled and presented in Table 4.3 of MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007.

◊ *Cost of FGD*: Installation of post-combustion SO_2 controls in the form of FGD has several impacts on facility operations, maintenance, and waste handling procedures. FGD systems generally require substantial land area for construction of the absorber towers, sorbent tanks, and waste handling equipment. The facility costs therefore depend on the cost and availability of space for construction of the FGD system. In addition, significant quantities of waste material may be generated that require disposal. The costs may be mitigated, however, by utilization of a forced oxidation FGD process that produces commercial-grade gypsum, which may be sold as a raw material for other commercial processes.

Table 10.7 presents the total estimated cost-per-ton of adding FGD-based SO_2 emission controls to ICI boilers for different boiler sizes, fuel types, and capacity factors. There is no indication that these cost data include possible revenues from gypsum sales, which would partially offset the costs of FGD controls.

Carbon dioxide is also emitted as a byproduct of FGD; therefore, the impacts of increased carbon emissions associated with this technology would need to be considered. CO_2 emissions will become more of an issue in the future if they are limited under climate change mitigation strategies. Given the uncertainty of such future strategies, costs related to increased carbon emissions from FGD cannot yet be assessed.

MANE-VU's request for a 28-percent reduction in non-EGU SO_2 emissions allows states flexibility in determining which sources to control, so that the most cost-effective control measures can be adopted and implemented over the next 10 years. Given the wide range of control options and costs available for this purpose, MANE-VU has concluded that the request for a 28-percent reduction in non-EGU SO_2 emissions is reasonable. New Hampshire concurs with this conclusion.

Table 10.7: Estimated Costs of Flue Gas Desulfurization for ICI Boilers (2006 dollars)

Fuel	Technology	SO_2 Reduction (%)	Capacity Factor (%)	Cost-Effectiveness ($/ton of SO_2 removed)		
				100 MMBtu/hr	250 MMBTU/hr	1,000 MMBTU/hr
High-Sulfur Coal [a]	FGD (dry)	40	14	3,781	2,637	1,817
			50	1,379	1,059	828
			83	1,006	814	676
Lower-Sulfur Coal [b]	FGD (dry)	40	14	4,571	3,150	2,119
			50	1,605	1,207	928
			83	1,147	906	744
Coal	FGD (spray dry)	90	14	4,183	2,786	1,601
			50	1,290	899	567
			83	843	607	407
High-Sulfur Coal	FGD (spray dry)	90	14	3,642	2,890	1,909
			50	1,116	875	601
			83	709	563	398
Lower-Sulfur Coal	FGD (wet)	90	14	4,797	3,693	2,426
			50	1,415	1,106	751
			83	892	705	492
Oil [c]	FGD (wet)	90	14	10,843	8,325	5,424
			50	2,269	1,765	1,184
			83	1,371	1,079	740

Note: Data as compiled and presented in Table 4.4 of MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007.

[a] Assumes sulfur content = 3.43% and ash content = 12.71%.

[b] Assumes sulfur content = 2.0% and ash content = 13.2%.

[c] Sulfur content of oil is not specified.

2) Non-EGU SO_2 Emission Reduction Measures outside MANE-VU – Time Necessary for Compliance: For pre- and post-combustion SO_2 emission controls, engineering and construction lead times will vary between 2 and 5 years, depending on the size of the facility and specific control technology selected. Generally, sources are given a 2- to 4- year phase-in period to comply with new rules, as previously described, and states generally have a 2-year period for compliance with RACT rules.

For the purposes of this review, it is assumed that a 2-year period after SIP submittal is adequate for pre-combustion controls (fuel switching or cleaning), and a 3-year period is adequate for the installation of post-combustion controls. MANE-VU has therefore concluded that there is sufficient time between 2008 and 2018 for affected states to adopt emission control requirements and for affected sources to install the necessary controls to meet MANE-VU's requested SO_2 emission reductions from non-EGU sources. New Hampshire concurs with this conclusion.

3) Non-EGU SO_2 Emission Reduction Measures Outside MANE-VU – Energy and Non-Air Quality Environmental Impacts of Compliance: The primary energy impact of pre- or post-combustion control alternatives is a potential increase in electricity usage. Fuel switching and cleaning do not significantly affect the efficiency of the boiler itself, but require additional energy to clean or blend coal. FGD systems typically operate with high-pressure drops across the control equipment and therefore consume significant amounts of electricity to operate blowers and circulation pumps. In addition, some combinations of FGD technology and plant configuration may require flue gas reheating to prevent physical damage to equipment, resulting in higher fuel usage.

The primary non-air environmental impacts of fuel switching derive from transportation of the fuel. Secondary environmental impacts derive from waste disposal and material handling operations (e.g. fugitive dust). For FGD systems, the generation of wastewater and sludge from the SO_2 removal process is a consideration. Wastewater from the FGD systems will increase sulfate, metals, and solids loading at the receiving wastewater treatment facility, resulting in potential impacts to operating cost, energy requirements, and effluent water quality. Processing of the wastewater sludge can require energy for stabilization and/or dewatering, and transporting the dewatered sludge to a landfill has additional environmental implications.

Fuel switching to a low-sulfur distillate fuel oil has a variety of beneficial consequences for ICI boilers. Low-sulfur distillate fuel is cleaner burning and emits less particulate matter, which reduces the rate of fouling of heating units substantially and permits longer time intervals between cleanings. According to a study conducted by NYSERDA (reference 10 in Attachment AA), boiler deposits are reduced by a factor of two by lowering the fuel sulfur content from 1,400 ppm to 500 ppm. These reductions in buildup of deposits result in longer service intervals between cleanings.

Reducing SO_2 emissions from ICI boilers would have positive environmental and health impacts. SO_2 controls would reduce acid deposition, helping to preserve aquatic life, forests, and crops as well as buildings and sculptures made of acid-sensitive materials. These emission reductions would also help to decrease ambient levels of $PM_{2.5}$, a significant contributor to premature morbidity and illness in individuals with heart or lung conditions.

MANE-VU has concluded that the energy and non-air environmental impacts of controlling SO_2 emissions from ICI boilers are justified in light of the beneficial impacts on regional haze, fine particulate air pollution, acid rain, and equipment operation, as described above. New Hampshire concurs with this conclusion.

4) Non-EGU SO_2 Emission Reduction Measures Outside MANE-VU – Remaining Useful Life of Any Potentially Affected Sources: Available information for remaining useful life estimates of ICI boilers indicates a wide range of life expectancies, depending on unit size, capacity factor, and level of maintenance performed. Typical life spans range from about 10 years to over 30 years. However, the remaining useful life of a specific source is highly variable; and older units are not likely to be retrofitted with expensive emission controls. Given the typical range of life expectancies of ICI boilers, the technical options available, and the flexibility that non-MANE-VU states would have to meet the Ask, MANE-VU has concluded that a 28-percent reduction in non-EGU SO_2 emissions is reasonable. New Hampshire concurs with this conclusion.

10.3 Reasonable Progress Goals for Class I Areas in the State

As required under 40 CFR 51.308(d)(1), this regional haze SIP establishes reasonable progress goals for Class I areas in New Hampshire for the 10-year period of the implementation plan ending in 2018. These RPGs are determined from modeling based on implementation of the proposed reasonable measures included in MANE-VU's long-term strategy. Table 10.8 provides a summary of the reasonable progress goals, in deciviews, for New Hampshire's two Class I areas: Great Gulf Wilderness and Presidential Range - Dry River Wilderness.

Table 10.8: Reasonable Progress Goals for Great Gulf Wilderness and Presidential Range - Dry River Wilderness (all values in deciviews)

Visibility Condition	Natural Visibility	2000-2004 Baseline Visibility	RPG (Visibility Expected by 2018)	Visibility Improvement Expected by 2018
20 Percent Worst Days (Average)	12.0	22.8	19.1	3.7
20 Percent Best Days (Average)	3.7	7.7	7.2	0.5

Both natural conditions and baseline visibility for the 5-year period from 2000 through 2004 were calculated in conformance with an alternative method recommended by the IMPROVE Steering Committee. (See Attachment L, "Baseline and Natural Visibility Conditions: Considerations and Proposed Approach to the Calculation of Baseline and Natural Visibility Conditions at MANE-VU Class I Areas," December 2006.) Future progress toward the 2018 visibility target will be calculated in a nationally consistent manner based on 5-year averages in accordance with EPA's "Guidance for Tracking Progress Under the Regional Haze Rule" (EPA-454/B-03-004, September 2003) with adjustments for the alternative method as recommended by the IMPROVE Steering Committee.

40 CFR 51.308(d)(1)(vi) requires that reasonable progress goals represent at least the visibility improvement expected from implementation of other Clean Air Act programs during the applicable planning period. The modeling that formed the basis for reasonable progress goals for MANE-VU Class I Areas included estimation of the effects of all other programs required by the Clean Air Act. MANE-VU's modeling also included the specific control measure assumptions described previously in Subsection 10.2. Additional information may be found in Section 6, Emissions Inventory, and Section 11, Long-Term Strategy, as well as in the documentation for the MANE-VU modeling.

In setting the reasonable progress goals to improve visibility at MANE-VU Class I Areas, New Hampshire recognizes that contributing states will have flexibility to submit SIP revisions and implement various control measures to meet these goals between now and 2018. The overall approach to reducing and preventing emissions that contribute to regional haze allows each state up to 10 years to implement reasonable SO_2 and NO_X control measures as appropriate and necessary.

10.4 Visibility Effects of (Additional) Reasonable Control Measures

MANE-VU's evaluations included modeling to estimate the effects on visibility of the New Hampshire/MANE-VU Ask. The results of this work are summarized below.

NESCAUM performed preliminary modeling as described in the report entitled "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G). NESCAUM also conducted more recent, revised modeling to assess the effects of all haze reduction strategies combined. The latter modeling is described in NESCAUM's "2018 Visibility Projections," May 13, 2008 (Attachment Q).

The NESCAUM modeling demonstrates that significant visibility benefits will accrue from implementation of the additional reasonable control measures described in Subsection 10.2, above. Figures 10.4 and 10.5 describe the results of this modeling. In the first of the two figures, the light yellow bars represent expected visibility at MANE-VU Class I Areas in 2018. Comparison of these values with the 2018 "glide slope" values (the plum-colored bars) shows that all areas are expected to experience visibility improvements that meet or exceed the uniform rate of progress calculated for each area. The second figure shows that, for the 20 percent of days having best visibility, expected visibility in 2018 will be better than it is today at all locations.

In conclusion, the reasonable control measures proposed by New Hampshire and the other MANE-VU states are found to be consistent with the stated national goals of preventing further visibility degradation while making measurable progress toward achieving natural visibility conditions in wilderness areas by 2064.

Figure 10.4: Demonstration of Required and Reasonable Visibility Progress for 20 Percent Worst Visibility Days

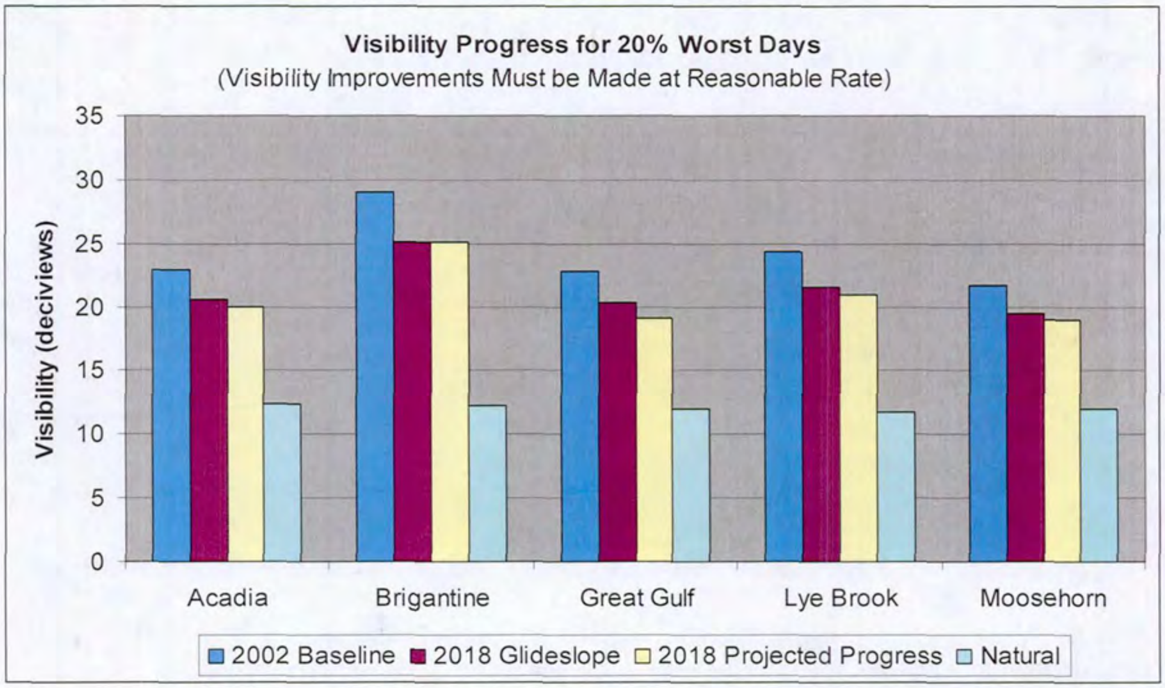
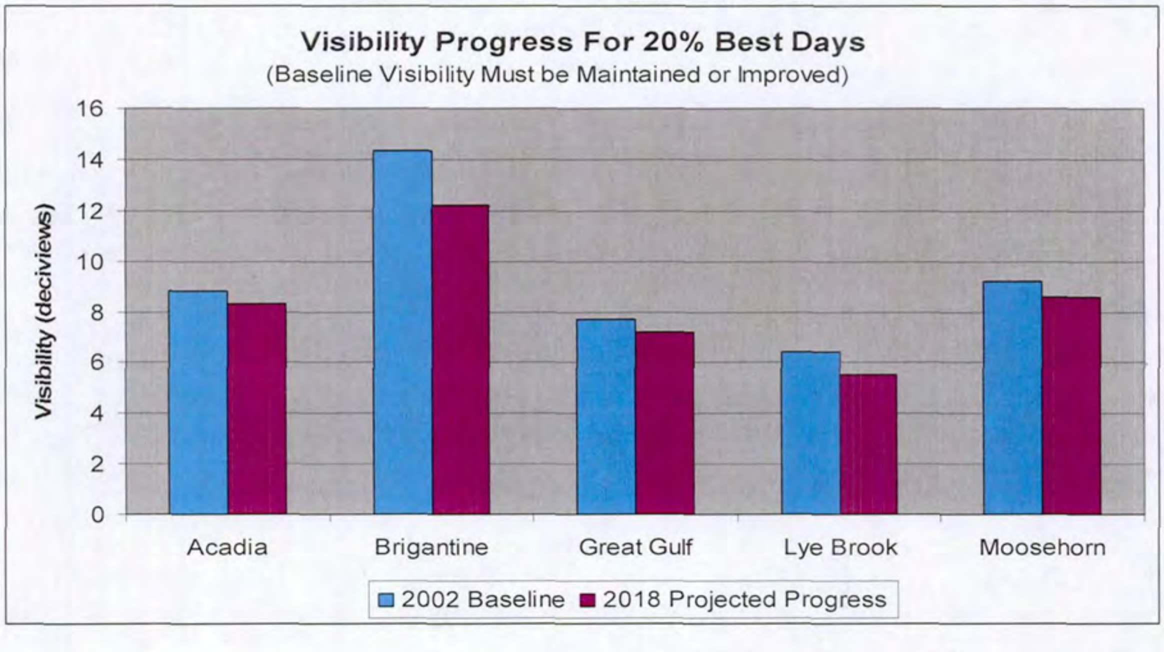


Figure 10.5: Demonstration of Required Maintenance or Improvement of Visibility for 20 Percent Best Visibility Days



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U.S. Environmental Protection Agency, *National Emission Standards for Hazardous Air Pollutants for Industrial/ Commercial/Institutional Boilers and Process Heaters*, http://cascade.epa.gov/RightSite/dk_public_collection_detail.htm?ObjectType=dk_docket_collection&cid=OAR-2002-0058&ShowList=items&Action=view (accessed Feb. 25, 2004).

11. LONG-TERM STRATEGY

40 CFR 51.308(d)(3) of the Regional Haze Rule requires the State of New Hampshire to submit a long-term strategy that addresses regional haze visibility impairment for all mandatory Class I federal areas within and outside the state that may be affected by emissions from within the state. Affected areas include the seven designated Class I areas within the MANE-VU region: Great Gulf Wilderness, Presidential Range-Dry River Wilderness, Acadia National Park, Moosehorn Wilderness, Roosevelt Campobello International Park, Lye Brook Wilderness, and Brigantine Wilderness. As presented in Section 3, Regional Planning and Consultation, New Hampshire consulted with other states to develop the coordinated emission management strategies contained in this SIP. The following describes how New Hampshire meets the long-term strategy requirements of the Regional Haze Rule.

New Hampshire's long-term strategy includes enforceable emission limitations, compliance schedules, and other measures necessary to achieve the reasonable progress goals described in Section 10. Additional measures may be reasonable to adopt at a later date after further consideration and review. In developing this long-term strategy, New Hampshire also considered the requirements of the Clean Air Act, Section 110 (a)(2)(D)(i)(II), pertaining to interstate and international transport of pollutants. NHDES has previously addressed this issue in New Hampshire's "Transport SIP Revision," submitted to EPA on March, 11, 2008. As that document observed, states must include provisions in their implementation plans to prohibit any source or activity from emitting air pollutants in amounts that would interfere with another state's ability to prevent significant deterioration of air quality and visibility. The long-term strategy presented herein is designed to protect visibility in New Hampshire as well as areas downwind from New Hampshire.

11.1 Overview of Strategy Development Process

The regional strategy development process identified reasonable measures that would reduce emissions contributing to visibility impairment at Class I areas by 2018 or earlier. The process of identifying potential emission reduction measures and the technical basis for the long-term strategy are discussed in this section. As a MANE-VU member and participant, New Hampshire supported several technical analyses undertaken to assist the MANE-VU states in deciding which regional haze control measures to pursue. These analyses are documented in the following reports:

- NESCAUM, "Contributions to Regional Haze in the Northeast and Mid-Atlantic United States," August 2006, otherwise known as the Contribution Assessment (Attachment B).
- ICF Resources, L.L.C., "Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model®," Final Draft Report, May 30, 2007, otherwise known as the CAIR Plus Report (Attachment BB);
- MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007, otherwise known as the Reasonable Progress Report (Attachment Y);
- NESCAUM, "Five-Factor Analysis of BART-Eligible Sources: Survey of Options for Conducting BART Determinations," June 1, 2007 (Attachment W); and

- NESCAUM, "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities," March 2005, otherwise known as the BART Report (Attachment Z).

MANE-VU reviewed a wide range of potential control measures aimed at reducing regional haze by the 2018 milestone. The process of choosing a set of control measures started in late 2005. OTC selected a contracting firm to assist with the analysis of ozone and regional haze control measure options and provided the contractor with a master list of some 900 potential control measures based on experience and previous state implementation plan work. With the help of an internal OTC Control Measures Workgroup, the contractor narrowed the list of regional haze control measures for further consideration by MANE-VU.

MANE-VU then developed an interim short list of possible control measures for regional haze. The identified control measures can be divided into three general categories:

- Beyond-CAIR sulfate reductions and related control measures targeted at specific electrical generating units (EGUs) in the eastern United States,
- Low-sulfur heating oil for industrial, commercial, institutional (ICI) boilers and residential sources (i.e., boilers and furnaces), and
- Emission controls on ICI boilers (both coal- and oil-fired); lime and cement kilns; residential woodstoves; and outdoor wood burning (including outdoor wood boilers).

The next step was to further refine this list, with the aid of several of the reports named above. The ICF CAIR Plus Report (Attachment BB) documents MANE-VU's assessment of the costs of CAIR and provides a cost analysis for additional SO_2 and NO_X controls in the eastern United States. The Reasonable Progress Report documents the assessment of control measures for EGUs and the other source categories selected for analysis. Further analysis is provided in the second of the two NESCAUM documents referenced above pertaining to Best Available Retrofit Technology (BART) controls.

The beyond-CAIR strategy for EGUs rose to the top of the list because the Contribution Assessment showed that EGU sulfate emissions have, by far, the largest impact on visibility in the MANE-VU Class I Areas. Similarly, a low-sulfur oil strategy gained traction after a NESCAUM-initiated conference with refiners and fuel-oil suppliers concluded that such a strategy could realistically be implemented within the next 10 years. Thus, the low-sulfur heating oil option for the residential and commercial sectors and the control measures option for the oil-fired ICI boiler sector merged into an overall strategy requiring the use of low-sulfur oil. Under this strategy, low-sulfur oil would be required for all residential and commercial heating units and all ICI boilers burning #2, #4, or #6 fuel oils.

During MANE-VU's internal consultation meeting in March 2007, member states reviewed the interim list of control measures to make additional refinements. States determined, for example, that there may be too few coal-fired ICI boilers in MANE-VU for these sources to be included in a regional strategy, but that they could be covered in programs adopted by individual states. The member states also decided that lime and cement kilns, of which there are few in the MANE-VU region, are most likely to be handled via the BART determination process. Residential wood burning and outdoor wood boilers remained on the list for those states where localized visibility impacts are a consideration even though emissions from these sources are primarily organic carbon and direct particulate matter. Finally, it was decided that the issue of outdoor wood burning should be examined further on a state-by-state basis because of concerns related to enforcement and penetration of existing state regulations. New Hampshire is currently considering additional regulation of this sector.

11.2 Technical Basis for Strategy Development

40 CFR 51.308(d)(3)(iii) requires New Hampshire to document the technical basis for the state's apportionment of emission reductions necessary to meet reasonable progress goals in each Class I area affected by New Hampshire's emissions. New Hampshire relied on technical analyses developed by MANE-VU to demonstrate that New Hampshire's emission reductions, when coordinated with those of other states and tribes, are sufficient to achieve reasonable progress goals in Class I areas located in New Hampshire and in other Class I areas affected by emissions originating in New Hampshire.

The emission reductions necessary to meet reasonable progress goals in Class I areas affected by New Hampshire are described in the following documents:

- NESCAUM, "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," December 2006 (Attachment L);
- NESCAUM, "The Nature of the Fine Particle and Regional Haze Air Quality Problems in the MANE-VU Region: A Conceptual Description," Final, November 2, 2006 (Attachment CC);
- NESCAUM, "Contributions to Regional Haze in the Northeast and Mid-Atlantic United States," August 2006, otherwise known as the Contribution Assessment (Attachment B).
- ICF Resources, L.L.C., "Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model®," Final Draft Report, May 30, 2007, otherwise known as the CAIR Plus Report (Attachment BB);
- MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007, otherwise known as the Reasonable Progress Report (Attachment Y);
- NESCAUM, "Five-Factor Analysis of BART-Eligible Sources: Survey of Options for Conducting BART Determinations," June 1, 2007 (Attachment W);
- NESCAUM, "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities," March 2005, otherwise known as the BART Report (Attachment Z);
- NESCAUM, "MANE-VU Modeling for Reasonable Progress Goals: Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G); and
- NESCAUM, "2018 Visibility Projections," May 13, 2008 (Attachment Q).

As described in Subsection 11.1, above, New Hampshire worked with other members of the Ozone Transport Commission and MANE-VU to evaluate a large number of potential emission reduction strategies covering a wide range of sources of SO_2 and other pollutants contributing to regional haze. 40 CFR 51.308(d)(3)(v) requires states to consider several factors in developing their long-term strategies. Operating within this framework and using available information about emissions and potential impacts, the MANE-VU Reasonable Progress Workgroup selected the following source categories for detailed analysis:

- Coal and oil-fired electric generating units (EGUs);
- Point and area source ICI boilers;
- Cement kilns and lime kilns;
- Sources capable of using low-sulfur heating oil; and
- Residential wood combustion and open burning.

These efforts led to the selection of the emission reduction strategies presented in this SIP.

11.3 Existing Commitments / Expected Measures to Reduce Emissions

40 CFR Section 51.308(d)(3)(v)(A) requires New Hampshire to consider emission reductions from ongoing pollution control programs. In developing its long-term strategy, New Hampshire considered air pollution programs being implemented between the 2002 baseline year and 2018. The emission reduction programs described in Parts 11.3.1, 11.3.2, and 11.3.3, below, represent commitments already made by New Hampshire and other states to implement air pollution control measures for EGU point sources, non-EGU point sources, and area sources, respectively. These control measures are the very same measures that were included in the 2018 emissions inventory and used in the modeling. While these control measures were not designed expressly for the purpose of improving visibility, the pollutants they control include those that contribute to visibility impairment in MANE-VU Class I Areas.

MANE-VU's 2018 beyond-on-the-way (BOTW) emissions inventory accounts for emission controls already in place as well as emission controls that are not yet finalized but are likely to achieve additional emission reductions by 2018. The BOTW inventory was developed based on the MANE-VU 2002 Version 3.0 inventory and the MANE-VU 2018 on-the-books/on-the-way (OTB/OTW) inventory. Inventories used for other RPOs reflect anticipated emissions controls that will be in place by 2018. The inventory is termed BOTW because it includes control measures that were developed for ozone SIPs that were not yet on the books in some states. For some states, BOTW also included controls that were under consideration for regional haze SIPs that have not yet been adopted. More information may be found in the following documents:

- MACTEC Federal Programs, Inc., "Development of Emissions Projections for 2009, 2012, and 2018 for NonEGU Point, Area, and Nonroad Sources in the MANE-VU Region," Final Report, February 28, 2007, otherwise known as the Emission Projections Report (Attachment N);

- Alpine Geophysics, LLC, "Documentation of 2018 Emissions from Electric Generating Units in the Eastern United States for MANE-VU's Regional Haze Modeling," Final Report, August 16, 2009 (Attachment H);

- NESCAUM, "MANE-VU Modeling for Reasonable Progress Goals: Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G); and

- NESCAUM, "2018 Visibility Projections," May 13, 2008 (Attachment Q).

11.3.1 Controls on EGUs Expected by 2018

The following EGU emission reduction programs were included in the modeling used to develop the reasonable progress goals. These programs represent the greatest opportunities for reducing SO_2 emissions at Class I areas in the MANE-VU region and serve as the starting point for MANE-VU's long-term strategy to mitigate regional haze.

***Clean Air Interstate Rule (CAIR)*:** This major federal rule was remanded to EPA to correct deficiencies and has been replaced with the proposed Transport Rule. The original CAIR imposed permanent emissions caps on sulfur dioxide (SO_2) and nitrogen oxides (NO_X) in the eastern United States by 2015. When fully effective, this program was expected to reduce SO_2 emissions in the CAIR region by up to 70 percent. To predict future emissions from EGUs after implementation of CAIR, MANE-VU used the Integrated Planning Model (IPM®)[30]. Adjustments to the IPM output were made to provide a more accurate representation of anticipated controls at specific EGU sources as documented in the Alpine Geophysics report listed above. In making these adjustments, emission controls originating from the following state and regional programs were considered:

***Connecticut EGU Regulations*:** Connecticut adopted the following regulations governing EGU emissions:

- *Regulations of Connecticut State Agencies (RCSA), section 22a-174-19a*, limiting the SO_2 emission rate to 0.33 lb/MMBtu for fossil-fuel-fired EGUs greater than 15 MW that are also Title IV sources (effective, 2007).
- *RCSA, section 22a-174-22*, limiting the non-ozone seasonal NO_X emission rate to 0.15 lb/MMBtu for fossil-fuel-fired EGUs greater than 15 MW (effective, 2007).
- *RCSA, section 22a-199*, limiting the mercury (Hg) emission rate to 0.0000006 lb/MMBtu for all coal-fired EGUs, or alternatively coal-fired EGUs can meet a 90-percent Hg emission reduction (effective, 2008).

***Delaware EGU Regulations*:** Delaware adopted the following regulations governing EGU emissions:

- *Reg. 1144, Control of Stationary Generator Emissions*, requiring emission controls for SO_2, PM, VOC, and NO_X state-wide, effective January 2006.
- *Reg. 1146, Electric Generating Unit (EGU) Multi-Pollutant Regulation,* requiring SO_2 and NO_X emission controls state-wide, effective December 2007. SO_2 reductions will be more than regulation specifies
- *Reg. 1148, Control of Stationary Combustion Turbine Electric Generating Unit Emissions*, requiring SO_2, NO_X, and $PM_{2.5}$ emission controls state-wide, effective January 2007.

[30] The IPM model runs also anticipated the implementation of EPA's Clean Air Mercury Rule (CAMR), which was recently vacated by the courts. However, MANE-VU believes that the adjustments made to the predicted SO_2 emissions from electric generating units (EGUs) will have a larger effect on the air quality modeling analysis conducted for this SIP than will the vacatur of the CAMR rule. The emission adjustments were based on states' comments on the actual levels of SO_2 controls expected to be installed in response to state-specific regulations and EPA's CAIR rule. MANE-VU believes these adjustments improve the reliability of both the emissions inventory and modeling results.

Delaware estimates that these regulations will result in the following emission reductions for affected units: SO_2 emissions of 32,630 tons in 2002 will decline to 8,137 tons in 2018 (a 75-percent reduction); NO_X emissions of 8,735tons in 2002 will decline to 3,740 tons in 2018 (a 57-percent reduction).

Also, Delaware anticipates the following reductions resulting from the consent decree with Valero Refinery Delaware City, DE (formerly Motiva, Valero Enterprises): SO_2 emissions of 29,747 tons in 2002 will decline to 608 tons in 2018 (a 98-percent reduction); NO_X emissions in 1,022 in 2002 will decline to 102 tons in 2018 (a 90-percent reduction).

Maine EGU Regulations: *Chapter 145, NO_X Control Program*, limits the NO_X emission rate to 0.22 lb/MMBtu for fossil-fuel-fired units greater than 25 MW built before 1995 with a heat input capacity between 250 and 750 MMBtu/hr, and also limits the NO_X emission rate to 0.15 lb/MMBtu for fossil-fuel-fired units greater than 25 MW built before 1995 with a heat input capacity greater than 750 MMBtu/hr (effective, 2007).

Massachusetts EGU Regulations: Based on the Massachusetts Department of Environmental Protection's 310 CMR 7.29, *Emissions Standards for Power Plants,* adopted in 2001, six of the largest fossil-fuel-fired power plants in Massachusetts must comply with emissions limitations for NO_X, SO_2, Hg, and CO_2. These regulations will achieve an approximately 50-percent reduction in NO_X emissions and a 50- to 75-percent reduction in SO_2 emissions. Depending on the compliance paths selected, the affected facilities will meet the output-based NO_X and SO_2 standards between 2004 and 2008. This regulation also limits the six grandfathered EGUs to a CO_2 emission rate of 1,800 lb/MWh.

New Hampshire EGU Regulations: New Hampshire adopted the following regulations governing EGU emissions (inclusive of the New Hampshire Clean Power Act):

- *Chapter Env-A 2900, Multiple Pollutant Annual Budget Trading and Banking Program*, capping NO_X emissions at 3,644 tons per year, SO_2 emissions at 7,289 tons per year, and CO_2 emissions at 5,425,866 tons CO_2 per year for all existing fossil-fuel-fired steam units by December 31, 2006.
- *Chapter Env-A 3200, NO_X Budget Trading Program*, limiting ozone season NO_X emissions on all fossil-fuel-fired EGUs greater than 15 MW to 0.15 lb/MMBtu, effective November 2, 2007.
- *RSA 125-O, Multiple Pollutant Reduction Program*, requiring the installation and operation of a flue gas desulfurization system (scrubber) on PSNH Merrimack Station Units MK1 and MK2 to reduce mercury emissions by at least 80 percent, with the co-benefit of SO_2 emission reductions (90 percent expected minimum).

New Jersey New Source Review Settlement Agreements: The New Jersey settlement agreement with PSEG required the following actions for specific EGUs:

- *Bergen Unit #2*: Repower to combined cycle by December 31, 2002.
- *Hudson Unit #2*: Install dry FGD or approved alternative technology by Dec. 31, 2006, to control SO_2 emissions and operate the control technology at all times the unit operates to limit SO_2 emissions to 0.15 lb/MMBtu; install SCR or approved alternative technology by May 1, 2007, to control NO_X emissions and operate the control technology year-round to limit NO_X emissions to 0.1 lb/MMBtu; and install a

baghouse or approved alternative technology by May 1, 2007, to control and limit PM emissions to 0.015 lb PM/MMBtu.

- *Mercer Unit #1*: Install dry FGD or approved alternative technology by Dec. 31, 2010, to control SO_2 emissions and operate the control technology at all times the unit operates to limit SO_2 emissions to 0.15 lb/MMBtu; and install SCR or approved alternative technology by 2005 to control NO_X emissions and operate the control technology during ozone season only in 2005 and year-round by May 1, 2006, to limit NO_X emissions to 0.13 lb/MMBtu.

- *Mercer Unit #2*: Install dry FGD or approved alternative technology by Dec. 31, 2012, to control SO_2 emissions and operate the control technology at all times the unit operates to limit SO_2 emissions to 0.15 lb/MMBtu; and install SCR or approved alternative technology by 2004 to control NO_X emissions and operate the control technology during ozone season only in 2004 and year-round by May 1, 2006, to limit NO_X emissions to 0.13 lb/MMBtu.

The New Jersey settlement also requires that units operating an FGD use coal having a monthly average sulfur content no greater than 2 percent.

New York EGU Regulations: New York adopted the following regulations governing EGU emissions:

- *Title 6 NYCRR Parts 237, Acid Deposition Reduction NO_X Budget Trading Program*, limits NO_X emissions on all fossil-fuel-fired EGUs greater than 25 MW to a non-ozone season cap of 39,908 tons in 2007.

- *Title 6 NYCRR Parts 238, Acid Deposition Reduction SO_2 Budget Trading Program*, limits SO_2 emissions from all fossil-fuel-fired EGUs greater than 25 MW to an annual cap of 197,046 tons per year starting in 2007 and an annual cap of 131,364 tons per year starting in 2008.

North Carolina Clean Smokestacks Act: Enacted in 2002, this legislation requires that coal-fired EGUs achieve a 77-percent cut in NO_X emissions by 2009 and a 73-percent cut in sulfur dioxide SO_2 emissions by 2013. This act also established annual caps on both SO_2 and NO_X emissions for the two primary utility companies in North Carolina, Duke Energy and Progress Energy. These reductions must be made in North Carolina, and allowances are not saleable.

Consent Agreements in the VISTAS region: The effects of the following consent agreements in the VISTAS states were reflected in the emissions inventories used for those states:

- *Santee Cooper*: A 2004 consent agreement calls for Santee Cooper in South Carolina to install and commence operation of continuous emission control equipment for $PM/SO_2/NO_X$ emissions; comply with system-wide annual $PM/SO_2/NO_X$ emissions limits; agree not to buy, sell, or trade SO_2/NO_X allowances allocated to Santee Cooper System as a result of this agreement; and to comply with emission unit limits of this agreement.

- *TECO*: Under a settlement agreement, by 2008, Tampa Electric in the state of Florida will install permanent emission control equipment to meet stringent pollution limits; implement a series of interim pollution reduction measures to reduce emissions while the permanent controls are designed and installed; and retire pollution emission allowances that Tampa Electric or others could use, or sell to others, to emit additional NO_X, SO_2, and PM.

- *VEPCO*: Virginia Electric and Power Co. agreed to spend $1.2 billion by 2013 to eliminate 237,000 tons of SO_2 and NO_X emissions each year from eight coal-fired electricity generating plants in Virginia and West Virginia.
- *Gulf Power 7*: A 2002 agreement calls for Gulf Power to upgrade its operation to cut NO_X emission rates by 61 percent at its Crist 7 generating plant by 2007 with major reductions beginning in early 2005. The Crist plant is a significant source of NO_X emissions in the Pensacola, Florida, area.

11.3.2 Controls on Non-EGU Point Sources Expected by 2018

For non-EGU sources within MANE-VU, New Hampshire relied on MANE-VU's Version 3.0 Emission Inventory for 2002. MACTEC conducted an analysis of various control measures as documented in the Emission Projections Report (Attachment N). Control factors were applied to the 2018 MANE-VU inventory for non-EGUs to represent the following national, regional, or state control measures:

- NO_X SIP Call Phase I (NO_X Budget Trading Program) (except ME, NH, VT);
- NO_X SIP Call Phase II (except ME, NH, VT);
- NO_X RACT in 1-hour Ozone SIPs (already included in the 2002 inventory);
- NO_X OTC 2001 Model Rule for ICI Boilers;
- 2-, 4-, 7-, and 10-year MACT Standards;
- Combustion Turbine and RICE MACT (NO_X co-benefits were not included and assumed to be small);
- Industrial Boiler/Process Heater MACT[31]; and
- Refinery Enforcement Initiative (Fluid catalytic cracking units and fluid coking units, process heaters and boilers, flare gas recovery, leak detection and repair, and benzene (wastewater)).

In addition, states provided control measure information about specific non-EGU sources or regulatory programs in their states. MANE-VU used the state-specific data to the extent it was available. For example, several states developed additional control measures in the course of their planning efforts to reduce ozone within the Ozone Transport Region (OTR). These control measures were included by MANE-VU in the inventories used for regional haze modeling. (The affected states may or may not have committed to adopting these measures in their ozone SIPs.) For specific states, the ozone-reduction strategies included in the modeling would reduce NO_X emissions from the following non-EGU point sources:

- Asphalt production plants in Connecticut, New Jersey, New York, and the District of Columbia;
- Cement kilns in Maine, Maryland, New York, and Pennsylvania; and

[31] The inventory was prepared before the MACT for Industrial Boilers and Process Heaters was vacated. Control efficiency was assumed to be 4 percent for SO_2 and 40 percent for PM. The overall effects of including these reductions in the inventory are estimated to be minimal.

- Glass and fiberglass furnaces in Maryland, Massachusetts, New Jersey, New York, and Pennsylvania.

For other regions, MANE-VU used emission inventory data developed by the RPOs for those regions, including VISTAS's Base G2, MRPO's Base K, and CenRAP's emissions inventory. Non-EGU source controls incorporated into the modeling include those required under the following consent agreements as reflected in the VISTAS inventory:

- *Dupont*: A 2007 agreement calls for E. I. Dupont Nemours & Co.'s James River plant to install dual absorption pollution control equipment by September 1, 2009, resulting in SO_2 emission reductions of approximately 1,000 tons annually. The James River plant is a non-EGU located in the state of Virginia.

- *Stone Container*: A 2004 agreement calls for the West Point Paper Mill in Virginia owned by Smurfit/Stone Container to control SO_2 emissions from its #8 Power Boiler by using a wet scrubber. This control device should result in reductions of over 3,500 tons of SO_2 in 2018.

11.3.3 Controls on Area Sources Expected by 2018

For area sources within MANE-VU, New Hampshire relied on MANE-VU's Version 3.0 Emissions Inventory for 2002. In general, MANE-VU developed the 2018 inventory for area sources by applying growth and control factors to the 2002 Version 3.0 inventory. Area source control factors were developed for the following national or regional control measures:

- Phase 1 of MANE-VU's low-sulfur fuel oil strategy for the inner-zone states (New Jersey, New York, Delaware, and Pennsylvania, or portions thereof) to reduce the sulfur content of:
  - #2 distillate oil to 0.05 percent (500 ppm) sulfur, by weight, by no later than 2012;
  - #4 residual oil to 0.25 percent sulfur, by weight, by no later than 2012;
  - #6 residual oil to 0.3-0.5 percent sulfur, by weight, by no later than 2012;

- Phase 1 of MANE-VU's low-sulfur fuel oil strategy for the outer-zone states (the rest of the MANE-VU region) to reduce the sulfur content of:
  - #2 distillate oil to 0.05 percent (500 ppm) sulfur, by weight, by no later than 2014;
  - #4 residual oil to 0.25-0.50 percent sulfur, by weight, by no later than 2018;
  - #6 residual oil to 0.5 percent sulfur or less, by weight, by no later than 2018;

- The Ozone Transport Commission's VOC Model Rules (for consumer products, architectural and industrial maintenance coatings, portable fuel containers, mobile equipment repair and refinishing, and solvent cleaning);

- Stage I vapor recovery systems at vehicle refueling stations in all New Hampshire counties and Stage II vapor recovery systems at vehicle refueling stations in the four southern counties classified as ozone nonattainment areas (Rockingham, Strafford, Hillsborough, and Merrimack);

- New Jersey post-2002 area source controls; and

- Residential woodstove NSPS.

The following additional control measures were included in the 2018 analysis to reduce NO_X and VOC emissions for the following area source categories for some (identified) states:

- NO_X control measures for combustion of coal; natural gas; and #2, #4, and #6 fuel oils (CT, NJ, and NY only);
- VOC control measures for adhesives and sealants (all MANE-VU states except New Jersey[32] and VT);
- VOC control measures for emulsified and cutback asphalt paving (all MANE-VU states except ME and VT);
- VOC control measures for consumer products (all MANE-VU states except VT); and
- VOC control measures for portable fuel containers (all MANE-VU states except VT).

Some of the area-source control measures listed above may have been developed by states for the primary purpose of reducing ozone within the Ozone Transport Region (OTR) – see Part 11.3.2 for information on other measures included in states' ozone SIPs.

11.3.4 Controls on Mobile Sources Expected by 2018

For the on-road mobile source emission inventory, New Hampshire relied on MANE-VU's Version 3.0 emission inventory, which included the following emission control measures for New Hampshire:

- Use of reformulated gasoline in the four southern counties classified as ozone nonattainment areas: Rockingham, Strafford, Hillsborough, and Merrimack;
- An enhanced safety inspection program, including an anti-tampering inspection for motor vehicles less than 20 years old;
- On-board diagnostics testing for 1996 and newer vehicles in lieu of the anti-tampering inspection;
- Federal On-Board Refueling Vapor Recovery (ORVR) Rule;
- Federal Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Requirements;
- Federal Heavy-Duty Diesel Engine Emission Standards for Trucks and Buses; and
- Federal Emission Standards for Large Industrial Spark-Ignition Engines and Recreational Vehicles

Similar programs in other MANE-VU states were included in the on-road mobile source emission inventory, where applicable. The last four items listed above are federal programs, briefly described here:

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

[32] New Jersey's emission reductions from control measures for adhesives and sealants apply only to area sources. No reductions for point sources (SCC 4-02-0007-xx) were included to avoid inventory double-counting.

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 to phase out Stage II programs, even in the worst nonattainment areas, once EPA has determined that onboard systems are in widespread use.

***Tier 2 Motor Vehicle Emissions Standards*:** Tier 2 is a fleet-averaging program modeled after the California LEV II standards. Manufacturers can produce vehicles with emissions ranging from relatively dirty to zero, but the mix of vehicles a manufacturer sells each year must have average NO_X emissions below a specified value. The Tier 2 regulations also require reduced gasoline sulfur levels. The reduction in sulfur levels contributes directly to cleaner air and has additional beneficial effects on vehicle emission control systems. The Tier 2 standards became effective in the 2005 model year and are included in the assumptions used for calculating mobile source emissions inventories used for 2018.

***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 will be phased in together between 2007 and 2010. Sulfur in diesel fuel must be lowered to enable modern pollution-control technology to be effective on the trucks and buses that use this fuel. EPA will require a 97-percent reduction in the sulfur content of highway diesel fuel from its current level of 500 parts per million (low-sulfur diesel) to 15 parts per million (ultra-low sulfur diesel).

***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 non-road 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. Non-road 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.

11.3.5 Controls on Non-Road Sources Expected by 2018

For non-road emission sources, New Hampshire used Version 3.0 of the MANE-VU 2002 Emissions Inventory. Because the NONROAD Model used to develop the non-road source emissions did not include aircraft, commercial marine vessels, and locomotives, MANE-VU's contractor, MACTEC, developed the inventory for these sources. Non-road 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 non-road emission control requirements such as the following:

- "Control of Air Pollution: Determination of Significance for Nonroad Sources and Emissions Standards for New Nonroad Compression Ignition Engines at or above 37 Kilowatts," 59 FR 31306, June 17, 1994.
- "Control of Emissions of Air Pollution from Nonroad Diesel Engines," 63 FR 56967, October 23, 1998.
- "Control of Emissions from Nonroad Large Spark-Ignition Engines and Recreational Engines (Marine and Land-Based)," Final Rule, 67 FR 68241, November 8, 2002.
- "Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel," Final Rule, April, 2004.

As noted above, inventory data for other regions were obtained from those regions' RPOs.

11.4 Additional Reasonable Measures

As required under 40 CFR 51.308(d)(1)(i)(A), New Hampshire and the other MANE-VU states applied four-factor analysis to potential control measures for the purpose of establishing reasonable progress goals (see Subsection 10.2 for detailed description). Reasonable measures include those that the affected states have already committed themselves to implementing, as described in Subsection 11.3, above. In addition, the MANE-VU states have identified other control measures that were found to be reasonable and were included in the modeling that was used to set reasonable progress goals. (These additional measures surpass the "beyond-on-the-way" emission controls and inventories.) All of the control measures – those embodied in the states' commitments to existing or planned programs and the additional reasonable control measures described below – comprise the long-term strategy for improving visibility at MANE-VU Class I Areas.

Specifically, the New Hampshire/MANE-VU long-term strategy includes the following additional measures to reduce pollutants that cause regional haze.

- Timely implementation of BART requirements.
- Anticipated Phase 2 of MANE-VU's low-sulfur fuel oil strategy to further reduce the sulfur content of distillate oil to 15 ppm by no later than:
  - 2016 for the inner-zone states (New Jersey, New York, Delaware, and Pennsylvania, or portions thereof); and
  - 2018 for the outer-zone states (the rest of the MANE-VU region).
- A 90-percent or greater reduction in sulfur dioxide (SO_2) emissions from each of the EGUs identified by MANE-VU as reasonably anticipated to cause or contribute to impairment of visibility in each mandatory Class I area in the MANE-VU region. (This requirement affects 167 point sources, or stacks, at EGU facilities in the eastern United States.) If it is infeasible to achieve this level of SO_2 reductions from specific EGUs, equivalent alternative measures will be pursued in the affected states.
- Continued evaluation of other control measures, including energy efficiency, alternative clean fuels, 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 combustion.

This suite of additional control measures are those that the MANE-VU states have agreed to pursue for the purpose of mitigating regional haze. The corollary is that the MANE-VU Class I states (Maine, New Hampshire, Vermont, and New Jersey) are asking states outside the MANE-VU region that contribute to visibility impairment inside the region to pursue similar measures. The control measures that non-MANE-VU states choose to pursue may be directed toward the same emission source sectors identified by MANE-VU for its own emission reductions, or they may be equivalent measures targeting other source sectors. Under MANE-VU's long-term strategy, states will be allowed up to ten years to pursue adoption and implementation of proposed control measures. While some measures that states pursue may not represent enforceable commitments immediately, they may become enforceable in the future as new laws are passed, rules are written, and facility permits are issued.

11.4.1 BART

Implementation of the BART provisions of the Regional Haze Rule (40 CFR 51.308(e)) is one of the reasonable strategies included in this SIP. For electrical generating units, EPA determined that CAIR (before its remand) would fulfill BART requirements for this sector. However, New Hampshire's approach is consistent with the MANE-VU long-term strategy; i.e., it goes beyond the original CAIR standards by requiring BART controls on all BART-eligible sources in the state. Proposed control measures for New Hampshire's two BART-eligible sources, both of which are EGUs, are described in Section 9 of this SIP. These two sources are also addressed in MANE-VU's targeted EGU strategy (see Part 11.4.3, below).

To assess the benefits of implementing BART controls for MANE-VU's non-EGU sectors, NESCAUM included in the final 2018 CMAQ modeling analysis anticipated emission reductions for the region's BART-eligible facilities, as described previously in Part 10.2.2 of this SIP. It is anticipated that twelve units at eight BART-eligible sources in MANE-VU would be controlled as a result of BART requirements alone (see Table 10.3).

Note that additional emission reductions will occur at many other BART-eligible facilities within MANE-VU as a result of controls achieved by other programs that serve as BART but are not specifically identified as such (e.g., RACT control measures). While not specifically identified as being attributable to BART, these additional emission reductions were fully accounted for in the 2018 CMAQ modeling.

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

11.4.2 Low-Sulfur Oil Strategy

The important assumption underlying MANE-VU's low-sulfur fuel oil strategy is that refiners can, by 2018, produce sufficient quantities of home heating and other fuel oils with lower sulfur content than current fuel supplies at only a small increase in price to the end user. The expected reductions in sulfur content range from 50 percent for the heavier grades (#4 and #6 residual) to a minimum of 75 percent and maximum of 99.25 percent for #2 fuel oil (also known as home heating oil, distillate, or diesel fuel). As much as three-fourths of the total sulfur reductions achieved by this strategy will come from using low-sulfur #2 distillate for space heating in the residential and commercial sectors. The costs of these emissions reductions are estimated at $550 to $750 per ton, as documented in the MANE-VU Reasonable Progress Report. While the costs of the low-sulfur fuel oil strategy remain somewhat uncertain, they appear to be reasonable when measured against the costs of controlling other sectors.

Currently there are logistical issues in supplying large quantities of low-sulfur oils to the PADD1B (northern New England region). This oil is supplied by PADD1A and barged into the region in quantities that allow for blending with high-sulfur fuels to produce 1-percent sulfur fuels. Current capacities are limited by Federal restrictions that prevent large ships from transferring fuels between two U.S. ports. The states of this region intend to build full capacity for 0.5-percent-sulfur #6 fuel oil by 2018.

The MANE-VU states agree that a low-sulfur oil strategy is reasonable to pursue in the next ten years. NHDES will review the details of this strategy coincident with New Hampshire's first regional haze SIP progress report, to ascertain that requiring the use of low-sulfur fuel remains viable for implementation by 2018.

11.4.3 Targeted EGU Strategy

MANE-VU has identified emissions from the top 167 EGU emission points, including three in New Hampshire, that contribute the most to visibility impairment at MANE-VU Class I Areas (see Figure 10.2). Controlling emissions from these contributing facilities is crucial to mitigating haze pollution in wilderness areas and national parks of the Northeast states.

MANE-VU's agreed regional strategy for the EGU source sector is to pursue a 90-percent control level on SO_2 emissions from the 167 identified stacks by 2018. MANE-VU has concluded that pursuing this level of sulfur reduction is both reasonable and cost-effective. For some units, actual SO_2 removal efficiencies would be expected to approach or exceed 95 percent. The costs of SO_2 emission reductions will vary by unit. MANE-VU's Reasonable Progress Report (Attachment Y) summarizes the available control methods and costs, which range from $170 to $5,700 per ton (2006 dollars), depending on site-specific factors such as size of unit, combustion technology used, and type of fuel burned.

As shown in Table 11.1, the three targeted EGUs in New Hampshire are projected to reduce their SO_2 emissions, in the aggregate, by 87 percent between 2002 and 2018.

Table 11.1: Projected SO_2 Emission Reductions from Targeted EGUs in New Hampshire

Facility Name/Unit	Targeted EGU	BART-Eligible	Fuel Type	2002 SO_2 Emissions (tons)	Control Method	SO_2 Emission Reductions (%)	SO_2 Emission Reductions (tons)	2018 SO_2 Emissions (tons)
Merrimack Station MK1	yes	no	coal	9,754	scrubber	90	8,779	975
Merrimack Station MK2	yes	yes	coal	20,902	scrubber	90	18,812	2,090
Newington Station NT1	yes	yes	fuel oil/ natural gas	5,226	0.50 lb/MMBtu SO_2 emission limit	67	3,484	1,742
TOTALS				**35,882**		**87**	**31,075**	**4,807**

Notes: All 2002 values are based on continuous emissions monitoring (CEM) data. For Newington Station, additional SO_2 emission reductions beyond the stated value may occur with a switch to 0.5-percent low-sulfur oil under MANE-VU's low-sulfur oil strategy.

These projections are conservative estimates for at least two reasons:

- The actual performance of scrubbers to be installed on PSNH's Merrimack Station Units MK1 and MK2 is expected to match or exceed MANE-VU's Ask level of 90-percent SO_2 from targeted EGUs. (Note that MANE-VU's Assessment of Control Options for BART-Eligible Sources, Attachment Z references 95-percent control reductions. However, this rate applies to EGUs greater than 200 MW at power plants having capacities above 750-MW, i.e., facilities larger than PSNH's. Also, note that the overall SO_2 control level for the three PSNH units would be greater than stated if the baseline reduction resulting from use of lower-sulfur coal were included in the efficiency calculation.)

- PSNH's Newington Station Unit NT1, being primarily an oil-fired EGU, is expected to have low utilization rates well into the future because of the economics associated with the cost of fuel. In 2007, high fuel costs caused this unit to operate only 5 percent of the time. In fact, the most recent IPM modeling predicts that this unit will be shut down permanently by 2018. (Note that MANE-VU, from the outset, never envisioned that this oil-fired unit would be capable of achieving a control level equal to the presumptive norm for large EGUs.)

Given these considerations, there is a high probability that New Hampshire will actually surpass MANE-VU's goal of a 90-percent overall reduction in SO_2 emissions from targeted EGUs by 2018. However, in the event that New Hampshire is unable to attain this level of emission reductions, equivalency could be demonstrated by alternative methods. For example:

- Credit could be taken for SO_2 emission reductions resulting from the recently completed fuel conversion of Schiller Station Unit 5 from coal to wood and from any similar fuel conversions that might occur for other New Hampshire EGUs in the future.

- Additional SO_2 emission reductions could be achieved before 2018 by requiring all sources that burn residual fuel oil to switch to residual fuel oil with a sulfur content of 0.5-percent (or lower). New Hampshire intends to investigate this possibility further.

The anticipated benefits to regional visibility that will result from using FGD technology on New Hampshire's largest EGUs are an intended consequence of New Hampshire's Multiple Pollutant Reduction Program, which was established by law in RSA Chapter 125-O. This program requires aggressive reductions in SO_2, NO_X, mercury, and carbon dioxide (CO_2) while simultaneously allowing state-level SO_2 credits for over- or early- compliance. Under this program, emission controls for SO_2 and mercury are scheduled to be installed and operational at New Hampshire's PSNH Merrimack Station Units MK1 and MK2 by July 1, 2013. In the meantime, NHDES will continue to evaluate other control measures for EGUs to determine whether it is reasonable to implement additional controls on those sources by that date. NHDES will provide an update on its determinations in New Hampshire's first regional haze SIP progress report.

Several other states within and outside the MANE-VU region have implemented state-specific EGU emission reduction programs that will help MANE-VU meet visibility improvement goals. Many of the state programs that will contribute to meeting the targeted EGU strategy are identified in Part 11.3.1 of this section. Listed below are other state programs not previously identified that will also contribute to meeting this strategy. These other programs may yield additional benefits by controlling emissions at certain EGUs not listed among the top 167 EGU stacks. The listed programs represent existing commitments by the states and, as such, were included in MANE-VU's most recent modeling.

***Maryland Healthy Air Act*:** Maryland adopted the following requirements governing EGU emissions:

- For NO_X: Phase I (2009) sets unit-specific annual caps totaling 20,216 tons and ozone-season caps totaling 8,900 tons.

  Phase II (2012) sets unit-specific annual caps totaling 16,667 tons and ozone-season caps totaling 7,337 tons.

- For SO_2: Phase I (2010) sets unit-specific annual caps totaling 48,818 tons.

  Phase II (2013) sets unit-specific annual caps totaling 37,235 tons.

- For mercury: Phase I (2010) requires a 12-month-rolling-average minimum removal efficiency of 80 percent.

  Phase II (2013) requires a 12-month-rolling-average minimum removal efficiency of 90 percent.

The specific EGUs included are: Brandon Shores (Units 1 and 2), C.P.Crane (Units 1 and 2), Chalk Point (Units 1, and 2), Dickerson (Units 1, 2, and 3), H.A. Wagner (Units 2 and 3) Morgantown (Units 1 and 2), and R. Paul Smith (Units 3 and 4). No out-of-state trading of emission allowances, no inter-company trading of allowances, and no banking of allowances from year to year were included in the analyses.

***New Jersey Mercury MACT Rule*:** Under this rule all coal-fired EGUs in New Jersey will have a mercury removal efficiency of 90 percent. (Some SO_2 reductions may occur as a co-benefit of mercury emission controls.)

***Consent Agreements in the VISTAS region*:** The following consent agreements in the VISTAS states were reflected in the emissions inventories used for those states:

- *East Kentucky Power Cooperative*: A July 2, 2007, consent agreement between EPA and East Kentucky Power Cooperative (EKPC) requires the utility to reduce its SO_2 emissions by 54,000 tons per year and its NO_X emissions by 8,000 tons per year, by installing and operating selective catalytic reduction (SCR) technology; low-NO_X burners, and PM and mercury continuous emissions monitors at the utility's Spurlock, Dale, and Cooper Plants. According to the EPA, total emissions from the plants will decrease between 50 and 75 percent from 2005 levels. As with all federal consent decrees, EKPC is precluded from using reductions required under other programs to meet the reduction requirements of the consent decree. EKPC is expected to spend $654 million to install pollution controls.

- *American Electric Power*: Under this agreement, American Electric Power (AEP) will spend $4.6 billion dollars for emission controls at sixteen plants located in Indiana, Kentucky, Ohio, Virginia, and West Virginia. These control measures will eliminate 72,000 tons of NO_X emissions each year by 2016 and 174,000 tons of SO_2 emissions each year by 2018 from the affected facilities.

11.5 Source Retirement and Replacement Schedules

40 CFR Section 51.308(d)(3)(v)(D) of the Regional Haze Rule requires New Hampshire to consider source retirement and replacement schedules in developing reasonable progress goals. Source retirement and replacement were considered in developing the 2018 emissions inventory described previously in Subsection 10.3, Reasonable Progress Goals for Class I Areas in the State. See also Table B-5 in the Emission Projections Report (Attachment N).

The following sources in New Hampshire were shut down (or replaced) after the 2002 base year and therefore were not included in the 2018 inventory:

- Batesville Manufacturing, Inc. (Nashua, NH)
- PSNH Schiller Station, Unit No. 5 boiler replacement (Portsmouth, NH)
- Groveton Paperboard, Inc. (Groveton, NH)
- Wausau Paper Printing & Writing, LLC (Groveton, NH)

Since the 2002 and 2018 inventories were developed and the modeling analyses performed, the following major source has also shut down:

- Fraser N.H. LLC (Berlin, NH)

11.6 Measures to Mitigate the Impacts of Construction Activities

40 CFR 51.308(d)(3)(v)(B) of the Regional Haze Rule requires New Hampshire to consider measures to mitigate the impacts of construction activities on regional haze. MANE-VU's consideration of control measures for construction activities is documented in "Technical Support Document on Measures to Mitigate the Visibility Impacts of Construction Activities in the MANE-VU Region," Draft, October 20, 2006," (Attachment DD).

The construction industry is already subject to requirements for controlling pollutants that contribute to visibility impairment. For example, federal regulations require the reduction of SO_2 emissions from construction vehicles. At the state level, New Hampshire's Code of Administrative Rules Env-A 1002, Fugitive Dust, requires the control of direct emissions of particulate matter (primarily crustal material) from mining, transportation, storage, use, and removal activities. These requirements apply to such sources as quarries, unpaved roads, cement plants, construction sites, rock-crushing operations, and general earth-moving activities. Controls may include wet suppression, covering, vacuuming, and other approved means.

MANE-VU's Contribution Assessment (Attachment B) found that, from a regional haze perspective, crustal material generally does not play a major role. On the 20 percent best-visibility days during the 2000-2004 baseline period, crustal material accounted for 6 to 11 percent of particle-related light extinction at MANE-VU Class I Areas. On the 20 percent worst-visibility days, however, the ratio was reduced to 2 to 3 percent. Furthermore, the crustal fraction is largely made up of pollutants of natural origin (e.g., soil or sea salt) that are not targeted under the Regional Haze Rule. 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.

For this regional haze SIP, New Hampshire considered additional measures to mitigate the impacts of construction activities but decided to defer evaluation of further controls. Future deliberations on potential control measures for construction activities and their possible implementation will be documented in the first regional haze SIP progress report in 2013.

11.7 Agricultural and Forestry Smoke Management

40 CFR 51.308(d)(3)(v)(E) requires New Hampshire to consider smoke management techniques related to agricultural and forestry management in developing the long-term strategy. MANE-VU's analysis of smoke management in the context of regional haze is documented in "Technical Support Document on Agricultural and Forestry Smoke Management in the MANE-VU Region, September 1, 2006," (Attachment V).

As that report notes, fires used for resource benefits are of far less significance to the total inventory of fine-particle pollutant emissions than other sources of wood smoke in the region. The largest wood smoke source categories, with respect to $PM_{2.5}$ emissions, are residential wood combustion (73 percent); open burning (15 percent); and industrial, commercial, and institutional wood combustion (9 percent). Unwanted fires involving buildings and wild lands make up only a minor fraction of wood burning emissions and cannot be reasonably addressed in a SIP. Fires that are covered under smoke management plans, including agricultural and prescribed forest burning, constitute less than one percent of total wood smoke emissions in MANE-VU.

Moreover, smoke emissions from all sources represent only a minor fraction of fine-particle mass that is the cause of regional haze. MANE-VU's Contribution Assessment (Attachment B) found that elemental carbon, the main ingredient of smoke, contributed only 3 to 4 percent of fine-particle mass on days of worst and best visibility. Additionally, elemental carbon absorbs light more readily than it scatters light. It is therefore reasonable to conclude that smoke emissions from controlled agricultural and forestry burning contribute, on average, only a small fraction of one percent of total light extinction on days of both good and poor visibility. NHDES has no information to indicate that this situation would change significantly over the next decade.

Nevertheless, New Hampshire intends to consult with the Forest Protection Bureau of the New Hampshire Department of Agriculture and with the New Hampshire Department of Resources and Economic Development (DRED) to consider smoke management in agricultural and forestry practices to address visibility effects at MANE-VU Class I Areas. In addition, New Hampshire will consider ways to improve the inventory of smoke emissions and to achieve a better understanding of the relative importance of agricultural and forestry sources (versus residential wood stoves, in particular) as contributors to regional haze. The results of these efforts will be documented in the first regional haze SIP progress report in 2013.

11.8 Estimated Effects of Long-Term Strategy on Visibility

40 CFR 51.308(d)(3)(v)(G) requires New Hampshire to consider, in developing its long-term strategy, the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy. NESCAUM conducted modeling to evaluate the expected improvements to visibility at affected Class I areas by 2018 as a consequence of implementing MANE-VU's long-term strategy. Those

visibility improvements will result, in part, from the efforts identified in this SIP to reduce emissions that originate in New Hampshire.

All Class I states affected by emissions originating in New Hampshire have (or will have) established reasonable progress goals for 2018 for each of their Class I areas. The control measures included in this SIP represent the reasonable efforts of New Hampshire, in conjunction with the efforts of other MANE-VU states, toward achieving the reasonable progress goals established by the affected states.

Based on the most recent MANE-VU modeling, the proposed control measures will reduce sulfate levels at affected Class I areas by about one-third on the worst visibility days and by 6 to 31 percent on the best visibility days by 2018. Nitrate and elemental carbon levels will also show substantial reductions across all areas for both best and worst days, while smaller reductions in organic carbon levels will occur. Small increases are predicted for the fine soil component of regional haze. There is a possibility that the predicted increases in this component are not real but, rather, related to structural differences in the data sets used in the modeling for the baseline and future years. (Specifically, the fire emissions inventory used in VISTAS for the base year relied on an earlier version of fire emissions data than the one used for the 2018 inventory.) No changes are predicted for sea salt because the model does not track this component.

The 2000-2004 visibility readings at affected Class I areas provide the baseline against which future visibility readings will be measured to assess progress deriving from implementation of New Hampshire's regional haze SIP and those of the other MANE-VU states. To determine baseline visibility for affected Class I areas, NHDES used the 2000-2004 IMPROVE monitoring data to calculate the average deciview values for the 20 percent best visibility days and the 20 percent worst visibility days over that period. (Note that both natural conditions and baseline visibility for the 5-year period were calculated in conformance with an alternative method recommended by the IMPROVE Steering Committee – see Subsection 4.1) Thus, the 20 percent best day and 20 percent worst day values represent average visibility conditions for the top and bottom quintiles.

To create the series of visibility graphs which follow, 2018 visibility estimates were made in accordance with EPA modeling guidance. First, 2002 daily average baseline concentrations were multiplied by their corresponding relative reduction factors to obtain 2018 projected concentrations for each day. The 2018 projected concentrations were then used to derive daily visibility in deciviews. As a final step, the deciview values for the 20 percent of days having best visibility were averaged, and the process repeated for the 20 percent of days having worst visibility. The resulting averages represent the projected upper and lower quintiles of visibility in 2018.

The following is provided to assist with interpretation of the line graphs in Figures 11.1 and Figures 11.3 through 11.6. Note that lower deciview values indicate better visibility.

- The irregular blue line (~) represents the 20 percent best visibility average value as determined from monitoring data for each year of the period 2001-2005.
- The irregular red line (~) represents the 20 percent worst visibility average value as determined from monitoring data for each year of the period 2001-2005.

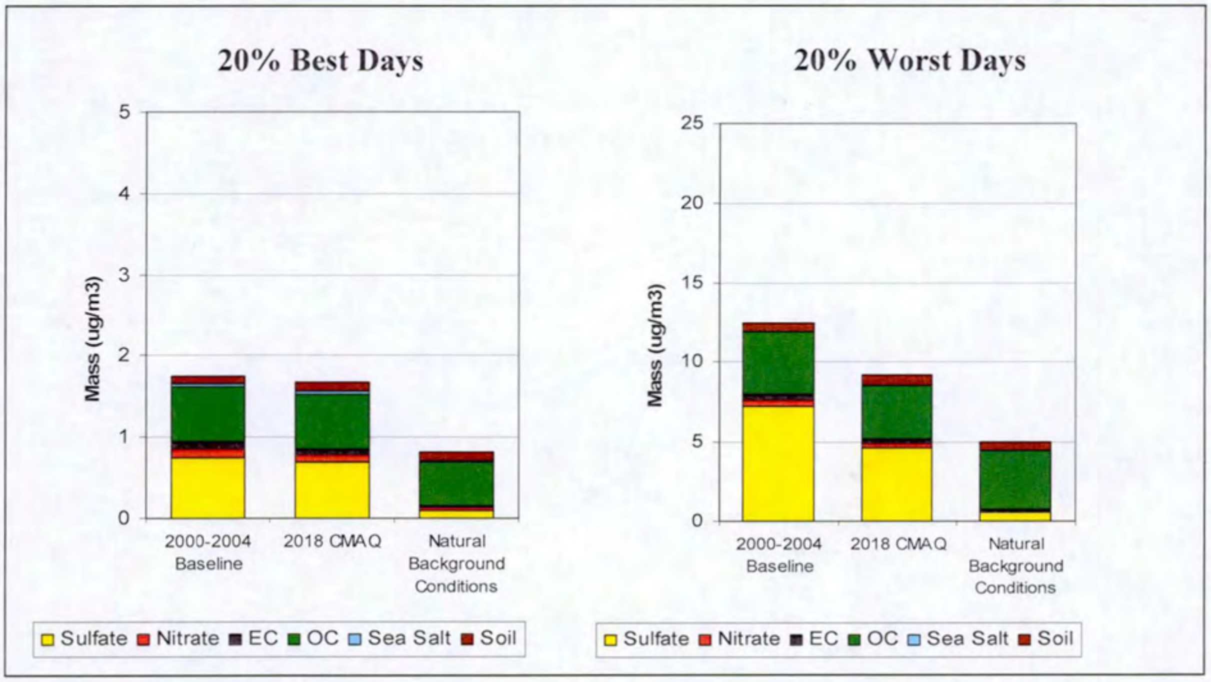
- The straight orange line (—) represents the 20 percent best visibility average value as determined from monitoring data for the 5-year period of 2000-2004. (This line represents the *20 percent best visibility baseline condition.*)
- The straight blue line (—) represents the 20 percent worst visibility average value as determined from monitoring data for the 5-year period of 2000-2004. (This line represents the *20 percent worst visibility baseline condition.*)
- The straight broken line (···) is a continuation of the 20 percent best visibility baseline, representing the 20 percent best visibility condition as it would be with no further degradation or improvement.
- The straight green line (—) represents the 20 percent worst visibility values that establish the uniform rate of progress for the period 2004-2064. (This line is sometimes referred to as the *uniform progress line*, or *"glide slope."* It was created by linear interpolation between the average 20 percent worst visibility baseline value from 2000-2004 and the 20 percent worst visibility value under natural conditions in 2064. If visibility improvements match this rate of progress, actual visibility will return to natural conditions in 2064. Visibility values used for the calculation of uniform rate of progress may be found in Table 10.1.)
- The light-green dash (–) shown at 2064 represents the theoretical 20 percent best visibility value under natural conditions (i.e., no anthropogenic emissions).
- The purple star (✶) represents the 20 percent best visibility value in 2018 after implementation of MANE-VU's long-term strategy, as predicted by the CMAQ model. (This value is a *reasonable progress goal.*)
- The blue star (✶) represents the 20 percent worst visibility value in 2018 after implementation of MANE-VU's long-term strategy, as predicted by the CMAQ model. (This value is a *reasonable progress goal.*)

Figure 11.1 illustrates predicted visibility improvements at Great Gulf Wilderness. Observe that the blue star lies below the green line, indicating that, by 2018, the long-term strategy of this SIP will result in visibility improvements surpassing the uniform rate of progress on days of worst visibility. Similarly, the position of the purple star below the dashed line indicates that visibility requirements will be met, i.e., there will be no further degradation from baseline conditions on days of best visibility.

Figure 11.2 presents bar graphs depicting expected improvements in haze-causing pollutant levels at Great Gulf Wilderness. (The data employed for these graphs also apply to Presidential Range - Dry River Wilderness.) The graph on the left shows concentrations of visibility-impairing pollutants on days of best visibility for the 2000-2004 baseline period, 2018 modeled year, and natural background condition. The graph on the right is a similar plot for days of worst visibility. The graphs show that almost all of the expected improvements will result from reductions in sulfate concentrations. If the states adhere to MANE-VU's reasonable progress goals, sulfate levels (as a fraction of the total pollutant burden) will fall from about 60 percent in 2000-2004 to no more than 50 percent in 2018 and to less than 10 percent (natural conditions) in 2064.

Figure 11.1: Expected Visibility Improvement at Great Gulf Wilderness Based on Most Recent Projections [33]

Figure 11.2: Expected Improvements in Pollutant Concentrations at Great Gulf Wilderness on Best and Worst Days



[33] The visibility improvement estimate for Great Gulf Wilderness also serves as an estimate for Presidential Range - Dry River Wilderness.

Figures 11.3 through 11.6 are line graphs showing anticipated visibility improvements for the other MANE-VU Class I Areas. All locations are projected to meet or exceed their uniform-rate-of-progress goals for 2018. In addition, all areas are expected to see improvements in best-day visibility relative to baseline values.

Figure 11.3: Expected Visibility Improvement at Acadia National Park Based on Most Recent Projections

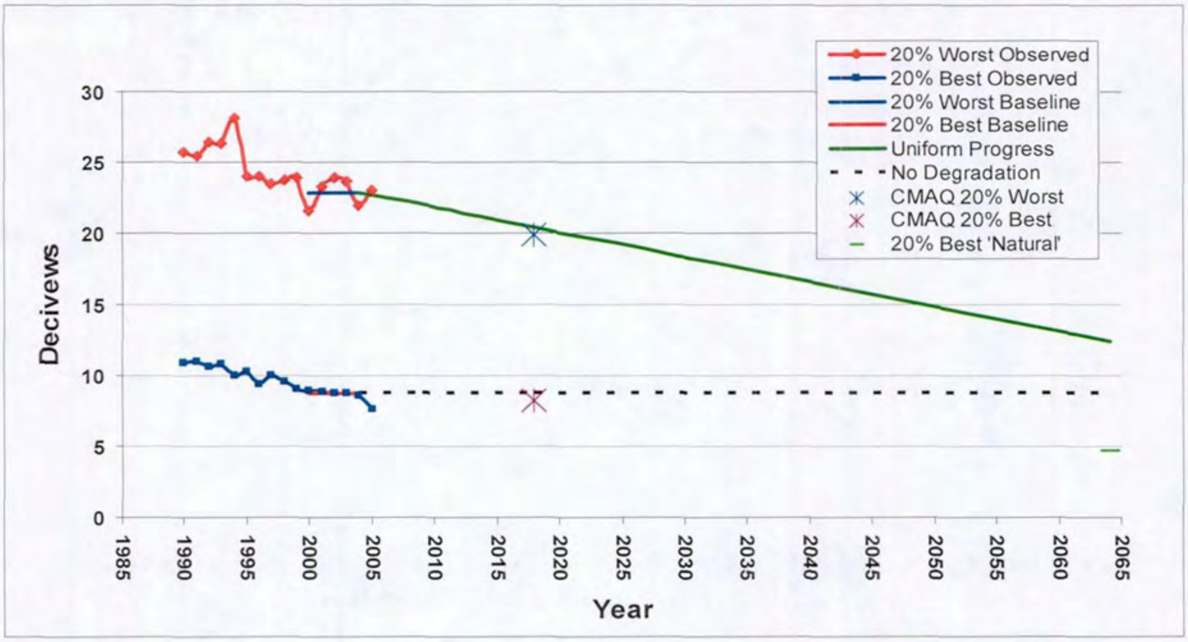


Figure 11.4: Expected Visibility Improvement at Brigantine National Wildlife Refuge Based on Most Recent Projections

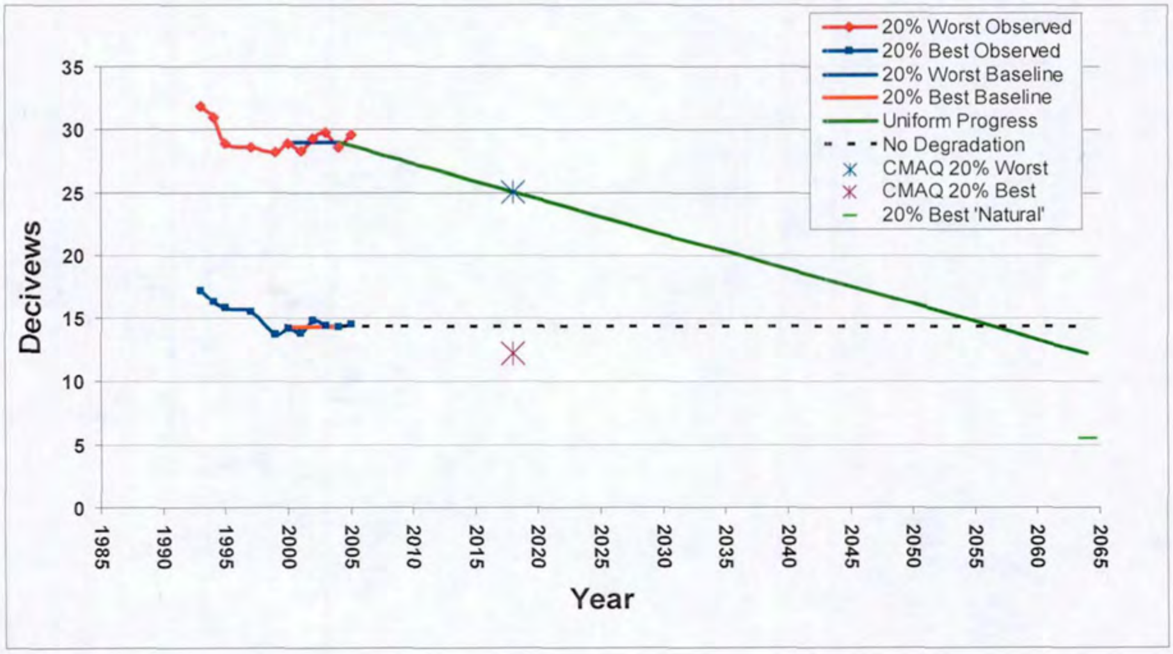


Figure 11.5: Expected Visibility Improvement at Lye Brook Wilderness Based on Most Recent Projections

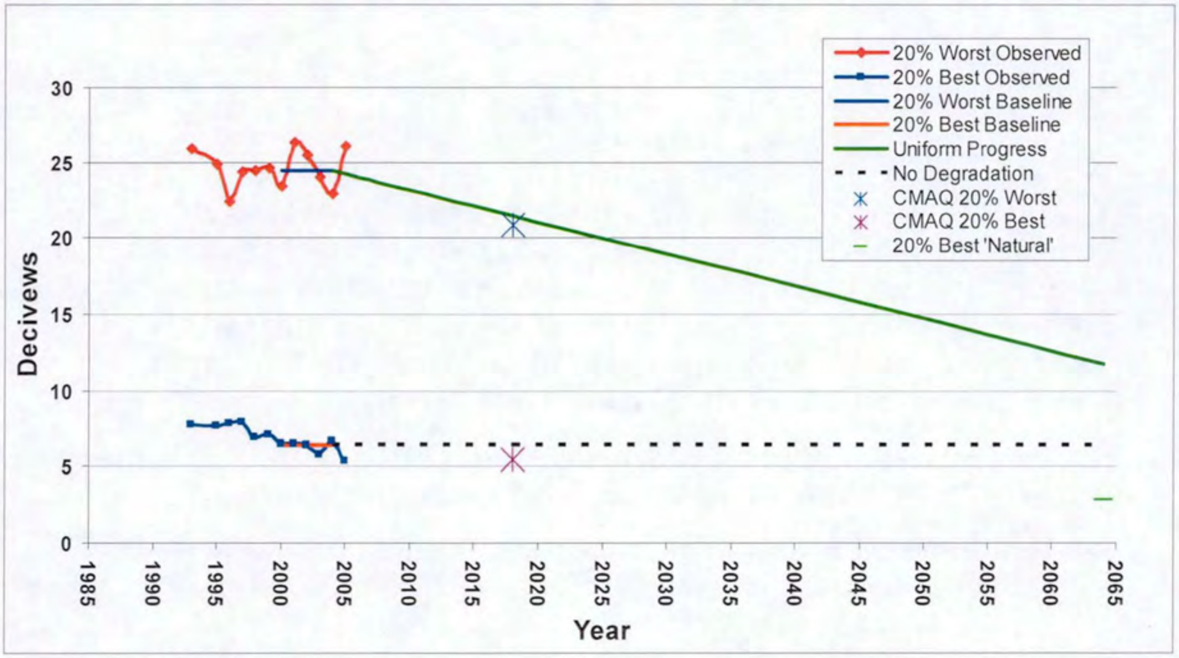
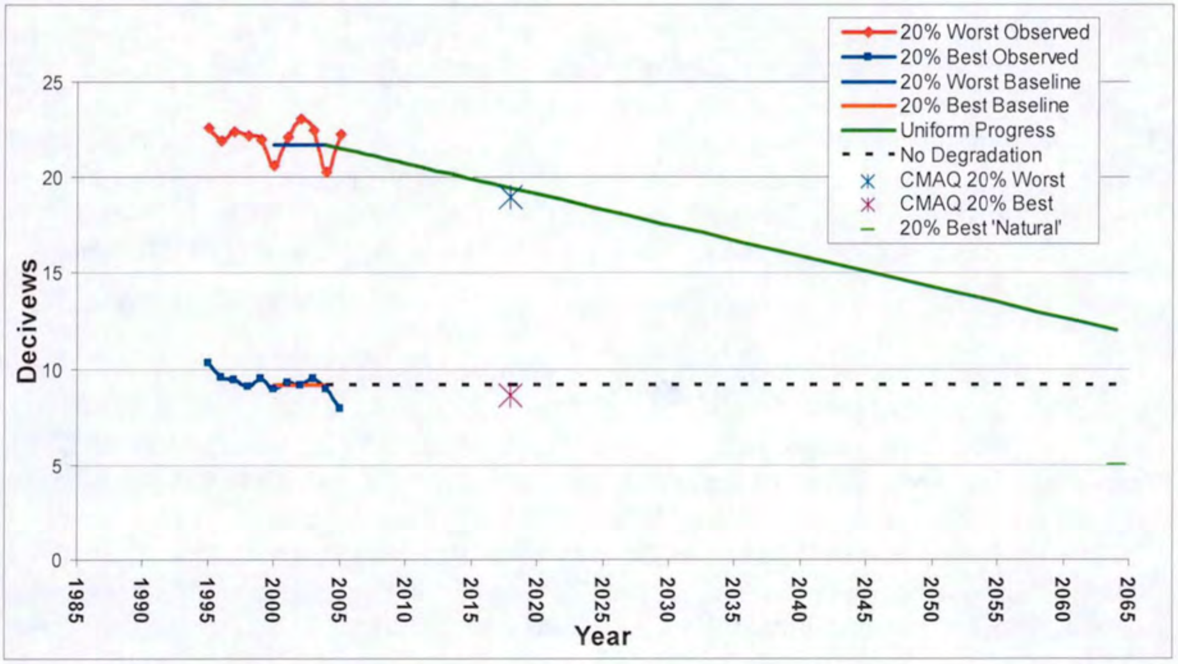


Figure 11.6: Expected Visibility Improvement at Moosehorn National Wildlife Refuge Based on Most Recent Projections[34]



[34] The visibility improvement estimate for Moosehorn Wilderness also serves as an estimate for Roosevelt/Campobello International Park.

11.9 New Hampshire's Share of Emission Reductions

40 CFR 51.308(d)(3)(ii) of the Regional Haze Rule requires New Hampshire to demonstrate that its implementation plan includes all measures necessary to obtain its share of emission reductions needed to meet the reasonable progress goals. The modeling analyses referenced in Subsection 11.8, above, demonstrate that the New Hampshire/MANE-VU long-term strategy is sufficient to meet these visibility goals.

The basis for the long-term strategy is a statement adopted by MANE-VU on June 20, 2007 (see Part 3.3.3, The MANE-VU "Ask"). This document provides that each state will have up to 10 years to pursue adoption and implementation of reasonable control measures for NO_X and SO_2 emission reductions. New Hampshire's regional haze SIP is wholly consistent with this long-term strategy. **To meet its obligation, New Hampshire agrees to pursue the following general and specific emission reduction measures**:

- Timely implementation of BART requirements at the two BART-eligible units in the state: PSNH Merrimack Station Unit MK2 and PSNH Newington Station Unit NT1;
- Participation in a regional low-sulfur fuel oil strategy that will result in SO_2 emission reductions from one oil-fired electrical generating unit, namely, PSNH Newington Station, as well as from ICI boilers and residential heating units across the state;
- Emission controls on targeted in-state EGUs that contribute to visibility impairment at Class I areas in the region – more specifically, compliance with New Hampshire law RSA 125-O, Multiple Pollutant Reduction Program, which mandates the installation of scrubbers on PSNH Merrimack Station Units MK1 and MK2 by July 1, 2013, to control SO_2 and mercury emissions. These controls will reduce SO_2 emissions at these units by at least 90 percent from 2002 levels. It is anticipated that the scrubber will be optimized for mercury emission reductions and therefore may not meet the 95 percent SO_2 reduction rate that is typical for scrubbers. However, the 90-percent minimum requirement effectively means that actual SO_2 emission reductions must *exceed* 90 percent on average. To the extent that these higher rates can be realized, they will be applied against the less than 90-percent SO_2 reduction expected at Newington station in order to fulfill the state's commitment to MANE-VU's targeted EGU strategy.
- Continued evaluation of other possible control measures for haze-causing emissions.

Implementation of the long-term strategy will produce significant changes in New Hampshire's emissions inventory by the end of the first planning period, 2018. Changes to the emissions inventory will also occur as a result of population growth; changes in land use and transportation; development of industrial, energy, and natural resources; and other air pollution control measures not directly related to regional haze. However, it is the expected reductions in SO_2 emissions that will have the greatest effect on visibility improvement at MANE-VU Class I Areas; and those reductions will be largely due to implementation of the control measures incorporated into this SIP. (As a precursor to sulfate, SO_2 emissions are responsible for most of the fine-particle mass on the haziest days at MANE-VU Class I Areas. See Section 8, Understanding the Sources of Haze-Causing Pollutants.)

Current and projected SO_2 emissions for the various source categories in New Hampshire and, for comparison, all of MANE-VU are summarized in Tables 11.2 and 11.3. These emissions represent the majority of all haze-causing pollutants originating within the state and region.

Further information on New Hampshire's emissions inventory, including other pollutants that contribute to visibility impairment, is available in Section 6, Emissions Inventory.

Table 11.2: SO_2 Emissions from Point, Area, and Mobile Sources in New Hampshire (tpy)

Source Category	Baseline 2002	Projected 2018	% Reduction 2002-2018
Area	7,072	972	86.3
Non-EGU Point	2,436	1,084	55.5
EGU Point	44,124	10,766	75.6
On-Road Mobile	777	537	30.9
Non-Road Mobile	891	246	72.4
TOTAL	55,300	13,605	75.4

Table 11.3: SO_2 Emission from Point, Area, and Mobile Sources in all of MANE-VU (tpy)

Source Category	Baseline 2002	Projected 2018	% Reduction 2002-2018
Area	286,921	129,656	54.8
Non-EGU Point	264,377	91,438	65.4
EGU Point	1,643,257	368,717	77.6
On-Road Mobile	40,090	8,757	78.2
Non-Road Mobile	57,257	8,643	84.9
TOTAL	2,291,902	607,211	73.5

The projected overall reduction of 75.4 percent for SO_2 emissions originating in New Hampshire exceeds by a small amount the projected average reduction of 73.5 for all of MANE-VU. This comparison indicates that New Hampshire will meet its share of anticipated SO_2 emission reductions within the region by 2018.

(Note: The emissions in Tables 11.2 and 11.3 represent MANE-VU's 2018 "Best and Final" modeling emissions inventories that were used in the final visibility modeling. The projected emissions and modeling incorporate the additional reasonable control measures of the long-term strategy: targeted EGUs, low-sulfur fuel, and timely implementation of BART. The values in the two tables reflect the assumptions used at the time the modeling was performed and are not adjusted for revisions made to the BART analyses after the MANE-VU visibility modeling was completed. For the low-sulfur fuel strategy and BART controls as applied to Unit NT1 specifically, the visibility modeling assumed a 50% reduction in SO_2 emissions. However, at a BART control level of 67% (see Table 9.3), the emission reductions for this unit would be greater than assumed for the final visibility modeling.)

11.10 Emission Limitations and Compliance Schedules

40 CFR 51.308(d)(3)(v)(C) requires New Hampshire to establish emission limitations and compliance schedules to meet reasonable progress goals. While emission limitations and

compliance schedules are already in place for some New Hampshire control measures outlined in Subsections 11.3 and 11.4, other such provisions will need to be established by law (Revised Statutes Annotated, RSA) or codified in New Hampshire Rules Governing the Control of Air Pollution (Env-A 100 - 4300); specifically:

- ***Best Available Retrofit Technology (BART)*:** The emission limitations and compliance schedule for New Hampshire's two BART-eligible sources are detailed in Section 9. The BART emission limitations will be enforceable through a combination of existing permit conditions and administrative rules, including Chapter Env-A 2300, Mitigation of Regional Haze (Attachment GG). New emission limitations created by this rule will be effective on July 1, 2013. All BART provisions will have this date as the compliance deadline.

- ***Low Sulfur Fuel Oil Requirements*:** NHDES will recommend legislation for mandatory use of low-sulfur fuel oil, as envisioned in the MANE-VU low-sulfur fuel strategy, as soon as fuel supply and cost data are deemed sufficient and favorable for legislative success. It remains New Hampshire's goal to implement the MANE-VU strategy by 2018, in accordance with the original timetable. NHDES previously anticipated that this emission control program could be achieved by revision of administrative rule Env-A 1604, Sulfur Content Limitations for Liquid Fuels. However, with the generally rising cost of fuels, including home heating oil, any NHDES rule that might further exacerbate fuel prices or create uncertainty regarding adequacy of supplies should more appropriately be addressed by New Hampshire's elected lawmakers.

- ***Emission Reductions from Specific EGUs*:** PSNH Merrimack Station Units MK1 and MK2 and PSNH Newington Station Unit NT1 are included in MANE-VU's targeted EGU strategy. The Merrimack plant is required by New Hampshire law to install a flue gas desulfurization system (scrubber) to remove SO_2 and other major pollutants by July 1, 2013 (see temporary permit for Units MK1 and MK2, Attachment EE). This control measure will simultaneously satisfy BART requirements for Unit MK2. PSNH Newington Station Unit NT1, which is also subject to BART limitations, will find it necessary to control fuel sulfur levels in order to achieve a more stringent SO_2 emission limit than is currently allowed (see BART Analyses for Sources in New Hampshire, Attachment X, and Title V operating permit, Attachment II).

NHDES will continue to evaluate all measures included in the long-term strategy to ascertain whether they remain reasonable for New Hampshire to implement by the end of the SIP planning period (2018) and will formalize that determination with the submission of the first regional haze SIP progress report in 2013. **New Hampshire intends to adopt all reasonable control measures as expeditiously as practicable, in a manner consistent with state law, so that they may be in place by the indicated compliance dates.**

11.11 Enforceability of Emission Limitations and Control Measures

40 CFR 51.308(d)(3)(v)(F) requires New Hampshire to ensure that emission limitations and control measures used to meet reasonable progress goals are enforceable. All control measures incorporated into law or codified in administrative rules will be enforceable. Any facility subject to state or federal permit requirements, including BART-eligible and Title V

facilities, will be required to comply with the specific permit conditions that reference the applicable provisions of those laws and rules.

In New Hampshire, the authority to create rules, issue permits, and enforce laws related to regional haze are established in RSA 125-C, Air Pollution Control. Under RSA 125-C:6, Powers and Duties of the Commissioner, the NHDES Commissioner is authorized to enforce the state's air laws, establish a permit program, accept and administer grants, and exercise all incidental powers necessary to carry out the statutory obligations.

Sections of New Hampshire law of particular relevance to the regional haze SIP are:

- RSA 125-C:4, Rulemaking Authority; Subpoena Power, which establishes requirements by which the Commissioner shall adopt rules related (but not limited) to:
  - primary and secondary ambient air quality standards;
  - prevention, control, abatement, and limitation of air pollution;
  - procedures to meet air pollution emergencies,
  - establishment and operation of a statewide permit system;
  - notification and public hearings on permit applications;
  - fees and procedures for permit application and review; and
  - procedures for air testing/monitoring and recordkeeping;

  and which authorizes the Commissioner to issue subpoenas requiring the attendance of witnesses, production of evidence, and taking of testimony as he may deem necessary.

- RSA 125-C:11, Permit Required, which authorizes the creation of a permit program and the issuance of permits requiring specific emission control measures, including enforceable emission limitations;

- RSA 125-C:12, Administrative Requirements, which authorizes the Commissioner to collect fees to recover the costs of reviewing and acting upon permit applications and enforcing the terms of permits issued; and

- RSA 125-C:15, Enforcement, which authorizes NHDES to issue orders to correct violations of RSA 125-C and establishes the legal authority for the enforcement of New Hampshire Rules Governing the Control of Air Pollution (Env-A 100 - 4300).

The New Hampshire rules provide for enforceable emission control measures and compliance schedules to meet the applicable requirements of the Clean Air Act and rules promulgated by EPA. The New Hampshire rules also define the permit program and fee structure for stationary sources, to ensure that national ambient air quality standards are achieved; specifically:

- Chapter Env-A 600, Statewide Permit System (effective 4-26-03, 7-28-04, 6-8-06, 4-3-08, and 4-22-09), provides for the issuance of temporary permits, state permits to operate, and Title V operating permits. Part Env-A 619 of this chapter addresses the prevention of significant deterioration of air quality and visibility protection, in accordance with the requirements of 40 CFR 51.166, 40 CFR 52.21 and RSA 125-C.

- Chapter Env-A, 700 Permit Fee System (effective 4-26-03 and 6-26-04) provides for the payment of fees to cover the reasonable costs of administering the permit program and of implementing and enforcing the terms and conditions of any permit.

With respect to specific control measures for visibility improvement under the Regional Haze Rule, the following enforceable provisions will apply:

- PSNH Merrimack Station Units MK1 and MK2 are required to install an FGD system by July 1, 2013, to achieve major emission reductions in SO_2 and other pollutants as established under New Hampshire law RSA 125-O, Multiple Pollutant Reduction Program, and as set forth in Temporary Permit No. TP-0008, reissued August 2, 2010 (Attachment EE).

- PSNH Newington Station Unit NT1 will be required to meet a new SO_2 emission limit of 0.50 lb/MMBtu by July 1, 2013, for any fuel or combination of fuels burned, as provided in administrative rule Env-A 2300, Mitigation of Regional Haze (Attachment GG).

- Statewide use of low-sulfur fuel oil for all emission sources, anticipated to be consistent with MANE-VU's low-sulfur fuel strategy, will be recommended for legislative action. The timing and outcome of such legislation will depend on the adequacy of fuel supplies, prevailing fuel costs, and the will of New Hampshire's lawmakers. The framework for this legislation would be similar to formerly proposed revisions to administrative rule Env-A 1604, Sulfur Content Limitations for Liquid Fuels (Attachment FF).

Ultimately, New Hampshire's Regional Haze SIP depends on implementation of enforceable emission limitations and control measures, both within the state and in other states identified as contributing to visibility impairment at New Hampshire's Class I Areas. Because New Hampshire has no jurisdiction over other states' actions, the attainment of regional progress goals will, to a large extent, be predicated on the good-faith efforts of contributing upwind states to meet their fair share of emission reductions through implementation of their own enforceable control measures. While New Hampshire can provide assurances regarding the implementation of in-state emission controls, the bulk of regional-haze-causing pollutants over New Hampshire will continue to come from out-of-state sources.

11.12 Prevention of Significant Deterioration

Part Env-A 619 of Chapter Env-A 600 of New Hampshire's Rules spells out the Prevention of Significant Deterioration (PSD) requirements of the Statewide Permit System. PSD is applicable to all major sources (or existing sources making a major modification) located in an area that is in attainment of the National Ambient Air Quality Standards. A major source is an emissions source that has the potential to emit more than 100 tons per year of any pollutant. One of the purposes of the PSD program is to protect air quality in national parks, wilderness areas, and other areas of special natural, scenic, or historic value. The PSD permitting process requires a technical air quality analysis and additional analyses to assess the potential impacts on soils, vegetation, and visibility at Class I areas.

PSD permit applicants are required to conduct such analyses, and may do so in consultation with NHDES and the relevant Federal Land Manager (FLM). Recommended procedures for evaluating the impacts of a proposed PSD source on air quality and visibility at Class I areas are provided in NHDES' "Guidance and Procedure for Performing Air Quality Modeling in New Hampshire," July 2006. New major sources and existing sources making major modifications will be constructed and operated so as not to degrade air quality or visibility. The PSD permitting program, as set for under Env-A 619, is an integral part of New Hampshire's long-term strategy for meeting its regional haze goals.

12. Administrative Details

NHDES held two public hearings related to New Hampshire's Regional Haze SIP Revision:

- On May 25, 2009, NHDES published in a statewide newspaper, the Manchester, NH, *Union Leader*, a public notice soliciting comment on New Hampshire's Regional Haze SIP Revision. The notice also announced the opportunity to request a public hearing for the SIP revision. A public hearing was held at NHDES headquarters on Wednesday, June 24, 2009.

- On November 19, 2010, NHDES published in a statewide newspaper, the Manchester, NH, *Union Leader*, a public notice soliciting comment on New Hampshire's proposed revision to the State Implementation Plan to add administrative rule Env-A 2300, Mitigation of Regional Haze. A public hearing on this SIP revision was held at NHDES headquarters on December 20, 2010.

Copies of the public notices are presented in Attachment JJ. Documentation certifying the public process is provided in Attachment KK. Evidence of legal authority to create and submit these SIP revisions may be found in Attachment LL.

NHDES received written comments on the SIP from EPA and the Federal Land Managers. NHDES also received written comments from the Appalachian Mountain Club and the Sierra Club. NHDES has addressed all comments in the SIP revision. Comments from EPA and the FLMs, and NHDES's formal responses to those comments, are included in Attachment I. Comments from the AMC and the Sierra Club, and responses to those comments, are included in Attachment J.

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New Hampshire Regional Haze SIP Revision 01/14/11
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ATTACHMENT B – MANE-VU Contribution Assessment

ATTACHMENT C – Inter-RPO State/Tribal and FLM Consultation Framework

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- MANE-VU Class I States Resolution
- MANE-VU Approach to the Development of "Consulting Groups"
- MANE-VU Board Meeting, June 7, 2007, Draft Agenda
- MANE-VU Class I States' Consultation Open Technical Call, July 19, 2007, Draft Agenda
- MANE-VU Class I States' Consultation, August 6, 2007, Draft Agenda
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- Summary of MANE-VU Class I States' Consultations
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- MANE-VU Statement on Controls outside MANE-VU
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- List of Top EGUs for MANE-VU Statements

ATTACHMENT F – Comments from VISTAS and West Virginia Department of Environmental Protection

- VISTAS Comments, April 25, 2008
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ATTACHMENT G – MANE-VU Modeling for Reasonable Progress Goals

ATTACHMENT H – Documentation of 2018 Emissions from EGUs in the Eastern United States

ATTACHMENT I – Comments from Federal Land Managers and EPA (with Responses)

- Letter from U.S. Dept. of Interior, Fish and Wildlife Service, August 1, 2006
- Letter from U.S. Dept. of Agriculture, Forest Service, October 13, 2006
- Comments from EPA (Preliminary), July 10, 2008
- Summaries of Conference Calls with FLMs
- Comments from EPA, October 24, 2008
- Response to EPA Comments, May 22, 2009
- Comments from U.S. Dept. of Interior, September 26, 2008
- Comments from U.S. Dept. of Agriculture, Forest Service, October 2, 2008
- Response to Federal Land Managers Comments, May 22, 2009
- Comments from EPA, June 26, 2009
- Comments from U.S. Dept. of Interior, June 26, 2009
- Letter from EPA Letter, February 25, 2010
- Response to EPA Comments, March 10, 2010
- EPA Comments on Env-A 2300, November 22, 2010
- Response to EPA Comments, December 9, 2010
- Comments from EPA, December 20, 2010
- Response to EPA Comments, January 14, 2011
- Comments from U.S. Dept. of Interior, December 20, 2010
- Response to FLMs Comments 01-14-11.pdf

ATTACHMENT J – Comments from Other Stakeholders

- Summary of Stakeholder Comments on RPG Modeling Draft Report
- Comments from ACCE, January, 9, 2008

- Comments from Dominion Resources Services, Inc., January 9, 2008
- Comments from Midwest Ozone Group, January 9, 2008
- Comments from Reliant Energy, January 9, 2008
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- Comments from Utility Air Regulatory Group, April 25, 2008
- Comments from Appalachian Mountain Club, June 26, 2009
- Response to AMC Comments
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- Comments from Sierra Club on Env-A 2300, November 22, 2010
- Response to Sierra Club Comments, January 14, 2011

ATTACHMENT K – MANE-VU Natural Background Visibility Conditions

ATTACHMENT L – MANE-VU Baseline and Natural Background Visibility Conditions

ATTACHMENT M – Technical Support Document for 2002 MANE-VU SIP Modeling Inventories, Version 3

ATTACHMENT N – Development of Emission Projections for 2009, 2012, and 2018 for NonEGU Point and Nonroad Sources in the MANE-VU Region

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ATTACHMENT P – NYSDEC Technical Support Document TSD-1c

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ATTACHMENT U – CALGRID Modeling Protocol

ATTACHMENT V – Technical Support Document on Agricultural and Forestry Smoke Management in the MANE-VU Region

ATTACHMENT W – MANE-VU Five-Factor Analysis of BART-Eligible Sources

ATTACHMENT X – BART Analyses for Sources in New Hampshire

ATTACHMENT Y – Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas

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ATTACHMENT BB – Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model (IPM®)

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ATTACHMENT DD – Technical Support Document on Measures to Mitigate Visibility Impacts of Construction Activities in the MANE-VU Region

ATTACHMENT EE – Temporary Permit for PSNH Merrimack Station

ATTACHMENT FF – Revisions to Env-A 1604, Sulfur Content Limitations for Liquid Fuels (Draft)

ATTACHMENT GG – Chapter Env-A 2300, Mitigation of Regional Haze

ATTACHMENT HH – Title V Operating Permit for PSNH Merrimack Station (Proposed)

ATTACHMENT II – Title V Operating Permit for PSNH Newington Station

ATTACHMENT JJ – Public Notices for SIP Revision

ATTACHMENT KK – Certification of Public Process

ATTACHMENT LL – Evidence of Legal Authority

The State of New Hampshire
DEPARTMENT OF ENVIRONMENTAL SERVICES

Thomas S. Burack, Commissioner

August 26, 2011

Mr. Curt Spalding
Regional Administrator
USEPA New England, Region I
5 Post Office Square, Suite 100
Boston, MA 02109-3912

Re: Revision to New Hampshire's State Implementation Plan to Meet the Requirements of the Clean Air Act, Section 169A, Protection of Visibility (Regional Haze)

Dear Administrator Spalding:

On January 14, 2011, the New Hampshire Department of Environmental Services (NHDES) submitted a State Implementation Plan (SIP) revision pertaining to protection of visibility and regional haze. Since that time, it has come to my attention that our submittal is in need of amendment. As Governor John Lynch's designee, I am submitting the enclosed amendments to the subject SIP revision.

The changes are shown in the enclosed red-lined pages. The entire text as amended, with one revised attachment, is also enclosed. Revised Attachment EE is the reissued Temporary Permit for Merrimack Station, which should be substituted for the previous Temporary Permit in Attachment EE.

If you have any questions regarding this submittal, please contact Jeff Underhill at (603) 271-1102.

Sincerely,

Robert R. Scott
Director
Air Resources Division

rrs/blh
enclosure: Amended NH Regional Haze SIP Revision w/attachment EE
Redlined pages

cc: Anne Arnold, USEPA Region I
Anne McWilliams, USEPA Region I
Tim Allen, USFWS (Lakewood, CO)
Ralph Perron, NPS
Holly Salazer, NPS (University Park, PA)
Sandra Silva, NPS
Chuck Sams, USFS (Atlanta, GA)
Scott Copeland, USFS

New Hampshire
Regional Haze SIP Revision

January 14, 2011
Amended August 26, 2011

Mid-Atlantic/Northeast Visibility Union (MANE-VU)

Prepared by

NEW HAMPSHIRE DEPARTMENT OF
Environmental Services

Air Resources Division

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ACKNOWLEDGEMENTS

The New Hampshire Department of Environmental Services would like to express appreciation to the dedicated staffs of the NESCAUM, MARAMA, and MANE-VU regional organizations and to the dedicated staffs of the MANE-VU member states for their invaluable assistance and timely contributions in the development of New Hampshire's Regional Haze SIP Revision.

FOREWORD

This document revises New Hampshire's State Implementation Plan (SIP) to meet requirements of the Clean Air Act related to protection of visibility. SIPs are dynamic documents describing the state's statutory and regulatory (i.e., enforceable) emission control measures that will be implemented to ensure compliance with National Ambient Air Quality Standards and goals. SIPs must be reviewed and updated periodically to stay current with administrative requirements, changing air quality standards or conditions, and new or amended federal programs. The terms "SIP" and "SIP revision" are sometimes used interchangeably in reference to new or revised portions of a state implementation plan. Regional Haze SIP, or Regional Haze Plan, refers specifically to that portion of the State Implementation Plan which addresses visibility improvement.

1. THE REGIONAL HAZE ISSUE

In 1999, the Environmental Protection Agency (EPA) issued regulations to improve visibility in 156 national parks and wilderness areas across the United States. The affected areas include many of our best known natural places, including the Grand Canyon, Yosemite, Yellowstone, Mount Rainier, Shenandoah, the Great Smokies, Acadia, and the Everglades. In New Hampshire, the two affected areas are Great Gulf Wilderness and Presidential Range - Dry River Wilderness.

These regulations address visibility impairment in the form of regional haze. Haze is an atmospheric phenomenon that obscures the clarity, color, texture, and form of what we see. It is caused primarily by anthropogenic (manmade) pollutants but can also be caused by a number of natural phenomena, including forest fires, dust storms, and sea spray. Some haze-causing pollutants are emitted directly to the atmosphere by anthropogenic emission sources such as electric power plants, factories, automobiles, construction activities, and agricultural burning. Others occur when gases emitted into the air (haze precursors) interact to form new particles that are carried downwind.

Emissions from these activities generally span broad geographic areas and can be transported hundreds or thousands of miles. Consequently, regional haze occurs in every part of the nation. Because of the regional nature of haze, EPA's regulations require the states to consult with one another toward the national goal of improving visibility – specifically, at the 156 parks and wilderness areas designated under the Clean Air Act as mandatory Class I Federal Areas.

The Regional Haze Rule calls for each state to establish *reasonable progress goals* for visibility improvement and to formulate a *long-term strategy* for meeting these goals. These requirements apply to any state having a Class I area as well as any state that contributes to visibility impairment at any (downwind) Class I area. The visibility goals must be designed both to improve visibility on the haziest days and to ensure that no degradation occurs on the clearest days.

A state's long-term strategy must include enforceable emission reduction measures designed to meet reasonable progress goals. The first long-term strategy covers the 10-15-year period ending in 2018, and subsequent revisions are to be issued every 10 years thereafter. In identifying the emission reduction measures to be included in the long-term strategy, states should address all types of manmade emissions contributing to visibility degradation in Class I areas, including those from mobile sources; stationary sources (such as factories); smaller, so-called "area" sources (such as residential wood stoves and small boilers); and prescribed fires.

In developing their plans, states can take into account emission reductions attributable to ongoing air pollution control programs at the state, regional, or national levels. For most states and regions of the country, however, additional emission control measures beyond those already on the books will be necessary if national visibility goals are to be achieved. In addition, the Regional Haze Rule mandates that control measures be implemented for certain existing sources placed into operation between 1962 and 1977. This portion of the rule is known as *BART*, for *Best Available Retrofit Technology*.

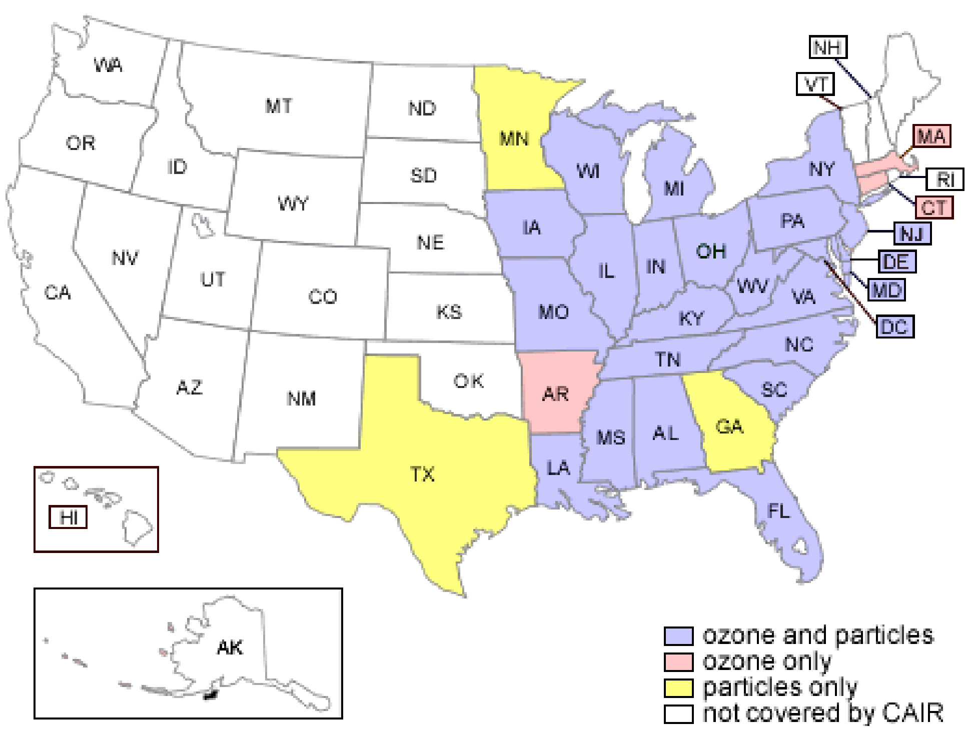
Each state's plan for addressing regional haze will take the form of a State Implementation Plan (SIP) revision. New Hampshire's SIP revision, presented here, was developed after extensive consultations with other states and regional planning organizations. In particular, New Hampshire contributed to many analyses and reports produced by the member states of the Northeast States for Coordinated Air Use Management (NESCAUM) and the Mid-Atlantic/Northeast Visibility Union (MANE-VU) for the purpose of coordinated regional haze planning. New Hampshire also consulted with states outside the Northeast and with the provinces of eastern Canada.

The regulatory, organizational, and technical basis for New Hampshire's regional haze plan will be found in Sections 1 through 8 of this SIP document. The prescriptive elements of New Hampshire's plan – Best Available Retrofit Technology (BART) provisions, reasonable progress goals, and long-term strategy – are described in detail in Sections 9 through 11.

1.1 Regional Haze Planning after Remand of CAIR

On March 10, 2005, EPA issued the Clean Air Interstate Rule (CAIR). This important federal rule was designed to achieve major permanent reductions in sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions in the eastern United States through a cap-and-trade system using emission allowances. CAIR would permanently cap emissions originating in 28 eastern states and the District of Columbia (Figure 1.1). Although New Hampshire was not designated as a participating CAIR state, this program would greatly affect future air quality in the state.

Figure 1.1: Map of CAIR States



http://www.epa.gov/cair/

According to EPA's CAIR website, SO_2 emissions in the affected states would be reduced by more than 70 percent from 2003 levels, and NO_X emissions by more than 60 percent from 2003 levels, upon full implementation of CAIR (see http://www.epa.gov/cair/).

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit found that CAIR violated basic provisions of the Clean Air Act. The Court vacated CAIR in its entirety and remanded to EPA to promulgate a new rule consistent with the Court's opinion. EPA appealed the decision amid widespread concern that, despite its flaws, some form of CAIR was preferable to the sudden regulatory void created by the Court's decision. Upon reconsideration, on December 23, 2008, the Court stayed the vacatur of CAIR but maintained the remand to EPA to promulgate a new rule consistent with the Court's July 11, 2008, opinion.

Because CAIR formed the regulatory underpinnings for most of the emission reductions that were to produce visibility improvements in mandatory Class I areas, the vacatur of CAIR would have represented a major difficulty for the individual states in attempting to comply with the Regional Haze Rule. While all eastern states have depended in varying degree on CAIR in the preparation of their regional haze SIPs, some Southeast states have relied almost entirely on CAIR to demonstrate compliance with the rule.

The CAIR Phase I requirements remain in place, and CAIR's regional control programs continue to operate while EPA develops replacement rules in response to the remand. On July 6, 2010, EPA announced a new rule to implement the Clean Air Act requirements pertaining to transport of air pollution across state boundaries. The proposed Transport Rule responds to the Court remand of CAIR and will replace CAIR when final (see http://www.epa.gov/airtransport/).

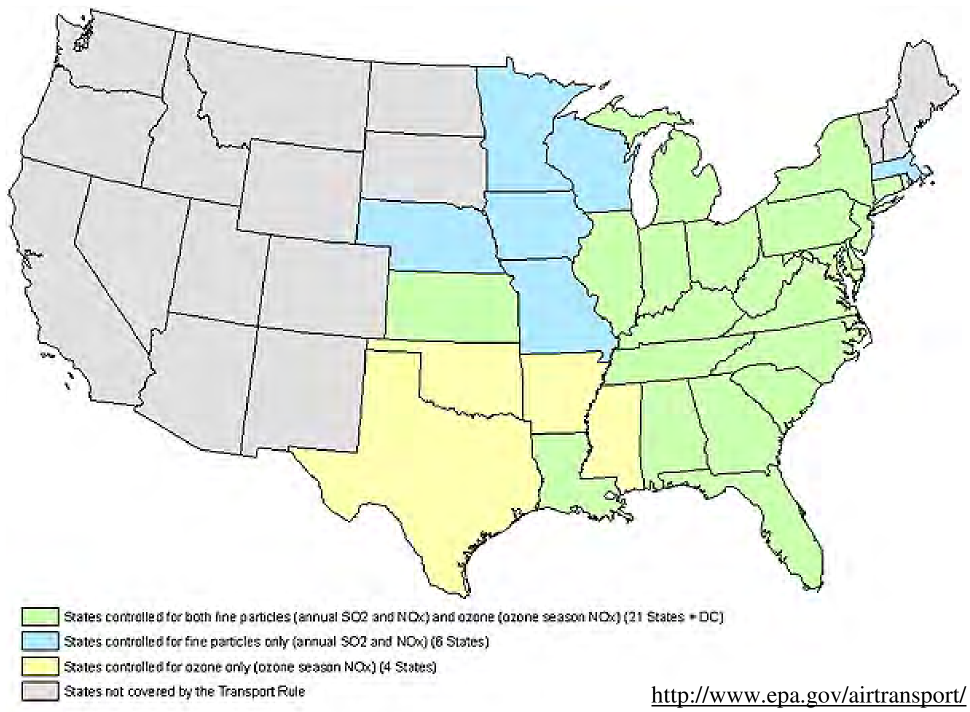
This rule would require 31 states and the District of Columbia (Figure 1.1a) to significantly improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other states:

- Twenty-eight states would be required to reduce both annual SO_2 and NOx emissions. By reducing the emissions from the upwind states, the proposal would help downwind states attain air quality standards, specifically the 24-hour $PM_{2.5}$ standards established in 2006 and the 1997 annual $PM_{2.5}$ standards.

- Twenty-six states would be required to reduce NOx emissions during the hot summer months of the ozone season because they contribute to downwind states' ozone pollution. By reducing the emissions from the upwind states, the proposal would help downwind states' attain air quality standards, specifically the 1997 ground-level ozone standard.

The final rule is expected in late spring 2011.

Figure 1.1a: Map of Transport Rule States



http://www.epa.gov/airtransport/

At this point it is not possible to comprehend all of the ramifications for regional haze planning resulting from the remand and replacement of CAIR. There may be some short-term slippage or loss in projected emission reductions as a consequence of the Court's July 11, 2008, decision. Over the longer term, New Hampshire anticipates that future emission controls under the Transport Rule and other CAIR-successor legislation will be at least as stringent as CAIR originally would have obtained. As to the validity of the already-completed planning components, a number of mitigating circumstances apply:

- With the introduction of the Transport Rule, the regulatory equivalency of CAIR and BART is removed as a BART compliance option. Application of BART provisions where the old CAIR previously might have sufficed is likely to yield even greater emission reductions from BART-eligible facilities.
- New Hampshire and many other states have instituted their own emission reduction programs through multi-pollutant legislation and other means. New Hampshire applauds the efforts of other states and encourages them to follow through with the implementation of laws, consent decrees, and other measures that would complement emission reductions from federal programs.
- Strict adherence to the spirit of the Clean Air Act in future national initiatives will probably result in emission reductions exceeding those previously projected for CAIR. A major limitation of the original CAIR was that it relied on interstate emissions trading and did not respond to the specific language of the Clean Air Act, Section 110(a)(2)(D), which prohibits *any* source or activity within a state from impairing the ability of another state to meet national air quality standards or visibility requirements. CAIR was only one tool, not an all-purpose remedy, for addressing the problem of interstate transport of pollutants.

- EPA's own emission reduction projections for electric generating units – the largest emission source category – are at least as great under the proposed Transport Rule as those put forth for CAIR (see Table 1.1). The comparison is valid for overall emissions but is not necessarily true for emissions on a state-by-state basis.

Table 1.1: Simple Comparison of SO_2 and NOx Total Emissions from Electric Generating Units in the CAIR or Transport Rule Regions* (Million Tons)

Pollutant	2005 Actual	2012		2014	
		Transport Rule	CAIR**	Transport Rule	CAIR**
SO_2	9.5	4.1	5.1	3.3	4.6
NOx – Annual	2.9	1.6	1.7	1.6	1.7
NOx – Ozone Season	1.0	0.7	0.8	0.7	0.8

* Emissions totals include states covered by either the Transport Rule or CAIR. For $PM_{2.5}$ (SO_2 and annual NOx), the following 30 states are included: AL, CT, DE, DC, FL, GA, IL, IN, IA, KS, KY, LA, MD, MA, MI, MN, MS, MO, NE, NJ, NY, NC, OH, PA, SC, TN, TX, VA, WV, WI. For ozone (ozone-season NOx), the following 30 states are included: AL, AR, CT, DE, DC, FL, GA, IL, IN, IA, KS, KY, LA, MD, MA, MI, MS, MO, NJ, NY, NC, OH, OK, PA, SC, TN, TX, VA, WV, WI.

** CAIR SO_2 totals are interpolations from emissions analysis originally done for 2010 and 2015. CAIR NOx totals are as originally projected for 2010. This CAIR modeling represents a scenario that differed somewhat from the final CAIR (the modeling did not include a regionwide ozone season NOx cap and included $PM_{2.5}$ requirements for the state of Arkansas).

Source: Table III.A–4 of Proposed Rules, *Federal Register*, Vol. 75, No. 147, August 2, 2010.

For the reasons given, NHDES expects that future emissions and air quality levels under post-CAIR scenarios are likely to be better than or, in the worst case, not very different from values predicted by MANE-VU's completed modeling, even though that modeling was based on implementation of CAIR as it was before the remand. Consequently, the reasonable progress goals and long-term strategy developed for New Hampshire's regional haze SIP still represent a defensible position from which to go forward with measures to improve visibility at MANE-VU's Class I Areas.

New Hampshire and the other MANE-VU states have maintained all along that the regional haze SIPs should look beyond the provisions of CAIR to identify additional emission control measures that could be effectively employed to mitigate regional haze. In this respect, New Hampshire and the rest of MANE-VU stand apart from some other states in asserting that additional measures beyond CAIR and the present Transport Rule are essential to meeting established visibility goals at MANE-VU's Class I Areas.

In describing New Hampshire's current situation, it may be helpful to note that the remand of CAIR and its subsequent replacement with the Transport Rule are complicating factors but not absolute impediments to making visibility progress in the near term. The salient points to consider are as follows:

- Because New Hampshire is a non-CAIR state and a non-Transport Rule state, these federal programs do not directly affect any of New Hampshire's proposed in-state control strategies for visibility improvement. The control measures identified in this regional haze SIP for in-state sources should be able to proceed without delay or obstruction.

- Sources in upwind states release most of the pollutants contributing to visibility impairment at New Hampshire's Class I areas. Therefore, New Hampshire will continue to depend on mitigative actions by other states if visibility goals are to be achieved for in-state Class I areas.
- By the time of the first regional haze SIP progress report (expected to be completed in 2013[1]) the regulatory framework should be clearer; and it is hoped that new modeling results will be available. If so, it will then be possible to fine-tune regional haze plans to meet the post-CAIR reality. **New Hampshire is committed to reviewing and updating its regional haze SIP as new information becomes available.**

It should be noted that many references to the original CAIR program appear throughout New Hampshire's Regional Haze SIP. These references serve two purposes: 1) They provide historical context, and 2) they help to maintain continuity with the large body of completed work – much of it based on CAIR – that serves as the foundation for regional haze planning in the MANE-VU states to date.

1.2 The Basics of Haze

Small particles and certain gaseous molecules in the atmosphere cause poor visibility by scattering and absorbing light, thereby reducing the amount of visual information about distant objects that reaches an observer. Some light scattering by air molecules and naturally occurring aerosols occurs even under natural conditions.[2]

The distribution of particles in the atmosphere depends on meteorological conditions and leads to various forms of visibility impairment. When high concentrations of pollutants are well mixed in the atmosphere, they form a uniform haze. When temperature inversions trap pollutants near the surface, the result can be a sharply demarcated layer of haze. Plume blight – a distinct, frequently brownish plume of pollution from a particular emissions source – occurs under stable atmospheric conditions, where pollutants take a long time to disperse.

Visibility impairment can be quantified using three different, but mathematically related measures: light extinction per unit distance (e.g., inverse megameters, or Mm^{-1})[3]; visual range (i.e., how far one can see); and deciviews (dv), a useful metric for measuring increments of visibility change that are just perceptible to the human eye. Each can be estimated from the ambient concentrations of individual particle constituents, taking into account their unique light-scattering (or absorbing) properties and making appropriate adjustments for relative humidity. Assuming natural conditions, visibility in the Northeast and Mid-Atlantic is estimated to be about 23 Mm^{-1}, which corresponds to a visual range of about 106 miles or 8 dv (the lower the dv, the better the visibility). Under current polluted conditions in the region, average visibility ranges from 103 Mm^{-1} in the south to 55 Mm^{-1} in the north; these values

[1] 40 CFR 51.308(g) states that the first progress report is due 5 years from the submittal of the initial implementation plan. The regional haze SIP was originally due on December 17, 2007. In New Hampshire's case, it is expected that the first progress report will be completed and submitted in 2013, near the midpoint of the 10-year initial planning period from 2008 to 2018.

[2] The fact that air molecules scatter more short-wavelength (blue) light accounts for the blue color of the sky. The term "aerosol" is defined as a suspension of particles in a gas. In this report, the term refers to particles suspended in the atmosphere.

[3] In units of inverse length. An inverse megameter (Mm^{-1}) is equal to one over one thousand kilometers.

correspond to a visual range of 24 to 44 miles or 23 to 17 dv, respectively. On the worst 20 percent of days, visibility impairment in Northeast and Mid-Atlantic Class I areas ranges from about 25 to 30 dv.

The small particles that commonly cause hazy conditions in the East are primarily composed of sulfate, nitrate, organic carbon, elemental carbon (soot), and crustal material (e.g., soil dust, sea salt, etc.). Of these constituents, only elemental carbon impairs visibility by absorbing visible light; the others scatter light. Sulfate, nitrate, and organic carbon[4] are secondary pollutants that form in the atmosphere from precursor pollutants, primarily sulfur dioxide (SO_2), oxides of nitrogen (NO_X), and volatile organic compounds (VOCs), respectively. By contrast, soot and crustal material and some organic carbon particles are released directly to the atmosphere. Particle constituents also differ in their relative effectiveness at reducing visibility. Sulfates and nitrates, for example, contribute disproportionately to haze because of their chemical affinity for water. This property allows them to grow rapidly, in the presence of moisture, to the optimal particle size for scattering light (i.e., 0.1 to 1 micrometer).

1.3 Anatomy of Regional Haze

Monitoring data collected over the last decade show that fine particle[5] concentrations, and hence visibility impairment, are generally highest near industrial and highly populated areas of the Northeast and Mid-Atlantic. Particle concentrations are lower, and visibility conditions are better, at the more northerly Class I sites (such as the Great Gulf and Presidential Range - Dry River Wildernesses in New Hampshire), where visibility on the 20 percent best days[6] is close to natural, unpolluted conditions. By contrast, visibility at the more southerly Brigantine site in New Jersey is substantially impaired even on the 20 percent clearest days. On the 20 percent haziest days, visibility impairment is substantial throughout the region.

Sulfate is the dominant contributor to fine particle pollution throughout the eastern U.S. On the haziest 20 percent of days, it accounts for one-half to two-thirds of total fine particle mass and is responsible for about three-quarters of total light extinction at Class I sites in the Northeast and Mid-Atlantic. Even on the clearest 20 percent of days, sulfate typically constitutes 40 percent or more of total fine particle mass in the region. Moreover, sulfate accounts for 60 to 80 percent of the difference in fine particle mass concentrations on hazy versus clear days.

Organic carbon consistently accounts for the next largest fraction of total fine particle mass; its contribution typically ranges from 20 to 30 percent on the haziest days. Notably, organic carbon accounts for as much as 40 to 50 percent of total mass on the clearest days, indicating that biogenic hydrocarbon sources (i.e., vegetation) are important at Class I areas in the region.

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[4] The term "organic carbon" encompasses a large number of hydrogen and carbon containing molecules. Light scattering secondary organic aerosols result from the oxidation of hydrocarbons that are emitted from many different sources, ranging from automobiles to solvents, to natural vegetation. Organic carbon can be emitted as a primary particle from sources such as wood burning, meat cooking, automobiles, and paved road dust.

[5] "Fine particles" refers throughout this study to particles less than or equal to 2.5 micrometers in diameter, consistent with US EPA's recently proposed fine particle National Ambient Air Quality Standard (NAAQS).

[6] "20 percent best visibility conditions" are defined throughout this report as the simple average of the lower 20th percentile of a cumulative frequency distribution of available data (expressed in deciviews). Similarly, "20 percent worst visibility conditions" represent the upper 20th percentile of the same distribution of available data.

The relative contributions of nitrate, elemental carbon, and fine soil are smaller than those of sulfate and organic carbon – typically less than 10 percent of total mass and varying with location. However, in some settings such as a monitoring site in Washington, DC,[7] nitrate plays a considerably larger role, pointing to the importance of local NO_X sources to fine-particle pollution in urban environments.

About half of the worst visibility days in the New Hampshire Class I Areas occur in the summer when meteorological conditions are more conducive to the formation of sulfate from SO_2 and to the oxidation of organic aerosols. The remaining worst visibility days are divided nearly equally among spring, winter, and fall. In contrast to sulfate and organic carbon, the nitrate contribution is typically higher in the winter months.[8] The crustal and elemental carbon fractions do not show a clear pattern of seasonal variation. In addition, winter and summer transport patterns are different, possibly leading to different contributions from upwind pollutant source regions.

The basis for EPA's regional haze regulations is recognition that visibility impairment is fundamentally a regional phenomenon. Emissions from numerous sources over a broad geographic area commonly create hazy conditions across large portions of the eastern U.S. as a result of the long-range transport of airborne particles and precursor pollutants in the atmosphere. The key sulfate precursor, SO_2, for example, has an atmospheric lifetime of several days and is known to be subject to transport distances of hundreds of miles. NO_X and some organic carbon species are also subject to long-range transport, as are small particles of soot and crustal material.

The importance of transport dynamics is well illustrated by a particularly severe haze episode that occurred in mid-July of 1999. During this episode, unusually hot and humid conditions coincided with the development of a high-pressure system over the Mid-Atlantic States that produced atmospheric stagnation over the heavily urbanized, southern portion of the northeastern Regional Planning Organization region (i.e., Philadelphia - DC - southern New Jersey). At the same time, wind patterns above the area of stagnation brought a steady flow of air from the Midwest into the New England states. This set of conditions resulted in several days of unusually high concentrations of fine-particle pollution throughout the region. On July 17, 1999, ambient sulfate concentrations at Acadia National Park were 40 percent higher than any previous measurement at that site since the late 1980s. On the same day, visibility at the Burlington, Vermont, airport was limited to just 3 miles. As is often the case, high concentrations of ground-level ozone accompanied these severe haze conditions. These coinciding conditions occurred because haze and ground-level ozone – although they are fundamentally different phenomena – tend to form and accumulate under similar meteorological conditions.

1.4 Regulatory Framework

In amendments to the Clean Air Act (CAA) in 1977, Congress added Section 169A (42 U.S.C. 7491), setting forth the following national visibility goal:

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[7] The Washington, DC, site is part of the IMPROVE nationwide monitoring network and is mentioned here for the purposes of comparison.

[8] This is largely due to the fact that the ammonium nitrate bond is more stable at lower temperatures. The role of ammonia in combination with both sulfate and nitrate is discussed further in later sections.

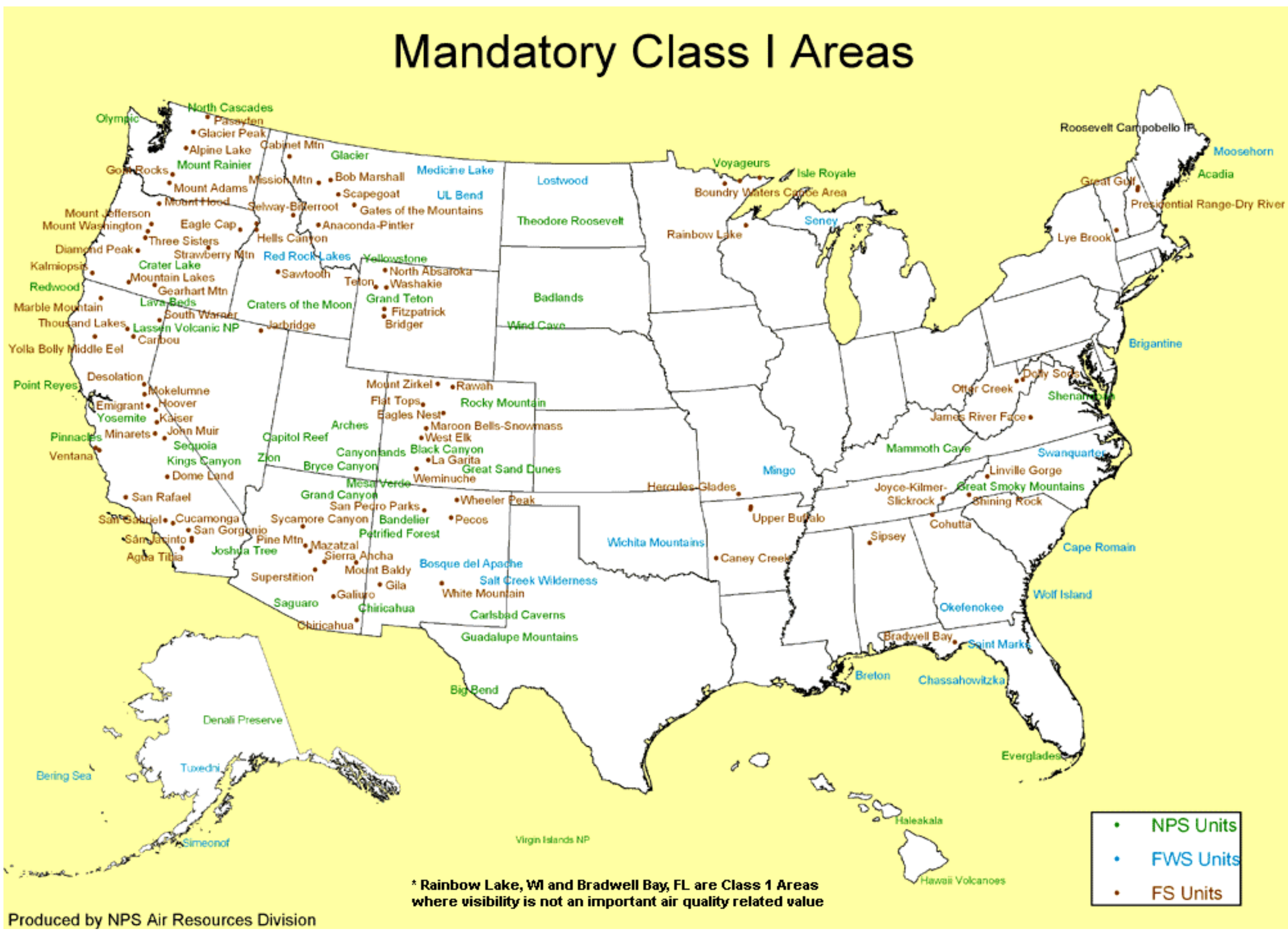
> "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution."

The "Class I" designation was given to each of 158 areas in existence as of August 1977 that met the following criteria:

- all national parks greater than 6000 acres
- all national wilderness areas and national memorial parks greater than 5000 acres
- one international park

In 1980, Bradwell Bay, Florida, and Rainbow Lake, Wisconsin, were excluded for purposes of visibility protection as federal Class I areas. Today, 156 national park and wilderness areas remain as Class I visibility protection areas (Figure 1.2).

Figure 1.2: Locations of Federally Protected Mandatory Class I Areas



Over the following years, modest steps were taken to address the visibility problems in Class I areas. The control measures taken mainly addressed plume blight from specific pollution sources, a localized phenomenon, and did little to address regional haze issues in the Eastern United States.

When the Clean Air Act was amended, again, in 1990, Congress added Section 169B (42 U.S.C. 7492), authorizing further research and regular assessments of progress made. In 1993, the National Academy of Sciences concluded that "current scientific knowledge is adequate and control technologies are available for taking regulatory action to improve and protect visibility."

In addition to authorizing creation of visibility transport commissions and setting forth their duties, Section 169B(f) of the CAA mandated creation of the Grand Canyon Visibility Transport Commission (GCVTC) to make recommendations to EPA for the region affecting the visibility of the Grand Canyon National Park. GCVTC submitted its report to EPA in June 1996, following four years of research and policy development. This report, as well as the many research reports prepared by the GCVTC, contributed invaluable information to EPA in its development of regulations for visibility improvement.

1.4.1 The Regional Haze Rule

The federal requirements that states must meet to achieve national visibility goals are contained in Title 40: Protection of Environment, Part 51 – Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Subpart P – Protection of Visibility (40 CFR 51.300-309). Known more simply as the Regional Haze Rule, these regulations were adopted on July 1, 1999, and went into effect on August 30, 1999. The rule seeks to address the combined visibility effects of various pollution sources over a large geographic region. This wide-reaching pollution net means that many states – even those without Class I Areas – are required to participate in haze reduction efforts. The specific requirements for States' regional haze SIPs are set forth in 40 CFR 51.308, Regional Haze Program Requirements.

In consultation with the states and tribes, EPA designated five Regional Planning Organizations (RPO) to assist with the coordination and cooperation needed to address the regional haze issue. The Mid-Atlantic and Northeast states, joined by the District of Columbia and tribes in the Northeast, formed the Mid-Atlantic / Northeast Visibility Union (MANE-VU).[9]

EPA's adoption of the Regional Haze Rule was not without controversy and legal challenges. On May 24, 2002, the U.S. Court of Appeals for the District of Columbia Circuit ruled on the challenge brought by the American Corn Growers Association against the Regional Haze Rule. The Court remanded the BART provisions of the rule to EPA and denied industry's challenge to the haze rule goals of achieving natural visibility levels and zero degradation. On June 15, 2005, EPA finalized a rule addressing the court's remand.

On February 18, 2005, the U.S. Court of Appeals for the D.C. Circuit issued another ruling vacating the Regional Haze Rule in part and sustaining it in part. For more information see *Center for Energy and Economic Development v. EPA*, no. 03-1222, (D.C. Cir. Feb. 18, 2005) ("*CEED* v. EPA"). In this case, the court granted a petition challenging provisions of the Regional Haze Rule governing the optional emissions trading program for certain Western States and Tribes (the WRAP Annex Rule).

In the aftermath of these decisions, EPA's final rulemaking incorporated the following

[9] MANE-VU includes the following member states: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and the District of Columbia. A more complete description of MANE-VU appears in Section 3 of this SIP.

changes to the Regional Haze Rule:

- Revised the regulatory text in 40 CFR 51.308(e)(2)(i) in response to the *CEED* court's remand, to
  - Remove the requirement that the determination of BART be based on cumulative visibility analyses, and
  - Clarify the process for making such determinations, including the application of BART presumptions for electric generating units (EGUs) as contained in 40 CFR 51, Appendix Y;
- Added new regulatory text in 40 CFR 51.308(e)(2)(vi) to provide minimum elements for cap-and-trade programs in lieu of BART; and
- Revised regulatory text in 40 CFR 51.309 to reconcile the optional framework for certain Western states and tribes to implement the recommendations of the GCVTC with the *CEED* decision.

1.4.2 State Implementation Plan

New Hampshire submits this State Implementation Plan revision to meet the requirements of EPA's Regional Haze Rule. To facilitate states' efforts, EPA prepared a checklist summarizing the requirements of the final Regional Haze Rule. Attachment A is a copy of the checklist with cross-references to sections of New Hampshire's Regional Haze SIP showing how the requirements have been met.

New Hampshire's Regional Haze Plan addresses the core requirements of 40 CFR 51.308(d) and the BART components of 40 CFR 50.308(e). In addition, this SIP addresses requirements pertaining to regional planning, and state/tribe and Federal Land Manager (FLM) coordination and consultation.

40 CFR 51.308(f) requires the New Hampshire Department of Environmental Services (NHDES) to submit periodic revisions to its Regional Haze SIP by July 31, 2018, and every ten years thereafter. **NHDES acknowledges and will comply with this schedule.**

40 CFR 51.308(g) requires NHDES to submit a report to EPA every 5 years that evaluates progress toward the reasonable progress goal for each mandatory Class I area located within the state and each mandatory Class I area located outside the state that may be affected by emissions from within the state. **NHDES will submit the first progress report, in the form of a SIP revision, within 5 years from submittal of the initial State Implementation Plan, but in no case later than December 31, 2013.**

Pursuant to 40 CFR 51.308(d)(4)(v), **NHDES will also make periodic updates to the New Hampshire's emissions inventory** (see Section 7, Emissions Inventory). NHDES proposes to complete these updates to coincide with the progress reports.

Lastly, pursuant to 40 CFR 51.308(h), **NHDES will submit a determination of adequacy of its regional haze SIP revision whenever a progress report is submitted.** Depending on the findings of its five-year review, New Hampshire will take one or more of the following actions at that time, whichever actions are appropriate or necessary:

- If New Hampshire determines that the existing State Implementation Plan requires no further substantive revision in order to achieve established goals for visibility improvement and emissions reductions, NHDES will provide to the EPA Administrator a negative declaration that further revision of the existing plan is not needed.

- If New Hampshire determines that its implementation plan is or may be inadequate to ensure reasonable progress as a result of emissions from sources in one or more other state(s) which participated in the regional planning process, New Hampshire will provide notification to the EPA Administrator and to those other state(s). New Hampshire will also collaborate with the other state(s) through the regional planning process, if viable regional organizations exist, for the purpose of developing additional strategies to address any such deficiencies in New Hampshire's plan.
- If New Hampshire determines that its implementation plan is or may be inadequate to ensure reasonable progress as a result of emissions from sources in another country, New Hampshire will provide notification, along with available information, to the EPA Administrator.
- If New Hampshire determines that its implementation plan is or may be inadequate to ensure reasonable progress as a result of emissions from sources within the state, New Hampshire will revise its implementation plan to address the plan's deficiencies within one year from this determination.

1.5 New Hampshire's Class I Areas

In New Hampshire, the U.S. Forest Service manages two Class I wilderness areas: the Great Gulf Wilderness and the Presidential Range - Dry River Wilderness, both located in New Hampshire's White Mountain National Forest.

Figure 1.3: Mt. Washington from the Southeast at Sunrise

These Class I areas flank the northern and southern slopes of the nationally renowned Mt. Washington, in the Presidential Range of the White Mountains (Figure 1.3). Mt. Washington is the highest mountain in the Northeast and attracts visitors (who can climb, drive, or ride to its summit) to enjoy expansive views from above tree line. Any action taken to improve visibility in the adjacent Great Gulf and Presidential Range-Dry River Wilderness Areas will also improve the vistas from the summit of Mt. Washington. The White Mountain National Forest is the main tourist attraction in New Hampshire and ranks among the most popular National

Forests in the country with over 7 million visitors annually (source: U.S. Forest Service, http://www.fs.fed.us/r9/forests/white_mountain/about/history/index.php).

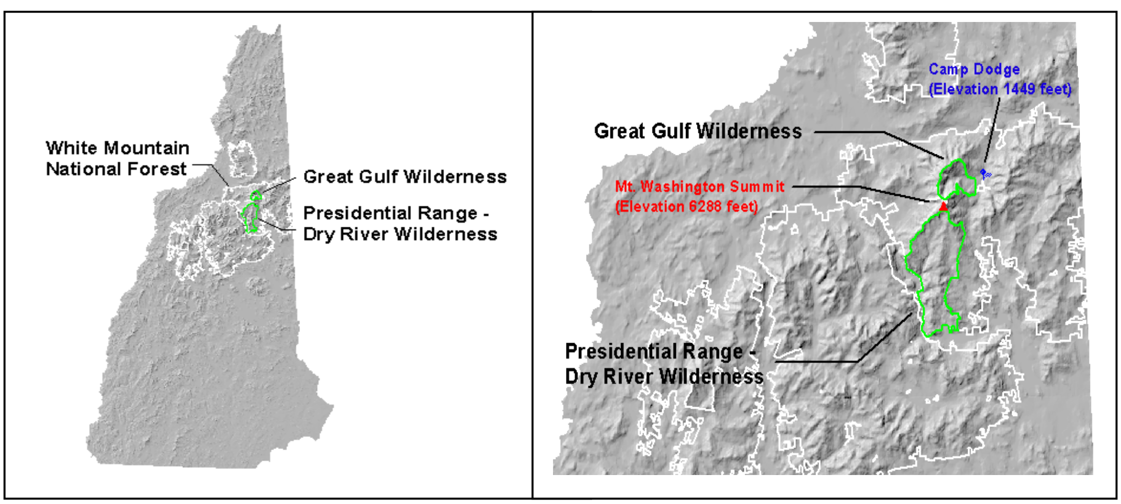
The Great Gulf Wilderness and the Presidential Range - Dry River Wilderness are two of 156 protected areas designated in 1977 as mandatory federal Class I areas for the purposes of the visibility protection program. Each of these areas covers thousands of acres containing high mountain terrain, scenic vistas, and interesting or unique geologic formations and vegetation communities. Many species of wildlife are present, including a number of alpine-zone residents. Among the alpine fauna are the northern bog lemming and two rare butterfly species. Cool, crystal-clear streams, cascades, and high-elevation ponds are common throughout the two areas, and the region is full of natural woodland. Hardwoods are most abundant on the lower slopes; mixed birches, maples, and spruce-fir dominate the mid-slopes; and spruce-fir are most common on the upper mountainsides. The unusual low-elevation tree line in the White Mountains of New Hampshire is caused by the high winds and harsh conditions this area experiences through the year. The result is a fragile, near-Arctic-tundra vegetation at the higher elevations.

The delicate ecosystems in both wilderness areas have been under stress resulting from years of highly acidic precipitation, which has leached plant nutrients from the soils and acidified mountain streams and ponds. The damage done by air pollution to Great Gulf and Presidential Range - Dry River Wilderness Areas will take decades to repair.

1.5.1 Great Gulf Wilderness

The Great Gulf Wilderness is located in Greens Grant in the White Mountain National Forest of northern New Hampshire (Figure 1.4). Occupying the northeastern slopes of the Presidential Range, Great Gulf covers an area of 5,552 acres and ranges in elevation from 1,680 to 5,807 feet.

Figure 1.4: Location of New Hampshire's Class I Areas



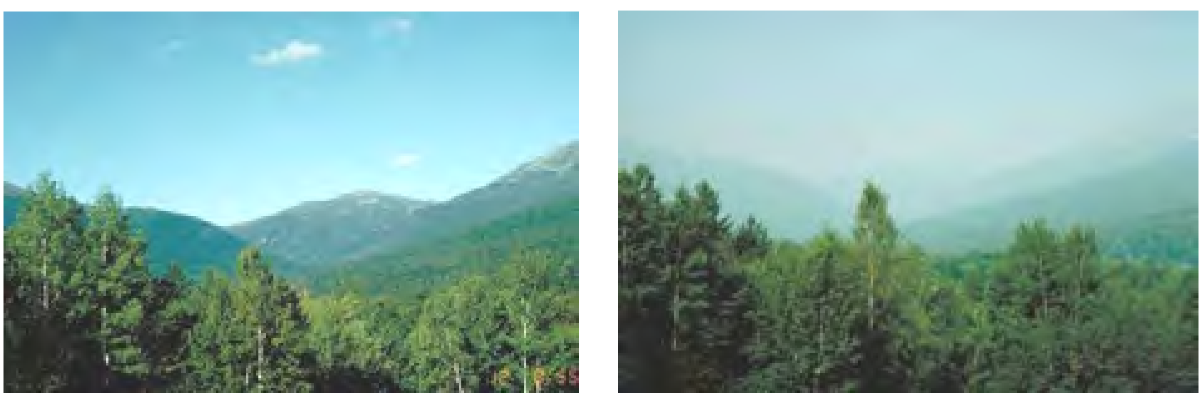
The Great Gulf Wilderness is formed by a high mountain valley located north-northeast of the Mt. Washington summit (Figures 1.5 and 1.6). The valley has steep walls rising from 1,100 feet to 1,600 feet above the valley floor. The area includes many rivulets that drain eastward to the West Fork of the Peabody River. For visitors, the Great Gulf has 21.3 miles of marked trails, which offer some of the best views of the ridges and summits of the Presidential Range.

Great Gulf receives about 20,000 visitors annually.

Figure 1.5: View of Great Gulf Wilderness from Mt. Washington

http://www.penemco.com/matthew/

Figure 1.6: Views of Great Gulf Wilderness from Lower Elevation on Clear (6 deciview) and Hazy (28 deciview) Days



http://www.wilderness.net

1.5.2 Presidential Range - Dry River Wilderness, New Hampshire

The Presidential Range - Dry River Wilderness is also located in Greens Grant in the White Mountain National Forest of northern New Hampshire (Figure 1.4); however, at 27,380 acres, it is about five times larger than the Great Gulf Wilderness. Ranging in elevation from 880 to 5,413 feet, the Presidential Range - Dry River Wilderness constitutes a rugged expanse of mountains and valleys lying to the south of Mt. Washington's summit. On its western side, the area flanks other peaks in the Presidential Range, including Mt. Eisenhower and Mt. Monroe. The wilderness area extends across and beyond the central valley of the Dry River to the Saco River, encompassing numerous brooks and smaller, heavily forested mountains (Figure 1.7).

Figure 1.7: Presidential Range - Dry River Wilderness in Autumn.

http://www.wilderness.net

As the name suggests, the Dry River is almost without water by late summer but swells quickly during heavy rains. There are ten trails in the wilderness area totaling 46.1 miles in length. Because of its remote location, this area receives fewer visitors than Great Gulf (about 7,000 annually). Its southern portion has almost no trails, is very steep and rugged, and offers a rare degree of solitude.

1.5.3 Monitoring and Recent Visibility Trends

Visibility monitoring at Great Gulf Wilderness and Presidential Range - Dry River Wilderness is accomplished with instruments located at a single site at Camp Dodge. This monitoring station, which represents both wilderness areas, measures and records light scattering, aerosols, and relative humidity (Table 1.2). The collected data are compiled and sorted to ascertain visibility levels on the 20 percent most and least visibility-impaired days, and this information is tracked over time to look for trends in visibility.

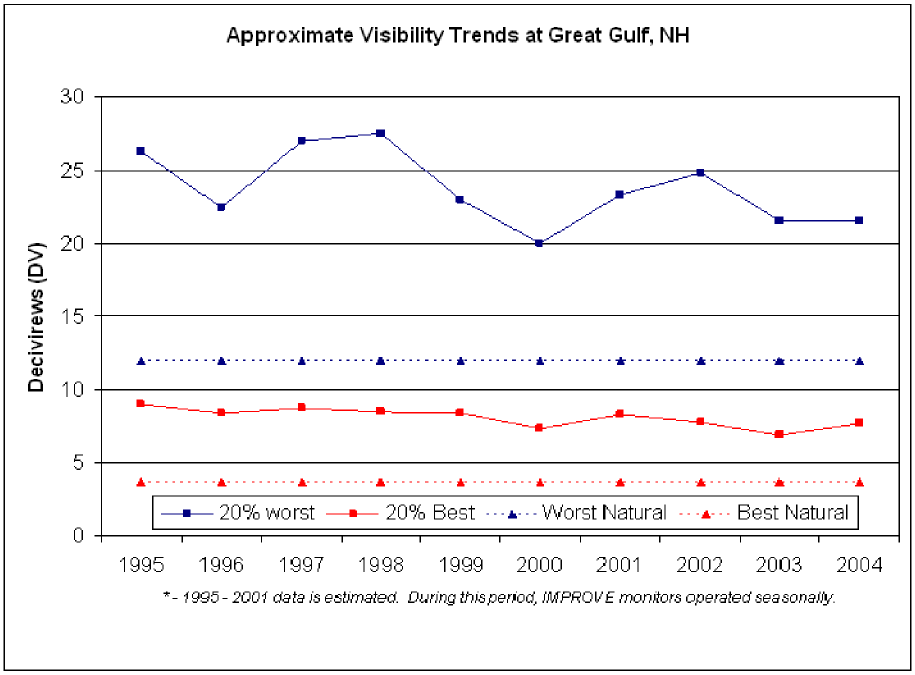
Table 1.2: Visibility Monitoring at Great Gulf and Presidential Range - Dry River Wilderness Areas

Parameter	Instrument
Scattering coefficient	Nephelometer
Aerosol	IMPROVE module A
Aerosol	IMPROVE module B
Aerosol	IMPROVE module C
Aerosol	IMPROVE module D
Meteorology	Relative humidity

Figure 1.8 depicts recent visibility trends (in annual average deciviews) at Great Gulf Wilderness and Presidential Range - Dry River Wilderness for the 20 percent most and least visibility-impaired days for each year from 1995 to 2004. The graph also shows the reconstructed natural background level. The difference between the 20 percent haziest days

and the natural background level shows the magnitude of the gap that needs to be closed in order to attain the national visibility goal established in the Clean Air Act.

Figure 1.8: Visibility Trends at Great Gulf and Presidential Range - Dry River Wilderness Areas



The plotted trend lines serve only as semi-quantitative indicators of baseline conditions for a number of reasons:

- As of 1999, there were no complete years of sampling data for the Great Gulf site; so the trend lines represent only the subset of summer months from May or June through September.
- Since the haziest days typically occur in the warmest months, average deciview values for the 20 percent most visibility-impaired summertime days would almost certainly be higher than the corresponding value for the year as a whole.
- The short time span of the trend plots (10 years' worth of data) makes it impossible to draw definitive conclusions about recent visibility trends in New Hampshire.

Despite these caveats, the trend plots do suggest the following:

- The 20 percent most visibility-impaired days have visibility readings in the order of 10 deciviews above the worst natural background level; and
- The 20 percent least visibility-impaired days have visibility readings in the order of 4 deciviews above the best natural background level.

2. AREAS CONTRIBUTING TO REGIONAL HAZE

40 CFR 51.308I(3) of the Regional Haze Rule requires states to determine their contributions to visibility impairment at mandatory Class I areas. Through source apportionment modeling (more fully described in Section 8, Understanding the Sources of Visibility-Impairing Pollutants), MANE-VU has identified and evaluated the major contributors to regional haze at MANE-VU Class I Areas as well as Class I areas in nearby Regional Planning Organizations (RPOs). The complete findings are contained in a report produced by the Northeast States for Coordinated Air Quality Management (NESCAUM) entitled, "Contributions to Regional Haze in the Northeast and Mid-Atlantic United States," August 2006, otherwise known as the Contribution Assessment (Attachment B).

The regional modeling performed by MANE-VU included a pollutant tagging scheme to produce a comprehensive assessment of the individual contributions from 28 nearby states to visibility impairment at the New Hampshire Class I areas and six other nearby Class I areas. The modeling also provided a partial accounting of the contributions from several states along the western and southern edges of the modeling domain (i.e., boundary conditions) where only a portion of the states' emissions were tracked. Modeling was conducted for the base year 2002 and then projected to year 2018, when currently anticipated emission control programs would be in place.

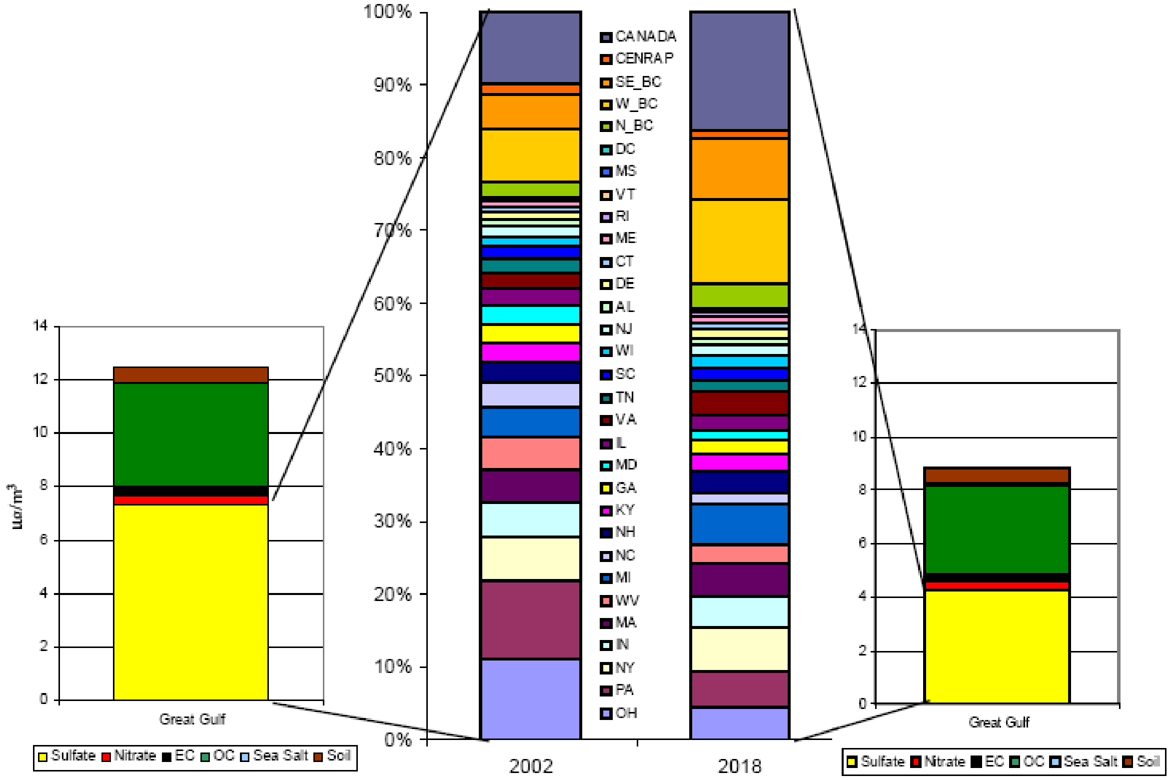
Modeling results indicate that the relative contributions of states within the modeling domain will decrease significantly by 2018 as a result of anticipated SO_2 emission reductions from implementation of existing state programs, applicable portions of the federal Clean Air Interstate Rule (or its replacement, the Transport Rule), and additional state and federal control measures described in following sections of this document. At the same time, there will be large *increases* in the *relative* contributions from Canada and the boundary areas. These predicted increases are not absolute increases in mass but are due simply to the fact that contributions from outside the modeling domain will represent a larger share of the total after the various emission control programs within the U.S. portion of the modeling domain have reduced contributions from within the domain.

It is noteworthy that projected SO_2 reductions from emission sources in New Hampshire are on pace with states originally enrolled in the CAIR program even though New Hampshire was not included in this program. As do many other states, New Hampshire has its own program for reducing SO_2 emissions.

According to the completed MANE-VU modeling, sulfate concentrations at the Great Gulf and Presidential Range - Dry River Wilderness Areas on the 20 percent worst visibility days will decline from 7.3 $\mu g/m^3$ in 2002 (representing the baseline period of 2000-2004) to 4.6 $\mu g/m^3$ in 2018. Included in these values is New Hampshire's own sulfate contribution, which is projected to drop from 0.4 $\mu g/m^3$ in 2002 to 0.3 $\mu g/m^3$ in 2018. Mirroring the results for sulfate, fine particulate matter ($PM_{2.5}$) concentrations from all sources are projected to fall by a similar percentage, from 12.5 $\mu g/m^3$ in 2002 to 9.2 $\mu g/m^3$ in 2018. The modeling that produced these results is described in Section 7, Air Quality Modeling, and in "2018 Visibility Projections," May 13, 2008 (Attachment Q). The emission control programs responsible for the projected visibility improvements are described in Section 11, Long-Term Strategy.

Figure 2.1 shows the magnitude of the 2002 (measured) and 2018 (projected) sulfate concentrations at the Great Gulf and Presidential Range - Dry River Wilderness Areas, as well as the relative mass contributions of each state, on the 20 percent worst visibility days. Similar findings apply to the other Class I areas (graphical figures for these other sites are available in the Contribution Assessment but, for brevity, are not repeated here).

Figure 2.1: Measured and Projected Mass Contributions in 2002 and 2018 at Great Gulf and Presidential Range - Dry River Wilderness Areas on 20 Percent Worst Visibility Days



IMPROVE mass 00-04 **REMSAD Contribution to Sulfate** **CMAQ RRF-Based 2018 Mass**

2.1 Class I Areas Affected by New Hampshire's Emission Sources

Emission sources within New Hampshire have had measurable impacts on visibility at Class I areas both within the state and at downwind locations. The magnitude of these impacts is described in detail in MANE-VU's Contribution Assessment (Attachment B). Table 2.1 briefly lists the affected Class I areas and New Hampshire's percent contribution to total annual sulfate at each area in the 2002 baseline year, as determined from the modeling.

Table 2.1: New Hampshire's Contributions to Total Annual Average Sulfate Impact (Percent, Mass Basis) at Eastern Class I Areas in 2002

Mandatory Class I Area(s)	Percent Contribution
Great Gulf Wilderness* & Presidential Range - Dry River Wilderness*	3.95
Acadia National Park*	2.25
Moosehorn Wilderness* & Roosevelt Campobello International Park*	1.74
Lye Brook Wilderness*	1.68
Brigantine Wilderness*	0.60
Shenandoah National Park	0.08
Dolly Sods Wilderness	0.04

*MANE-VU Class I Area

Interestingly, New Hampshire's own SO_2 emissions account for only about 4 percent of visibility-impairing sulfate in New Hampshire's Class I Areas and approximately 2 percent of visibility-impairing sulfate in the downwind Class I areas of Acadia National Park, Moosehorn Wilderness, Roosevelt Campobello International Park, and Lye Brook Wilderness. Also, New Hampshire's emissions account for less than 1 percent of visibility-impairing sulfate in the more southerly Class I areas of Brigantine Wilderness, Shenandoah National Park, and Dolly Sods Wilderness.

2.2 States Contributing to Visibility Impairment in New Hampshire's Class I Areas

Through participation in the MANE-VU regional haze planning process, New Hampshire has identified the states and Canadian provinces contributing to visibility impairment at New Hampshire's two Class I areas: the Great Gulf Wilderness and the Presidential Range - Dry River Wilderness. Table 2.2 lists the states and regions responsible for visibility degradation at these Class I areas, and the corresponding percentage contributions to total sulfate impact. Taken from MANE-VU's Contribution Assessment, the data provide clear evidence that the large majority of sulfate pollution at New Hampshire's Class I areas originates from sources outside the state and, more significantly, from sources outside the MANE-VU region. Note that "other" sources contribute nearly a quarter of the total sulfate impact. These sources represent all emissions from outside the modeling domain (i.e., boundary conditions, including emissions coming primarily from regions lying west of the Mississippi River).

Table 2.2: Contributions of Individual MANE-VU States and Other Regions to Total Annual Average Sulfate Impact (Percent, Mass Basis) at New Hampshire's Class I Areas in 2002

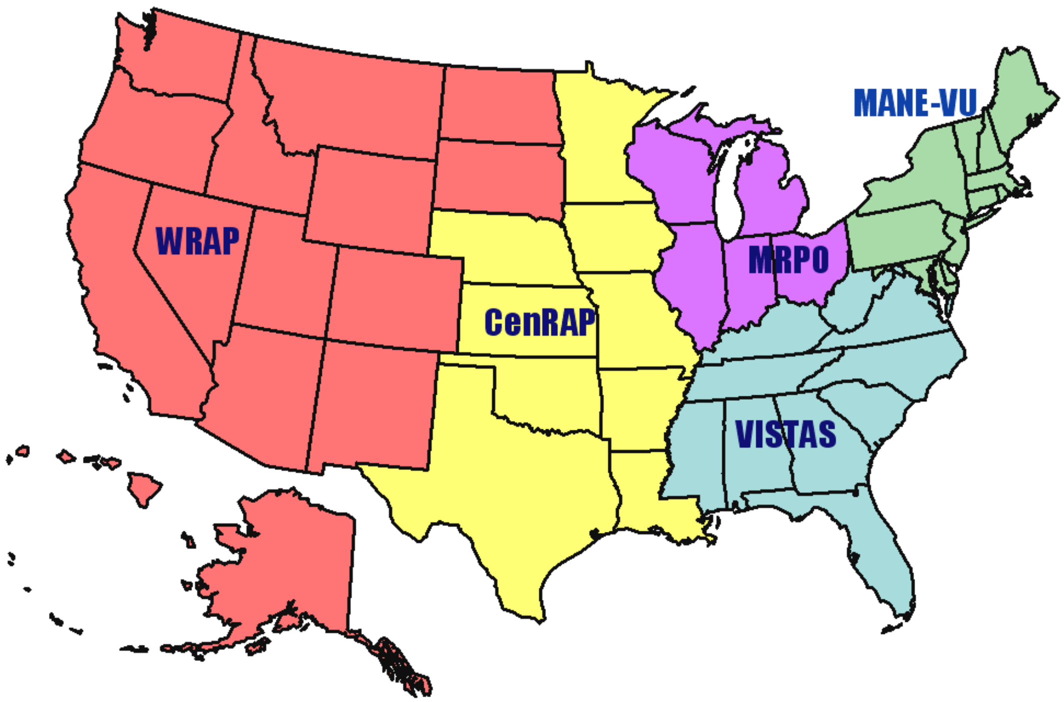
State or Region	Percent Contribution
Pennsylvania	8.30
New York	5.68
New Hampshire	3.95
Massachusetts	3.11
Maine	2.33
Maryland	1.92
New Jersey	0.89
Delaware	0.63
Connecticut	0.48
Vermont	0.41
Rhode Island	0.11
District of Columbia	0.01
MANE-VU	27.83
MRPO	20.10
VISTAS	12.04
CenRAP	1.65
Canada	14.84
Other	23.54

Note: Indicated percent contributions from, VISTAS, CenRAP, and Canada apply only to those portions lying within the modeling domain (see Figure 7.1). Actual contributions, especially from CenRAP, would be higher than stated.

3. REGIONAL PLANNING AND CONSULTATION

In 1999, EPA and affected states/tribes agreed to create five Regional Planning Organizations (RPOs) to facilitate interstate coordination on State Implementation Plans (SIPs) addressing regional haze. The RPOs, and states/tribes within each RPO, are required to consult on emission management strategies toward visibility improvement in affected Class I areas. As shown in the accompanying map (Figure 3.1), the five RPOs are MANE-VU (Mid-Atlantic/Northeast Visibility Union), VISTAS (Visibility Improvement State and Tribal Association of the Southeast), MRPO (Midwest Regional Planning Organization), CenRAP (Central Regional Air Planning Association), and WRAP (Western Regional Air Partnership). New Hampshire is a member of MANE-VU.

Figure 3.1: EPA-Designated Regional Planning Organizations (RPOs).



3.1 Mid-Atlantic / Northeast Visibility Union (MANE-VU)

MANE-VU's work is managed by the Ozone Transport Commission (OTC) and carried out by OTC, the Mid-Atlantic Regional Air Management Association (MARAMA), and the Northeast States for Coordinated Air Use Management (NESCAUM). The states, tribes, and federal agencies comprising MANE-VU are listed in Table 3.1. Individuals from the member states, tribes, and agencies, along with professional staff from OTC, MARAMA, and NESCAUM, make up the various committees and workgroups. MANE-VU also established a Policy Advisory Group (PAG) to provide advice to decision-makers on policy questions. EPA, Federal Land Managers, states, and tribes are represented on the PAG, which meets on an as-needed basis.

Table 3.1: MANE-VU Members

Connecticut	Rhode Island
Delaware	Vermont
Maine	District of Columbia
Maryland	Penobscot Nation
Massachusetts	St. Regis Mohawk Tribe
New Hampshire	U.S. Environmental Protection Agency*
New Jersey	U.S. Fish and Wildlife Service*
New York	U.S. Forest Service*
Pennsylvania	U.S. National Park Service*

*Non-voting member

Since its inception on July 24, 2001, MANE-VU has created an active committee structure to address both technical and non-technical issues related to regional haze. The primary committees are the Technical Support Committee (TSC) and the Communications Committee, While the work of these committees are instrumental to policies and programs, all policy decisions reside with and are made by the MANE-VU Board.

The TSC is charged with assessing the nature and magnitude of the regional haze problem within MANE-VU, interpreting the results of technical work, and reporting on such work to the MANE-VU Board. This committee has evolved to function as a valuable resource on all technical projects and issues for MANE-VU. The TSC has established a process to ensure that important regional-haze-related projects are completed in a timely fashion, and members are kept informed of all MANE-VU tasks and duties. In addition to the formal working committees, there are three standing workgroups of the TSC assigned by topic area: the Emissions Inventory Workgroup, the Modeling Workgroup, and the Monitoring/Data Analysis Workgroup.

The Communications Committee is charged with developing approaches to inform the public about the regional haze problem and making recommendations to the MANE-VU Board to facilitate that goal. This committee oversees the production of MANE-VU's newsletter and outreach tools, both for stakeholders and the public, regarding regional issues affecting MANE-VU's members.

3.2 Regional Consultation and the "Ask"

On May 10, 2006, MANE-VU adopted the Inter-RPO State/Tribal and FLM Consultation Framework (Attachment C). That document set forth the principles presented in Table 3.2. The MANE-VU states and tribes applied these principles to the regional haze consultation and SIP development process. Issues addressed included regional haze baseline assessments, natural background levels, and development of reasonable progress goals – described at length in later sections of this SIP.

Table 3.2: MANE-VU Consultation Principles for Regional Haze Planning

1. All State, Tribal, RPO, and Federal participants are committed to continuing dialogue and information sharing in order to create understanding of the respective concerns and needs of the parties.
2. Continuous documentation of all communications is necessary to develop a record for inclusion in the SIP submittal to EPA.
3. States alone have the authority to undertake specific measures under their SIP. This inter-RPO framework is designed solely to facilitate needed communication, coordination and cooperation among jurisdictions but does not establish binding obligation on the part of participating agencies.
4. There are two areas which require State-to-State and/or State-to-Tribal consultations ("formal" consultations): (i) development of the reasonable progress goal for a Class I area, and (ii) development of long-term strategies. While it is anticipated that the formal consultation will cover the technical components that make up each of these policy decision areas, there may be a need for the RPOs, in coordination with their State and Tribal members, to have informal consultations on these technical considerations.
5. During both the formal and informal inter-RPO consultations, it is anticipated that the States and Tribes will work collectively to facilitate the consultation process through their respective RPOs, when feasible.
6. Technical analyses will be transparent, when possible, and will reflect the most up-to-date information and best scientific methods for the decision needed within the resources available.
7. The State with the Class I area retains the responsibility to establish reasonable progress goals. The RPOs will make reasonable efforts to facilitate the development of a consensus among the State with a Class I area and other States affecting that area. In instances where the State with the Class I area can not agree with such other States that the goal provides for reasonable progress, actions taken to resolve the disagreement must be included in the State's regional haze implementation plan (or plan revisions) submitted to the EPA Administrator as required under 40 CFR §51.308(d)(1)(iv).
8. All States whose emissions are reasonably anticipated to contribute to visibility impairment in a Class I area, must provide the Federal Land Manager ("FLM") agency for that Class I area with an opportunity for consultation, in person, on their regional haze implementation plans. The States/Tribes will pursue the development of a memorandum of understanding to expedite the submission and consideration of the FLMs' comments on the reasonable progress goals and related implementation plans. As required under 40 CFR §51.308(i)(3), the plan or plan revision must include a description of how the State addressed any FLM comments.
9. States/Tribes will consult with the affected FLMs to protect the air resources of the State/Tribe and Class I areas in accordance with the FLM coordination requirements specified in 40 CFR §51.308(i) and other consultation procedures developed by consensus.
10. The consultation process is designed to share information, define and document issues, develop a range of options, solicit feedback on options, develop consensus advice if possible, and facilitate informed decisions by the Class I States.
11. The collaborators, including States, Tribes and affected FLMs, will promptly respond to other RPOs'/States'/Tribes' requests for comments.

The following points offer a snapshot of several important ways in which MANE-VU member states and tribes have cooperatively addressed regional haze:

- *Prioritization*: MANE-VU developed a process to coordinate MARAMA, OTC, and NESCAUM staff in developing budget priorities, project rankings, and the eventual federal grant requests.
- *Issue Coordination*: MANE-VU established a conference call and meeting schedule for each of its committees and workgroups. In addition, its MANE-VU directors regularly discussed pertinent issues.
- *SIP Policy and Planning*: MANE-VU states/tribes collaborated on the development of a regional haze SIP template and the technical aspects of the SIP development process.
- *Capacity Building*: To educate its staff and members, MANE-VU included technical presentations on conference calls and organized workshops with nationally recognized experts. Presentations on data analysis, Best Available Retrofit Technology (BART) applicability, inventory topics, modeling, and control measures were effective education and coordination tools.
- *Routine Operations*: MANE-VU staff at OTC, MARAMA, and NESCAUM established a coordinated approach to budget tracking, project deliverables and due dates, workgroup meetings, inter-RPO consultations, etc.

Both formal and informal consultations within MANE-VU have been ongoing since the organization's establishment in 2001; but the bulk of formal consultation took place in 2007, as outlined in Table 3.3. Further documentation of consultation meetings and calls is included in Attachment D.

Table 3.3: Summary of MANE-VU's Consultations on Regional Haze Planning

MANE-VU Intra-Regional Consultation Meeting, March 1, 2007:

MANE-VU members reviewed the requirements for regional haze plans, preliminary modeling results, the work being done to prepare the MANE-VU report on reasonable progress factors, and control strategy options under review.

MANE-VU Intra-State Consultation Meeting, June 7, 2007:

The MANE-VU Class I states adopted a statement of principles, and all MANE-VU members discussed draft statements concerning reasonable controls within and outside of MANE-VU. Federal Land Managers also attended the meeting, which was open to stakeholders.

MANE-VU Conference Call, June 20, 2007:

The MANE-VU states concluded discussions of statements concerning reasonable controls within and outside MANE-VU and agreed on the statements called the MANE-VU "Ask" (see Part 3.2.2 of this SIP), including a statement concerning controls within MANE-VU, a statement concerning controls outside MANE-VU, and a statement requesting a course of action by the U.S. EPA. Federal Land Managers also participated in the call. Upon approval, all statements as well as the statement of principles adopted on June 7 were posted and publicly available on the MANE-VU website. The MANE-VU Ask was determined to represent New Hampshire's needs for meeting Regional Haze rule requirements and was thus adopted as the New Hampshire Ask.

MANE-VU Class I States' Consultation Open Technical Call, July 19, 2007:

The MANE-VU/New Hampshire Ask was presented to states in other RPOs, RPO staff, and Federal Land Managers; and an opportunity was provided to request further information. This call was intended to provide information to facilitate informed discussion at follow-up meetings.

MANE-VU Consultation Meeting with MRPO, August 6, 2007:

This meeting, held at LADCO offices in Chicago, was attended by representatives of MANE-VU and MRPO states as well as staff. The meeting provided an opportunity to formally present the MANE-VU/ New Hampshire Ask to MRPO states and to consult with them on the reasonableness of the requested controls. Federal Land Manager agencies also attended the meeting.

MANE-VU Consultation Meeting with VISTAS, August 20, 2007:

This meeting, held at State of Georgia offices in Atlanta, was attended by representatives of MANE-VU and VISTAS states. The meeting provided an opportunity to formally present the MANE-VU/New Hampshire Ask to VISTAS states and to consult with them on the reasonableness of the requested controls. Federal Land Manager agencies also attended the meeting.

MANE-VU / MRPO Consultation Conference Call, September 13, 2007:

As a follow-up to the meeting held on August 6 in Chicago, this call provided an opportunity for MANE-VU to clarify further what was being asked of the MRPO states. The flexibility in the Ask was explained. MRPO and MANE-VU staff agreed to work together to facilitate discussion of further controls on ICI boilers and EGUs.

MANE-VU Air Directors' Consultation Conference Call, September 26, 2007:

MANE-VU members clarified their understanding of the Ask and provided direction to modeling staff regarding interpretation of the Ask for purposes of estimating visibility impacts of the requested controls.

3.2.1 New Hampshire-Specific Consultations

40 CFR 51.308(d)(3)(i) of the Regional Haze Rule requires the State of New Hampshire to consult with other states/tribes to develop coordinated emission management strategies. This requirement applies both when emissions from a state/tribe are reasonably anticipated to contribute to visibility impairment in Class I areas outside the state/tribe and when emissions from other states/tribes are reasonably anticipated to contribute to visibility impairment at mandatory Class I areas within a state/tribe.

New Hampshire consulted with other states/tribes by participating in the MANE-VU and inter-RPO processes leading to the creation of coordinated strategies on regional haze. This coordinated effort considered the individual and aggregated impacts of states'/tribes' emissions on Class I areas within and outside the states/tribes.

As described in Section 2, Areas Contributing to Regional Haze, emissions originating in New Hampshire have had, and will continue to have, impacts on other Class I areas in the region. Accordingly, New Hampshire has entered into consultations with the states and provinces in which the affected Class I areas are located (Table 3.4).

Table 3.4: Class I Area States Requesting Consultation with New Hampshire

Class I Federal Area	State / Province
Great Gulf Wilderness	New Hampshire
Presidential Range - Dry River Wilderness	New Hampshire
Acadia National Park	Maine
Moosehorn Wilderness	Maine
Roosevelt Campobello International Park	Maine / New Brunswick
Lye Brook Wilderness	Vermont
Brigantine Wilderness	New Jersey

The listed states represent only a fraction of those with whom New Hampshire has entered into consultations on regional haze. Through the MANE-VU process, more than twenty states and Canadian provinces have been identified as contributing to visibility degradation in New Hampshire's two Class I areas: the Great Gulf Wilderness and the Presidential Range - Dry River Wilderness. On April 2, 2007, NHDES sent letters formally requesting consultation under the Regional Haze Rule to states and Canadian provinces – specifically, those shown via modeling to contribute at least 2 percent of visibility-impairing sulfates at Class I Areas in New Hampshire (refer to Contribution Assessment, Attachment B), and all other states located within MANE-VU.

To maintain consistency within MANE-VU, every MANE-VU member was requested to consult with New Hampshire. Several states outside MANE-VU were also requested to join this consultation in response to the findings of MANE-VU's evaluations. In addition, the Canadian Provinces of Ontario and Quebec were invited to join in informal consultation with New Hampshire, although they are under no legal obligation to meet U.S. requirements. Table 3.5 provides a complete listing of states, provinces, and regional planning organizations invited to participate in consultations with New Hampshire on measures to mitigate regional haze. Note that all MANE-VU states with Class I areas have similarly requested consultation with New Hampshire on the regional haze issue.

Table 3.5: States (Listed by Regional Planning Organization) and Provinces Contributing to Visibility Impairment at New Hampshire's Class I Areas

MANE-VU	VISTAS	MRPO	International
Connecticut	Georgia	Illinois	Ontario, Canada
Delaware	Kentucky	Indiana	Quebec, Canada
District of Columbia	North Carolina	Michigan	
Maine	South Carolina	Ohio	
Maryland	Tennessee		
Massachusetts	Virginia		
New Jersey	West Virginia		
New York			
Pennsylvania			
Rhode Island			
Vermont			

As a result of the invitation to consult, Ontario, Canada, invited representatives of NHDES, Vermont Department of Environmental Conservation (VTDEC), Maine Department of Environmental Protection (MEDEP), New York Department of Environmental Conservation (NYDEC), and NESCAUM to join the Shared Air Summit in Toronto on June 12, 2007, followed by an informal consultation meeting with representatives from Ontario on June 13, 2007. At these meetings, Ontario announced its plan to shut down all coal electrical generation and challenged participating states to pursue similar goals. Considerable discussion took place regarding trans-border air pollution transport and its affect on human health.

Formal inter-regional consultation meetings took place on August 6, 2007, in Rosemont, Illinois, (for Midwestern states) and on August 20, 2007, in Atlanta, Georgia, (for Southern states). Consultation continues with the Midwestern states, seeking common approaches for reducing power plant emissions beyond the levels defined under the original CAIR rule, controls on industrial boilers, and cleaner-burning fuels for mobile sources. Ongoing consultation with MRPO focuses mainly on the health benefits of reducing ozone and small particulate emissions; however, the control measures being considered would also result in visibility improvements.

Throughout the consultation process, New Hampshire was guided by the principals contained in a resolution adopted by the MANE-VU Class I states on June 7, 2007. In the resolution, the Class I states agreed to set reasonable progress goals for 2018 that would provide visibility improvement at least as great as that which would be achieved under a uniform rate of progress to reach natural visibility conditions by 2064. The goals would be set by the Class I states at levels reflecting implementation of measures determined to be reasonable after consultation with the contributing states. At the same time, the Class I states recognized that each state should be given the flexibility to choose other measures that achieve the same or greater benefits.

The final results of New Hampshire's consultation efforts will ultimately rest with the individual states as they develop and implement their own regional haze SIPs. The other MANE-VU states have agreed to incorporate certain control measures into their SIPs, but most of these plans are still under development. For the non-MANE-VU states, New Hampshire has the expectation that the same or equivalent control measures will be included in those states plans. However, some states – particularly those within the VISTAS region –

have already submitted draft SIPs that do not go as far in controlling emissions as MANE-VU would like. See Subpart 3.2.2.3 and Part 3.2.4, below, for further discussion related to the non-MANE-VU states.

3.2.2 The MANE-VU "Ask"

In addition to having a set of guiding principles for consultation (as described in Table 3.2, above), MANE-VU needed a consistent technical basis for emission control strategies to combat regional haze. After much research and analysis, on June 20, 2007, MANE-VU adopted the following pair of documents (available in Attachment E), which provide the technical basis for consultation among the interested parties and define the basic strategies for controlling pollutants that cause visibility impairment at Class I areas in the eastern U.S.:

- "Statement of the Mid-Atlantic / Northeast Visibility Union (MANE-VU) Concerning a Course of Action within MANE-VU toward Assuring Reasonable Progress," and
- "Statement of the Mid-Atlantic / Northeast Visibility Union (MANE-VU) Concerning a Request for a Course of Action by States outside of MANE-VU toward Assuring Reasonable Progress."

Together, these documents are known as the MANE-VU "**Ask**." Because New Hampshire agrees in total to the language and substance of these documents, the **MANE-VU's Ask is also the New Hampshire Ask**. The particular emission management strategies that comprise the Ask are described in Subparts 3.2.2.1 through 3.2.2.3, below.

3.2.2.1 Meeting the "Ask" – MANE-VU States

The member states of MANE-VU have stated their intention to meet the terms of the Ask in their individual State Implementation Plans. The Ask for member states promises that each state will pursue the adoption and implementation of the following emission management strategies, as appropriate and necessary:

- ***Timely implementation of BART requirements***, in accordance with 40 CFR 51.308(e).
- ***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 reduce the sulfur content of distillate oil further 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 reduce the sulfur content of distillate oil further to 15 ppm by 2018, depending on supply availability;
- ***A targeted EGU strategy*** for the top 100 electric generating unit (EGU) emission points, or stacks, identified by MANE-VU as contributing to visibility impairment at each mandatory Class I area in the MANE-VU region. (The combined list for all

seven MANE-VU Class I Areas contains 167 distinct emission points. Consequently, this strategy is sometimes referred to as the 167-stack strategy.) The targeted EGU strategy calls for a 90-percent or greater reduction in sulfur dioxide (SO_2) emissions from all identified units. If it is infeasible to achieve that level of reduction from these specific units, equivalent alternative measures will be investigated in such state; and

- ***Continued evaluation of other control measures***, including improvements in energy efficiency, use of alternative (clean) fuels, further control 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 combustion. These and other measures will be evaluated during the consultation process to determine whether they are reasonable strategies to pursue.

⇨ **NHDES supports the SIPs of each of its fellow MANE-VU states, provided that these commitments are incorporated into approvable State Implementation Plans.**

3.2.2.2 Meeting the "Ask" – New Hampshire

New Hampshire, being a MANE-VU member state, adopted the Ask at the MANE-VU Board meeting on June 7, 2007. New Hampshire intends to meet the terms of this agreement by controlling its two in-state BART-eligible sources with timely control strategies as well as pursuing the low-sulfur fuel oil strategy. Both BART-eligible sources also fall on the list of the top 167 contributing EGU emission points.

The larger of these facilities (Merrimack Station Unit MK2) will be controlled with scrubber technology by July 1, 2013 to comply with New Hampshire law. The other facility, a smaller, oil-fired unit (Newington Station Unit NT1), will control fuel sulfur levels under BART requirements to reduce SO_2 emissions. NHDES has determined that controlling the latter facility to the 90-percent level of the Ask is not reasonable at this time and will seek alternative measures to achieve the equivalent overall reduction in SO_2 emissions. The facility has low utilization (about 5 percent in 2007), making it cost-ineffective to retrofit with scrubber technology. NHDES anticipates that controls installed at Merrimack Station, the largest SO_2 source within the state, will result in reductions greater than the 90 percent specified under the Ask, thereby offsetting, at least partially, the expected lesser control level at the oil-fired unit. Additional reductions in SO_2 emissions are planned through the use of lower-sulfur fuels across a variety of source categories, including industrial, commercial, and institutional (ICI) boilers and home heating units. For more details, refer to Section 11, Long-Term Strategy.

3.2.2.3 Meeting the "Ask" – States outside MANE-VU

New Hampshire agrees with the MANE-VU Ask for consulting states outside the MANE-VU region. This Ask requests the affected states to pursue adoption and implementation of the following control strategies, as appropriate and necessary:

- ***Timely implementation of BART requirements***, as described for the MANE-VU states;
- ***A targeted EGU strategy***, as described for the MANE-VU states, for the top 167 EGU stacks contributing the most to visibility impairment at mandatory Class I areas in the MANE-VU region, or an equivalent SO_2 emission reduction within each state;
- ***Installation of reasonable control measures on non-EGU sources*** by 2018 to achieve

an additional 28 percent reduction in non-EGU SO_2 emissions beyond current on-the-books/on-the-way (OTB/OTW) measures, resulting in an emission reduction that is equivalent to that from MANE-VU's low-sulfur fuel oil strategy (see Section 11, Long-Term Strategy);

- ***Continued evaluation of other control measures***, including additional reductions in SO_2 and NO_X emissions from all coal-burning facilities by 2018 and promulgation of new source performance standards for wood combustion. These and other measures will be evaluated during the consultation process to determine whether they are reasonable strategies to pursue.

⇨ **NHDES looks for each consulting state to address specifically, in its Regional Haze SIP, each element of the MANE-VU Ask.**

NHDES is concerned that non-MANE-VU states may be inclined not to adopt MANE-VU's Ask because of the associated costs, potential conflicts, and relative lack of perceived benefits within their jurisdictions. On the basis of consultations held, MANE-VU members believe that some non-MANE-VU states will choose not to pursue reductions beyond basic post-CAIR controls and BART requirements. New Hampshire understands that, among non-MANE-VU states that have already submitted their regional haze SIPs to EPA, a number of the affected states have decided not to address major elements of the MANE-VU Ask in their plans.

There are some positive developments, however. Many states of the MRPO are working with MANE-VU states to investigate the potential for widespread use of low-sulfur fuel oil and installation of emission controls on ICI boilers within their regions. The Midwest states would be more likely than Southeast states to adopt a low-sulfur oil strategy because the VISTAS states do not have the same extent of fuel oil usage and lack the inventory infrastructure found in more northerly states. Both MRPO and VISTAS claim that a substantial portion of the top 167 contributing EGU stacks will be controlled. However, instead of taking concrete actions on uncontrolled or under-controlled facilities, many of these states appear to be satisfied with meeting minimal requirements and are not looking for additional emission reductions. Further discussion of these issues is provided in Part 3.2.4, below.

3.2.3 Technical Ramifications of Differing Approaches

MANE-VU states intended to develop a modeling platform that was common in terms of meteorology and emissions with each of the other nearby RPOs. The RPOs worked hard to form a common set of emissions with similar developmental assumptions. Even with the best of intentions, it became difficult to keep up with each RPO's updates and corrections. Each rendition of emissions inventory improved its quality, but even a single update to one RPO's emissions required each of the other RPOs to adopt the updates. With each rendition, the revised emissions had to be re-blended with the full set of emission files for all associated RPOs in the modeling domain. Because each rendition put previous modeling efforts out of date, and a single modeling run could take more than a month to complete, inventory updates have contributed to SIP delays. The emission inventory conflicts have been excessively time-consuming and caused most states to miss the official filing date of December 17, 2007.

The RPOs also took differing perspectives on which version of the EGU dispatching model to use. At the beginning of the process, International's Integrated Planning Model (IPM®) version 2.1.9 was available, and EPA agreed to its use for emissions preparation. Subsequently, IPM version 3.0 became available and was preferred by some users because of its updated fuel costs. MRPO adopted IPM v3.0 for its use, but VISTAS stayed with IPM v2.1.9. Rather than develop non-comparative datasets for its previous IPM analyses, MANE-VU opted also to remain with IPM v2.1.9. Therefore, for the three eastern RPOs, differing emissions assumptions eventually worked their way into the final set of modeling assumptions.

MANE-VU's most recent visibility projections take into account on-the-books/on-the-way (OTB/OTW) emissions control programs for 2018, and go further by including additional reasonable controls in the region, as developed through the MANE-VU Ask. It should be noted that other RPOs may not have included such measures in their final modeling and, as a result, may have been able to complete their analyses ahead of New Hampshire's. Where that is the case, those states' modeling results will be inconsistent with meeting the terms of the Ask – a situation that may not be adequately addressed in their individual SIPs.

3.2.4 Consultation Issues

40 CFR 51.308(d)(1)(iv) of the Regional Haze Rule describes another consultation requirement for Class I states. If a contributing state does not agree with a Class I state on its reasonable progress goal, the Class I state must describe in its SIP submittal the actions taken to resolve the disagreement.

While states without Class I areas are required to consult at the request of states with Class I areas, the Regional Haze Rule does not actually require the states to agree on a common course of action. Instead, if agreement cannot be reached, the disagreement needs to be described in each state's SIP along with a description of what actions were taken to resolve the disagreement. Most states willingly consulted with NHDES and took New Hampshire's regional haze Ask under serious consideration. In fact, all of the MANE-VU states worked together to strategize on how to develop a common approach to meeting the Ask. All states involved in these discussions found that working together helped them to develop plans that would produce region-wide visibility and health benefits. In particular, reductions in SO_2 emissions, because they would yield lower ambient concentrations of fine particle ($PM_{2.5}$) pollution, would help all MANE-VU states in meeting the NAAQS and would have direct benefits to public health and welfare.

A few non-MANE-VU states did not respond to New Hampshire's consultation requests or responded by downplaying the magnitude of their states' contributions to visibility impairment at New Hampshire's Class I areas. Some states claimed that CAIR alone set the standard for reasonableness. By this rationale, any measure more expensive than CAIR on a cost-per-ton basis would not be reasonable. A uniform rate of progress was all that some states felt was required; and if that set of conditions could be met with CAIR (or its successor), then no other measures needed to be considered. Also a concern for New Hampshire is the possibility that some states may have performed modeling for establishment of reasonable progress goals without including the effects of a rigorous BART determination for the non-EGU sector. It is apparent that the various regions of the country have differing interpretations of how the Regional Haze Rule should be applied.

In a letter to MANE-VU dated April 25, 2008 (Attachment F), VISTAS indicated that for its member states, most actions exceeding CAIR requirements would not be reasonable. MANE-VU has taken a more rigorous position with respect to additional control measures – including the belief that controls on ICI boilers and use of low-sulfur fuels are reasonable measures *and* that it is not reasonable to assume reductions from EGUs for planning purposes unless they are explicitly incorporated into a State Implementation Plan. More specifically, MANE-VU believes that a sector-wide average of 50-percent control on coal-fired boilers and 75-percent control on oil-fired boilers are reasonable targets that can be achieved cost-effectively. Also, MANE-VU believes that low sulfur fuels – even though they are less widely available in the Southeast U.S. than in the Northeast – still represent a reasonable control measure in light of the widespread requirement for use of such fuels throughout the MANE-VU region. The reasonableness of these additional controls is examined more fully in Section 10, Reasonable Progress Goals.

During the consultation process, disagreements such as these were worked through to the maximum extent possible, and the results of these consultations are summarized below:

- *Situation*: BART analyses and projected controls were not fully incorporated into the VISTAS emissions inventory provided to MANE-VU. VISTAS stated that they would further review BART-applicable controls.

  → *Outcome*: In MANE-VU's modeling to determine reasonable progress goals, MANE-VU made no adjustments to controls in the VISTAS region to reflect application of BART beyond the information that VISTAS provided.

- *Situation*: The low-sulfur fuel oil strategy adopted by MANE-VU elicited concerns from MRPO and VISTAS as not being reasonable because of the limited availability of low-sulfur fuel oil and the historically lower usage of this fuel within their regions.

  → *Outcome*: MANE-VU agreed to modify the Ask to reflect greater flexibility in providing for alternative measures that would produce a comparable rate of emission reductions. Accordingly, the Ask for non-MANE-VU states was modified to provide for an overall 28 percent reduction in SO_2 emissions wherever they were found to be reasonable. In MANE-VU's modeling to determine reasonable progress goals, SO_2 emissions from non-EGU sources in non-MANE-VU contributing states were reduced by this same amount.

- *Situation*: MANE-VU received no response from other RPOs concerning non-EGU control measures that they did consider reasonable.

  → O*utcome*: As a default position, MANE-VU's modeling included emission adjustments for those regions based on MANE-VU's own analyses of what constituted reasonable control measures from non-EGU sources (see Section 10 , Reasonable Progress Goals).

- *Situation*: The targeted EGU strategy was thought by some non-MANE-VU states to be too restrictive and too difficult to achieve. MANE-VU recognized that a 100-percent compliance with this portion of the Ask was unlikely to occur because the CAIR trading market would probably dominate. However, MANE-VU had hoped that non-MANE-VU states would make a more concerted effort toward meeting this request. MANE-VU did receive a partial list of facilities that were expected to comply.

→ *Outcome*: For the top contributing EGU stacks located within the MANE-VU, MRPO, and VISTAS regions, expected emission reductions resulting from the Ask were distributed among facilities on the basis of recommendations received during inter- and intra-regional consultations. To maintain the CAIR emissions budget as predicted by the modeling, excess emission reductions (also predicted by the modeling) were uniformly added back to EGUs in all three regions.

While the original CAIR rule would have been the primary determinant of which EGUs among the top 167 stacks are to be fitted with emission controls, at the same time, MANE-VU recognized that these units are the primary sources affecting visibility in the MANE-VU states. For the initial planning, MANE-VU has allowed flexibility as to how other RPOs meet the Ask. However, MANE-VU expects that, over time, these actual facilities will need to be controlled if significant improvements in visibility at affected Class I areas are to be realized.

MANE-VU believes that the goals of the Ask will be attained only by means of binding obligations to EGU emission reductions beyond the levels of control that CAIR originally would have provided. MANE-VU therefore maintains that additional federal action is needed to achieve the visibility benefits shown to be feasible through sensitivity modeling (see Attachment G, "MANE-VU Modeling for Reasonable Progress Goals: Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008) and demonstrated to be available at reasonable cost (see Attachment H, Alpine Geophysics, LLC, "Documentation of 2018 Emissions from Electric Generating Units in the Eastern United States for MANE-VU's Regional Haze Modeling," Final Report, August 16, 2009).

MANE-VU's position on this issue is formally expressed in its "Statement of the Mid-Atlantic / Northeast Visibility Union (MANE-VU) Concerning a Request for a Course of Action by the U.S. Environmental Protection Agency (EPA) toward Assuring Reasonable Progress," adopted June 20, 2007. This statement, more commonly known as MANE-VU's National Ask, is included in Attachment E.

Although other RPOs did not adopt all of the same philosophies or processes for their regional haze SIPs, the consultation process maintains a central role in regional haze planning. New Hampshire is pleased with the significant opportunities identified for ongoing consultation with other states concerning long-term strategies not only for regional haze mitigation but also for improved air quality in general.

3.2.5 State/Tribe and Federal Land Manager Coordination

New Hampshire will continue to coordinate and consult with the Federal Land Managers during the development of future progress reports and plan revisions, as well as during the implementation of programs having the potential to contribute to visibility impairment in the mandatory Class I areas.

40 CFR 51.308(i) of the Regional Haze Rule requires coordination between states/tribes and the Federal Land Managers (FLMs). Opportunities have been provided by MANE-VU for FLMs to review and comment on each of the technical documents developed by MANE-VU and included in this SIP. New Hampshire has identified agency contacts to the FLMs as required under 40 CFR 51.308(i)(1). New Hampshire has consulted with the FLMs in the development of this plan and, in accordance with 40 CFR 51.308(i)(2), has provided the

FLMs an opportunity for consultation, in person, at least 60 days prior to holding any public hearing on the SIP. The draft SIP was submitted to the FLMs on August 1, 2008, for review and comment.

Pursuant to 40 CFR 51.308(i) (3), New Hampshire has requested and received comments on the regional haze SIP from the Federal Land Managers. NHDES received preliminary comments from the U.S. Department of the Interior (DOI), National Park Service (NPS) and U.S. Fish and Wildlife Service (FWS) on August 27, 2008, and from the U.S. Department of Agriculture, U.S. Forest Service (USFS) on August 28, 2008. Formal comments from DOI -NPS and FWS on the SIP were received in a letter dated September 26, 2008. Conference calls to discuss the agencies' comments took place on August 28 and September 18, 2008, with representatives from NPS, USFS, USFWS, EPA, and NHDES in attendance. Following these consultations, NHDES revised the draft implementation plan to address the agencies' comments. A public hearing on the draft final SIP was held at NHDES headquarters on Wednesday, June 24, 2009. The U.S. Department of the Interior, National Park Service provided final written comments during the public comment period, which ended on June 26, 2009. Subsequently, in a letter dated December 20, 2010, DOI-NPS provided additional written comments coincident with a second public hearing on the Regional Haze SIP revision. Those comments have been duly considered and addressed in the completion of the SIP.

A compilation of comments received, responses by NHDES, and summaries of conference calls is presented in Attachment I of this plan. All of these documents were made available for public review during the public comment period. (Note: The MANE-VU states also received comments from other stakeholders during the planning process; their comments can be found in Attachment J.)

The comments submitted by the FLMs were both general and specific. The reviewing agencies found New Hampshire's Regional Haze SIP to be well written and comprehensive. The uncertainty surrounding the future of CAIR and discrepancies in modeling (especially inclusion of the MANE-VU Ask) between MANE-VU and other RPOs were identified as broad topics for further discussion through the consultation process. Comments of a specific nature were relatively minor for the most part. The agencies requested that NHDES provide additional information in support of New Hampshire's BART analyses. NHDES's responses to the agencies' comments are addressed point-by-point in the response document contained in Attachment I.

40 CFR 51.308(i) (4) requires procedures for continuing consultation between the states/tribes and FLMs on the implementation of the visibility protection program. In particular, New Hampshire will consult with the designated visibility protection program coordinators for the National Park Service, U. S. Fish and Wildlife Service, and U.S. Forest Service, periodically and as circumstances require, on the following implementation items:

1. Status of emissions strategies identified in the SIP as contributing to improvements in the worst-day visibility;
2. Summary of major new source permits issued;
3. Status of New Hampshire's actions toward completing any future assessments or rulemakings on sources identified as probable contributors to visibility impairment, but not directly addressed in the most recent SIP revision;

4. Any changes to the monitoring strategy or status of monitoring stations that might affect tracking of reasonable progress;
5. Work underway for preparing the 5-year SIP review and/or 10-year SIP revision, including any items where the FLMs' consideration or support is requested; and
6. Summary of topics discussed in ongoing communications (e.g., meetings, emails, etc.) between New Hampshire and the FLMs regarding implementation of the visibility improvement program.

3.2.6 EPA Consultation and Review

New Hampshire has consulted with EPA on many occasions in the course of regional haze modeling and plan development, and EPA has provided specific input regarding completion of the SIP. On July 10, 2008, NHDES received written comments from EPA on an early SIP draft that was submitted to the agency for preliminary review. On October 24, 2008, NHDES received additional written comments from EPA on a modified version that was identical to the draft SIP reviewed by the FLMs. Following the public hearing, in a letter dated June 26, 2009, EPA provided formal comments on the draft final SIP. In conjunction with subsequent further revisions to the Regional Haze SIP, EPA made additional comments on February 25, 2010, November 22, 2010, and December 20, 2010.

New Hampshire has addressed EPA's comments by making appropriate amendments to the SIP, all of which are incorporated into the present document. EPA's specific comments and NHDES's responses are included in Attachment I.

4. ASSESSMENT OF BASELINE AND NATURAL VISIBILITY CONDITIONS

Pursuant to 40 CFR 51.308(d) (2) of the Regional Haze Rule, states must determine baseline and natural visibility conditions for each Class I area within their jurisdictions. This information allows states to assess current levels of visibility degradation and provides a basis for setting reasonable progress goals toward restoration of natural visibility conditions in Class I areas.

The effectiveness of any plan to reduce regional haze in Class I areas is dependent on the availability of reliable data. The Interagency Monitoring of Protected Visual Environments (IMPROVE) program was established in 1985 to provide the data necessary to support the creation of Federal and State implementation plans for the protection of visibility in Class I areas. IMPROVE has made it possible to assess current visibility conditions, track changes in visibility, and identify the chemical species and emission sources responsible for visibility impairment. In particular, IMPROVE data were used to calculate baseline and natural conditions for MANE-VU Class I Areas.

The IMPROVE monitors listed in Table 4.1 provide data representative of Class I Areas in the MANE-VU region.

Table 4.1: IMPROVE Monitors for MANE-VU Class I Areas

IMPROVE Site / Location	Class I Area(s) Served	Latitude, Longitude	State
ACAD1 Acadia National Park	Acadia National Park	44.38, -68.26	Maine
MOOS1 Moosehorn Wilderness	Moosehorn Wilderness; Roosevelt Campobello International Park	45.13, -67.27	Maine
GRGU1 Great Gulf Wilderness	Great Gulf Wilderness; Presidential Range - Dry River Wilderness	44.31, -71.22	New Hampshire
LYBR1 Lye Brook Wilderness	Lye Brook Wilderness	43.15, -73.13	Vermont
BRIG1 Brigantine National Wildlife Refuge	Brigantine National Wildlife Refuge	39.47, -74.45	New Jersey

http://www.vista.circa.colostate.edu/views/; http://vista.cira.colostate.edu/improve/

4.1 Calculation Methodology

In September 2003, EPA issued guidance for the calculation of natural background and baseline visibility conditions. The guidance provided a default method and described certain refinements that states might consider in order to tailor their estimates to any Class I areas not adequately represented by the default method. At that time, MANE-VU calculated natural visibility for each of the MANE-VU Class I Areas using the default method for the 20 percent best and 20 percent worst visibility days. MANE-VU also evaluated ways to refine the estimates. Potential refinements included 1) increasing the multiplier used to calculate impairment attributed to carbon, 2) adjusting the formula used to calculate the 20 percent best and worst visibility days, and 3) accounting for visibility impairment caused by sea salt at coastal sites. However, MANE-VU found that these refinements did not significantly improve the accuracy of the estimates, and MANE-VU states desired a consistent approach to visibility assessment. Therefore, default estimates were used with the understanding that this methodology would be reconsidered upon demonstrated improvements in the science.

Once the technical analysis of visibility conditions was complete, MANE-VU provided an opportunity to comment to federal agencies and stakeholders. The proposed approach to visibility assessment was posted on the MANE-VU website on March 17, 2004, and a stakeholder briefing was held on the same day. Comments were received from the Electric Power Research Institute (EPRI), the Midwest Ozone Group (MOG), the Appalachian Mountain Club, the National Parks Conservation Association, the National Park Service, and the US Forest Service.

Several comments supported the proposed approach in general; other comments were divided among four main topics: 1) the equation used to calculate visibility, 2) the statistical technique used to estimate the 20 percent best and worst visibility days, 3) the inclusion of transboundary effects and fires, and 4) the timing as to when new information should be included. All comments were reviewed and summarized by MANE-VU; and air directors were briefed on comments, proposed response options, and implications. Attachment J provides a compilation of comments received and a summary of stakeholders' comments.

MANE-VU's position on natural background conditions was presented in a report issued in June 2004 (see Attachment K, "Natural Background Visibility Conditions: Considerations and Proposed Approach to the Calculation of Natural Background Visibility Conditions at MANE-VU Class I Areas," June 10, 2004). The report stated, "Refinements to other aspects of the default method (e.g., refinements to the assumed distribution or treatment of Rayleigh extinction, inclusion of sea salt, and improved assumptions about the chemical composition of the organic fraction) may be warranted prior to submission of SIPs depending on the degree to which scientific consensus is formed around a specific approach…"

In 2006, the IMPROVE Steering Committee adopted an alternative reconstructed extinction equation to revise certain aspects of the default method. The scientific basis for these revisions was well understood, and the Committee determined that the revisions improved the performance of the equation at reproducing observed visibility at Class I sites.

In 2006, MANE-VU conducted an assessment of the default and alternative approaches for calculation of baseline and natural background conditions at MANE-VU Class I Areas. Based on that assessment, in December 2006, MANE-VU recommended adoption of the alternative reconstructed extinction equation for use in the regional haze SIPs. (See Attachment L, "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," December 2006.) MANE-VU will continue to participate in further research efforts on this topic and will reconsider the calculation methodology as scientific understanding evolves.

4.2 MANE-VU Baseline Visibility

The IMPROVE program has calculated the 20 percent best and 20 percent worst baseline

(2000-2004) and natural visibility conditions using the EPA-approved alternative method described above for each MANE-VU Class I Area. The data are posted on the Visibility Information Exchange Web System (VIEWS) operated by the regional planning organizations. The information can be accessed at http://vista.cira.colostate.edu/views/) and is summarized in Table 4.2 below. Displayed are the five-year average baseline visibility values for the period 2000-2004, natural visibility levels, and the difference between baseline and natural visibility values for each of the MANE-VU Class I Areas. The difference columns (best and worst) are of particular interest because they describe the magnitude of visibility impairment attributable to manmade emissions, which are the focus of the Regional Haze Rule.

The five-year averages for 20 percent best and worst visibility were calculated in accordance with 40 CFR 51.308(d)(2), as detailed in NESCAUM's Baseline and Natural Background document found in Attachment L.

Table 4.2: Summary of Baseline Visibility and Natural Visibility Conditions for the 20 Percent Best and 20 Percent Worst Visibility Days at MANE-VU Class I Areas

Class I Area(s)	2000-2004 Baseline (deciviews)		Natural Conditions (deciviews)		Difference (deciviews)	
	Best 20%	Worst 20%	Best 20%	Worst 20%	Best 20%	Worst 20%
Acadia National Park	8.8	22.9	4.7	12.4	4.1	10.5
Moosehorn Wilderness and Roosevelt Campobello International Park	9.2	21.7	5.0	12.0	4.1	9.7
Great Gulf Wilderness and Presidential Range - Dry River Wilderness [10]	7.7	22.8	3.7	12.0	3.9	10.8
Lye Brook Wilderness	6.4	24.5	2.8	11.7	3.6	12.7
Brigantine Wilderness	14.3	29.0	5.5	12.2	8.8	16.8

Source: VIEWS (http://vista.circa.colostate.edu/views/), prepared on 6/22/2007

4.3 New Hampshire Class I Areas – Baseline Visibility

As indicated in the table above, the 2001-2004 baseline visibility for the Great Gulf and Presidential Range - Dry River Wilderness Class I areas was 7.7 deciviews for the 20 percent best visibility days and 22.8 deciviews for the 20 percent worst visibility days. These are average values based on data collected at the Great Gulf (GRGU1) IMPROVE monitoring site. As described in Section 5, Monitoring Strategy of this SIP, New Hampshire accepts designation of this monitoring site as representative of the Great Gulf and Presidential Range - Dry River Wilderness Areas in accordance with 40 CFR 51.308(d)(2)(i). (The two wilderness areas are close enough together that a single monitor suffices.)

Tables 4.3 lists the baseline visibility for the 20 percent best and 20 percent worst visibility days for each year of the period 2000-2004, from which the valid four-year average values in Table 4.2 were calculated. The averages were determined in accordance with 40 CFR 51.308(d)(2), as detailed in the NESCAUM Baseline and Natural Background document found in Attachment L of this SIP. The deciview visibility values for best and worst days

[10] Deciview values based on 4-year average for 2001-2004 (data collection in 2000 was for summer only).

were obtained from data included in Attachment L.

Table 4.3: Baseline Visibility for the 20 Percent Best Days and 20 Percent Worst Days During 2000-2004 in New Hampshire Class I Areas

Class I Area(s)	Year	Baseline Visibility (deciviews)		Note
		20% Best	20% Worst	
Great Gulf Wilderness and Presidential Range - Dry River Wilderness	2000	7.4	20.0	11
	2001	8.3	23.3	
	2002	7.8	24.8	
	2003	6.9	21.6	
	2004	7.7	21.6	
	Average	7.7	22.8	12

Source: VIEWS (http://vista.circa.colostate.edu/views)

4.4 New Hampshire Class I Areas – Natural Background

Natural background refers to the visibility conditions that existed before human activities affected air quality in the region. Consistent with the stated visibility goals of the Clean Air Act, natural background is identified as the visibility target to be reached by 2064 in each Class I area.

The Great Gulf and Presidential Range - Dry River Wilderness Class I areas have an estimated natural background visibility of 3.7 deciviews on the 20 percent best days and 12.0 deciviews on the 20 percent worst days. These best and worst 20 percent visibility values were calculated using the above-referenced EPA guidelines and approved alternative method described in NESCAUM's Baseline and Natural Background document (Attachment L).

5. AIR MONITORING STRATEGY

In the mid-1980's, the Interagency Monitoring of Protected Visual Environments (IMPROVE) program was established to measure visibility impairment in mandatory Class I areas throughout the United States. The monitoring sites are operated and maintained through a formal cooperative relationship between the U.S. EPA, National Park Service, U.S. Fish and Wildlife Service, Bureau of Land Management, and U.S. Forest Service. In 1991, several additional organizations joined the effort: State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials (which have since merged under the name National Association of Clean Air Agencies), Western States Air Resources Council, Mid-Atlantic Regional Air Management Association, and Northeast States for Coordinated Air Use Management.

5.1 IMPROVE Program Objectives

The IMPROVE program provides scientific documentation of the visual air quality of America's wilderness areas and national parks. Many individuals and organizations – land

[11] Approximate values, based on summer-only observations.

[12] Based on 4 valid years, 2001-2004

managers; industry planners; scientists, including university researchers; public interest groups; and air quality regulators – use the data collected at IMPROVE sites to understand and protect the visual air quality resource in Class I areas. Major objectives of the IMPROVE program include the following:

- Establish current visibility and aerosol conditions in mandatory Class I areas;
- Identify chemical species and emission sources responsible for existing anthropogenic visibility impairment;
- Document long-term trends for assessing progress towards the national visibility goals;
- Provide regional haze monitoring for all visibility-protected federal Class I areas where practical, as required by EPA's Regional Haze Rule.

5.2 Monitoring Requirements

EPA's Regional Haze Rule establishes air monitoring requirements that affected states must meet to assess visibility impairment caused by regional haze in Class I areas. The following describes how New Hampshire is complying with specific sections of the rule:

- 40 CFR 51.308(d)(4) requires a monitoring strategy for measuring, characterizing, and reporting regional haze / visibility impairment that is representative of all mandatory Class I areas. (Note that this monitoring strategy must be coordinated with the additional requirements of 40 CFR 51.305, which is not applicable to New Hampshire.) New Hampshire's monitoring strategy relies on participation in the IMPROVE network and Visibility Information Exchange Web System (VIEWS). NHDES will evaluate the monitoring network periodically and make appropriate adjustments to it as necessary, consistent with the IMPROVE program objectives stated above. However, New Hampshire's commitment to following this strategy and providing continuing assessments of progress toward national visibility goals at mandatory Class I Areas will remain contingent on sufficient federal funding in support of monitoring program requirements and associated databases. In the event that existing funding sources are eliminated or curtailed, New Hampshire will consult with the FLMs on the most practicable course of action.
- 40 CFR 51.308(d)(4)(i) requires states to establish additional monitoring sites or equipment as needed to assess whether reasonable progress goals are being achieved toward visibility improvement at mandatory Class I areas. At this time, the current monitors are sufficient to make this assessment. New Hampshire's commitment to maintain the current level of monitoring, and to expand monitoring or analysis should such action become necessary, will remain contingent on federal funding assistance.
- 40 CFR 51.308(d)(4)(ii) requires each affected state to include procedures by which monitoring data and other information are used to determine the state's contribution of emissions to visibility impairment at mandatory Class I areas both within and outside the state. New Hampshire's estimated contributions are summarized in Subsection 2.1 of this SIP and are documented in a detailed technical analysis prepared by NESCAUM entitled, "Contributions to Regional Haze in the Northeast and Mid-Atlantic United States," August 2006 (Attachment B). The NESCAUM study used various tools and techniques to assess the contributions of individual states and regions to visibility degradation in Class I areas within and outside MANE-VU.
- 40 CFR 51.308(d)(4)(iv) requires a state to submit visibility monitoring data annually

for each Class I area and, if possible, to provide the data in electronic format. The Federal Land Manager submits the data, and the data are posted on the VIEWS website.

- 40 CFR 51.308(d)(4)(v) requires a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in mandatory Class I areas within New Hampshire. Section 6, Emissions Inventory, addresses this requirement.
- 40 CFR 51.308(d)(4)(vi) requires that SIPs provide other elements, including reporting, recordkeeping, and other measures necessary to assess and report on visibility. While NHDES believes the current IMPROVE network is sufficient to adequately measure and report progress toward the regional haze goals set for New Hampshire's and other Class I areas, NHDES in the past has found additional monitoring information to be useful in assessing patterns of regional visibility and fine particle pollution. Examples of these data sources include:
  - The MANE-VU RAIN network, which provides continuous, speciated information on rural aerosol characteristics and visibility parameters;
  - The EPA CASTNET program, which has provided complementary rural fine particle speciation data at non-Class I sites;
  - The EPA Speciation Trends Network (STN), which provides speciated, urban fine particle data to help develop a comprehensive picture of local and regional sources;
  - State-operated rural and urban speciation sites using IMPROVE or Speciation Trends Network (STN) methods (the latter program comprising 54 monitoring stations located mainly in or near larger metropolitan areas); and
  - The Supersites program, which has undertaken special studies to expand knowledge of the processes that control fine particle formation and transport in the region.

  Assuming that these resources will continue to be available and that fiscal realities will allow, New Hampshire will continue using these and other data sources for the purposes of understanding visibility impairment and documenting progress toward national visibility goals for Class I areas under the Regional Haze Rule.

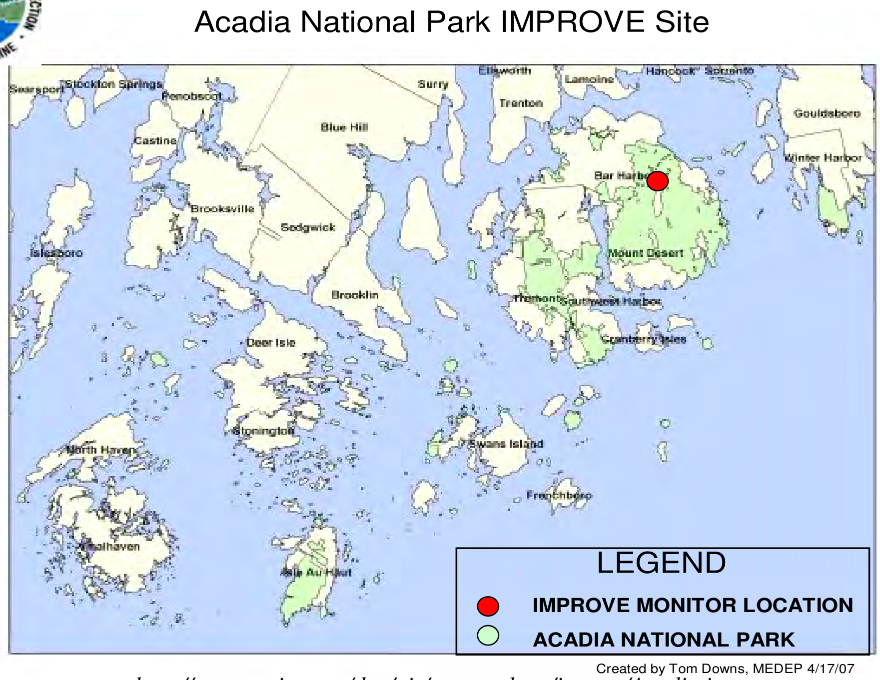
5.3 Monitoring Sites for MANE-VU Class I Areas

IMPROVE monitoring sites have been established for each of the Class I areas in the region. The Great Gulf Wilderness and Presidential Range - Dry River Wilderness share a single monitoring site. Each of the other MANE-VU Class I Areas has its own monitoring site.

5.3.1 Acadia National Park, Maine

The IMPROVE monitor for Acadia National Park (ACAD1) is located at park headquarters, near Bar Harbor, Maine, at elevation 157 meters, latitude 44.38°, and longitude -68.26°. This monitor is operated and maintained by the National Park Service. New Hampshire considers the ACAD1 site as adequate for assessing reasonable progress toward visibility goals at Acadia National Park, and no additional monitoring sites or equipment are necessary at this time.

Figure 5.1: Map of Acadia National Park Showing Location of IMPROVE Monitor



http://www.maine.gov/dep/air/meteorology/images/Acadia.jpg

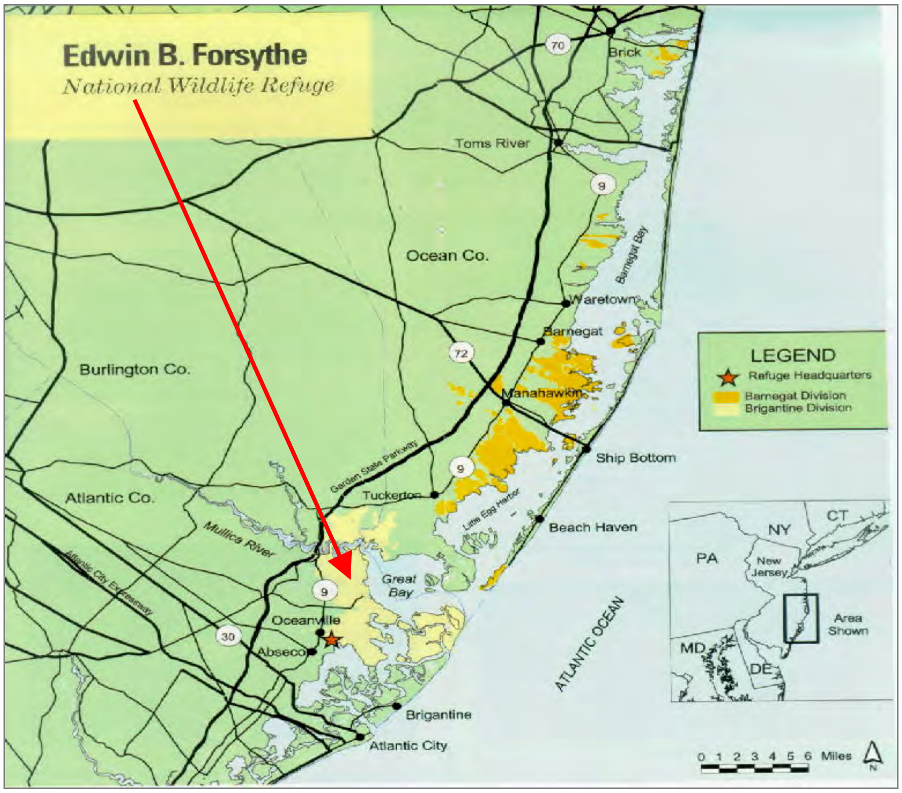
Figure 5.2: Acadia National Park on Clear and Hazy Days

http://www.hazecam.net/class1/acadia.html

5.3.2 Brigantine Wilderness, New Jersey

The IMPROVE monitor for the Brigantine Wilderness (BRIG1) is located at the Edwin B. Forsythe National Wildlife Refuge Headquarters in Oceanville, New Jersey, at elevation 5 meters, latitude 39.47˚, and longitude -74.45˚. This monitor is operated and maintained by the U.S. Fish & Wildlife Service. New Hampshire considers the BRIG1 site as adequate for assessing reasonable progress toward visibility goals at the Brigantine Wilderness, and no additional monitoring sites or equipment are necessary at this time.

Figure 5.3: Map of Edwin B. Forsythe National Wildlife Refuge



<u>http://www.fws.gov/northeast/forsythe/MAP.htm</u>

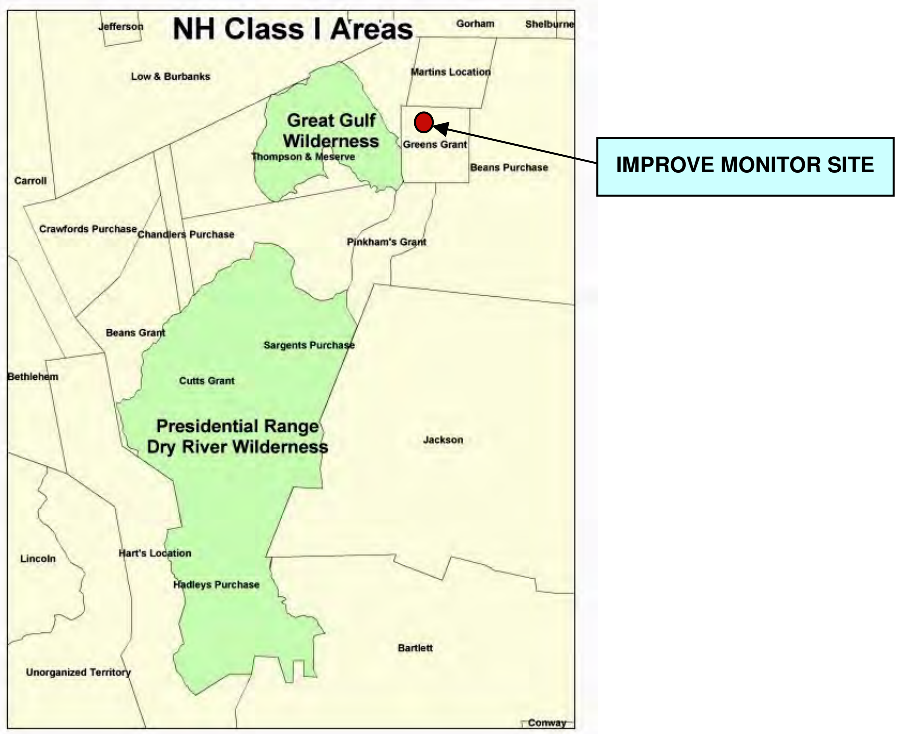
Figure 5.4: Brigantine Wilderness on Clear and Hazy Days

<u>http://www.hazecam.net/class1/brigantine.html</u>

5.3.3 Great Gulf Wilderness, New Hampshire

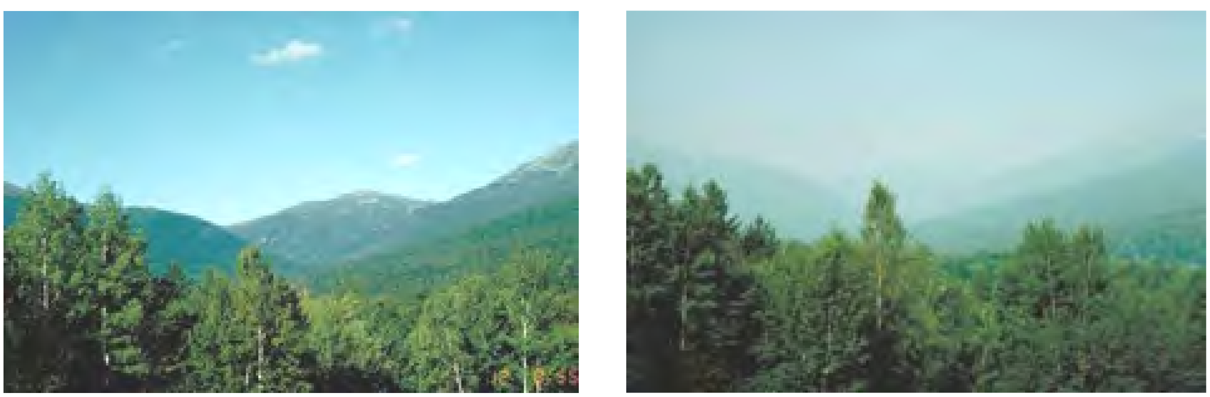
The IMPROVE monitor for the Great Gulf Wilderness (GRGU1) is located at Camp Dodge, in the mid-northern area of Greens Grant in the White Mountain National Forest. The monitor site lies just east and south of where Route 16 crosses the Greens Grant / Martins Location boundary, south of Gorham, New Hampshire, at elevation 454 meters, latitude 44.31˚, and longitude of -71.22˚. This monitor, which also represents the Presidential Range - Dry River Wilderness (see 5.3.4 below), is operated and maintained by the U.S. Forest Service. New Hampshire considers the GRGU1 site as adequate for assessing reasonable progress toward visibility goals at the Great Gulf Wilderness, and no additional monitoring sites or equipment are necessary at this time.

Figure 5.5: Map of Great Gulf and Presidential Range - Dry River Wilderness Areas Showing Location of IMPROVE Monitor



http://www.maine.gov/dep/air/meteorology/images/NHclass1.jpg

Figure 5.6: Great Gulf Wilderness on Clear and Hazy Days



http://www.wilderness.net

5.3.4 Presidential Range - Dry River Wilderness, New Hampshire

The IMPROVE monitor for the Presidential Range - Dry River Wilderness is also the monitor for Great Gulf Wilderness (GRGU1), as described above. New Hampshire considers the GRGU1 site as adequate for assessing reasonable progress toward visibility goals at the Presidential Range - Dry River Wilderness, and no additional monitoring sites or equipment are necessary at this time.

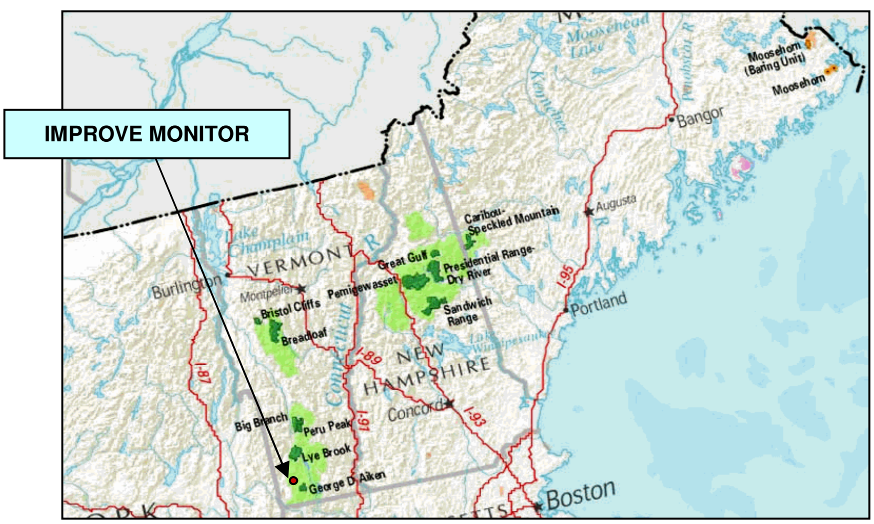
Figure 5.7: Presidential Range - Dry River Wilderness in Autumn

http://www.wilderness.net

5.3.5 Lye Brook Wilderness, Vermont

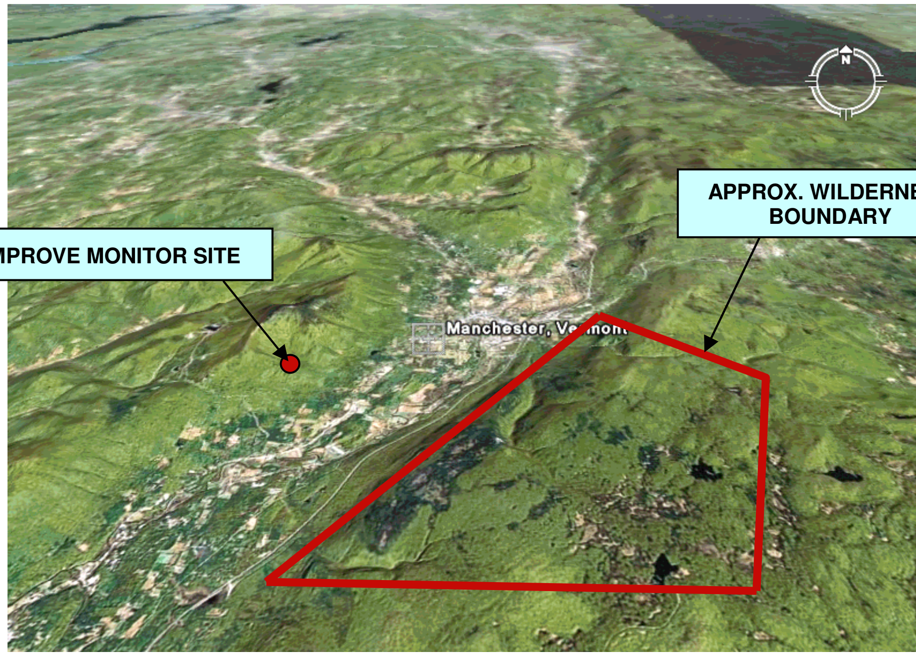
The IMPROVE monitor for the Lye Brook Wilderness (LYBR1) is located on Mount Equinox at the windmills in Manchester, Vermont, at elevation 1015 meters, latitude 43.15˚, and longitude of -73.13˚. The monitor does not lie within the wilderness area but is situated on a mountain peak across the valley to the west of the wilderness area. The IMPROVE site and the Lye Brook Wilderness are at similar elevations. The monitor is operated and maintained by the U.S. Forest Service. New Hampshire considers the LYBR1 site as adequate for assessing reasonable progress toward visibility goals at the Lye Brook Wilderness, and no additional monitoring sites or equipment are necessary at this time.

Figure 5.8: Location of Lye Brook Wilderness IMPROVE Monitor



http://www.wilderness.net/index.cfm?fuse=NWPS&sec=stateView&state=NH&map=menhvt

Figure 5.9: Aerial View of Lye Brook Wilderness IMPROVE Monitoring Site



sources: GoogleEarth; and Paul Wishinski, Vermont DEC, Air Pollution Control Division

Figure 5.10: Lye Brook Wilderness on Clear and Hazy Days

http://www.hazecam.net/class1/lye.html

5.3.6 Moosehorn Wilderness, Maine

The IMPROVE monitor for the Moosehorn Wilderness (MOOS1) is located near McConvey Road, about one mile northeast of the National Wildlife Refuge Baring (ME) Unit Headquarters, at elevation 78 meters, latitude 45.13°, and longitude -67.27°. This monitor also represents the Roosevelt Campobello International Park in New Brunswick, Canada. The monitor is operated and maintained by the U.S. Fish & Wildlife Service. New Hampshire considers the MOOS1 site as adequate for assessing reasonable progress toward visibility goals at the Moosehorn Wilderness, and no additional monitoring sites or equipment are necessary at this time.

Figure 5.11: Map of the Baring and Edmunds Divisions of the Moosehorn National Wildlife Refuge Showing Location of IMPROVE Monitor

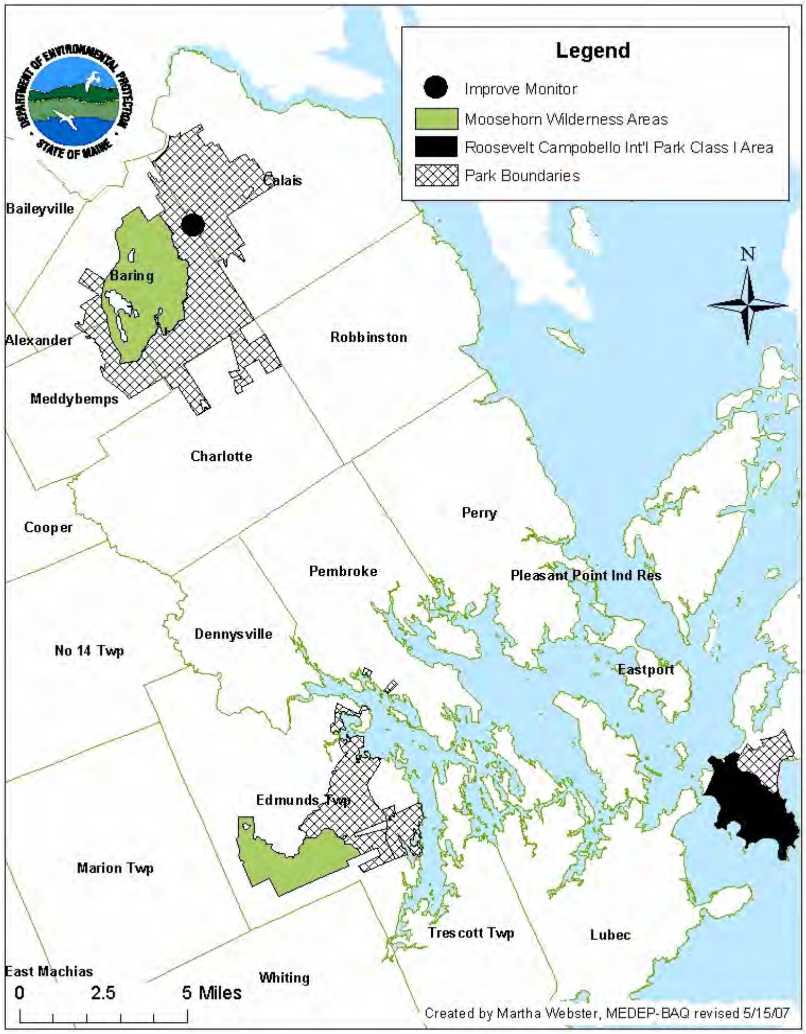
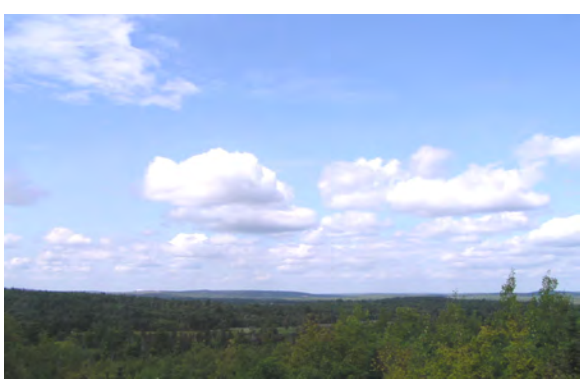


Figure 5.12: Moosehorn Wilderness on Clear and Hazy Days

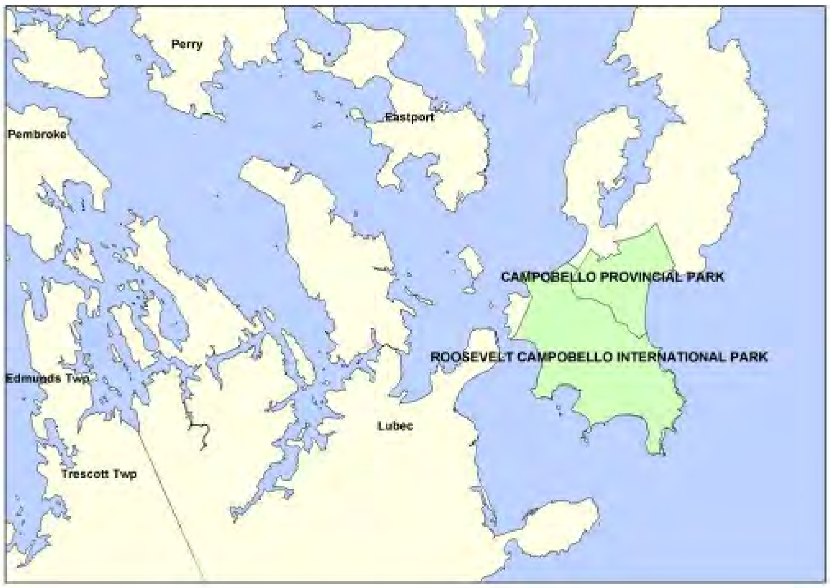


http://www.hazecam.net/moosehorn.html

5.3.7 Roosevelt Campobello International Park, New Brunswick, Canada

The IMPROVE monitor for Roosevelt Campobello International Park is also the monitor for the Moosehorn Wilderness (MOOS1), as described above. New Hampshire considers the MOOS1 site as adequate for assessing reasonable progress toward visibility goals at Roosevelt Campobello International Park, and no additional monitoring sites or equipment are necessary at this time.

Figure 5.13: Map of Roosevelt Campobello International Park



http://www.maine.gov/dep/air/meteorology/images/rcip.jpg

Figure 5.14: Roosevelt Campobello International Park on Clear and Hazy Days

source: Chessie Johnson

6. EMISSIONS INVENTORY

40 CFR 51.308(d)(4)(v) of EPA's Regional Haze Rule requires a statewide emissions inventory of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I area. The inventory must include emissions for a baseline year, future (projected) year, and the most recent year for which high-quality data are available. New Hampshire's baseline year, 2002, is also the most recent year for which data are available. The pollutants inventoried by New Hampshire include nitrogen oxides (NO_X), sulfur dioxides (SO_2), volatile organic compounds (VOCs), fine particles (particulate matter less than 2.5 micrometers in diameter, or $PM_{2.5}$), coarse particles (particulate matter less than 10 micrometers in diameter, or PM_{10}), and ammonia (NH_3). The following source categories were included in New Hampshire's emissions inventory: stationary point sources, stationary area sources, on-road mobile sources, non-road mobile sources, and biogenic sources. These emissions categories are discussed further in Subsection 7.3, Model Platforms.

6.1 Baseline and Future-Year Emissions Inventories for Modeling

40 CFR 51.308(d) (3) (iii) of EPA's Regional Haze Rule requires the State of New Hampshire to identify the baseline emissions inventory on which emission control strategies are founded. The baseline inventory is intended to be used for assessing progress in making emission reductions. In accordance with EPA's guidance memorandum "2002 Base Year Emission Inventory SIP Planning: 8-hour Ozone, $PM_{2.5}$, and Regional Haze Programs," November 18, 2002, all of the MANE-VU states are using 2002 as the baseline year for regional haze.

Previously, on July 5, 2006, New Hampshire submitted its 2002 baseline inventory to EPA to meet its implementation planning obligations under the 8-hour ozone program. It should be noted, however, that emissions inventories are not static documents, but are constantly revised and updated to reflect the input of better emissions estimates as they become available. With contractor assistance, MARAMA developed a 2002 baseline modeling inventory using the inventories that New Hampshire and other states submitted to EPA to meet their SIP obligations and the requirements of the Consolidated Emissions Reporting Rule (CERR). To create the 2002 baseline inventory for modeling, MARAMA and its contractor quality-assured and augmented states' inventories and generated the necessary input files for the emissions processing model. As described in Part 6.1.1 below, work on this effort underwent several versions. Therefore, the 2002 baseline emissions summarized in this document may differ slightly from New Hampshire's original 2002 baseline inventory submittal.

Future-year inventories for 2009, 2012, and 2018 were projected from the 2002 base year. These future-year emissions inventories include emissions growth due to projected increases in economic activity as well as emissions reductions expected from the implementation of control measures. While the 2009 and 2012 emissions projections were originally developed in support of New Hampshire's and other states' ozone attainment demonstrations, the inventory for 2018 (the year targeted by the Regional Haze Rule) was developed for the specific purposes of regional haze SIP planning. Therefore, although the 2009 and 2012 projected inventories are mentioned in subsequent sections, only the 2002 baseline inventory and 2018 projected inventory are described below in Subsection 6.4, Summary of Emissions Inventories.

Accurate baseline and future-year emissions inventories are crucial to the analyses required for the regional haze SIP process. These emissions inventories were used to drive the air quality modeling simulations undertaken to assess the visibility improvements that would result from possible control measures. Air quality modeling was also used to perform a pollution apportionment, which evaluates the contribution to visibility impairment by geographic region and emission source sector.

To be compatible with the air quality modeling simulations, the baseline and future-year emissions inventories were processed with the Sparse Matrix Operator Kernel Emissions (SMOKE) emissions pre-processor for subsequent input into the CMAQ and REMSAD air quality models described in Subsection 7.3. Further description of the base and future-year emissions inventories is provided below.

6.1.1 Baseline Inventory (2002)

The starting point for the 2002 baseline emissions inventory was the 2002 inventory submittals that were made to EPA by state and local agencies as part of the Consolidated Emissions Reporting Rule (CERR). With contractor assistance (E.H. Pechan & Associates, Inc.,), MANE-VU then coordinated and quality-assured the 2002 inventory data, and prepared it for input into the SMOKE emissions model. The 2002 emissions from non-MANE-VU areas within the modeling domain were obtained from other Regional Planning Organizations for their corresponding areas. These Regional Planning Organizations included the Visibility Improvement State and Tribal Association of the Southeast (VISTAS), the Midwest Regional Planning Organization (MRPO), and the Central Regional Air Planning Association (CenRAP).

The 2002 baseline inventory went through several iterations. Work on Version 1 of the 2002 MANE-VU inventory began in April 2004, and the final inventory and SMOKE input files were completed during January 2005. Work on Version 2 (covering the period of April through September 2005) involved incorporating revisions requested by some MANE-VU state/local agencies on the point, area, and on-road categories. Work on Version 3 (covering the period from December 2005 through April 2006) included additional revisions to the point, area, and on-road categories as requested by some states. Thus, the Version 3 inventory for point, area, and on-road sources was built upon Versions 1 and 2. This work also included development of the biogenic inventory. In Version 3, the non-road inventory was completely redone because of changes that EPA made to the NONROAD2005 non-road mobile emissions model.

Version 3 of the MANE-VU 2002 baseline emissions inventory was used in the regional air quality modeling simulations. Further description of the data sources, methods, and results for this version of the 2002 baseline inventory is presented in E.H. Pechan & Associates, Inc., "Technical Support Document for 2002 MANE-VU SIP Modeling Inventories, Version 3, November 20, 2006, also known as the Baseline Emissions Report (Attachment M).
Emissions inventory data files are available on the MARAMA website at:
http://www.marama.org/visibility/EI_Projects/index.html.

6.1.2 Future-Year Emissions Inventories

Future-year emissions inventories are provided in MACTEC's technical support document, "Development of Emissions Projections for 2009, 2012, and 2018 for NonEGU Point, Area, and Nonroad Sources in the MANE-VU Region," Final Report, February 28, 2007, also known as the Emission Projections Report (Attachment N). This document describes the data sources, methods, and modeling results for three future years, five emission source sectors, two emission control scenarios, seven pollutants, and eleven states plus the District of Columbia. The following summarizes the basic framework of the future-year inventories that were developed:

- ***Projection years*:** 2009, 2012, and 2018;
- ***Emission source sectors*:** point-source electric generating units (EGUs), point-source non-electric generating units (non-EGUs), area sources, non-road mobile sources, and on-road mobile sources.
- ***Emission control scenarios*:**
    - A combined on-the-books/on-the-way (OTB/OTW) control strategy accounting for emission control regulations already in place as of June 15, 2005, as well as some emission control regulations that are not yet finalized but are expected to achieve additional emission reductions by 2009; and
    - A beyond-on-the-way (BOTW) scenario to account for anticipated Phase 1 implementation of a low-sulfur fuel strategy for non-EGU sources and controls from potential new regulations that may be necessary to meet attainment and other regional air quality goals, mainly for ozone.
    - An updated scenario (sometimes referred to as "best-and-final") to account for additional potentially reasonable control measures. For the MANE-VU region, these include: SO_2 reductions at a set of 167 EGUs which were identified as contributing to visibility impairment at northeast Class I areas; anticipated Phase 2 implementation of a low-sulfur fuel strategy for non-EGU sources; and implementation of a Best Available Retrofit Technology (BART) strategy for BART-eligible sources not controlled under other programs.

  (Note: Refer to Section 11, Long-Term Strategy, for detailed descriptions of specific control strategies.)
- ***Pollutants*:** ammonia, carbon monoxide (CO), oxides of nitrogen (NO_X), sulfur dioxide (SO_2), volatile organic compounds (VOCs), fine particulate matter ($PM_{2.5}$, sum of filterable and condensable components), and coarse particulate matter (PM_{10}, sum of filterable and condensable components).
- ***States*:** Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont, plus the District of Columbia (all members of the MANE-VU region).

6.2 Emission Processor Selection and Configuration

The Sparse Matrix Operator Kernel Emissions (SMOKE) model was used to format the emissions inventories for use with the air quality models that are discussed in Subsection 7.3. SMOKE is primarily an emissions processing system, as opposed to a true emissions inventory preparation system, in which emissions estimates are simulated from "first principles." This means that, with the exception of mobile and biogenic sources, SMOKE's purpose is to provide an efficient, modern tool for converting emissions inventory data into the formatted emissions files required for a photochemical air quality model. The SMOKE emissions processing that was performed in support of the air quality modeling for regional haze is described further in Subsection 7.2.

6.3 Inventories for Specific Source Categories

There are five emission source classifications in the emissions inventory, as follows:

- Stationary point,
- Stationary area,
- Non-road mobile,
- On-road mobile, and
- Biogenic.

Stationary point sources are large sources that emit greater than a specified tonnage per year, as described below. ***Stationary area sources*** are those sources whose individual emissions are relatively small (i.e., dry cleaners, service stations, agricultural areas, fires, etc.), but because of the large number of these sources, their collective emissions are significant. ***Non-road mobile sources*** are equipment that can move but do not use the roadways (i.e., lawn mowers, construction equipment, railroad locomotives, marine vessels, aircraft, etc.). ***On-road mobile sources*** include automobiles, trucks, buses, and motorcycles that use the roadway system. ***Biogenic sources*** include the off-gassing of natural sources such as trees, crops, grasses, and natural decay of plants.

The subsections below give an overview of each of the source categories and the methods that were used to develop their corresponding baseline and future-year emissions estimates. All emissions data were prepared for modeling in accordance with EPA guidance.

6.3.1 Stationary Point Sources

Point source emissions are emissions from large individual sources. Generally, point sources have permits to operate, and their emissions are individually calculated based on source-specific parameters. Emissions estimates for point sources are usually made on a regular basis, and the largest point sources are inventoried annually. Sources with emissions greater than or equal to 100 tons per year (tpy) of a criteria pollutant, 10 tpy of a single hazardous air pollutant (HAP), or 25 tpy for total HAPs are considered to be major sources. Emissions from smaller point sources are also calculated individually but less frequently. Point sources are further subdivided into EGUs and non-EGUs.

6.3.1.1 Electric Generating Units (EGUs)

The base-year inventory for EGU sources were based on 2002 continuous emissions monitoring (CEM) data reported to EPA in compliance with the Acid Rain Program or 2002 state emissions inventory data. The CEM data provided actual hourly emission values used in the modeling of SO_2 and NO_X emissions from these large sources. See Chapter II, Section A.2.a.i of the "Technical Support Document for 2002 MANE-VU SIP Modeling Inventories," Version 3 (Attachment M) for a discussion of the quality assurance steps performed on the CEM data that were included in the 2002 baseline modeling inventory. Emissions of other pollutants (e.g., VOCs, CO, NH_3, and $PM_{2.5}$) were provided by the states in most instances.

Future-year inventories of EGU emissions for 2009, 2012 and 2018 were developed using ICF International's Integrated Planning Model (IPM®) to forecast growth in electric demand and replacement of older, less efficient and more polluting power plants with newer, more efficient and cleaner units. This effort was undertaken by an inter-RPO workgroup. While the output of the IPM model predicts that a certain number of older plants will be replaced by newer units to meet future electric growth and state-specific NO_X and SO_2 caps, New Hampshire did not directly rely on the closure of any particular plant in establishing the 2018 inventory upon which the reasonable progress goals were set.

The IPM model results do not provide a reliable basis upon which to predict EGU closures. Specific plant closures in the New Hampshire are addressed in Section 10, Reasonable Progress Goals. Preliminary modeling was performed with unchanged IPM 2.1.9 model results. However, prior to the most recent modeling, future-year EGU inventories were adjusted as follows:

- First, IPM predictions were reviewed by permitting and enforcement staff of the MANE-VU states. In many cases, staff believed that the IPM shutdown predictions were unlikely to occur. In particular, many oil-fired EGUs in urban areas were predicted to be shut down by IPM. Similar source information was solicited from states in both VISTAS and MRPO. As a result of this model validation, the IPM modeling output was adjusted before the most recent modeling to reflect staff knowledge of specific plant status in MANE-VU, VISTAS, and MRPO states. Where expected EGU operating status was contrary to what was predicted by IPM modeling, the future-year emissions inventory was adjusted to reflect the expected operation of those plants.
- Second, as a result of inter- and intra-RPO consultations, MANE-VU agreed to pursue certain emission control measures (see Section 3, Regional Planning). For EGUs, the agreed-upon approach was to pursue emission reductions from each of the top 167 stacks located in MANE-VU, MRPO, and VISTAS that contributed the most to visibility impairment at any Class I area in the MANE-VU region. This approach, known as the targeted EGU strategy, is further described in Section 11 of this SIP.

6.3.1.2 Non-EGU Point Sources

The primary basis for the 2002 baseline non-EGU emissions inventory was data reported by state and local agencies for the CERR. As described in Part 6.1.1, MANE-VU's contractor, E.H. Pechan & Associates (Pechan), coordinated the quality assurance of the inventory and prepared the necessary files for input into the SMOKE emissions model. Further information on the preparation of the MANE-VU 2002 baseline point source modeling emissions inventory can be found in Chapter II of the Baseline Emissions Report (Attachment M).

Projected non-EGU point source emissions were developed for the MANE-VU region by MACTEC Federal Programs, Inc. under contract to Mid-Atlantic Regional Air Management Association (MARAMA). The specific methodologies that were employed are described in Section 2 of the Emission Projections Report (Attachment N). MACTEC used state-supplied growth factor data, where available, to project future-year emissions. Where state-supplied data were not available, MACTEC used EPA's Economic Growth and Analysis System, Version 5.0 (EGAS 5.0) to develop applicable growth factors for the non-EGU component. MACTEC also incorporated the applicable federal and state emissions control programs to account for the expected emissions reductions that will take place under the OTB/OTW and BOTW scenarios.

6.3.2 Stationary Area Sources

Stationary area sources include sources whose individual emissions are relatively small but, because the number of sources is large, their collective emissions are significant. Some examples include dry cleaners, service stations, and residential heating. For each area source, emissions are estimated by multiplying an appropriate emission factor by some known indicator of collective activity, such as fuel usage, number of households, or population.

The area source emissions inventory submittals made for the CERR became the basis for the area source portion of the 2002 baseline inventory. MANE-VU's consultant, Pechan, prepared the area source modeling inventory using the CERR submittals as a starting point. Pechan quality-assured the inventory and augmented it with additional data, including MANE-VU-sponsored inventories for categories such as residential wood combustion and open burning. Details on the preparation of MANE-VU's 2002 baseline area source emissions inventory can be found in Chapter III of the Baseline Emissions Report (Attachment M).

In similar fashion, MACTEC prepared future-year area source emission projections for the MANE-VU region. The specific methodologies employed are described in Section 3 of the Emission Projections Report (Attachment N). MACTEC applied growth factors to the 2002 baseline area source inventory using state-supplied data, where available, or using the EGAS 5.0 growth factor model. MACTEC also accounted for the appropriate control strategies in the future year projections.

6.3.3 Non-Road Mobile Sources

Non-road mobile sources are equipment that can move but do not typically use the roadways, such as construction equipment, aircraft, railroad locomotives, and lawn & garden equipment. For the majority of non-road mobile sources, emissions are estimated using the EPA's NONROAD model. Aircraft, railroad locomotives, and commercial marine vessels are not included in the NONROAD model; and their emissions are estimated using applicable references and methodologies. Again, Pechan prepared the 2002 baseline modeling inventory using the state and local CERR submittals as a starting point. Details on the preparation of the 2002 baseline non-road inventory are described in Chapter IV of the Baseline Emissions Report (Attachment M).

Future-year non-road mobile source emissions were projected for the MANE-VU region by MACTEC. The methodologies employed are discussed in Section 4 of the Emission Projections Report (Attachment N). MACTEC used EPA's NONROAD2005 non-road vehicle emissions model as contained in EPA's National Mobile Inventory Model (NMIM). Since the calendar year is an explicit input into the NONROAD model, future-year emissions for non-road vehicles could be calculated directly for the applicable projection years. For the non-road vehicle types that are not included in the NONROAD model (i.e. aircraft, locomotives, and commercial marine vessels), MACTEC used the 2002 baseline inventory and the projected inventories that EPA developed for these categories for the Clean Air Interstate Rule (CAIR) to develop emission ratios and subsequent combined growth and control factors. Since the future years for the CAIR projections did not precisely match those required for the purposes of ozone, particulate matter, and regional haze analyses (i.e. 2009, 2012, and 2018), MACTEC used linear interpolation to develop factors for the required future years.

6.3.4 On-Road Mobile Sources

The on-road emissions source category consists of vehicles that are meant to travel on public roadways, including cars, trucks, buses, and motorcycles. The basic methodology used for on-road mobile source calculations is to multiply vehicle-miles-traveled (VMT) by emission factors developed using the EPA's MOBILE6 motor vehicle emission factors model. The on-road mobile category requires that SMOKE model inputs be prepared instead of the SMOKE/IDA emissions data format that is required by the other emission source categories. Therefore, for the 2002 baseline inventory, Pechan prepared the necessary VMT and MOBILE6 inputs in SMOKE format.

Projected on-road mobile source inventories were developed by NESCAUM for the MANE-VU region for ozone, particulate matter, and regional haze SIP purposes. As with the other emissions source categories, projected on-road mobile inventories were developed for calendar years 2009, 2012, and 2018. As part of this effort, MANE-VU member states were asked to provide VMT data and MOBILE6 model inputs for the applicable calendar years. Using the inputs supplied by the MANE-VU member states, NESCAUM compiled and generated the required SMOKE/MOBILE6 emissions model inputs. Further details regarding the on-road mobile source projections can be found in NESCAUM's "Technical Memorandum, Development of MANE-VU Mobile Source Projection Inventories for SMOKE/MOBILE6 Application," June 2006 (Attachment O).

6.3.5 Biogenic Emission Sources

For the purposes of the 2002 baseline modeling emissions inventory, biogenic emissions were calculated for the modeling domain by the New York State Department of Environmental Conservation (NYSDEC). NYSDEC used the Biogenic Emissions Inventory System (BEIS) Version 3.12 as contained within the SMOKE emissions processing model. Biogenic emissions estimates were made for CO, nitrous oxide (NO) and VOCs. Further details about the biogenic emissions processing can be found in NYSDEC's technical support document TSD-1c, "Emission Processing for the Revised 2002 OTC Regional and Urban 12 km Base Case Simulations," September 19, 2006 (Appendix P), and in Chapter VI of Pechan's "Technical Support Document for 2002 MANE-VU SIP Modeling Inventories," Version 3, November 20, 2006 (Appendix M). Biogenic emissions were assumed to remain constant for the future-years analysis – a reasonable approximation reflecting the expectation that most of the region will remain heavily forested for the duration of the planning period.

6.4 Summary of Emissions Inventories

New Hampshire's baseline and future-year emissions inventories are summarized in Tables 6.1 through 6.4, below. All values are reported in tons per year (tpy). The three different emissions inventories for 2018 represent the emission control scenarios described under the third bullet in Part 6.1.2 of this section.

Table 6.1: 2002 Emissions Inventory Summary for New Hampshire (tpy)

Emission Sector	VOC	NO_X	$PM_{2.5}$	PM_{10}	NH_3	SO_2
Point	1,599	9,759	2,938	3,332	74	46,560
Area	65,370	10,960	17,532	43,328	2,158	7,072
Mobile	16,762	33,283	562	814	1,447	777
Non-Road Mobile	22,376	9,912	965	1,058	9	891
Biogenic	141,894	482	--	--	--	--
TOTAL	248,001	64,396	21,997	48,532	3,688	55,300

Table 6.2: 2018 OTB/OTW Emissions Inventory Summary for New Hampshire (tpy)

Emission Sector	VOC	NO_X	$PM_{2.5}$	PM_{10}	NH_3	SO_2
Point	1,367	4,524	3,208	3,397	184	10,583
Area	64,368	12,430	18,316	49,801	2,789	7,421
Mobile	6,564	7,671	263	282	1,916	537
Non-Road Mobile	15,003	6,344	634	697	11	246
Biogenic	141,894	482	--	--	--	--
TOTAL	229,196	31,451	22,421	54,177	4,900	18,787

Table 6.3: 2018 BOTW Emissions Inventory Summary for New Hampshire (tpy)

Emission Sector	VOC	NO_X	$PM_{2.5}$	PM_{10}	NH_3	SO_2
Point	1,292	4,258	3,208	3,397	184	10,568
Area	62,650	12,180	18,087	49,544	2,789	3,118
Mobile	6,564	7,671	263	282	1,916	537
Non-Road Mobile	15,003	6,344	634	698	12	246
Biogenic	141,894	482	--	--	--	--
TOTAL	227,403	30,935	22,192	53,921	4,901	14,469

Table 6.4: 2018 Most Recent Emissions Inventory Summary for New Hampshire (tpy)

Emission Sector	VOC	NO_X	$PM_{2.5}$	PM_{10}	NH_3	SO_2
Point	1,291	4,258	3,208	3,397	184	11,849
Area	62,649	12,180	14,993	21,775	2,789	972
Mobile	6,564	7,671	263	282	1,916	537
Non-Road Mobile	15,003	6,344	634	697	11	246
Biogenic	141,894	482	--	--	--	--
TOTAL	227,401	30,935	19,098	26,151[13]	4,900	13,604

[13] An adjustment factor was applied during the processing of emissions data to restate fugitive particulate matter emissions. Grid models have been found to overestimate fugitive dust impacts when compared with ambient samples; therefore, an adjustment is typically applied to account for the removal of particles by vegetation and other terrain features. The summary emissions for PM_{10} in Table 6.4 reflect this adjustment. Comparable adjustments were not made to PM_{10} values listed in Tables 6.1 through 6.3.

7. AIR QUALITY MODELING

Air quality modeling to assess regional haze has been performed cooperatively between New Hampshire and its regional planning organization, MANE-VU, with major modeling being conducted by NESCAUM and screening modeling being conducted by NHDES. These modeling efforts include emissions processing, meteorological input analysis, and chemical transport modeling to perform regional air quality simulations for calendar year 2002 and several future periods, including the primary target date, 2018, for this SIP. Modeling was conducted in order to assess contributions from upwind areas as well as New Hampshire's contribution to Class I areas in downwind states. Further, the modeling evaluated visibility benefits of specific control measures being considered to achieve reasonable progress goals and establish a long-term emissions management strategy for MANE-VU Class I Areas.

Several modeling tools were utilized for these analyses:

- The Fifth-Generation Pennsylvania State University/National Center for Atmospheric Research (NCAR) Mesoscale Model (MM5) was used to derive the required meteorological inputs for the air quality simulations.
- The Sparse Matrix Operator Kernel Emissions (SMOKE) emissions modeling system was used to process and format the emissions inventories for input into the air quality models.
- The Community Mesoscale Air Quality model (CMAQ) was used for the primary SIP modeling.
- The Regional Model for Aerosols and Deposition (REMSAD) was used during contribution apportionment.
- The California Puff Model (CALPUFF) was used to assess the contribution of individual states' emissions to sulfate levels at selected Class I receptor sites.
- The CALGRID photochemical grid model was used to perform screening-level analyses of emission control strategies.

Each of these tools has been evaluated and found to perform adequately. The SIP-pertinent modeling underwent full performance testing, and the results were found to meet the specifications of EPA modeling guidance.

For more details on the regional haze modeling, refer to the NESCAUM report, "MANE-VU Modeling for Reasonable Progress Goals: Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G). The detailed modeling approach for the most recent 2018 projections can be found in NESCAUM's "2018 Visibility Projections," May 13, 2008 (Attachment Q).

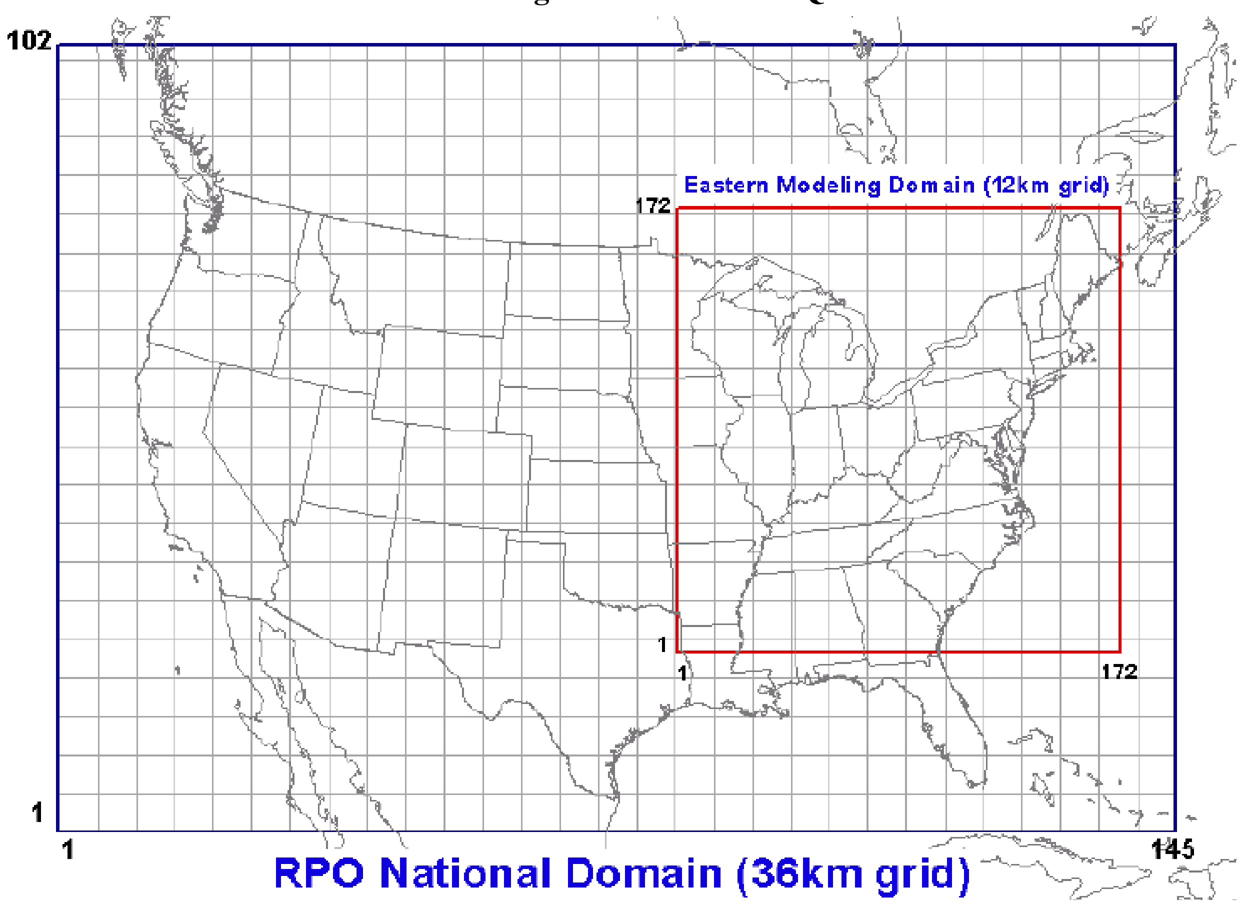
7.1 Meteorology

The meteorological inputs for the air quality simulations were developed by the University of Maryland (UMD) using the MM5 meteorological modeling system. Meteorological inputs were generated for 2002 to correspond with the baseline emissions inventory and analysis year. The MM5 simulations were performed on a nested grid (Figure 7.1). The modeling domain is composed of a 36-km, 145 x 102 continental grid and a nested 12-km, 172 x 172 grid encompassing the eastern United States and parts of Canada. In cooperation with the New York State Department of Conservation (NYSDEC), an assessment was made for the period of May-September 2002 to compare the MM5 predictions with observations from a variety of data sources, including:

- Surface observations from the National Weather Service and the Clean Air Status and Trends Network (CASTNET),
- Wind-profiler measurements from the Cooperative Agency Profilers (CAP) network,
- Satellite cloud image data from the UMD Department of Atmospheric and Oceanic Science, and
- Precipitation data from the Earth Observing Laboratory at NCAR.

Further details regarding the MM5 meteorological processing and the modeling domain can be found in NYSDEC's technical support document TSD-1a, "Meteorological Modeling Using Penn State/NCAR 5th Generation Mesoscale Model (MM5)," February 1, 2006 (Attachment R), and in the NESCAUM report, "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," November 27, 2007 (Attachment G).

Figure 7.1: Modeling Domains Used in MANE-VU Air Quality Modeling Studies with CMAQ



Note: Outer (blue) domain is 36-km grid. Inner (red) domain is 12-km grid. Gridlines are shown at 180-km intervals (5×5 36-km cells and 15×5 12-km cells).

7.2 Data Preparations

Emissions data were prepared for input into the CMAQ and REMSAD air quality models using the SMOKE emissions modeling system. SMOKE supports point, area, mobile (both on-road and non-road), and biogenic emissions. The SMOKE emissions modeling system uses flexible processing to apply chemical speciation as well as temporal and spatial allocation to the emissions inventories. SMOKE incorporates the Biogenic Emission Inventory System (BEIS) and EPA's MOBILE6 motor vehicle emission factor model to process biogenic and on-road mobile emissions, respectively. Vector-matrix multiplication is used during the final processing step to merge the various emissions components into a single model-ready emissions file. Examples of processed emissions outputs are shown in Figure 7.2.

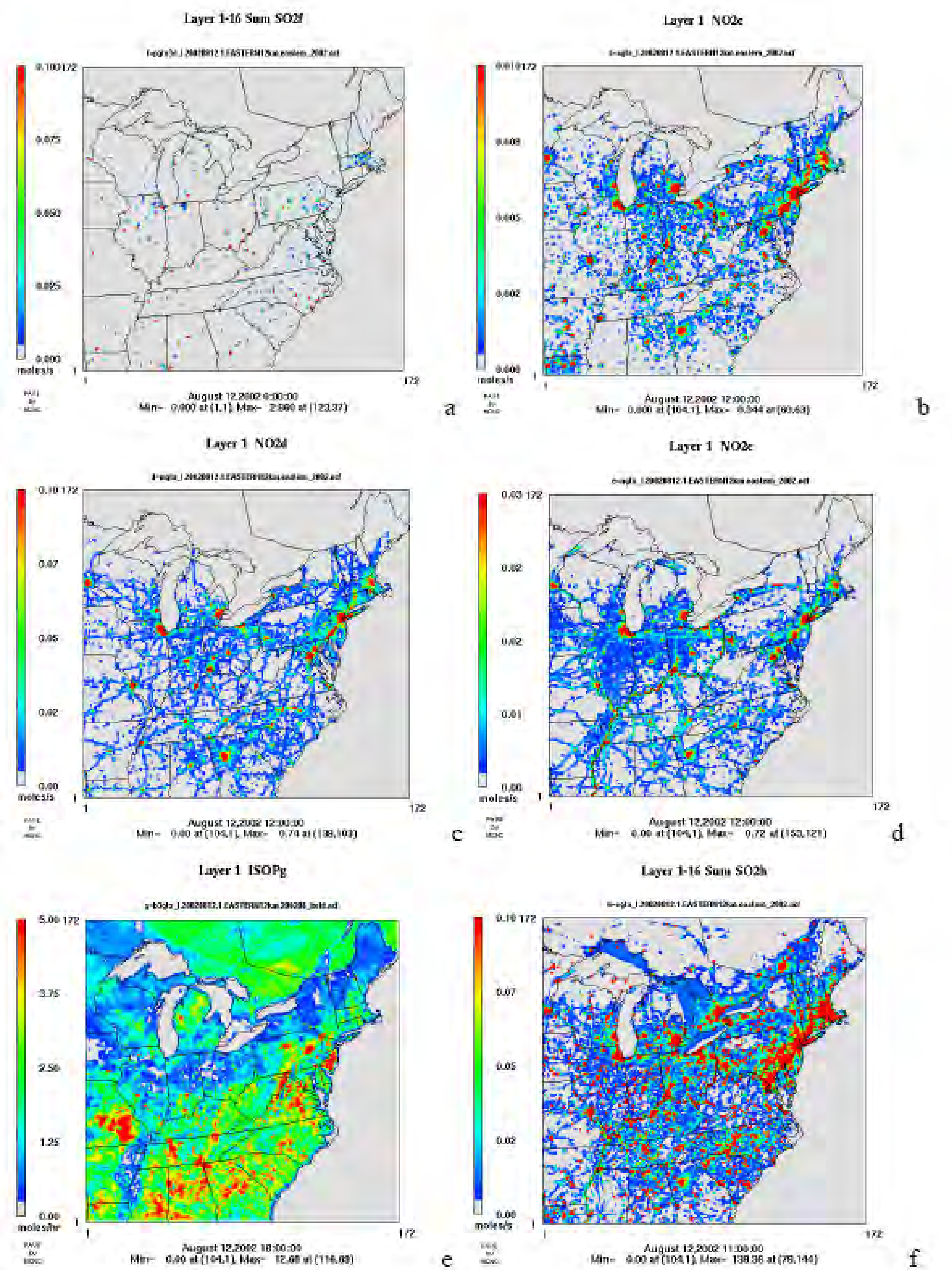
Further details on the SMOKE processing conducted in support of the air quality simulations is provided in NYSDEC's technical support document TSD-1c, "Emission Processing for the Revised 2002 OTC Regional and Urban 12 km Base Case Simulations," September 19, 2006 (Attachment P), and in NESCAUM's report, "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G). Additional details on the emissions inventory preparation can be found in Section 6 of this report.

7.3 Model Platforms

Two regional-scale air quality models, CMAQ and REMSAD, were used for the air quality simulations that directly supported the regional haze SIP effort. CMAQ was developed by EPA and was used to perform the primary SIP-related modeling. The CMAQ modeling simulations were also an important tool for the 8-hour ozone SIP process. REMSAD was developed by ICF Consulting/Systems Applications International with support from EPA. REMSAD was used by NESCAUM to perform a source apportionment (contribution assessment) analysis. All of the air quality simulations that were used in the SIP efforts were performed on the 12-km eastern modeling domain shown in Figure 7.1, above.

NYSDEC performed an extensive model performance analysis to evaluate CMAQ model predictions against observations of ozone, $PM_{2.5}$, and other pollutant species. This model performance evaluation is described in detail in NYSDEC's technical support document TSD-1e, "CMAQ Model Performance and Assessment, 8-Hr OTC Ozone Modeling," February 23, 2006 (Attachment S). A model performance evaluation for $PM_{2.5}$ species, aerosol extinction coefficient, and the haze index is provided in NESCAUM's report, "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G).

Figure 7.2: Examples of Processed Model-Ready Emissions: (a) SO_2 from Point, (b) NO_2 from Area, (c) NO_2 from On-Road, (d) NO_2 from Non-Road, (e) Isoprene from Biogenic, and (f) SO_2 from all Source Categories



7.3.1 CMAQ

The CMAQ air quality simulations were performed cooperatively among five modeling centers: NYSDEC, the New Jersey Department of Environmental Protection (NJDEP) in association with Rutgers University, the Virginia Department of Environmental Quality (VADEQ), UMD, and NESCAUM. NYSDEC also performed an annual 2002 CMAQ simulation on the 36-km domain shown in Figure 7.1; this simulation was used to derive the boundary conditions for the inner 12-km eastern modeling domain. Boundary conditions for the 36-km simulations were obtained from a run of the GEOS-Chem (Goddard Earth Observing System) global chemistry transport model that was performed by researchers at Harvard University. The technical options that were used in performing the CMAQ simulations are described in detail in NYSDEC's technical support document TSD-1d, "8hr Ozone Modeling Using the SMOKE/CMAQ System," February 1, 2006 (Attachment T). Further technical details regarding the CMAQ model and its execution are also provided in NESCAUM's report, "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G).

7.3.2 REMSAD

The REMSAD modeling simulations were used to produce the contribution assessment required by the Regional Haze Rule. REMSAD's species tagging capability makes it an important tool for this purpose. The REMSAD model simulations were performed on the same 12-km eastern modeling domain as shown in Figure 7.1. NESCAUM's report, "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G), further describes the REMSAD model and its application to the regional haze SIP efforts.

7.3.3 CALGRID

In addition to the SIP-quality modeling platforms described above, another modeling platform was developed for use as a screening tool to evaluate additional control strategies or to perform sensitivity analyses. The CALGRID model was selected as the basis for this platform. CALGRID is a grid-based photochemical air quality model that is designed to be run in a Windows environment. In order to make the CALGRID model the best possible tool to supplement the SIP-quality CMAQ and REMSAD modeling, the current version of the CALGRID platform was set up to be run with the same set of inputs as the SIP-quality models. The CALGRID air quality simulations were run on the same 12-km eastern modeling domain that was used for CMAQ and REMSAD. This model's performance was comparable to the performance of the already evaluated CMAQ and REMSAD models and was thus determined to perform adequately.

Conversion utilities were developed to reformat the meteorological inputs, the boundary conditions, and the emissions data for use with the CALGRID modeling platform. Pre-merged SMOKE emissions files were obtained from the modeling centers and reformatted for input into Emission Processor version 6 (EMSPROC6), the emissions pre-processor for the CALGRID modeling system. EMSPROC6 allows the CALGRID user to adjust emissions temporally, geographically, and by emissions category for control strategy analysis. The pre-merged SMOKE files that were obtained from the modeling centers were broken down into the biogenic, point, area, non-road, and on-road emissions categories. These files by component were then converted for use with EMSPROC6, thus giving CALGRID users the flexibility to analyze a wide variety of emissions control strategies. Additional information on the CALGRID modeling platform can be found in NHDES' "Modeling Protocol for the OTC CALGRID Screening-Level Modeling Platform for the Evaluation of Ozone," May 23, 2007 (Attachment U).

7.3.4 CALPUFF

CALPUFF is a non-steady-state Lagrangian puff model that simulates the dispersion, transport, and chemical transformation of atmospheric pollutants. Two parallel CALPUFF modeling platforms were developed by the Vermont Department of Environmental Conservation (VTDEC) and the Maryland Department of the Environment (MDE). The VTDEC CALPUFF modeling platform utilized meteorological observation data from the National Weather Service (NWS) to drive the CALMET meteorological model. The MDE platform utilized the same MM5 meteorological inputs that were used in the modeling done in support of the ozone and regional haze SIPs. These two platforms were run in parallel to evaluate individual states' contributions to sulfate levels at Northeast and Mid-Atlantic Class I areas. The CALPUFF modeling effort is described in detail in NESCAUM's report, "Contributions to Regional Haze in the Northeast and Mid-Atlantic United States," August 2006 (Attachment B).

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8. UNDERSTANDING THE SOURCES OF HAZE-CAUSING POLLUTANTS

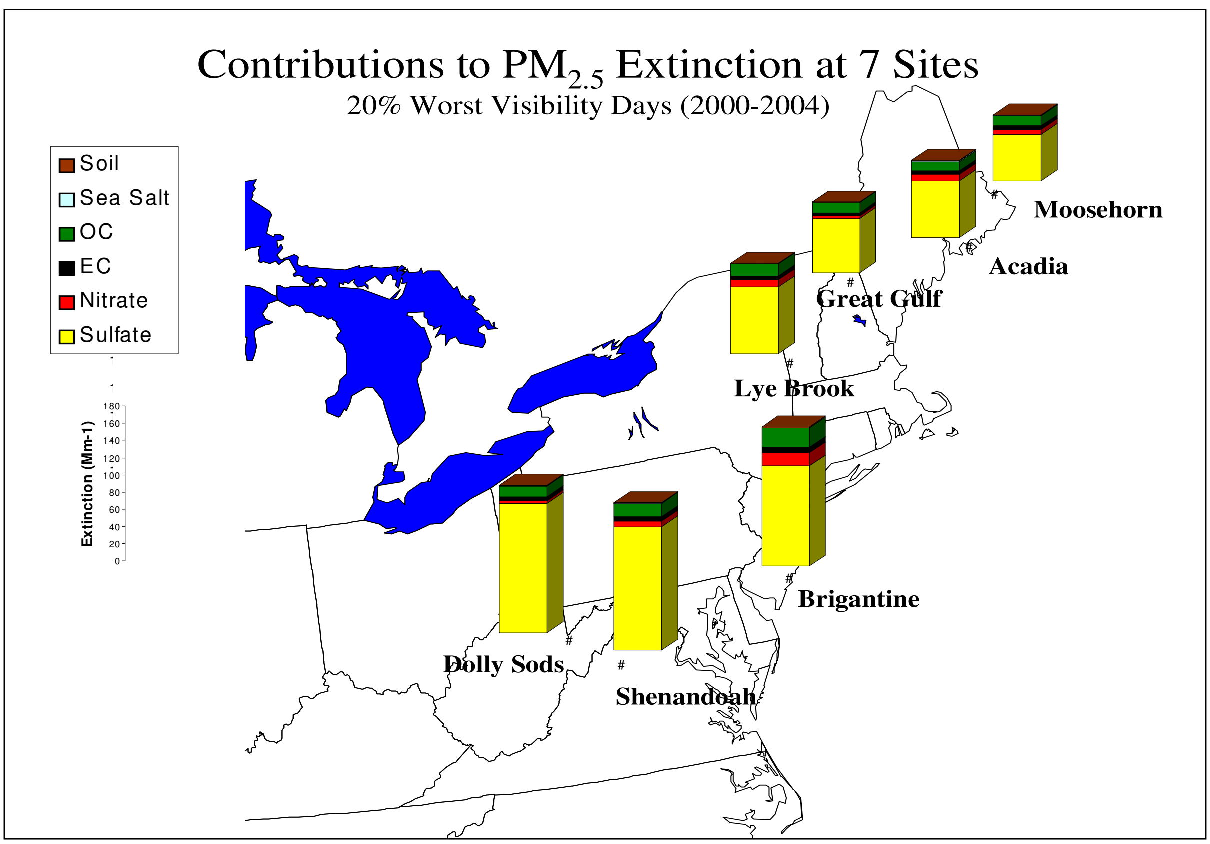
This section explores the origins, quantities, and roles of visibility-impairing pollutants emitted in the eastern United States and Canada that contribute significantly to regional haze at MANE-VU's mandatory Class I areas.

8.1 Fine-Particle Pollutants

The pollutants primarily responsible for fine particle formation, and thus contributing to regional haze, include SO_2, NO_X, VOCs, NH_3, PM_{10}, and $PM_{2.5}$. The MANE-VU Contribution Assessment (Attachment B), finalized in August 2006, reflects a conceptual model in which sulfate emerges as the most important single constituent of haze-forming fine particle pollution and the principle cause of visibility impairment across the Northeast region. Sulfate alone accounts for anywhere from ½ to ⅔ of total fine particle mass on the 20 percent haziest days at MANE-VU Class I Areas. This translates to about ⅔ to ¾ of visibility extinction on those days.

Visibility extinction is a measure of the ability of particles to scatter and absorb light. Extinction is expressed in units of inverse mega-meters (Mm^{-1}). Figure 8.1 shows the dominance of sulfate in visibility extinction calculated from 2000-2004 baseline data for seven Northeast Class I Areas.

Figure 8.1: Contributions to $PM_{2.5}$ Extinction at Seven Class I Areas



Given the dominant role of sulfate in the formation of regional haze in the Northeast and Mid-Atlantic Regions, MANE-VU concluded that an effective emissions management approach would rely heavily on broad-based regional SO_2 control measures in the eastern United States. The focus on SO_2 as MANE-VU's first priority makes sense not only because of its dominant role in regional haze but also because its emission sources are well understood. Moreover, the control measures needed for SO_2 emission reductions are readily available, cost-effective, and could be implemented quickly. On the basis of the scientific evidence, it is apparent that the bulk of haze-causing pollution can be eliminated by pursuing SO_2 emission controls.

Organic carbon was found to be the next largest contributor to haze after sulfate. In comparison with sulfate, the emission sources of organic carbon, are diverse, variable, more diffuse, and less well understood; and the problem of controlling organic carbon emissions is exceedingly complex. For these reasons, MANE-VU considered organic carbon to be the subject of possible future control measures but not a specific target pollutant in the initial strategy to mitigate regional haze.

8.2 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 and nearby Class I areas. Based on estimates obtained by several evaluation methods, emissions that originated within MANE-VU states contributed approximately one-fourth of the total sulfate aerosol recorded at New Hampshire's Class I areas in 2002. More specifically, four different estimation methods yielded the following contribution ranges: MANE-VU, 21-28 percent; MRPO, 20-27 percent; VISTAS, 12-18 percent; CenRAP, 2-5 percent; Canada, 7-19 percent; and all other regions, 23-24 percent (see Tables 8.1, 8.2, 8.3, and 8.5 of the Contribution Assessment for details).

It should be pointed out that the listed values for VISTAS, CenRAP, and Canada understate the actually percentage contributions from those regions because they count only emissions originating within the modeling domain (see Figure 7.1). Actual contributions, especially in the case of CenRAP, would be considerably higher than stated. Differences between actual and stated values are lumped into "Other."

These findings highlight the importance of emissions from outside MANE-VU to visibility impairment inside the region. Note that, although there is some variation in the contribution estimates among the different assessment methods employed, there is a general consistency of results from one method to another.

Table 8.1 displays the results of just one of the methods used (the REMSAD model) to assess state-by-state and regional contributions to annual sulfate impacts in nine Class I areas.

Table 8.1: Percent Contributions (Mass Basis) of Individual MANE-VU States and Other Regions to Total Annual Sulfate Impacts at Northeast Class I Areas (REMSAD)

Contributing State or Region	Mandatory Class I Area						
	Acadia ME	Brigantine NJ	Dolly Sods WV	Great Gulf & Presidential Range - Dry River, NH	Lye Brook VT	Moosehorn & Roosevelt Campobello ME	Shenandoah VA
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
MRPO	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
CenRAP	0.88	1.12	1.58	1.65	1.67	0.82	1.48
Canada	8.69	7.11	3.90	14.84	12.43	7.85	4.75
Other	33.79	16.78	12.70	23.54	18.99	44.17	12.48

Note: Indicated percent contributions from, VISTAS, CenRAP, and Canada apply only to those portions lying within the modeling domain (see Figure 7.1). Actual contributions, especially from CenRAP, would be higher than stated.

Source: Table 8-1 of the MANE-VU Contribution Assessment

Figures 8.2 and 8.3, also borrowed from the Contribution Assessment, illustrate another method for identifying and ranking states' contributions to sulfate at Class I areas using the 2002 data. This simple technique for deducing the relative impact of emissions from specific point sources on specific receptor sites involves calculating the ratio of annual emissions (Q) to source-receptor distance (d). The ratio (Q/d) is then multiplied by a factor to account for the frequency effect of prevailing winds. The use of this technique is explained in the Contribution Assessment (see pages 4-12 to 4-17 of Attachment B).

Figure 8.2: Ranked Sulfate Contributions to Northeast Class I Receptors Based on Q/d Method (Mass Basis), by Location of Origin

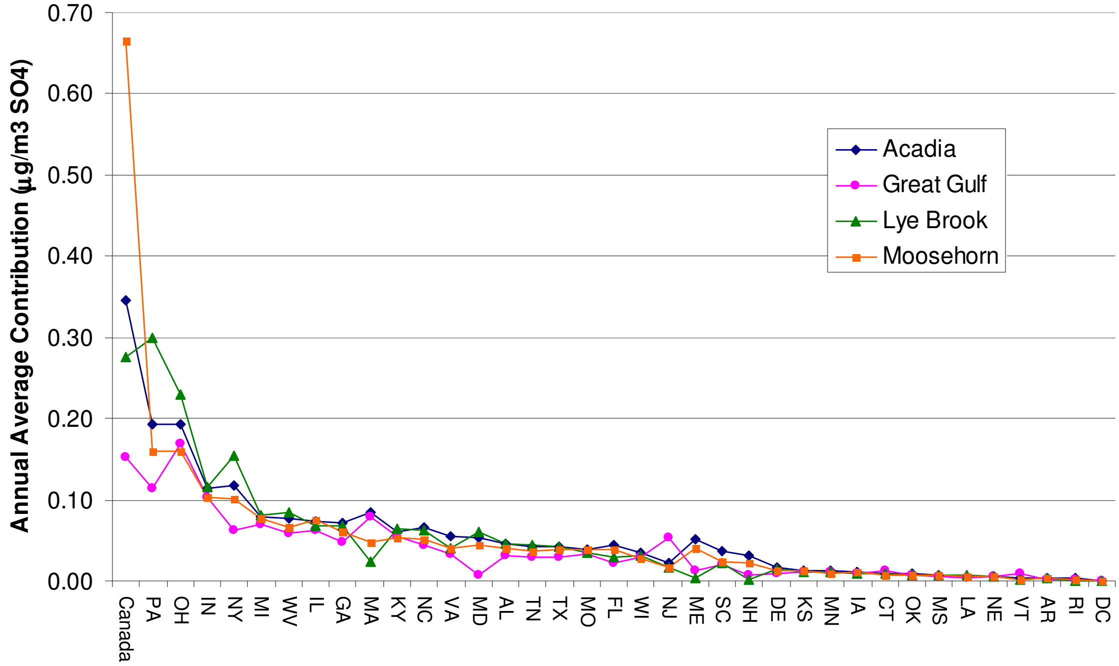
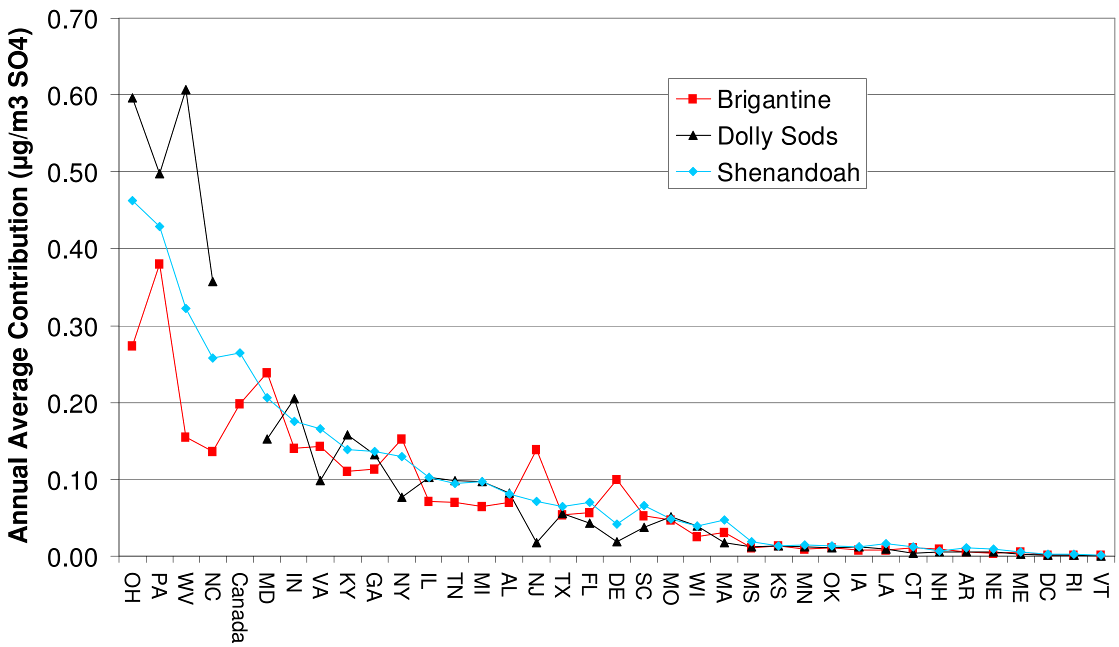


Figure 8.3: Ranked Sulfate Contributions to Mid-Atlantic Class I Receptors Based on Q/d Method (Mass Basis), by Location of Origin



The first of the Q/d plots covers the four northern Class I areas with IMPROVE monitoring in MANE-VU. The second covers one Class I area in the southern part of MANE-VU and two neighboring Class I areas in the VISTAS region. Observe, again, the comparative importance of emissions from Canada and from states outside the MANE-VU region.

The ranking of emission contributions to visibility impairment in the MANE-VU Class I Areas by methods such as these has direct relevance to the consultation process described previously in Section 3, Regional Planning and Consultation. Using results from the REMSAD model, MANE-VU applied the following three criteria to identify states and regions for the purposes of consultation on regional haze:

1. Any state/region that contributed 0.1 $\mu g/m^3$ sulfate or greater on the 20 percent worst visibility days in the base year (2002),
2. Any state/region that contributed at least 2 percent of total sulfate observed on the 20 percent worst visibility days in 2002, and
3. Any state/region among the top ten contributors on the 20 percent worst visibility days in 2002.

For the purposes of deciding how broadly to consult, the MANE-VU States settled on the second of the three criteria: any state/region that contributed at least 2 percent of total sulfate observed on the 20 percent worst visibility days in 2002.

In Figures 8.4 through 8.10, below, states and regions meeting the three listed criteria are identified graphically for seven Class I areas: Shenandoah and Dolly Sods are Class I areas in the VISTAS region that are impacted by emissions from MANE-VU states; the other five Class I areas are in MANE-VU. Note that the IMPROVE monitor at Great Gulf also represents the Presidential Range - Dry River Wilderness, and the IMPROVE monitor at Moosehorn also represents Roosevelt Campobello International Park.

Each figure has the following components:

- On the left is a single bar graph of the IMPROVE-monitored $PM_{2.5}$ mass concentration ($\mu g/m^3$) by constituent species for the baseline years 2000-2004. The yellow, bottom portion of the bar represents the measured sulfate concentration.
- The middle component of each figure provides a bar graph of the 2002 total sulfate contribution of each state or region as estimated by REMSAD.
- Finally, the right segment contains three maps showing which states meet the criteria described above.

Connecticut, Rhode Island, Vermont, and the District of Columbia were not identified as being among the political or regional units contributing at least 2 percent of sulfate at any of the seven Class I areas. However, as participants in MANE-VU, those entities have agreed to pursue adoption of regional control measures aimed at visibility improvement on the haziest days and prevention of visibility degradation on the clearest days.

Figure 8.4: Modeled 2002 Contributions to Sulfate at Great Gulf, by State

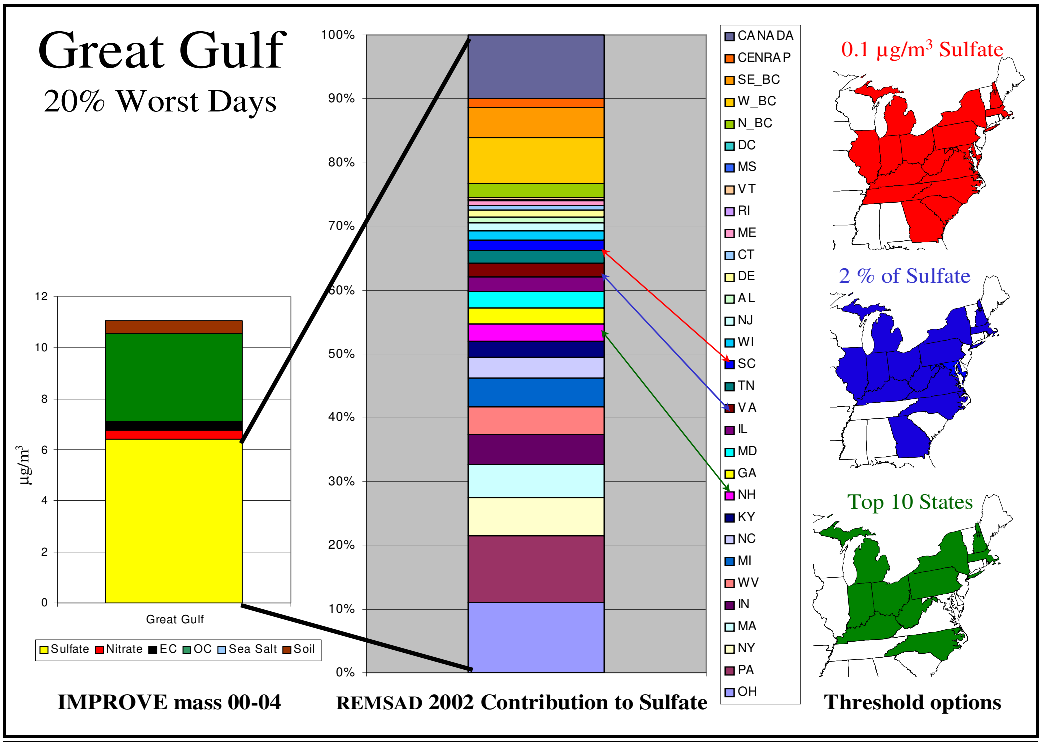


Figure 8.5: Modeled 2002 Contributions to Sulfate at Brigantine, by State

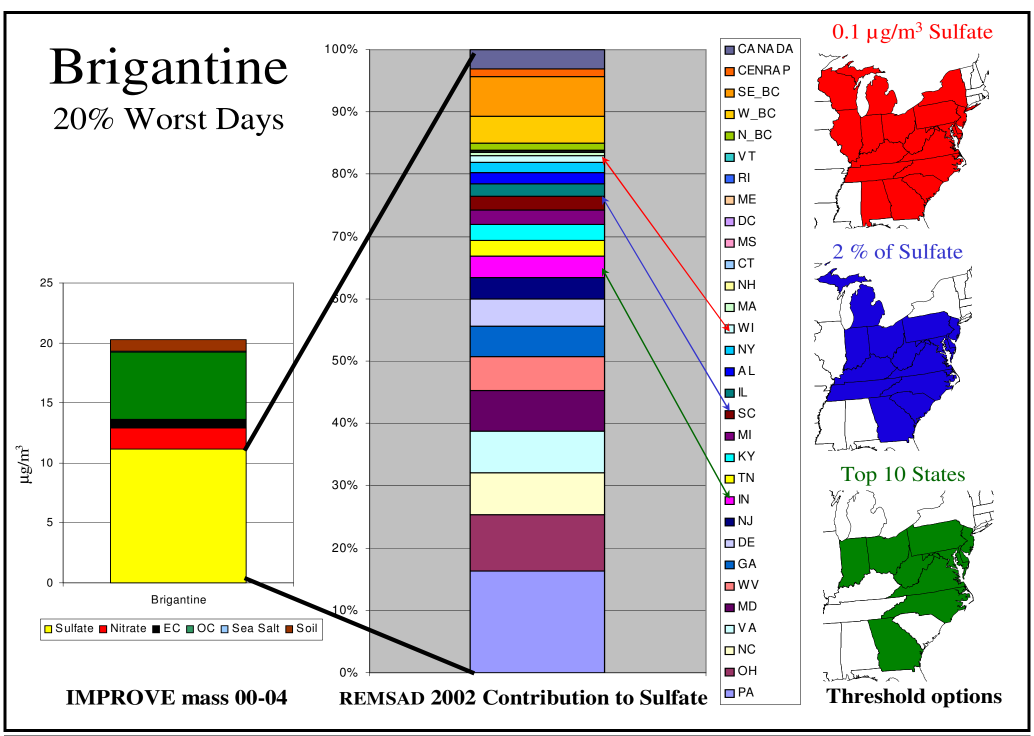


Figure 8.6: Modeled 2002 Contributions to Sulfate at Lye Brook, by State

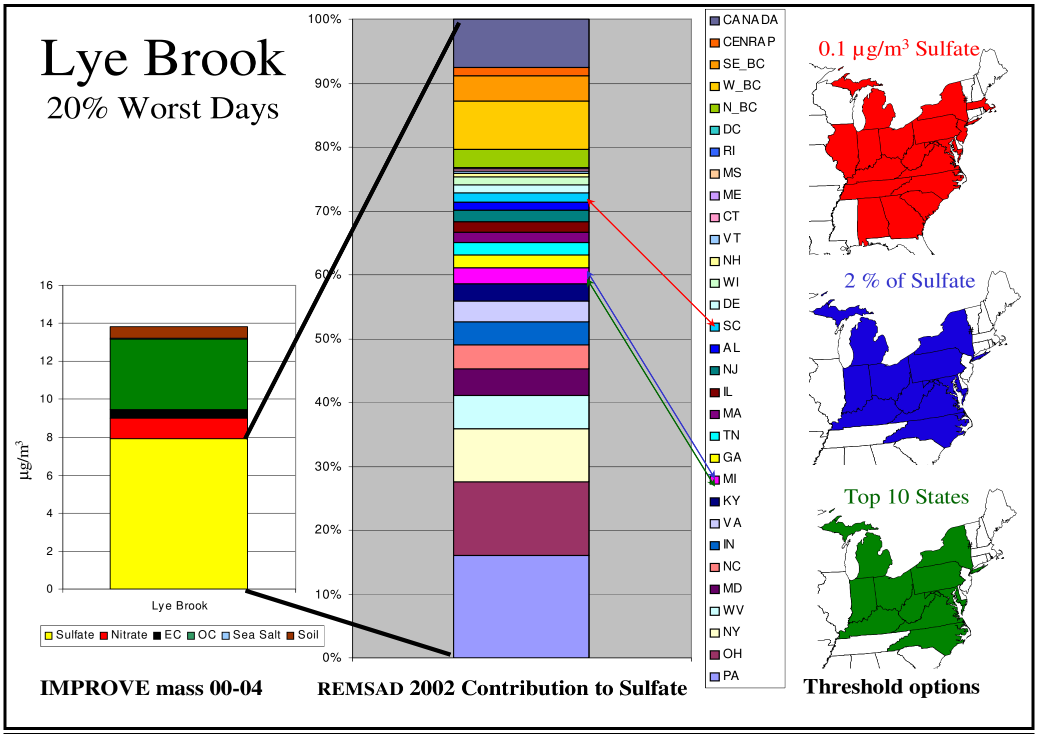


Figure 8.7: Modeled 2002 Contributions to Sulfate at Acadia, by State

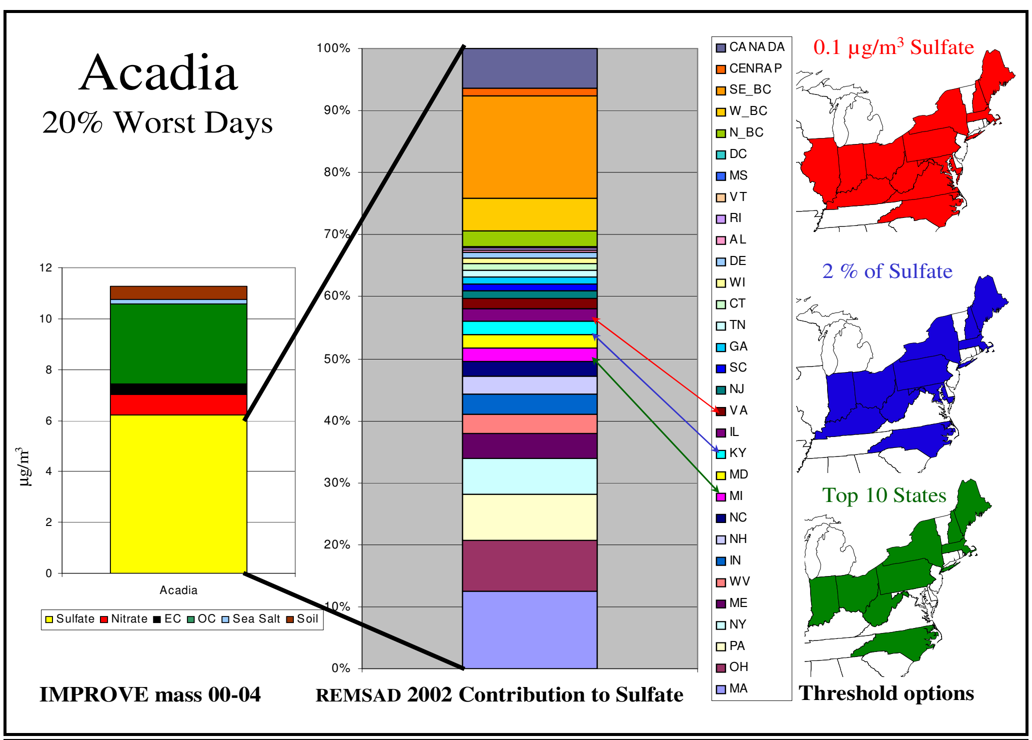


Figure 8.8: Modeled 2002 Contributions to Sulfate at Moosehorn, by State

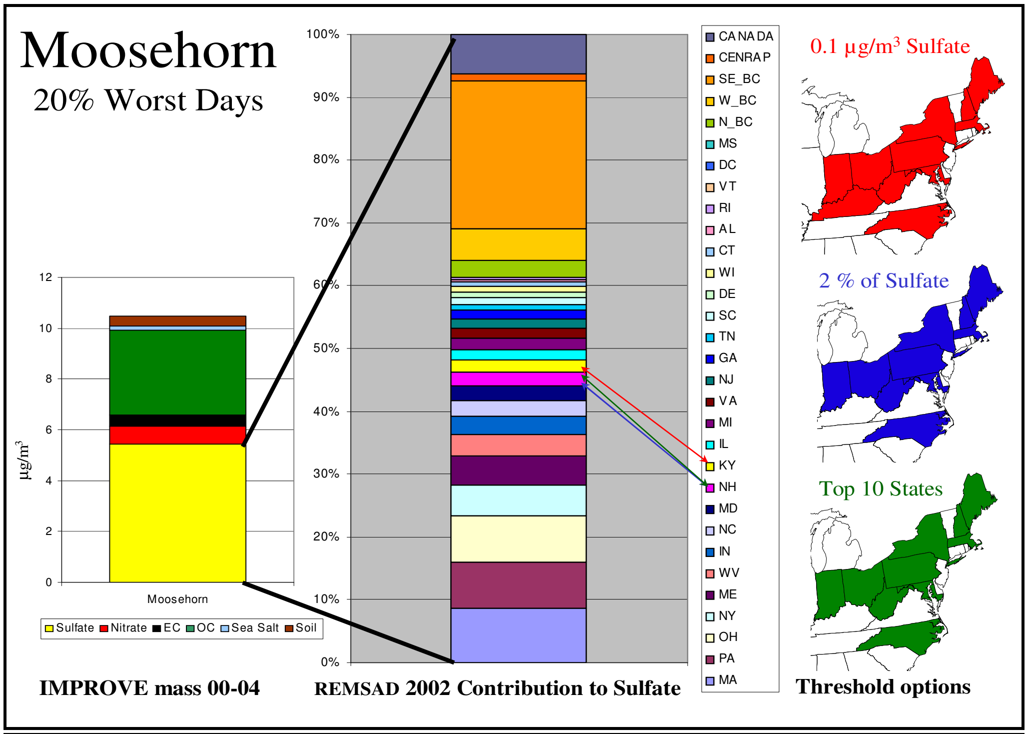


Figure 8.9: Modeled 2002 Contributions to Sulfate at Shenandoah, by State

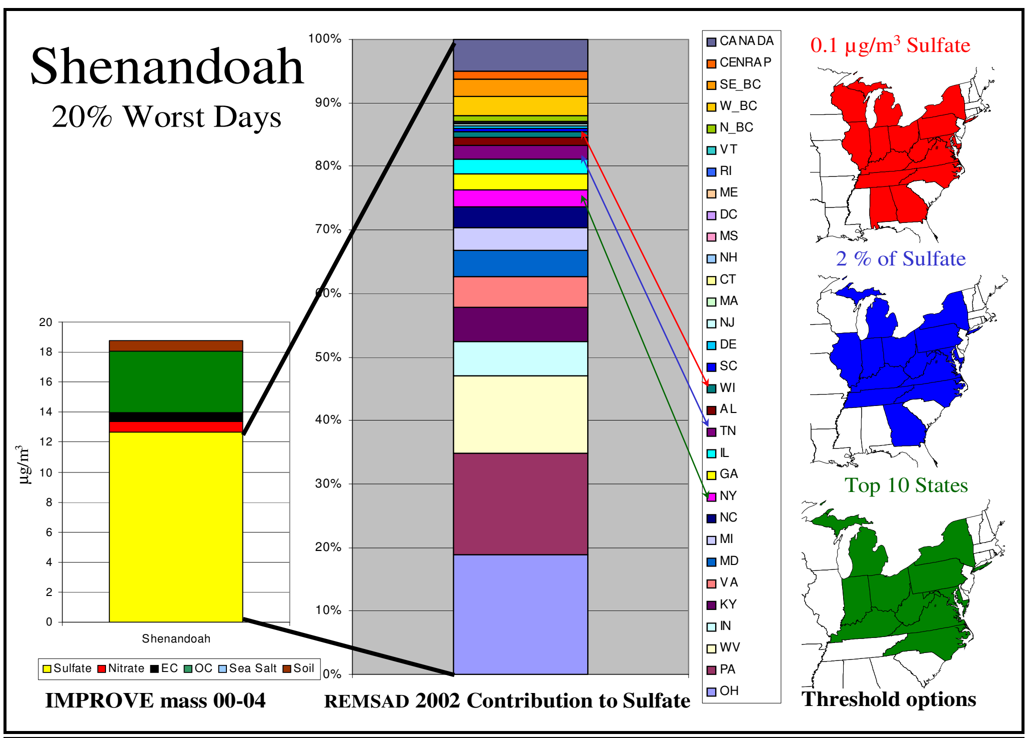
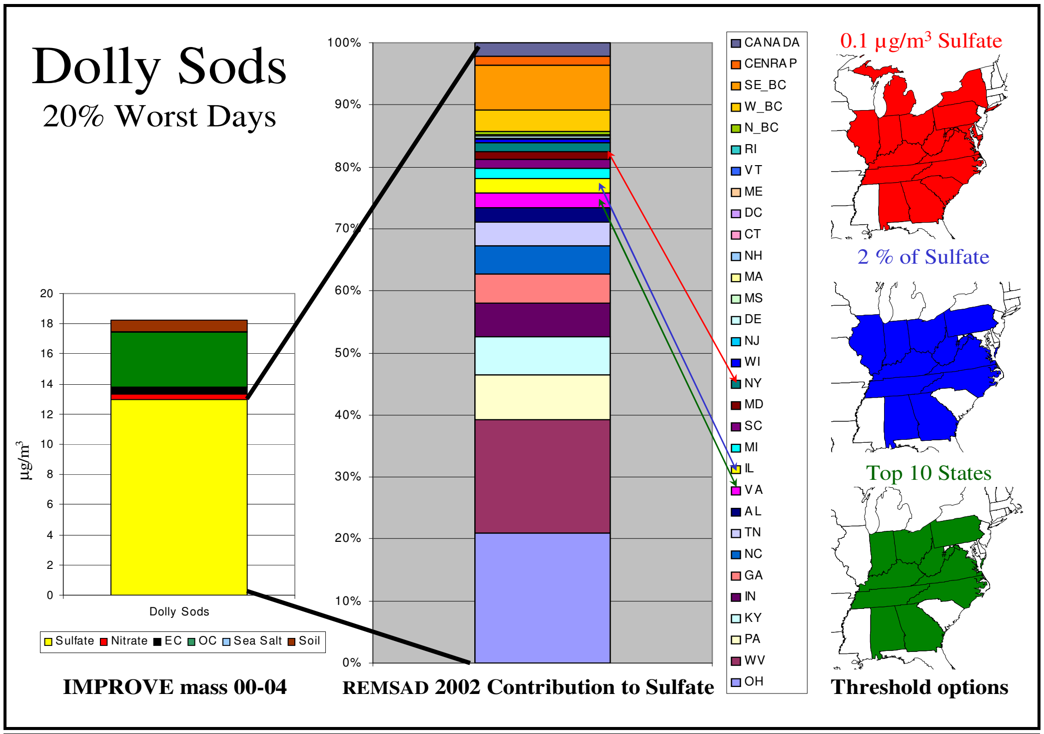


Figure 8.10: Modeled 2002 Contributions to Sulfate at Dolly Sods, by State



8.3 Emission Sources and Characteristics

As previously mentioned, the major pollutants responsible for regional haze are SO_2, NO_X, VOCs, NH_3, PM_{10}, and $PM_{2.5}$. The following is a description of the sources (e.g., point, area, and mobile) and characteristics of pollutant emissions contributing to haze in the eastern United States. Emissions data and graphics presented for the purposes of this section are taken from the MANE-VU 2002 Baseline Emissions Inventory, Version 2.0 (note that the more recent MANE-VU 2002 Baseline Emissions Inventory, Version 3.0, released in April 2006, has superseded Version 2.0 for modeling purposes). Although the emissions inventory database also includes carbon monoxide (CO), this primary pollutant is not considered here because it does not contribute to regional haze.

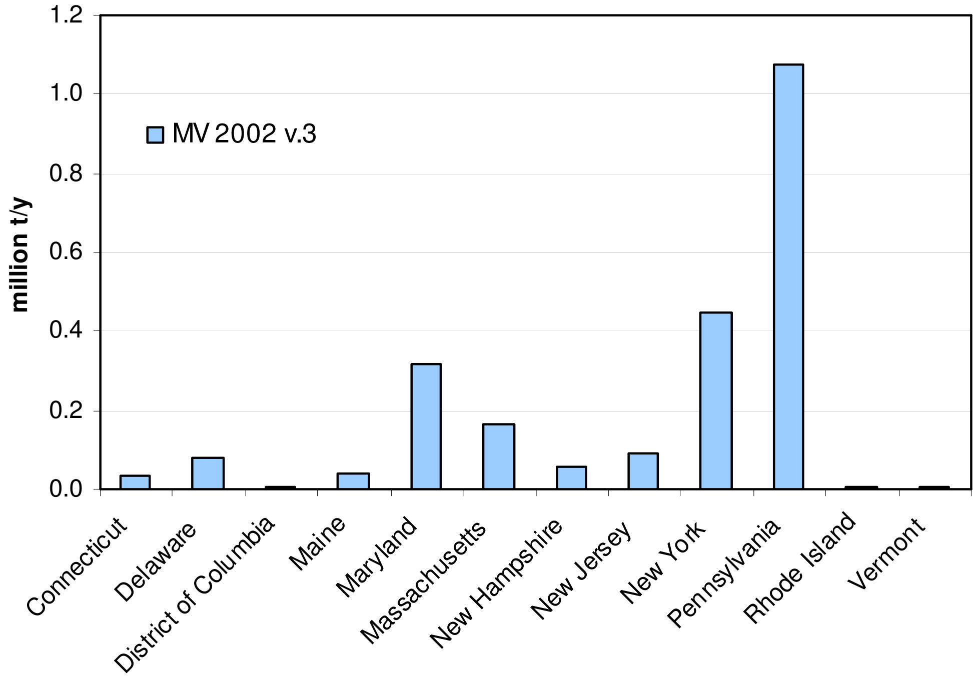
8.3.1 Sulfur Dioxide (SO_2)

SO_2 is the primary precursor pollutant for sulfate particles. Sulfate particles commonly account for more than 50 percent of particle-related light extinction at northeastern Class I areas on the clearest days and for as much as 80 percent or more on the haziest days. Hence, SO_2 emissions are an obvious target of opportunity for reducing regional haze in the eastern United States. Combustion of coal and, to a lesser extent, of certain petroleum products accounts for most anthropogenic SO_2 emissions. In fact, in 1998, a single source category – coal-burning power plants – was responsible for two-thirds of total SO_2 emissions nationwide (NESCAUM, 2001a).

Figure 8.11 shows SO_2 emissions in the MANE-VU states as extracted from the 2002 MANE-VU inventory (MARAMA, 2005). Most states in the region showed declines in annual SO_2 emissions through 2002 compared with those from previous inventories.

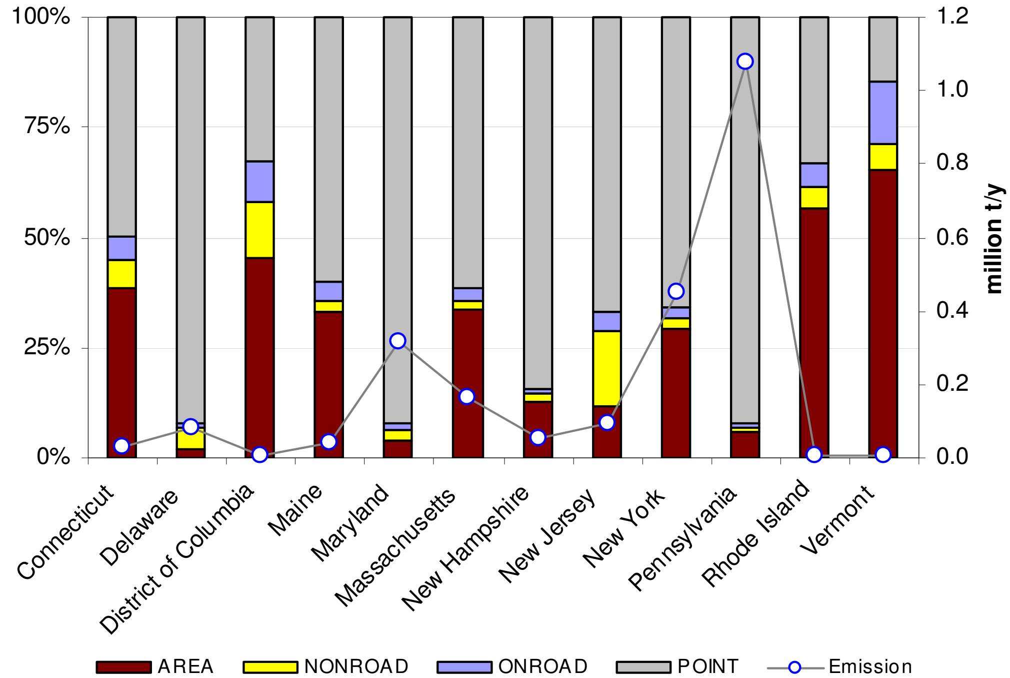
This decline can be attributed in part to implementation of Phase 2 of the Acid Rain Program, which in 2000 further reduced allowable emissions below Phase 1 levels and extended emission limits to a greater number of power plants.

Figure 8.11: Annual Sulfur Dioxide (SO_2) Emissions, by State



The bar graph in Figure 8.12 displays the percentage contributions from different emission source categories to annual SO_2 emissions in the MANE-VU states in 2002. The chart shows that point sources – consisting mainly of stationary combustion sources for generating electricity, industrial power, and heat – dominate SO_2 emissions in the region. Smaller stationary combustion sources, referred to collectively as area sources, are another important source category in the MANE-VU states. These include smaller industrial, commercial, and institutional boilers as well as residential heating sources. By contrast, on-road and non-road mobile sources make a relatively minor contribution to overall SO_2 emissions in the region (NESCAUM, 2001a).

Figure 8.12: 2002 Sulfur Dioxide (SO_2) Emissions, by State
Bar Graph = Percentage Fractions of Four Source Categories
Line Graph = Total Annual Emissions (10^6 tpy)



8.3.2 Volatile Organic Compounds (VOC)

Existing emissions inventories generally refer to volatile organic compounds (VOCs) as hydrocarbons whose volatility and reactivity in the atmosphere make them particularly important to ozone formation. From a regional haze perspective, there is less concern with the volatile organic gases emitted directly to the atmosphere than with the secondary organic aerosols (SOAs) that VOCs form after undergoing condensation and oxidation. Thus the VOC inventory category is of interest primarily because of the organic carbon component of $PM_{2.5}$.

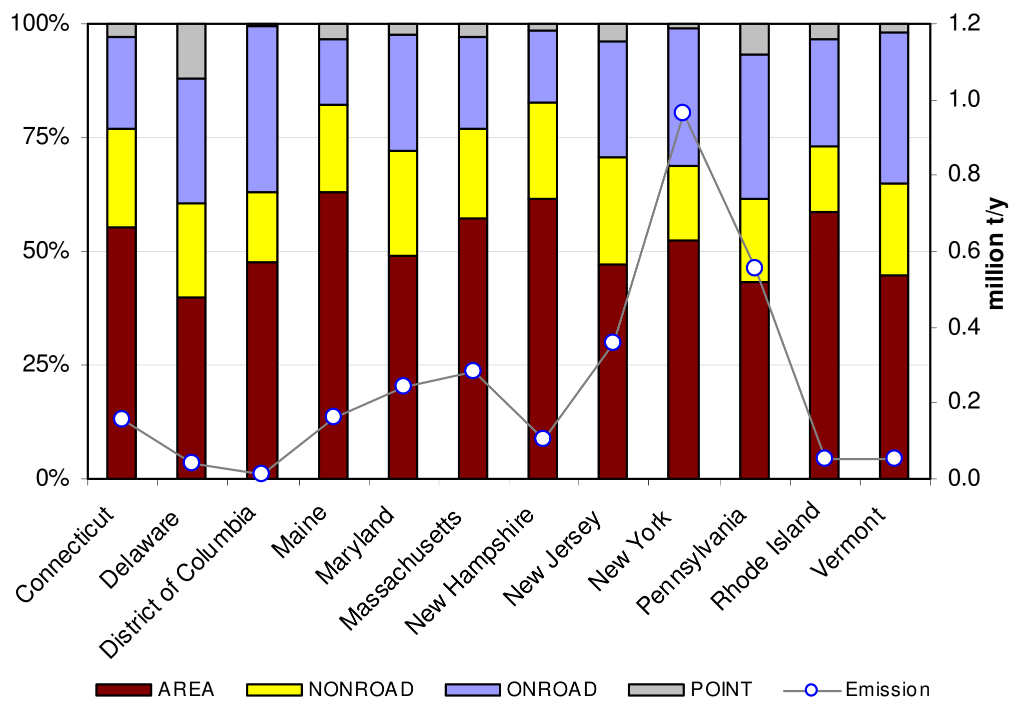
After sulfate, organic carbon generally accounts for the next largest share of fine particle mass and particle-related light extinction at northeastern Class I sites. The term organic carbon encompasses a large number and variety of chemical compounds that may be emitted directly from emission sources as components of primary PM or that may form in the atmosphere as secondary pollutants. The organic carbon present at Class I areas includes a mix of species, including pollutants originating from anthropogenic (i.e., manmade) sources as well as biogenic hydrocarbons emitted by vegetation. Recent efforts to cut back on manmade organic carbon emissions have been undertaken mainly for the purpose of reducing summertime ozone formation in urban centers. Future efforts to make further reductions in organic carbon emissions may be driven by programs that address fine particles and visibility.

Understanding the source regions and transport dynamics for organic carbon in MANE-VU and nearby Class I areas is likely to be more complex than for sulfate. This complexity derives from the large number and diversity of organic carbon species, the wide variation in their transport characteristics, and the fact that a given species may undergo numerous complex chemical reactions in the atmosphere. Thus, the organic carbon contribution to visibility impairment at most Class I areas in the region is likely to include manmade pollution from nearby sources, manmade pollution transported from a distance, and biogenic emissions – especially terpenes from coniferous forests.

As shown in Figure 8.13, the VOC inventory is dominated by mobile (on- and off-road) sources and area sources. Mobile sources of VOCs include evaporative emissions from transportation fuels and exhaust emissions from gasoline passenger vehicles and diesel-powered, heavy-duty vehicles. VOC emissions may also originate from a variety of area sources (including those that use organic solvents, architectural coatings, and dry cleaning fluids) as well as from some point sources (e.g., industrial facilities and petroleum refineries).

Biogenic VOCs (not included in Figure 8.13) may play an important role within the rural settings typical of Class I areas. The oxidation of hydrocarbon molecules containing seven or more carbon atoms is generally the most significant pathway for the formation of light-scattering organic aerosol particles (Odum et al., 1997). Smaller reactive hydrocarbons that may contribute significantly to urban smog (ozone) are less likely to play a role in organic aerosol formation, although it is noted that high ozone levels can have an indirect effect on visibility by promoting the oxidation of other available hydrocarbons, including biogenic emissions (NESCAUM, 2001a). In short, further work is needed to characterize the organic carbon contribution to regional haze in the MANE-VU states and to develop emissions inventories that will be of greater value for visibility planning purposes. As pointed out in Subsection 8.1, above, organic carbon could be the subject of future control measures to mitigate regional haze but is not the focus of initial planning.

Figure 8.13: 2002 Volatile Organic Carbon (VOC) Emissions, by State
Bar Graph = Percentage Fractions of Four Source Categories
Line Graph = Total Annual Emissions (10^6 tpy)



8.3.3 Oxides of Nitrogen (NO_X)

NO_X emissions contribute to visibility impairment in the eastern U.S. by forming light-scattering nitrate particles. Nitrate generally accounts for a substantially smaller fraction of fine particle mass and related light extinction than sulfate and organic carbon at northeastern Class I areas. Notably, nitrate may play a more important role in urban settings and in the wintertime. In addition, NO_X may have an indirect effect on summertime visibility by virtue of its role in the formation of ozone, which in turn promotes the formation of secondary organic aerosols (NESCAUM, 2001a).

Since 1980, nationwide emissions of NO_X from all sources have shown little change. Emissions increased by 2 percent between 1989 and 1998 (EPA, 2000a). To a large extent, increases from the industrial and transportation sectors have been offset by emission reductions from power plant combustion sources implemented during the same time period. Figure 8.14 shows NO_X emissions in 2002 for each state in the MANE-VU region. In the several years just prior to 2002, most MANE-VU states experienced declining NO_X emissions.

Mobile sources and power plants generally dominate state and national NO_X emissions inventories. Nationally, power plants account for more than one-quarter of all NO_X emissions, amounting to over six million tons annually. The electric sector plays an even larger role in parts of the industrial Midwest, where power plants contribute significantly to NO_X emissions. By contrast, mobile sources dominate the NO_X inventories for more urbanized MANE-VU states, as shown in Figure 8.15. In these states, on-road mobile sources (i.e., highway vehicles) represent the largest NO_X source category. Emissions from non-road (i.e., off-highway) mobile sources, primarily diesel-powered engines, also make up a substantial fraction of the inventory.

Figure 8.14: Annual Nitrogen Oxide (NO_X) Emissions, by State

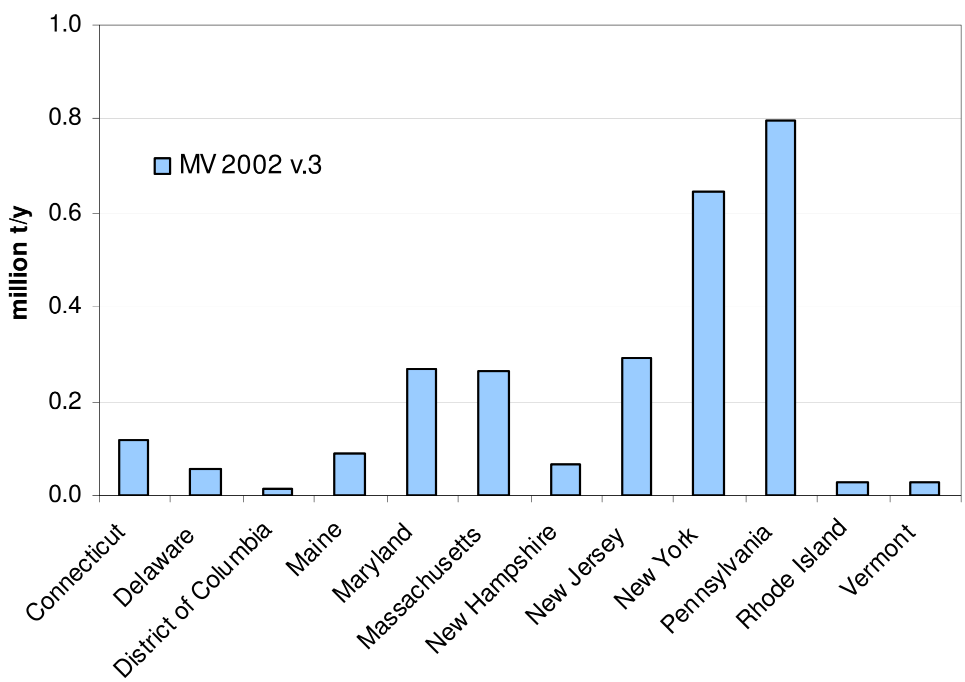
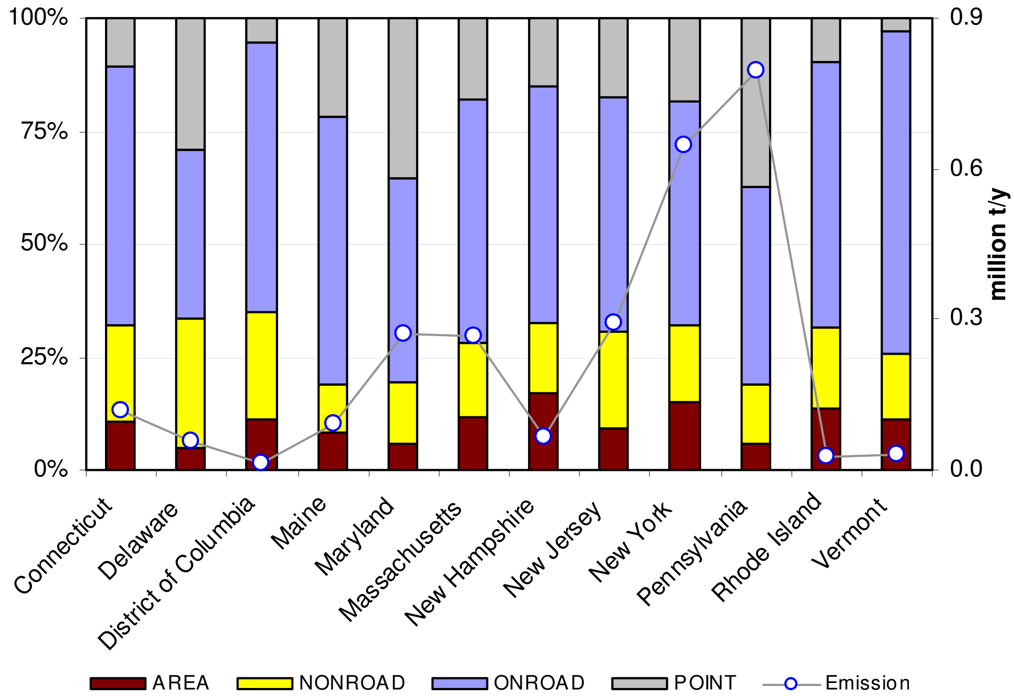


Figure 8.15: 2002 Nitrogen Oxide (NO_X) Emissions, by State
Bar Graph = Percentage Fractions of Four Source Categories
Line Graph = Total Annual Emissions (10^6 tpy)



8.3.4 Primary Particulate Matter (PM_{10} and $PM_{2.5}$)

Directly emitted, or "primary," particles (as distinct from secondary particles that form in the atmosphere through chemical reactions involving precursor pollutants such as SO_2 and NO_X) can also contribute to regional haze. For regulatory purposes, a distinction is made between particulate matter (PM) with an aerodynamic diameter less than or equal to 10 micrometers (PM_{10}) and smaller particles with an aerodynamic diameter less than or equal to 2.5 micrometers ($PM_{2.5}$).

Figures 8.16 and 8.17 show PM_{10} and $PM_{2.5}$ emissions, respectively, for the MANE-VU states as reported for the 2002 base year. Most states showed a steady decline in annual PM_{10} emissions in the years leading up to the 2002 inventory. By contrast, emission trends for primary $PM_{2.5}$ were more variable.

Crustal sources are significant contributors of primary PM emissions. This category includes fugitive dust emissions from construction activities, paved and unpaved roads, and agricultural tilling. Typically, monitors estimate PM_{10} emissions from these types of sources by measuring the horizontal flux of particulate mass at a fixed downwind sampling location within perhaps 10 meters of a road or field. Comparisons between estimated emission rates for fine particles using these types of measurement techniques and observed concentrations of crustal matter in the ambient air at downwind receptor sites suggest that physical or chemical processes remove a significant fraction of crustal material relatively quickly. As a result, it rarely entrains into layers of the atmosphere where it can be transported to downwind receptor locations. Because of this discrepancy between estimated emissions and observed ambient concentrations, modelers typically reduce estimates of total $PM_{2.5}$ emissions from all crustal sources by applying a factor of 0.15 to 0.25 to the total $PM_{2.5}$ emissions before including them in modeling analyses.

Figure 8.16: Primary Coarse Particle (PM_{10}) Emissions, by State

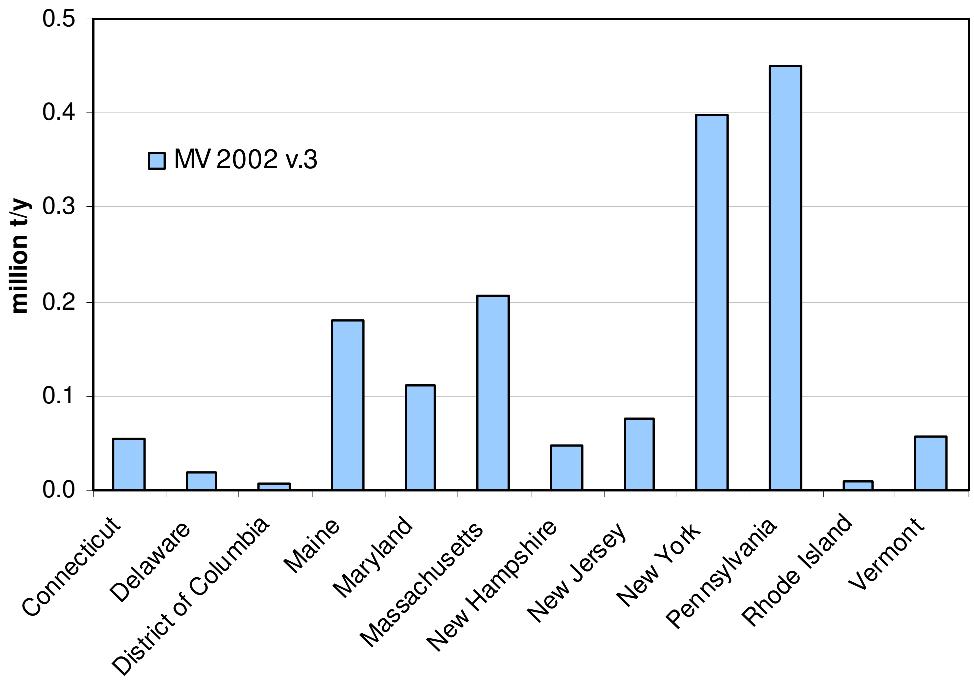
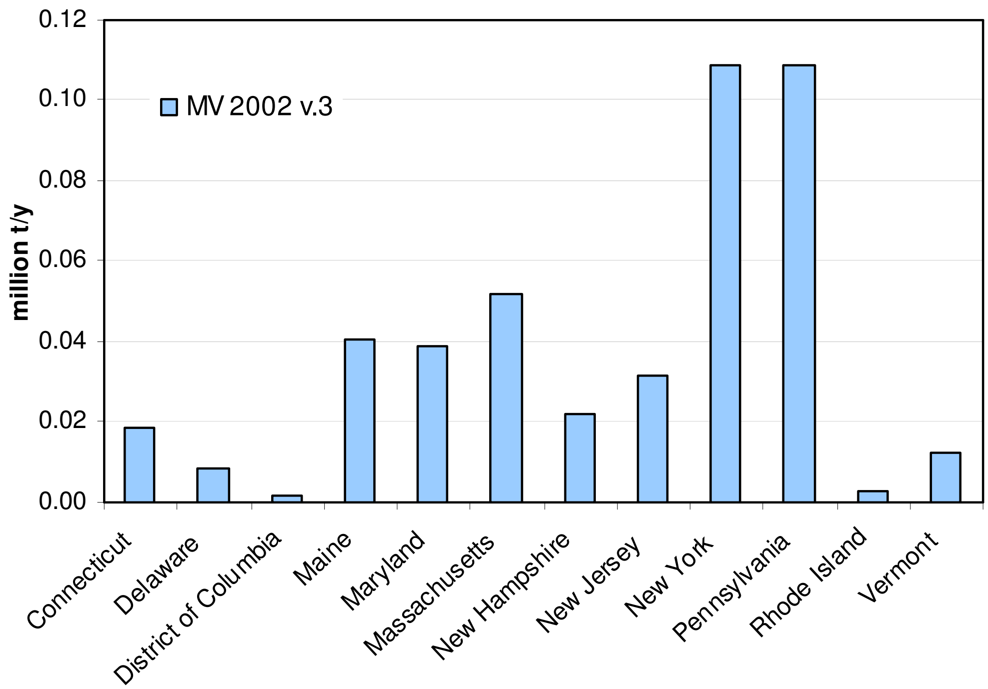


Figure 8.17: Primary Fine Particle ($PM_{2.5}$) Emissions, by State



From a regional haze perspective, crustal material generally does not play a major role. On the 20 percent best visibility days during the baseline period (2000-2004), crustal PM accounted for six to eleven percent of particle-related light extinction at MANE-VU Class I sites. On the 20 percent worst visibility days, however, crustal material generally plays a much smaller role, ranging from two to three percent visibility extinction, than other haze-forming pollutants. Moreover, the crustal fraction includes materials of natural origin, such as soil or sea salt, that is not targeted under the Regional Haze Rule. Of course, the crustal fraction can be influenced by construction, agricultural practices, and road maintenance (including wintertime salting). Thus, to the extent that these types of activities are found to affect visibility at Northeastern Class I areas, control measures to reduce coarse and fine particulate matter deriving from crustal material may prove beneficial and are within the purview of EPA or state agencies.

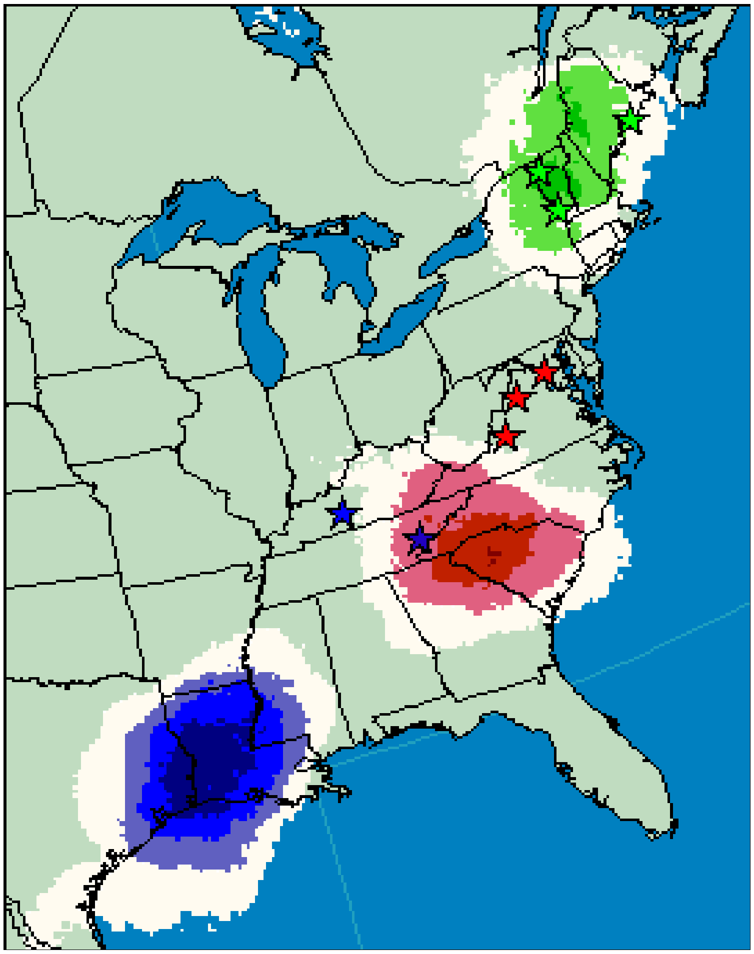
Experience from the western United States, where the crustal component has played a more significant role in overall particulate levels, may be applicable to the extent that it is relevant to the situation in the eastern states. In addition, a few areas in the Northeast, such as New Haven, Connecticut, and Presque Isle, Maine, have had some experience with the control of dust and road-salt stemming from regulatory obligations related to their past non-attainment status with respect to the NAAQS for PM_{10}.

Current emissions inventories for the entire MANE-VU area indicate that residential wood combustion represents 25 percent of primary fine particle emissions in the region. This finding implies that rural sources can play an important role as well as contributions from the region's many populous urban areas. An important consideration in this regard is that residential wood combustion occurs mainly in the winter months, while managed or prescribed burning activities occur largely in other seasons. The latter category includes agricultural field-burning, prescribed burning of forested areas, and miscellaneous burning activities such as construction waste burning. Particulate emissions from many of these sources can be managed by limiting allowed burning activities to times when favorable meteorological conditions can efficiently disperse the emissions.

Although data are currently lacking, New Hampshire and other MANE-VU states are concerned about the growing use of residential wood stoves by homeowners seeking alternatives to petroleum-based fuels for home heating. Recent, localized problems with smoke emissions from outdoor wood boilers (wood-fired hydronic heaters) prompted the New Hampshire legislature, in August 2008, to pass a law that tightens requirements on the sale, installation, and use of these devices. NHDES will keep close watch on smoke emissions from the residential sector to determine whether additional control measures on this source category may be necessary in the next few years.

Figure 8.18, taken from Appendix B of the MANE-VU Contribution Assessment, represents the results of source apportionment and trajectory analyses on wood smoke in the area extending from the Gulf States to the Northeast. The green-highlighted portion of the map depicts the wood smoke source region in the Northeast states. The stars on the map represent air monitor sites (including those at several Class I areas) whose data sets were determined to be useful to the modeling analysis. Although New Hampshire's Great Gulf Wilderness was not specifically analyzed, it is believed that the green portion of the map adequately characterizes the wood smoke source region in the vicinity of this Class I area.

Figure 8.18: Wood Smoke Source Regional Aggregations



Northeast: ACAD, PMRC, LYBR
Mid-Atlantic: WASH, SHEN, JARI
Southeast: GRSM, MACA

MANE-VU's "Technical Support Document on Agricultural and Forestry Smoke Management in the MANE-VU Region," September 1, 2006 (Attachment V), concluded that fire from land management activities was not a major contributor to regional haze in MANE-VU Class I Areas, and that the majority of emissions from fires were from residential wood combustion.

Figures 8.19 and 8.20 show that area sources dominate primary PM emissions. (EPA's National Emissions Inventory categorizes residential wood combustion and some other combustion sources as area sources.) The relative contribution of point sources is larger in the primary $PM_{2.5}$ inventory than in the primary PM_{10} inventory because the crustal component of particulate emissions (consisting mainly of larger, or coarse, particles) contributes more to overall PM_{10} levels than to $PM_{2.5}$ levels. At the same time, pollution control equipment commonly installed at large point sources is usually more efficient at capturing coarse particle emissions.

Figure 8.19: 2002 Primary Coarse Particle (PM_{10}) Emissions, by State
Bar Graph = Percentage Fractions of Four Source Categories
Line Graph = Total Annual Emissions (10^6 tpy)

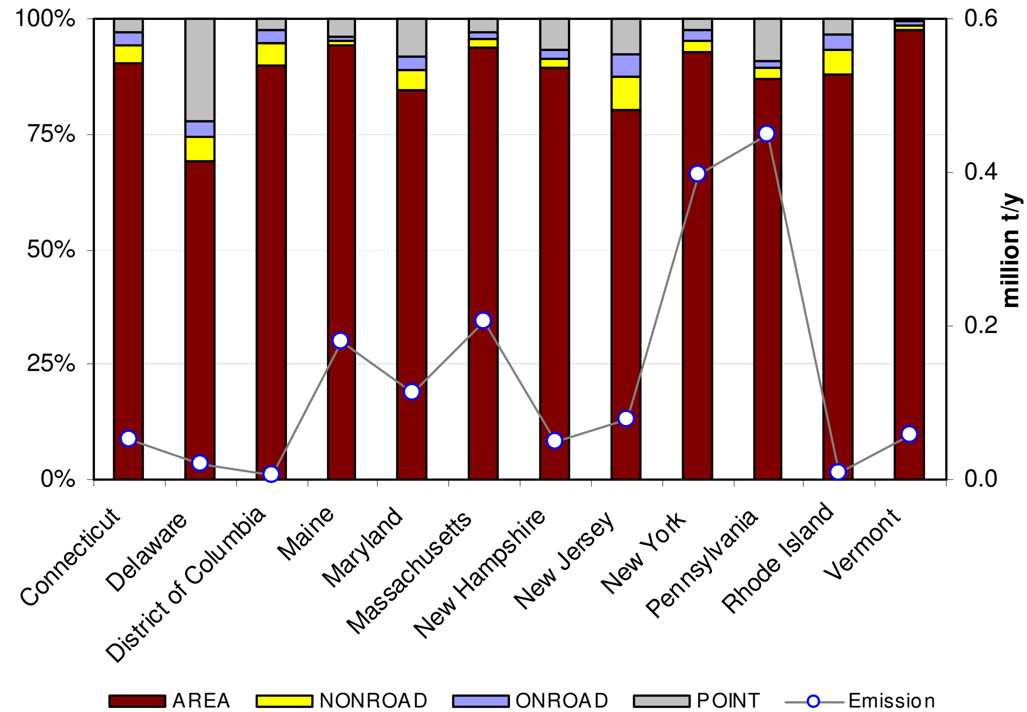
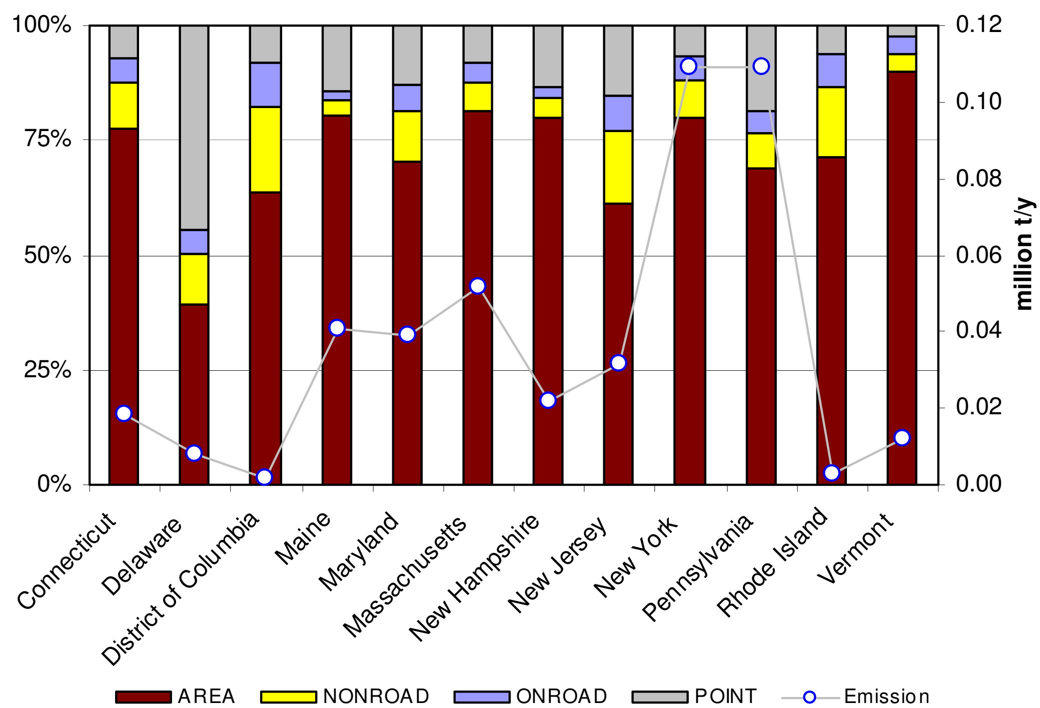


Figure 8.20: 2002 Primary Fine Particle ($PM_{2.5}$) Emissions, by State
Bar Graph = Percentage Fractions of Four Source Categories
Line Graph = Total Annual Emissions (10^6 tpy)



8.3.5 Ammonia Emissions (NH_3)

Because ammonium sulfate ($(NH_3)_2SO_4$) and ammonium nitrate (NH_3NO_3) are significant contributors to atmospheric light scattering and fine particle mass, knowledge of ammonia emission sources is important to the development of effective regional haze reduction strategies. According to 1998 estimates, livestock agriculture and fertilizer use accounted for approximately 86 percent of all ammonia emissions to the atmosphere (EPA, 2000b). However, improved ammonia inventory data are needed as inputs to the photochemical models used to simulate fine particle formation and transport in the eastern United States. States were not required to include ammonia in their emissions data collection efforts until fairly recently (see the Consolidated Emissions Reporting Rule, 67 CFR 39602, June 10, 2002). Therefore, emissions data for ammonia do not exist at the same level of detail or reliability as exists for other pollutants.

Ammonium ion (formed from ammonia emissions to the atmosphere) is an important constituent of airborne particulate matter, typically accounting for 10–20 percent of total fine particle mass. Reductions in ammonium ion concentrations can be instrumental to controlling regional haze because such reductions yield proportionately greater reductions in fine particle mass. Ansari and Pandis (1998) showed that a 1 $\mu g/m^3$ reduction in ammonium ion could result in up to a 4 $\mu g/m^3$ reduction in fine particulate matter. Decision makers, however, must weigh the benefits of ammonia reduction against the significant role it plays in neutralizing acidic aerosol.[14]

To address the need for improved ammonia inventories, MARAMA, NESCAUM, and EPA funded researchers at Carnegie Mellon University (CMU) in Pittsburgh to develop a regional ammonia inventory (Davidson et al., 1999). This study focused on three issues with respect to current emission estimates: 1) a wide range of ammonia emission factors, 2) inadequate temporal and spatial resolution of ammonia emissions estimates, and 3) a lack of standardized ammonia source categories.

The CMU project established an inventory framework with source categories, emission factors, and activity data that are readily accessible to the user. With this framework, users can obtain data in a variety of formats[15] and can make updates easily, allowing additional ammonia sources to be added or emission factors to be replaced as better information becomes available (Strader et al., 2000; NESCAUM, 2001b).

Figures 8.21 and 8.22 show estimated ammonia emissions for the MANE-VU states in 2002. Area and on-road mobile sources dominate the ammonia inventory data. Specifically, emissions from agricultural sources and livestock production account for the largest share of estimated ammonia emissions in the MANE-VU region, except in the District of Columbia. The two other sources contributing significant emissions are wastewater treatment systems and gasoline exhaust from highway vehicles.

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[14] SO_2 reacts in the atmosphere to form sulfuric acid (H_2SO_4). Ammonia can partially or fully neutralize this strong acid to form ammonium bisulfate or ammonium sulfate. If planners focus future control strategies on ammonia and do not achieve corresponding SO_2 reductions, fine particles formed in the atmosphere will be substantially more acidic than those presently observed.

[15] For example, the user will have the flexibility to choose the temporal resolution of the output emissions data or to spatially attribute emissions based on land-use data.

Figure 8.21: Ammonia (NH_3) Emissions, by State

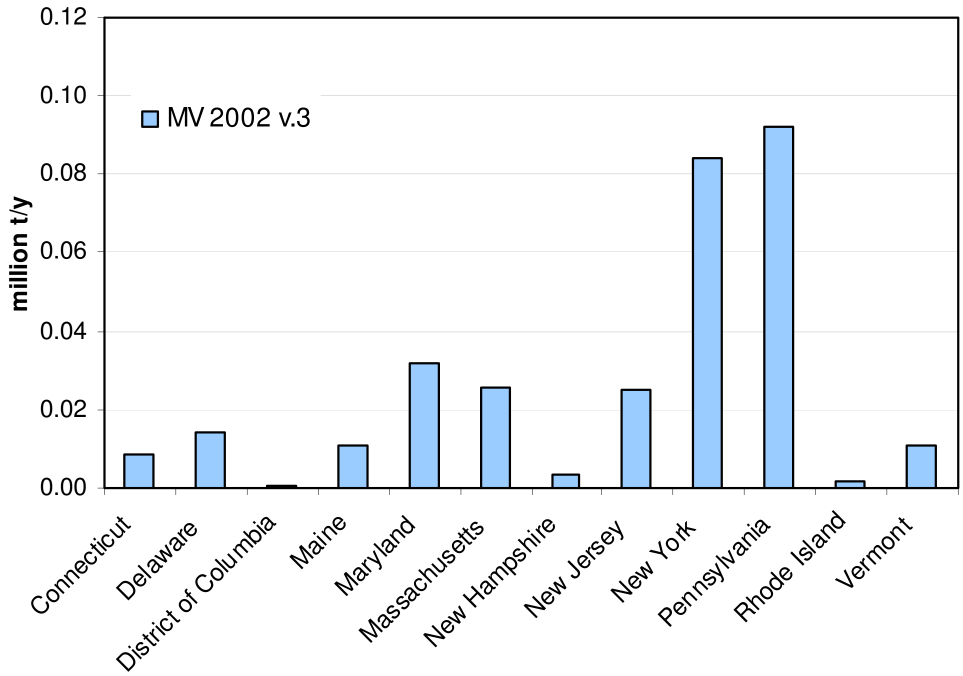
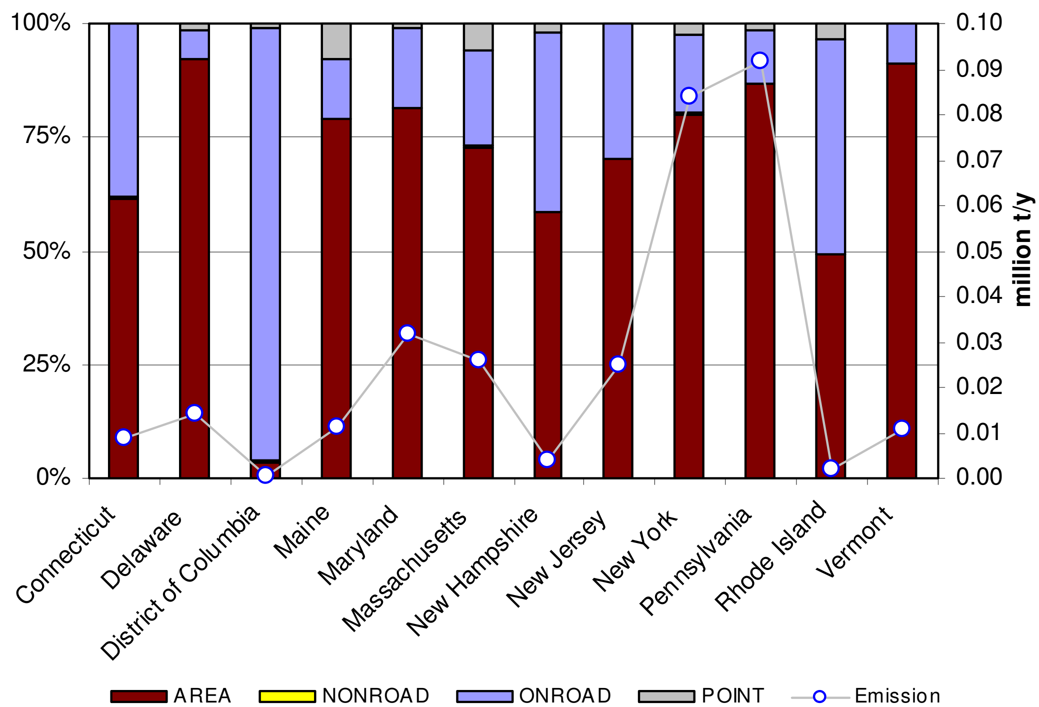


Figure 8.22: 2002 Ammonia (NH_3) Emissions, by State
Bar Graph = Percentage Fractions of Four Source Categories
Line Graph = Total Annual Emissions (10^6 tpy)



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9. BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

In the Regional Haze Rule, EPA included provisions for reducing emissions of visibility-impairing pollutants from large sources that, because of their age, were exempted from new source performance standards (NSPS) established under the Clean Air Act. These provisions, known as Best Available Retrofit Technology, or BART, are published in 40 CFR 51.308(e).

Under this part of the rule, New Hampshire is required to submit an implementation plan containing emission limitations representing Best Available Retrofit Technology and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I area. This requirement applies unless New Hampshire demonstrates that an emissions trading program or other alternative will achieve greater reasonable progress toward natural visibility conditions. New Hampshire, with the help of the MANE-VU Regional Planning Organization, has developed a strategy meeting the requirements of BART. This section of the SIP specifically addresses how New Hampshire's plan satisfies BART requirements. A more general description of BART implementation within MANE-VU is presented later in Part 10.2.2 of Section 10, Reasonable Progress Goals.

The BART provisions of the Regional Haze Rule require states to develop an inventory of sources within each state that would be eligible for BART controls. The rule also:

- Outlines methods to determine whether a source is "reasonably anticipated to cause or contribute to haze,"
- Defines the methodology for conducting BART control analysis,
- Provides presumptive performance levels for electricity generating units (EGUs) greater than 200 MW at fossil-fuel-fired power plants larger than 750 megawatts (all BART-eligible EGUs in New Hampshire are below this size); and
- Provides a justification for the use of the Clean Air Interstate Rule (CAIR) as meeting BART requirements for CAIR-affected electrical generating units (EGUs). (Note: With the remand of CAIR and its replacement with the proposed Transport Rule, EPA's previous determination of regulatory equivalency is invalid. New Hampshire has always held that, because the old CAIR requirements were not source-specific, they should not, in the general case, be considered equivalent to BART requirements, which *are* source-specific.)

Beyond the specific elements listed above, EPA has allowed the states a great deal of flexibility in implementing the BART program. Because of the collective importance of BART sources to the management of regional haze, the MANE-VU Board decided, in June 2004, that a BART determination would be made by the member states for each BART-eligible source, without exception. **Consequently, New Hampshire has completed a BART analysis on all BART-eligible sources in the state.** This process includes consideration of the available technology, potential improvements in visibility, and other factors described later in this section.

9.1 BART Applicability

The BART requirements pertain to large facilities in each of 26 source categories that meet certain criteria, including industrial boilers, pulp and paper mills, cement kilns, and other large stationary sources. The BART program applies to units installed and operated between 1962 and 1977 with the potential to emit more than 250 tons per year of a visibility-impairing pollutant. Each BART-eligible unit must undergo a case-by-case analysis to determine whether new emission restrictions are appropriate to limit the unit's impact on visibility at Class I areas.

9.2 BART-Eligible Sources in New Hampshire

A list of New Hampshire's BART-eligible sources is presented in Table 9.1. These sources were identified using the methodology contained in 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule, adopted July 6, 2005.

Table 9.1: BART-Eligible Sources in New Hampshire

MANE-VU BART ID	Source and Unit	BART Pollutants	Location
NH1	Public Service of New Hampshire Merrimack Station <u>Unit MK2</u> 320-MW EGU	SO_2 NO_X PM	Bow, NH
NH2	Public Service of New Hampshire Newington Station <u>Unit NT1</u> 400-MW EGU	SO_2 NO_X PM	Newington, NH

Note: Both BART-eligible sources are located at power plants smaller than the 750-MW minimum size for which EPA has provided presumptive performance levels.

9.2.1 Cap-Outs and Shutdowns

Many facilities in the MANE-VU region are relatively small emission sources with potential emissions exceeding the BART applicability threshold of 250 tons per year of haze-causing pollutants but whose actual emissions are well below 250 tons in any year. Some of these facilities may have accepted an enforceable permit limitation restricting their emissions to less than 250 tons per year. Any otherwise BART-eligible facility may be allowed to "cap-out" of BART by accepting enforceable permit limits. In addition, some BART-eligible facilities within the region may have permanently shut down. **In New Hampshire, no BART-eligible facilities capped out or permanently shut down to avoid BART.**

9.2.2 Small Source Exemptions

As provided in 40 CFR 51.308(e)(1)(ii)I of the Regional Haze Rule, a state is not required to make a BART determination for either SO_2 or NO_X if a BART-eligible source has the potential to emit less than 40 tons per year of these pollutants, or for PM_{10} if a BART-eligible source emits less than 15 tons per year of this pollutant. **No BART-eligible sources in New Hampshire have been exempted from the BART determination process.**

9.2.3 Large Electrical Generating Units

Under 40 CFR 51.308(e)(1)(ii)(B), the determination of BART for large EGUs at fossil-fuel-fired power plants having a total generating capacity greater than 750 megawatts must follow the guidelines presented in 40 CFR Part 51, Appendix Y. This part of the rule defines the process for making BART determinations on a case-by-case basis. (States are not required to use this process when making BART determinations for other types of sources.) **Because all BART-eligible EGUs in New Hampshire are installed at power plants smaller than 750**

MW, they are not subject to the guidelines of 40 CFR Part 51, Appendix Y. However, as discussed in Subsection 9.4 below, NHDES has conducted a source-specific BART analysis using the Appendix Y guidelines for each of these EGUs.

9.3 Determination of BART Requirements for BART-Eligible Sources and Analysis of Best Retrofit Technologies

40 CFR 51.308(e)(1)(ii)(A) requires that, for each BART-eligible source within the state, any BART determination must be based on an analysis of the best system of continuous emission control technology available and the associated emission reductions achievable. In addition to considering available technologies, this analysis must evaluate five specific factors for each source:

1. The costs of compliance,
2. The energy and non-air quality environmental impacts of compliance,
3. Any existing pollution control technology in use at the source,
4. The remaining useful life of the source, and
5. The degree of visibility improvement which may reasonably be anticipated from the use of BART.

NESCAUM examined, from a regional perspective, the various options available to MANE-VU states for meeting these requirements. The findings are contained in the NESCAUM report "Five-Factor Analysis of BART Eligible Sources: Survey of Options for Conducting BART Determinations," June 1, 2007 (Attachment W).

9.3.1 BART Determinations and Required Control Levels

NHDES has performed BART determinations for all BART-eligible sources in New Hampshire. The BART level of control for each source was taken to be that level of continuous emission reductions that would be achieved by installation of the best retrofit system, after considering the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

For its BART determinations on each BART-eligible source, NHDES used the method in 40 CFR Part 51, Appendix Y, Guidelines for BART Determinations under the Regional Haze Rule. Detailed BART analyses for New Hampshire's two BART sources, PSNH Merrimack Station Unit MK2 and PSNH Newington Station Unit NT1, are presented in Attachment X. The application of BART to these two sources yields estimated emission reductions from the 2002 baseline year in the following amounts:

- Approximately 22,000 tons per year of sulfur dioxide,
- Approximately 100+ tons per year of nitrogen oxides, and
- No additional reduction in particulate matter (existing controls = BART).

Tables 9.2 and 9.3 summarize the BART determinations for the two BART-eligible sources in New Hampshire for the visibility-impairing pollutants SO_2, NO_X, and PM. Included in these tables are the baseline and BART control levels, BART emission limits, and annual emissions before and after BART implementation.

Table 9.2: Emission Reductions Resulting from BART Controls at PSNH Merrimack Station Unit MK2

Pollutant	BART Controls	Baseline Capacity Factor (%)	2002 Baseline Emissions (tpy)	Baseline Control Level (%)	BART Control Level (%)	BART Emission Limit	Est. 2002 Emissions after BART (tpy)	Est. 2002 Emission Reductions (tpy)
SO_2	Flue gas desulfurization (FGD) (July 1, 2013)	72	20,902	40 [16]	90 [17] (as initially modeled)	10% of uncontrolled SO_2 emissions, calendar monthly avg.	2,090	18,812
NO_X	Selective catalytic reduction (SCR) (existing)	72	2,871	85	85 (same as baseline)	0.30 lb/MMBtu, 30-day rolling average	2,871	122[18]
PM	Two electrostatic precipitators (ESPs) in series (existing)	72	210	99	99 (same as baseline)	0.08 lb/MMBtu total suspended particulate (TSP) [19]	210	0

Table 9.3: Emission Reductions Resulting from BART Controls at PSNH Newington Station Unit NT1

Pollutant	BART Controls	Baseline Capacity Factor (%)	2002 Baseline Emissions (tpy)	Baseline Control Level (%)	BART Control Level (%)	BART Emission Limit	Est. 2002 Emissions after BART (tpy)	Est. 2002 Emission Reductions (tpy)
SO_2	SO_2 emission limitation (July 1, 2013)	19 [20]	5,226	0	67 [21]	0.50 lb/MMBtu, 30-day rolling average	1,742	3,484 [22]
NO_X	Low-NOx burners, overfire air, and water injection (existing)	19	943	33 [23]	33 (same as baseline)	0.35 lb/MMBtu (oil) and 0.25 lb/MMBtu (oil/gas), daily avg. (= RACT limit)	943	0
PM	ESP (existing)	19	196	42 / 93 [24]	42 / 93 (same as baseline)	0.22 lb/MMBtu total suspended particulate (TSP)	196	0

[16] The 40% baseline level of control for Unit MK2 is based on a switch to a lower-sulfur coal that occurred in 1994.

[17] For modeling purposes, a control level of 90% from baseline 2002 SO_2 emissions has been applied as a conservative estimate of expected performance. The actual rate of reduction from baseline 2002 emissions will vary, depending on the sulfur content of coal used in future years. Unit MK2 will continue to be subject to Title V operating permit conditions that limit coal sulfur content to 2.0 lb/MMBtu gross heat content and that require SO_2 emissions to be controlled to no more than 10 percent of the uncontrolled SO_2 emission rate (i.e., 90% SO_2 removal).

[18] Estimated emission reductions from baseline that would occur with existing controls and a revised emission limit of 0.30 lb/MMBtu.

[19] This revised emission limit will simultaneously apply to Unit MK1 (not a BART-eligible source).

[20] The current Title V operating permit for PSNH Newington Station limits the annual capacity factor for Unit NT1 to 66.2%. This capacity factor limit is expressed as a restriction on the maximum annual heat input rating for the unit.

[21] Minimum expected reduction based on 100% use of residual fuel oil at 0.4% actual sulfur content, or a 50:50 ratio (Btu basis) of natural gas to residual fuel oil at 0.8% actual sulfur content. The reduction in maximum permitted SO_2 emissions is 75%.

[22] Additional emission reductions beyond the stated value may occur with a switch to 0.5% low-sulfur oil upon implementation of MANE-VU's low-sulfur oil strategy by no later than 2018.

[23] The baseline level of NO_X control was calculated by comparing emission test results from October 1992 (0.371 lb/MMBtu) to test results from 2001 (0.249 lb/MMBtu) after a number of NO_X reduction projects were completed on Unit NT1.

[24] The lower value is based on a 2001 stack test value of 0.058 lb/MMBtu and an AP42 uncontrolled emission factor of 0.103 lb/MMBtu. The higher value is the stated efficiency under normal operating conditions from a 1971 Buell Envirotech Corp. performance specification for this unit; maximum efficiency under design conditions is stated as 98 percent.

In Table 9.2, the BART control level for sulfur dioxide, for PSNH Merrimack station Unit MK2, is stated as 90 percent. This control level is based on implementation of New Hampshire statute RSA 125-O, Multiple Pollutant Reduction Program, which requires installation and operation of a flue gas desulfurization, or scrubber, system on both units at this facility. Because the scrubber will be optimized for mercury emission reductions, Unit MK2 may not experience the typical SO_2 removal efficiency of 95 percent associated with new FGD technology. Consequently, a more conservative SO_2 control level of 90 percent (minimum) was established as an operating condition in the facility's air permit. (The Multiple Pollutant Reduction Program requires the scrubber to operate at a sustained control level of 80 percent or greater for mercury emission reductions.) The required SO_2 control level effectively means that actual SO_2 emission reductions must *exceed* 90 percent on average.

The modest reduction in NOx emissions for Unit MK2 would result from operational changes with existing control equipment. These changes would be necessary to ensure compliance with a BART performance level of 0.30 lb/MMBtu, which is lower than the current effective emission limit of 0.37 lb/MMBtu.

In Table 9.3, for PSNH Newington Station Unit NT1, the BART control level for sulfur dioxide is based on an emission limitation of 0.50 lb/MMBtu, applicable to all fuels and fuel mixtures. (The boiler can be fired with either natural gas or liquid fuel (i.e., residual fuel oil or biofuel), or it can be co-fired with both types of fuel at the same time.) Note that SO_2 emissions from this unit may be further reduced with the planned introduction of 0.5-percent-sulfur residual fuel oil by 2018 upon implementation of MANE-VU's low-sulfur oil strategy (contingent on fuel availability and cost). See Parts 10.2.3 and 11.4.2 of this SIP for a detailed description of this control measure.

9.3.2 Visibility Improvements Resulting from BART

To assess the degree of visibility improvement associated with the implementation of BART controls, NHDES conducted a set of CALPUFF modeling runs for the New Hampshire BART-eligible sources under controlled and uncontrolled conditions. Results were tabulated for the average of the 20% worst natural visibility (about 11.7 to 12.4 dv) and the 20% worst baseline visibility (about 22.8 dv) modeled days at each nearby Class I area. The BART guidelines suggest that models be used in a "relative" way to estimate the expected visibility benefits of BART controls. NHDES normalized the CALPUFF modeling results, calculated predicted visibility extinctions, and then applied predicted extinctions to a best-fit equation to the actual observed extinction-to-deciview relationship measured at Acadia NP, Great Gulf NWR, and Lye Brook NWR. Thus, CALPUFF was applied in a relative way using real data as the basis. The CALPUFF-predicted visibility benefits from BART controls on the 20% worst natural and 20% worst baseline visibility days are shown in Tables 9-4 and 9-5 for New Hampshire's two BART facilities, Unit MK2 at PSNH Merrimack Station and Unit NT1 at PSNH Newington Station.

Further description of the assessment of visibility impacts from these two BART sources may be found in the detailed BART analyses presented in Attachment X.

Table 9-4. CALPUFF Modeling Results for Merrimack Station Unit MK2: Visibility Improvements from BART Controls

On the 20% ~~Best~~ Worst Natural Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	90% with FGD	1.07	0.83	**0.17**
NOx	Additional 25% with SCR upgrade	0.21	0.18	**0.10**
PM	90% with upgraded controls	0.16	0.12	**0.03**
On the 20% Worst Baseline Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	90% with FGD	**0.26**	**0.20**	0.03
NOx	Additional 25% with SCR upgrade	**0.07**	**0.06**	0.03
PM	90% with upgraded controls	**0.07**	**0.05**	<0.01*

* below sensitivity limit of model

Note: Values in **boldface** are considered as having greater validity in the modeling estimation of maximum visibility benefits from BART controls.

Table 9-5. CALPUFF Modeling Results for Newington Station Unit NT1: Visibility Improvements from BART Controls

On the 20% ~~Best~~ Worst Natural Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	FGD (90% sulfur reduction*)	0.57	0.45	0.09
	1.0%-S residual fuel oil (50% sulfur reduction*)	0.30	0.24	0.05
	0.5%-S residual fuel oil (75% sulfur reduction*)	0.46	0.36	0.07
	0.3%-S residual fuel oil (85% sulfur reduction*)	0.52	0.40	0.08
	0.50 lb SO_2/MMbtu (77% sulfur reduction*)	0.47	0.37	0.08
	Switch from 0.50 lb SO_2/MMbtu emission limit to 0.3%S residual fuel oil	*<0.05*	*0.03*	*<0.01****
NOx	SNCR (25% NOx reduction**)	0.11	0.10	0.04
	SCR (78% NOx reduction**)	0.34	0.30	0.12
PM	Baghouse (85% PM reduction**)	0.05	0.04	0.01
On the 20% Worst Baseline Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	FGD (90% sulfur reduction*)	**0.13**	**0.10**	<0.01***
	1.0%-S residual fuel oil (50% sulfur reduction*)	**0.07**	**0.06**	<0.01***
	0.5%-S residual fuel oil (75% sulfur reduction*)	**0.11**	**0.09**	0.01
	0.3%-S residual fuel oil (85% sulfur reduction*)	**0.13**	**0.10**	0.01
	0.50 lb SO_2/MMbtu (77% sulfur reduction*)	**0.11**	**0.09**	0.01
	Switch from 0.50 lb SO_2/MMbtu emission limit to 0.3%S residual fuel oil	***0.01***	***0.01***	*<0.01****
NOx	SNCR (25% NOx reduction**)	**0.04**	**0.03**	0.01
	SCR (78% NOx reduction**)	**0.11**	**0.10**	0.03
PM	Baghouse (85% PM reduction**)	**0.02**	**0.02**	<0.01***

* from maximum permitted level

Note: Values in **boldface** are considered as having greater validity in the modeling estimation of maximum visibility benefits from BART controls.

** from baseline level with existing controls
*** below sensitivity limit of model

NHDES also used the CALGRID photochemical model to perform a screening-level analysis of the anticipated effects of BART controls at New Hampshire's two BART-eligible sources (see Part 7.3.3 for a description of the CALGRID modeling platform). Separate CALGRID modeling runs were conducted to examine the effects of selected emission control measures on each of these sources. One run assessed the effects of installing scrubber technology on Merrimack Station Unit MK2. The second run assessed the effects of switching to lower-sulfur residual fuel oil for Newington Station Unit NT1. Both simulations were performed for the full summer modeling episode (May 15 to September 15, 2002) and used the 2018 BOTW emissions inventory scenario as a baseline (see Part 6.1.2 for a description of all future-year emissions inventories). The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutant within the region. NHDES post-processed the modeled concentration reductions to estimate the corresponding visibility improvements at Class I areas.

Based on the CALGRID modeling results, the installation of scrubber technology on Merrimack Station Unit MK2 is expected to reduce near-stack maximum predicted 24-hour average SO_2 concentration impacts by up to 21 $\mu g/m^3$ (8 ppb by volume) and maximum predicted 24-hour average $PM_{2.5}$ concentration impacts by up to 1 $\mu g/m^3$. The largest modeled pollutant concentration reductions occur within a 50-kilometer radius of the facility, an area which does not contain any federal Class I areas. For the affected Class I areas (located 100 to 500 kilometers away), reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, are expected to yield a nominal improvement in visibility (about 0.1 deciview) on direct-impact hazy days.

For Newington Station Unit NT1, CALGRID modeling predicted that switching to lower-sulfur residual fuel oil would reduce near-stack maximum predicted 24-hour average SO_2 concentration impacts by 2 $\mu g/m^3$ and maximum predicted 24-hour average $PM_{2.5}$ concentration impacts by 0.1 $\mu g/m^3$. At the affected Class I areas, reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, would yield negligible visibility improvement, according to the CALGRID modeling results.

9.4 Alternatives to BART for Any Source

40 CFR 51.308(e)(1)(v)(2) of the Regional Haze Rule provides that a state may opt to implement an emissions trading program or other alternative measure rather than require sources subject to BART to install, operate, and maintain BART. In such case, the state must demonstrate that the emissions trading program or other alternative measure will achieve greater reasonable progress than would be achieved through the installation and operation of BART. To make this demonstration, the state must submit an implementation plan containing the elements listed in the above-referenced part of the rule.

New Hampshire does not support the provisions of the BART rule that allow emissions trading programs or other alternative measures because they are not likely to yield visibility improvements equivalent to those that would accrue from source-specific BART controls. **Consequently, NHDES does not propose to use alternative measures for BART-eligible sources in New Hampshire.**

9.5 BART Enforceable Provisions and Implementation Schedule

The enforceable provisions and compliance schedule for BART are summarized in Tables 9-6 and 9-7 for New Hampshire's two BART-eligible sources. The BART control measures will be enforceable through a combination of existing permit conditions and administrative rules, including a newly adopted administrative rule Env-A 2300, Mitigation of Regional Haze (see Attachment GG).

40 CFR 51.308(e)(1)(iv) requires that BART must be in operation for each applicable source no later than five years after SIP approval. New Hampshire is requiring all BART-eligible sources to install and operate BART controls as expeditiously as practicable but in no case later than July 1, 2013.

40 CFR 51.308(e)(1)(v) requires that each source subject to BART maintain the required control equipment and establish procedures to ensure such equipment is properly operated and maintained. New Hampshire will meet this requirement by including in the Title V operating permit for each BART-eligible source provisions to ensure proper operation and maintenance of the control equipment. Note that, because New Hampshire does not have a merged construction permitting and Title V permitting program, requirements related to BART first need to be placed into a state temporary permit (i.e., construction permit) before they can be incorporated subsequently into a federal Title V operating permit.

Table 9-6: BART Enforceable Provisions and Compliance Schedule for PSNH Merrimack Station Unit MK2

Pollutant	BART Controls / Emission Limitations	Regulatory Citations*	Compliance Date
SO_2	Fuel sulfur limits (existing); Flue gas desulfurization (FGD), with required SO_2 percent reduction set at maximum sustainable rate, but not less than 90% as a calendar monthly average	Administrative Rule Env-A 1606.01, Maximum Sulfur Content Allowable in Coal; Temporary permit for FGD system (TP-0008); Proposed Title V operating permit (TV-0055);	FGD: July 1, 2013
NO_X	SCR (existing); NOx emission limit of 0.30 lb/MMBtu, 30-day rolling average	Proposed Title V operating permit (TV-0055); Administrative Rule Env-A 2300, Mitigation of Regional Haze	Rule: July 1, 2013
PM	Two ESPs in series (existing) TSP emission limit of 0.08 lb/MMBtu	Proposed Title V operating permit (TV-0055); Administrative Rule Env-A 2300, Mitigation of Regional Haze	Rule: July 1, 2013

Table 9-7: BART Enforceable Provisions and Compliance Schedule for PSNH Newington Station Unit NT1

Pollutant	BART Controls / Emission Limitations	Regulatory Citations*	Compliance Date
SO_2	SO_2 emission limit of 0.50 lb/MMBtu, 30-day rolling average, applicable to any fuel type or mix	Administrative Rule Env-A 2300, Mitigation of Regional Haze	Rule: July 1, 2013
NO_X	Low-NOx burners, overfire air, and water injection (existing); NOx emission limits of 0.35 lb/MMBtu with oil and 0.25 lb/MMBtu with oil/gas, 24-hour calendar day average	Title V operating permit (TV-OP-054)	N.A. (Existing controls are BART)
PM	Electrostatic precipitator (existing); TSP emission limit of 0.22 lb/MMBtu	Title V operating permit (TV-OP-054)	N.A. (Existing controls are BART)

*Applicable permits and rules are available in Attachments FF through II.

10. REASONABLE PROGRESS GOALS

40 CFR 51.308 (d)(1) of the Regional Haze Rule requires New Hampshire to establish, for each Class I area within the state, reasonable progress goals (RPG) toward achieving natural visibility conditions. On June 1, 2007, the U.S. Environmental Protection Agency (EPA) released final guidance to be used by states in setting reasonable progress goals. The goals must provide for visibility improvement on the days of greatest visibility impairment and ensure no visibility degradation on the days of least visibility impairment for the duration of the State Implementation Plan (SIP) period.

As provided in 40 CFR 51.308 (d)(1)(iv), the state must consult with other states in the setting of reasonable progress goals. The rule states:

> "In developing each reasonable progress goal, the State must consult with those States which may reasonably be anticipated to cause or contribute to visibility impairment in the mandatory Class I Federal area. In any situation in which the State cannot agree with another such State or group of States that a goal provides for reasonable progress, the State must describe in its submittal the actions taken to resolve the disagreement. In reviewing the State's implementation plan submittal, the Administrator will take this information into account in determining whether the State's goal for visibility improvement provides for reasonable progress towards natural visibility condition."

New Hampshire consulted with states found to contribute to visibility impairment at New Hampshire's Class I areas and with states that requested consultation with New Hampshire regarding visibility conditions at their Class I areas. In particular, New Hampshire worked closely with the other MANE-VU states to ensure consistency of approach in setting reasonable progress goals. **Accordingly, New Hampshire agrees with the reasonable progress goals established by Maine, Vermont, and New Jersey.** A description of the consultation process is found under Section 3, Regional Planning and Consultation.

The Regional Haze Rule also requires each Class I state to consider four factors in setting reasonable progress goals: cost, time needed for compliance, energy and non-air quality environmental impacts, and remaining useful life. In addition, the state must show that it considered the uniform rate of improvement and the emission reduction measures needed to achieve it for the period covered by the implementation plan. If the state proposes a rate of progress slower than the uniform rate of progress, the state must assess the number of years it would take to attain natural conditions if visibility improvement continues at the rate proposed.

10.1 Calculation of Uniform Rate of Progress

As a benchmark to aid in developing reasonable progress goals, MANE-VU compared baseline visibility conditions to natural visibility conditions at each MANE-VU Class I area. The difference between baseline and natural visibility conditions for the 20 percent worst days was used to determine the uniform rate of progress that would be needed during each implementation period in order to attain natural visibility conditions by 2064. Table 10.1 presents baseline visibility, natural visibility, and required uniform rate of progress for each MANE-VU Class I area. Visibility values are expressed in deciviews (dv), where each single-unit deciview decrease would represent a barely perceptible improvement in visibility.

Table 10.1: Uniform Rate of Progress Calculation (all values in deciviews)

Class I Area	2000-2004 Baseline Visibility (20% Worst Days)	Natural Visibility (20% Worst Days)	Total Improvement Needed by 2018	Total Improvement Needed by 2064	Uniform Annual Rate of Improvement
Acadia National Park	22.9	12.4	2.4	10.5	0.174
Moosehorn Wilderness and Roosevelt Campobello International Park	21.7	12.0	2.3	9.7	0.162
Great Gulf Wilderness and Presidential Range - Dry River Wilderness	22.8	12.0	2.5	10.8	0.180
Lye Brook Wilderness	24.5	11.7	3.0	12.8	0.212
Brigantine Wilderness	29.0	12.2	3.9	16.8	0.280

Note: Both natural conditions and baseline visibility for the 5-year period from 2000 through 2004 were calculated in conformance with an alternative method recommended by the IMPROVE Steering Committee.[25]

The reasonable progress goals established for MANE-VU's Class I Areas, described later in Subsection 10.3, are expected to provide visibility improvements in excess of the uniform rates of progress shown above.

[25] "Baseline and Natural Visibility Conditions, Considerations and Proposed Approach to the Calculation of Baseline and Natural Visibility Conditions at MANE-VU Class I Areas," NESCAUM, December 2006.

[26] In addition, Vermont identified at least one source in Wisconsin as a significant contributor to visibility impairment at the Lye Brook Wilderness Class I Area.

10.2 Identification of (Additional) Reasonable Control Measures

New Hampshire and the other MANE-VU states have identified specific emission control measures – beyond those which individual states or RPOs had already made commitments to implement – that would be reasonable to undertake as part of a concerted strategy to mitigate regional haze. The proposed additional control measures were incorporated into the regional strategy adopted by MANE-VU on June 20, 2007, to meet the reasonable progress goals established in this SIP. The basic elements of this strategy are described in the New Hampshire/MANE-VU "Ask" (see Part 3.2.2 under Section 3, Regional Planning and Consultation). States targeted for coordinated actions toward achieving these goals include all of the MANE-VU states plus Georgia, Illinois, Indiana, Kentucky, Michigan, North Carolina, Ohio, South Carolina, Tennessee, Virginia, and West Virginia.[26]

In addition to including proposed emission controls in the eastern United States, MANE-VU determined that it was reasonable to include anticipated emission reductions in Canada in the modeling used to set reasonable progress goals. This determination was based on evaluations conducted before and during the consultation process (see description of relevant consultations in Part 3.2.1). Specifically, the modeling accounts for six coal-burning electric generating units (EGUs) in Canada having a combined output of 6,500 MW that are scheduled to be shut down and replaced by nine natural gas turbine units equipped with selective catalytic reduction (SCR) by 2018.

The process of identifying reasonable measures and setting reasonable progress goals is described in the subsections which follow. Further elaboration on the reasonable measures which make up the New Hampshire/MANE-VU long-term strategy is provided in Section 11 of this SIP. Under this plan, the affected states will have a maximum of 10 years to implement reasonable and cost-effective control measures to reduce primarily SO_2 and NO_X emissions. For a description of how proposed emission control measures were modeled to estimate resulting visibility improvements, see Subsection 10.4, Visibility Affects of (Additional) Reasonable Control Measures.

10.2.1 Rationale for Determining Reasonable Controls

40 CFR 51.308(d)(1)(i)(A) of EPA's Regional Haze Rule requires that, in establishing reasonable progress goals for each Class I area, the state must consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources. The SIP must include a demonstration showing how these factors were taken into consideration in setting the RPGs. These factors are sometimes termed the "four statutory factors," since their consideration is required by the Clean Air Act.

Early Focus on SO_2: MANE-VU conducted a Contribution Assessment (Attachment B) and developed a conceptual model that showed the dominant contributor to visibility impairment at all MANE-VU Class I areas during all seasons in the base year was particulate sulfate formed from emissions of SO_2. While other pollutants, including organic carbon, will need to be addressed in order to achieve the national visibility goals, MANE-VU's contribution assessment suggested that an early emphasis on SO_2 would yield the greatest near-term benefit. Therefore, it is reasonable to conclude that the additional measures considered in setting reasonable progress goals require reductions in SO_2 emissions.

Contributing Sources: The MANE-VU Contribution Assessment indicates that emissions from within MANE-VU in 2002 were responsible for approximately 25 percent of the sulfate at MANE-VU Class I Areas. Sources in the Midwest and Southeast regions were responsible for about 15 to 25 percent each. Point sources dominated the inventory of SO_2 emissions. Therefore, MANE-VU's long-term strategy includes additional measures to control sources of SO_2 both within the MANE-VU region and in other states that were determined to contribute to regional haze at MANE-VU Class I Areas.

The Contribution Assessment documented the source categories most responsible for visibility degradation at MANE-VU Class I Areas. As described in Section 11, Long-Term Strategy, there was a collaborative effort between the Ozone Transport Commission and MANE-VU to evaluate a large number of potential control measures. Several measures that would reduce SO_2 emissions were identified for further study.

Four-Factor Analysis: These efforts led to production of the MANE-VU report by MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007, otherwise known as the Reasonable Progress Report (Attachment Y). This report provides an analysis of the four statutory factors for five major source categories: electrical generating units (EGUs); industrial, commercial, and institutional (ICI) boilers; cement and lime kilns; heating oil combustion; and residential wood combustion. Table 10.2 summarizes the results of MANE-VU's four-factor analysis for the source categories considered.

Table 10.2: Summary of Results from Four-Factor Analysis of Different Source Categories

Source Category	Primary Regional Haze Pollutant	Control Measure(s)	Average Cost in 2006 dollars (per ton of pollutant reduction)	Compliance Timeframe	Energy and Non-Air Quality Environmental Impacts	Remaining Useful Life
Electric Generating Units	SO_2	Switch to a low-sulfur coal (generally <1% sulfur); switch to natural gas (virtually 0% sulfur); coal cleaning; flue gas desulfurization (FGD), including wet, spray-dry, or dry.	\$775-\$1,690 based on IPM® v.2.1.9 * \$170-\$5,700 based on available literature	2-3 years following SIP submittal	Fuel supply issues, possible permitting issues, reduced electricity production capacity, wastewater issues	50 years or more
Industrial, Commercial, Institutional Boilers	SO_2	Switch to a low-sulfur coal (generally <1% sulfur); switch to natural gas (virtually 0% sulfur); switch to a lower-sulfur oil; coal cleaning; combustion controls; flue gas desulfurization (FGD), including wet, spray-dry, or dry.	\$130-\$11,000 based on available literature; dependent on size.	2-3 years following SIP submittal	Fuel supply issues, potential permitting issues, control device energy requirements, wastewater issues	10-30 years
Cement and Lime Kilns	SO_2	Fuel switching; flue gas desulfurization (FGD), including wet, spray-dry, or dry; advanced flue gas desulfurization (FGD).	\$1,900-\$73,000 based on available literature; dependent on size.	2-3 years following SIP submittal	Control device energy requirements, wastewater issues	10-30 years

Heating Oil	SO_2	Switch to lower-sulfur fuel (varies by state)	\$550-\$750 based on available literature; high degree of uncertainty with this cost estimate	Currently feasible; capacity issues may influence timeframe for implementation of new fuel standards	Increased furnace/boiler efficiency, reduced furnace/boiler maintenance requirements	18-25 years
Residential Wood Combustion	PM	State implementation of NSPS, ban on resale of uncertified devices, installer training certification or inspection program, pellet stoves, EPA Phase II certified RWC devices, retrofit requirement, accelerated changeover requirement or inducement	\$0-\$10,000 based on available literature	Several years, depending on mechanism for emission reductions	Increased efficiency of combustion device, reduced greenhouse gas emissions	10-15 years

* Integrated Planning Model® CAIR versus CAIR plus analysis conducted for MARAMA/MANE-VU by ICF Consulting, L.L.C.

The MANE-VU states reviewed the four-factor analyses presented in the Reasonable Progress Report, consulted with one another about possible control measures, and concluded by adopting the statements known as the MANE-VU Ask. These statements identify the control measures that would be pursued toward improving visibility in the region. The following discussions focus on the four basic control strategies chosen by MANE-VU and examined with the modeling to establish the reasonable progress goals:

1. Best Available Retrofit Technology (BART),
2. Low-sulfur fuel oil requirements,
3. Emission reductions from specific EGUs, and
4. Additional measures determined to be reasonable.

10.2.2 Best Available Retrofit Technology Controls

The MANE-VU states have identified approximately 100 BART-eligible sources of all types, including EGUs, in the region. Most of these facilities are already controlling emissions in response to other federal or state air programs or are likely to install emission controls under new programs. A complete compilation of BART-eligible sources in the MANE-VU region is available in Appendix A of MANE-VU's "Assessment of Control Technology Options for BART-Eligible Sources," March 2005, also known as the BART Report (Attachment Z).

To assess the benefits of implementing BART in the MANE-VU region, NESCAUM estimated emission reductions for twelve BART-eligible sources in MANE-VU states that would probably be controlled as a result of BART requirements alone. These sources include one EGU and eleven non-EGUs. The affected sources were identified by a survey of states' staff members, who furnished data on the potential control technologies and expected control levels for these sources under BART implementation. The twelve (non-EGU) sources are listed in Table 10.3 along with their 2002 baseline and 2018 estimated emissions. Information on these sources was incorporated into the 2018 emissions inventory projections that were used in the modeling to set reasonable progress goals.

Table 10.3: Estimated Emissions from BART-Eligible Facilities in MANE-VU States (Non-EGU Facilities Likely to be Controlled as a Result of BART Alone)

State	Facility Name	Unit Name	SCC Code	Plant ID (MANE-VU Inventory)	Point ID (MANE-VU Inventory)	Facility Type	2002 SO_2 Emissions (tons)	2018 SO_2 Emissions (tons)
MD	EastAlco Aluminum	28	30300101	021-0005	28	Metal Production	1,506	1,356
MD	Eastalco Aluminum	29	30300101	021-0005	29	Metal Production	1,506	1,356
MD	Lehigh Portland Cement	39	30500606	013-0012	39	Portland Cement	9	8
MD	Lehigh Portland Cement	16	30500915	021-0003	16	Portland Cement	1,321	1,189
MD	Lehigh Portland Cement	17	30500915	021-0003	17	Portland Cement	9,76	8,78
MD	Westvaco Fine Papers	2	10200212	001-0011	2	Paper and Pulp	8,923	1,338
ME	Wyman Station	Boiler 3	10100401	2300500135	004	EGU	616	308
ME	SAPPI Somerset	Power Boiler 1	10200799	2302500027	001	Paper and Pulp	2,884	1,442
ME	Verso Androscoggin LLC	Power Boiler 1	10200401	2300700021	001	Paper and Pulp	2,964*	1,482
ME	Verso Androscoggin LLC	Power Boiler 2	10200401	2300700021	002	Paper and Pulp	3,086*	1,543
NY	Kodak Park Division	U00015	10200203	8261400205	U00015	Chemical Manufacturer	2,3798	1,4216
NY	Lafarge Building Materials, Inc	41000	30500706	4012400001	041000	Portland Cement	14,800	4,440

Note: Many additional sources in MANE-VU are BART-eligible but are expected to be controlled as a result of other emission reduction programs (e.g., state-specific multi-pollutant programs).

*Data for 1999 baseline year.

***Best Available Retrofit Technology is Reasonable*:** BART controls are part of the strategy for improving visibility at MANE-VU Class I Areas. MANE-VU prepared reports to provide states with information about available control technologies (e.g., MANE-VU's BART Report referenced above), estimated cost ranges, and other factors associated with those controls. The reasonable progress goals established in this regional haze SIP assume that states whose emissions affect Class I areas in New Hampshire and elsewhere in MANE-VU will make determinations demonstrating the reasonableness of BART controls for sources in their states.

10.2.3 Low-Sulfur Fuel Strategy

The MANE-VU region, especially the Northeast, is heavily reliant on distillate oil for home space heating, with more than 4 million gallons used, according to 2006 estimates from the Energy Information Administration[27]. Likewise, the heavier residual oils are widely used by non-EGU sources and, to a lesser extent, the EGU sector. The sulfur content of distillate fuels currently averages above 2,000 ppm (0.2 percent). Although the sulfur content of residual

[27] U.S. Department of Energy, EIA, Table F3a, at http://www.eia.doe.gov/emeu/states/sep_fuel/html/fuel_use_df.html.

oils varies by source and region, it can exceed 2.0 percent. Combustion of distillate and residual fuel in the MANE-VU states resulted in SO_2 emissions totaling approximately 380,000 tons in 2002.

As the second component of MANE-VU's long-term strategy, the member states agreed to pursue, where appropriate, measures that would require the sale and use of fuel oils having reduced sulfur content. This strategy would be implemented in two phases:

- Phase 1 would require reducing the sulfur content in distillate (#1 and # 2) fuel oils from current levels of 2,000 to 2,300 ppm (0.20 to 0.23 percent) to a maximum of 500 ppm (0.05 percent) by weight. It would also restrict the sale of heavier blends of residual (# 4, #5, and # 6) fuel oils that have sulfur content greater than 2,500 ppm (0.25 percent) and 5,000 ppm (0.5 percent) by weight, respectively.
- Phase 2 would require further reducing the sulfur content of the distillate fraction from 500 ppm (0.05 percent) to 15 ppm (0.015 percent) while keeping the sulfur limits on residual oils at first-phase levels.

The two phases would be introduced in sequence with slightly different timing for an inner zone of MANE-VU states[28] and the remainder of MANE-VU states. While all MANE-VU states have agreed to pursue implementation of both phases to full effect by the end of 2018, not every state can make a firm commitment to these measures today. Although New Hampshire intends to pursue the low-sulfur fuel strategy, it is unable to finalize rules or legislation within the timeframe required for this SIP Submittal. Therefore, the low-sulfur fuel strategy is not included as a component of the New Hampshire Regional Haze SIP but will be further studied and pursued as appropriate at a future date.

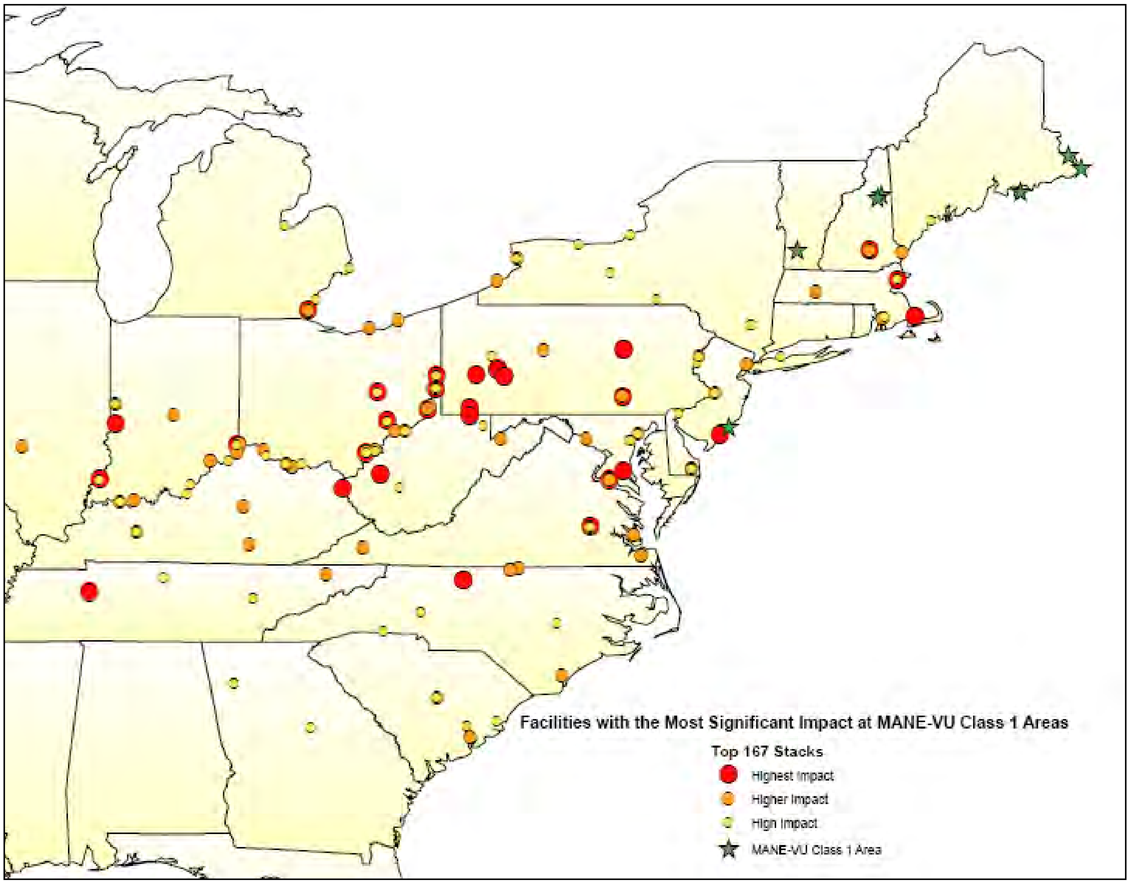
10.2.4 Targeted EGU Strategy for SO_2 Reduction

Electrical generating units (EGUs) are the single largest sector contributing to visibility impairment at MANE-VU's Class I Areas. SO_2 emissions from power plants continue to dominate the emissions inventory. Sulfate formed through atmospheric processes from SO_2 emissions are responsible for over half the mass and approximately 70-80 percent of visibility extinction on the days of worst visibility (see NESCAUM's Contribution Assessment, Attachment B).

To ensure that EGU control measures are targeted at those units having the greatest impact on visibility at MANE-VU Class I Areas, a CALPUFF modeling analysis was conducted to identify the individual sources responsible for the highest contributions to visibility degradation. Accordingly, MANE-VU developed lists of the 100 EGU emission points (stacks) having the largest impacts at each MANE-VU Class I Area during 2002. The combined list for all seven MANE-VU Class I Areas identified a total of 167 distinct emission points. These 167 stacks are spread across the Northeast, Southeast, and Midwest (Figure 10.2).

[28] The inner zone includes New Jersey, Delaware, New York City, and possibly portions of eastern Pennsylvania.

Figure 10.1: Location of 167 EGU Stacks Contributing the Most to Visibility Impairment at MANE-VU Class I Areas

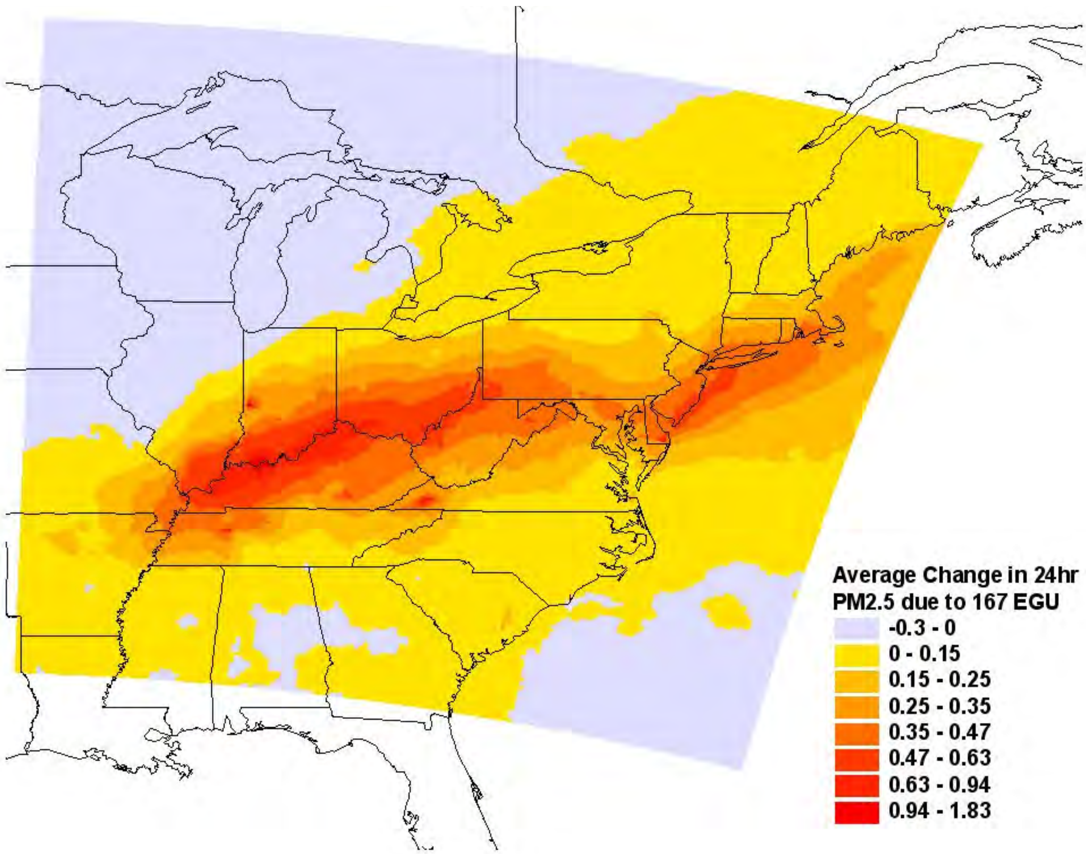


Note: Some facilities have more than one stack.

After consultations with its member states and with other RPOs, MANE-VU requested a 90-percent reduction in SO_2 emissions from the top 167 stacks by no later than 2018 (see the MANE-VU "Ask"). NESCAUM's preliminary modeling for MANE-VU showed that SO_2 emission reductions of this magnitude from the targeted facilities would produce substantial improvements in ambient 24-hour $PM_{2.5}$ concentrations. Assuming a control level equal to 10 percent of the 2002 baseline emissions (i.e., 90-percent emission reduction), NESCAUM used CMAQ to model sulfate concentrations in 2018 after implementation of controls. The modeled sulfate values were then converted to estimates of $PM_{2.5}$ concentration. Figure ~~10.3~~ 10.2 displays the predicted average change in 24-hr $PM_{2.5}$.

The map illustrates the reductions in fine-particle pollution in the Eastern U.S. that would result from implementation of the targeted EGU strategy for SO_2. Improvements in $PM_{2.5}$ levels would occur throughout the MANE-VU region and portions of the VISTAS and MRPO regions, especially along the Ohio River Valley.

Figure 10.2: Preliminary Estimate of Average Change in 24-hr $PM_{2.5}$ Resulting from a 90-Percent Reduction in SO_2 Emissions from the Top 167 EGU Stacks Affecting MANE-VU Class I Areas



Although the reductions would be both advantageous and potentially large, MANE-VU determined, after further consultation with affected states, that it was unreasonable to expect that the full 90-percent reduction in SO_2 emissions would be achieved by 2018. Therefore, additional modeling was conducted to assess the more realistic scenario in which emissions would be controlled by the individual facilities and/or states to levels already projected to take place by that date. At some facilities, the actual emission reductions are anticipated to be greater or less than the 90 percent benchmark. For details, see Alpine Geophysics' report for MARAMA entitled, "Documentation of 2018 Emissions from Electric Generating Units in the Eastern United States for MANE-VU's Regional Haze Modeling," Final Report, August 16, 2009 (Attachment H).

***Targeted EGU SO_2 Reduction Strategy Controls are Reasonable*:** MANE-VU identified specific EGU stacks that were significant contributors to visibility degradation at MANE-VU Class I Areas in 2002. The CALPUFF modeling analyses identifying potentially significant contributing sources are documented in the Contribution Assessment. MANE-VU obtained information about existing and planned controls on emissions from those stacks. These analyses and information on proposed EGU controls are presented in MANE-VU's Reasonable Progress Report and the Contribution Assessment as well as in Section 6, Emissions Inventory, and Section 11, Long-Term Strategy section of this SIP.

Based on information gathered from the states and regional planning organizations, MANE-VU anticipated that emissions from many of the targeted EGU stacks would be subject to EPA's Clean Air Interstate Rule (CAIR). However, because CAIR – recently remanded and scheduled for replacement – was a cap-and-trade program, it was not possible to predict with certainty which of the 167 stacks would actually be controlled under CAIR in 2018.

Four-Factor Analysis – Targeted EGU SO_2 Reduction Strategy: The following discussion addresses each of the four factors with respect to the strategy of controlling specific EGUs. Information is taken primarily from the MANE-VU Reasonable Progress Report (Attachment Y) and MANE-VU BART Report (Attachment Z).

1) Targeted EGU SO_2 Reduction Strategy – Costs of Compliance: Technologies to control the precursors of regional haze are commercially available today. Because EGUs are the most significant stationary source of SO_2, NO_X, and PM, they have been subject to extensive federal and state regulations to control all three pollutants. The technical feasibility of control technologies has been successfully proven for a substantial number of small (e.g., 100 MW) to very large (over 1,000 MW) boilers burning different types of coal. Over the last few years, the cost data clearly indicate that many technologies provide substantial and cost-effective emission reductions.

Both wet and dry scrubbers are in wide commercial use in the U.S. for controlling SO_2 emissions from coal-fired power plants. The capital costs for new or retrofit wet or dry scrubbers are higher than the capital costs for NO_X and PM controls. The MANE-VU BART report found that the capital costs of scrubbers ranged from $180/kW for large units (greater than 600 MW) to as high as $350/kW for small units (200 to 300 MW). Typical costs were in the range of 200 to 500 dollars per ton of SO_2 removed, but rose steeply for small units burning lower-sulfur coal and operating at low capacity factors. (See pages 2-22 through 2-25 of the BART Report, Attachment Z).

The MANE-VU Reasonable Progress Report (Attachment Y) reviewed options for controlling coal-fired EGU boilers, including switching to lower-sulfur coal, switching to natural gas, coal cleaning, and flue gas desulfurization (FGD). The most effective control option (but not necessarily appropriate for all installations) is FGD, which can achieve up to 95 percent reduction in SO_2 emissions. The costs of different technologies vary considerably among units and were estimated to range from as low as $170/ton to as high as $5,700/ton.

Table 10.4 summarizes the estimated costs of controlling SO_2 emissions, expressed in dollars per ton of SO_2 removed.

Table 10.4: Estimated Cost Ranges for SO_2 Control Options for Coal-Fired EGU Boilers (2006 dollars per ton of SO_2 removed)

Technology	Description	Performance	Cost Range (2006 dollars/ton of SO_2 Reduced)
Switch to a Low Sulfur Coal (generally <1% sulfur)	Replace high-sulfur bituminous coal combustion with lower-sulfur coal	50-80% reduction in SO_2 emissions by switching to a lower-sulfur coal	Potential reduction in coal costs, but possibly offset by expensive retrofits and loss of boiler efficiency
Switch to natural gas (virtually 0% sulfur)	Replace coal combustion with natural gas	Virtually eliminate SO_2 emissions by switching to natural gas	Unknown – cost of switch is currently uneconomical due to price of natural gas
Coal Cleaning	Coal is washed to remove some of the sulfur and ash prior to combustion	20-25% reduction in SO_2 emissions	2-15% increase in fuel costs based on current prices of coal
Flue Gas Desulfurization (FGD) – Wet	SO_2 is removed from flue gas by dissolving it in a lime or limestone slurry. (Other alkaline chemicals are sometimes used)	30-95%+ reduction in SO_2 emissions	\$570-\$5,700 for EGUs <1,200 MW \$330-\$570 for EGUs >1,200 MW
Flue Gas Desulfurization (FGD) – Spray Dry	A fine mist containing lime or other suitable sorbent is injected directly into flue gas	60-95%+ reduction in SO_2 emissions	\$570-\$4,550 for EGUs <600 MW \$170-\$340 for EGUs >600 MW
Flue Gas Desulfurization (FGD) –Dry	Powdered lime or other suitable sorbent is injected directly into flue gas	40-60% reduction in SO_2 emissions	\$250-\$850 for EGUs ~300 MW

Table references:
1. EIA website accessed on 2/20/07: http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html
2. EIA website accessed on 2/20/07: http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html
3. STAPPA-ALAPCO. *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*; March 2006.

To predict future emissions and further evaluate the costs of emission controls for electric generating units, MANE-VU and other RPOs have followed the example of the US Environmental Protection Agency (EPA) in using the Integrated Planning Model (IPM®), an integrated economic and emissions model for EGUs. This model projects electricity supplies based on various assumptions while at the same time developing least-cost solutions to electrical generating needs within specified emissions targets. IPM also provides estimates of the costs of complying with various policy requirements.

EPA developed IPM version 2.1.9 and used this model to evaluate the impacts of CAIR and the Clean Air Mercury Rule (CAMR). (Note that CAMR was vacated by the federal courts and is no longer in effect.) Recently, EPA updated their input data and developed IPM v.3.0. However, because of time constraints, all MANE-VU runs were based on EPA IPM v.2.1.9 with changes made to the input assumptions.

The RPOs collaborated with one another to update the inputs to IPM v.2.1.9 using more current data on the EGUs and more realistic fuel prices. The resulting IPM run is called VISTAS PC_1f. This IPM run serves as the basis for regional air quality modeling for ozone and haze SIPs in MANE-VU and the OTC.

MANE-VU, through MARAMA, contracted with the consulting firm ICF Resources, L.L.C. to prepare two new IPM runs, as documented in "Comparison of CAIR and CAIR Plus Proposal using the Integrated Planning Model (IPM®)," Final Draft Report, May 30, 2007 (Attachment BB). The first run, known as the MARAMA CAIR Base Case run (also known as MARAMA_5c), was based on the VISTAS PC_1f run and underlying EPA IPM v.2.1.9 with some updated information on fuel prices, control constraints, etc. The second run, called the MARAMA CAIR Plus run (also known as MARAMA_4c), was similarly based on VISTAS PC_1f run and the underlying EPA IPM v.2.1.9. The MARAMA CAIR Plus run included updated information used in the VISTAS run but assumed lower NO_X emission caps and higher SO_2 retirement ratios.

Based on the modeling results, MANE-VU estimates that the marginal cost of SO_2 emission reductions (the cost of reducing one additional ton of emissions) ranges from $640/ton in 2008 to $1,392/ton in 2018 (see Table 6, "Allowance Prices (Marginal Costs) of Emissions Reductions…," in Attachment BB).

Costs will vary for individual plants to reduce emissions by 90 percent, as recommended in the New Hampshire/MANE-VU Ask. However, this strategy provides states with flexibility to pursue controls on specific sources as appropriate and to control emissions from alternative sources, if necessary, to meet the 90 percent target established in the Ask.

Given the importance of SO_2 emissions from specific EGUs to visibility impairment in MANE-VU Class I Areas, the MANE-VU Commissioners, after weighing all factors – the availability of technology to reduce emissions, the estimated costs of controls, the costs of alternative measures, the flexibility to achieve alternative reductions if necessary, etc. – concluded that the costs of the targeted EGU strategy are reasonable. New Hampshire agrees with this conclusion.

2) Targeted EGU SO_2 Reduction Strategy – Time Necessary for Compliance: MANE-VU's Reasonable Progress Report indicates that, generally, sources are given a 2- to 4-year phase-in period to comply with new rules. Under Phase I of the NO_X SIP call, EPA provided a compliance date of about 3½ years from the SIP submittal date. Most MACT standards allow a 3-year compliance period. Under Phase II of the NO_X SIP Call, EPA provided for 2-year compliance period from the SIP submittal date. New Hampshire concludes that there is more than sufficient time between 2008 and 2018 for affected states to adopt requirements and for affected sources to install necessary controls.

3) Targeted EGU SO_2 Reduction Strategy – Energy and Non-Air Quality Environmental Impacts of Compliance: The MANE-VU Reasonable Progress Report identified several energy and non-air quality impacts from additional EGU controls. Large-scale fuel switching could potentially impact fuel supplies. Flue gas desulfurization systems may generate wastewater and sludge (which is sometimes recycled as a useful byproduct). On the other hand, SO_2, NO_X, and ammonia controls would have beneficial environmental impacts by reducing acid deposition and nitrogen deposition to water bodies and natural land areas. Emission reductions for these pollutants would also produce decreases in ambient levels of $PM_{2.5}$ and result in corresponding health benefits. Similarly, mercury emissions may be reduced by the addition of controls for other pollutants. New Hampshire concludes that the energy and non-air quality impacts of additional EGU controls are reasonable.

4) Targeted EGU SO_2 Reduction Strategy – Remaining Useful Life of Any Potentially Affected Sources: As noted in the MANE-VU Reasonable Progress Report, remaining useful life estimates of EGU boilers indicate a wide range of operating lifetimes, depending on unit size, capacity factor, and level of maintenance performed. Typical life expectancies range to 50 years or more. Additionally, implementation of air pollution regulations over the years has necessitated emission control retrofits that have increased the expected life spans of many EGUs. The lifetime of an EGU may be extended through repair, re-powering, or other strategies if the unit is more economical to run than to replace with power from other sources. Extending facility lifetime may be particularly likely for a unit serving an area with limited transmission capacity to bring in other power.

10.2.5 Non-EGU SO_2 Emissions Reduction Strategy for Non-MANE-VU States

In addition to the measures described above (i.e., BART, low-sulfur fuel, and targeted EGU controls), New Hampshire asked states in neighboring regional planning organizations to consider further non-EGU emission reductions comparable to those achieved by MANE-VU states through application of MANE-VU's low-sulfur fuel strategy. Previous modeling indicated that the MANE-VU low-sulfur fuel strategy would achieve a greater than 28-percent reduction in non-EGU SO_2 emissions by 2018. After consultation with other states and consideration of comments received, MANE-VU decided to include, in the latest modeling for the VISTAS and MRPO regions, implementation of control measures capable of achieving SO_2 emission reductions equivalent to MANE-VU's 28-percent reduction in non-EGU SO_2 emissions in 2018.

To model the effects of this strategy on visibility at MANE-VU Class I Areas, MANE-VU had to make reasonable assumptions about where the requested emission reductions would occur in the VISTAS and MRPO states without knowing precisely how those reductions would be realized. As a way to represent approximately a 28-percent reduction in non-EGU SO_2 emissions, the following reductions were modeled:

- For control measures in VISTAS and MRPO states:
  - Coal-fired ICI boilers: SO_2 emissions were reduced by 60 percent.
  - Oil-fired ICI boilers: SO_2 emissions were reduced by 75 percent.
  - ICI boilers lacking fuel specification: SO_2 emissions were reduced by 50 percent.
- For additional controls *only* in the VISTAS states: SO_2 emissions from other oil-fired area sources were reduced by 75 percent (based on the same SCCs identified in MANE-VU's oil strategies list).

This modeling scenario represents just one example of realistic strategies that states outside of MANE-VU could employ to meet the non-EGU SO_2 emissions reductions requested by MANE-VU.

New Hampshire acknowledges that a number of non-MANE-VU states have not included, or may not include, the requested 28-percent reduction in non-EGU SO_2 emissions in their State Implementation Plans at the present time. New Hampshire expects these states to revisit the MANE-VU Ask in the course of future regional haze SIP revisions and to make commitments to this request where feasible. NHDES will continue to monitor other states' actions with respect to regional haze planning. In time, actual reductions could turn out to be greater or less than the MANE-VU Ask. If necessary, New Hampshire will adjust its reasonable progress goals and long-term strategy at a later date to be consistent with programs implemented by the non-MANE-VU states. Any such adjustments would be incorporated into New Hampshire's first regional haze SIP revision in 2013.

***Non-EGU SO_2 Emission Reduction Measures Outside MANE-VU are Reasonable*:** After EGUs, ICI boilers are the next largest class of SO_2 emitters. ICI boilers are thus a logical choice among non-EGU sources for consideration of additional SO_2 control measures.

ICI Boiler Control Options: Air pollution reduction and control technologies for ICI boilers have advanced substantially over the past 25 years. However, according to a 1998 survey of industrial boilers by EPA (2004), only 2 percent of gas-fired boilers and 3 percent of oil-fired boilers had installed any kind of air pollution control device. A larger percentage of coal-fired boilers had installed air pollution controls: specifically, 47 percent had installed some type of control device, mainly to control particulate matter (PM). Post-combustion SO_2 controls were used by less than one percent of industrial boilers in 1998, with the exception of boilers firing petroleum coke (2 percent of boilers using this fuel had acid scrubbers). A small percentage of industrial boilers had combustion controls in place in 1998, although additional low-NO_X firing systems may have been installed since that date.

Almost all SO_2 emission control technologies fall into the category of reducing SO_2 after its formation as opposed to minimizing its formation during combustion. The method of SO_2 control appropriate for any individual ICI boiler is dependent upon the type of boiler, type of fuel, capacity utilization, and the types and staging of other air pollution control devices. However, cost-effective emission reduction technologies for SO_2 are available and are effective in reducing emissions from the exhaust gas stream of ICI boilers. Post-combustion SO_2 control is accomplished by reacting the SO_2 in the gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use, depending on the particular technology. SO_2 reduction technologies are commonly referred to as flue gas desulfurization (FGD) and are usually described in terms of the process conditions (wet versus dry), byproduct utilization (throwaway versus saleable) and reagent utilization (once-through versus regenerable).

The exceptions to the nearly universal use of post-combustion controls are found in fuel switching, coal cleaning, and fluidized bed boilers, in which limestone is added to the fuel in the combustion chamber. Both pre- and post-combustion SO_2 emission control alternatives for ICI boilers are outlined in Table 10.5. Further description of these technology options is available in Chapter 4 of the MANE-VU Reasonable Progress Report (Attachment Y).

The SO_2 removal efficiency of these controls varies from 20 to 99+ percent depending on the fuel type and control technology. For coal-fired boilers, options include switching to low-sulfur coal, coal cleaning, wet FGD, dry FGD, and spray dryers. The overall SO_2 reductions vary from a low of 20 to 25 percent for fuel switching to a high of 60 to 95 percent for wet FGD and spray dry FGD. The majority of control strategies, however, are capable of achieving a 60 percent or greater reduction. Thus, assuming that coal-fired ICI boilers adopt varying levels of controls, with most choosing a 50- to 70- percent reduction strategy and fewer choosing either the 20-percent or the 90-percent reduction strategy, the region-wide average would be likely to fall in the vicinity of a 60- percent reduction in SO_2 emissions. This assumption is validated by data showing that wet FGD systems represent 85 percent of the FGD systems in use in the United States and that these systems have an average SO_2

removal efficiency of 78 percent. MANE-VU's modeling of a 60-percent reduction in SO_2 emission from coal-fired ICI boilers is therefore reasonable.

Table 10.5: Available SO_2 Control Options for ICI Boilers

Technology	Description	Applicability	Performance
Switch to a Low Sulfur Coal (generally <1% sulfur)	Replace high-sulfur bituminous coal combustion with lower-sulfur coal	Potential control measure for all coal-fired ICIs currently using coal with high sulfur content	50-80% reduction in SO_2 emissions by switching to a lower-sulfur coal
Switch to Natural Gas (virtually 0% sulfur)	Replace coal combustion with natural gas	Potential control measure for all coal-fired ICIs	Virtually eliminate SO_2 emissions by switching to natural gas
Switch to a Lower Sulfur Oil	Replace higher-sulfur residual oil with lower-sulfur distillate oil. Alternatively, replace medium sulfur distillate oil with ultra-low sulfur distillate oil	Potential control measure for all oil-fired ICIs currently using higher sulfur content residual or distillate oils	50-80% reduction in SO_2 emissions by switching to a lower-sulfur oil
Coal Cleaning	Coal is washed to remove some of the sulfur and ash prior to combustion	Potential control measure for all coal-fired ICI boilers	20-25% reduction in SO_2 emissions
Combustion Control	A reactive material, such as limestone or bi-carbonate, is introduced into the combustion chamber along with the fuel	Applicable to pulverized coal-fired boilers and circulating fluidized bed boilers	40%-85% reductions in SO_2 emissions
Flue Gas Desulfurization (FGD) - Wet	SO_2 is removed from flue gas by dissolving it in a lime or limestone slurry. (Other alkaline chemical are sometimes used)	Applicable to all coal-fired ICI boilers	30-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) - Spray Dry	A fine mist containing lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	60-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) - Dry	Powdered lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	40-60% reduction in SO_2 emissions

For oil-fired boilers, options include switching to a lower-sulfur fuel (e.g., oil or natural gas), dry FGD, and spray dryers. The overall SO_2 reductions vary from a low of 40 to 60 percent for dry FGD to a high of 60 to 95 percent for spray dry FGD. For comparison, the MANE-VU low-sulfur fuel strategy assumes a 50- to 90- percent reduction in SO_2 emissions from oil-fired ICI boilers. Assuming a normal distribution of control strategies chosen by the sources, MANE-VU's modeling of an average 75-percent reduction in SO_2 emission from oil-fired ICI boilers is reasonable.

For ICI boilers in which a fuel was not specified, a 50-percent reduction in SO_2 emissions was assumed. ICI boilers in this category include those outside the MANE-VU region for which the current inventory did not specify the type of fuel burned. Because a response from the MRPO was not received, this assumption also encompasses some of the uncertainty regarding the implementation of MANE-VU's non-EGU Ask. Given the paucity of data, a lower reduction in SO_2 emissions (50 percent) was assumed for this category than for coal- or oil-fired ICI boilers. Implementation of one or more of the suggested SO_2 control options to achieve, on average, a 50-percent reduction in SO_2 emissions at these sources is a reasonable assumption.

For emissions from other area oil-combustion sources in the VISTAS region, an SO_2 reduction of 75 percent was assumed. This reduction is equal to the reduction that would result from implementing the MANE-VU low-sulfur fuel strategy for this sector. The four-factor analysis for the low-sulfur fuel strategy was described in Part 10.2.3 of this section.

Four-Factor Analysis – Non-EGU SO_2 Emission Reduction Measures Outside MANE-VU: Based on the survey of available technologies outlined above and the four-factor analyses summarized below, MANE-VU concludes that each of the strategies assumed for modeling purposes to meet the New Hampshire/MANE-VU Ask of a 28-percent reduction in non-EGU SO_2 emissions is reasonable. States should have no difficulty in meeting this benchmark in light of the control efficiencies that are attainable at reasonable costs with retrofit technologies that are available for ICI boilers today.

1) Non-EGU SO_2 Emission Reduction Measures outside MANE-VU – Costs of Compliance: Industrial boilers have a wider range of sizes than EGUs and often operate over a wider range of capacities. Thus, cost estimates for the same technologies will generally span a relatively larger range, and costs for an individual boiler will depend on the capacity of the boiler and typical operating conditions. In general, cost-effectiveness increases as boiler size and capacity factor (a measure of boiler utilization) increases.

MANE-VU's Reasonable Progress Report (Attachment Y) provides emission control cost estimates for ICI boilers in the range of $130 to $11,000 per ton of SO_2 removed, a very wide spread due to the variability of sources and control options in this category. All costs presented below for emission controls on ICI boilers are borrowed from this report. Dollar amounts originated from EPA publications cited in the report and are restated in 2006 dollars using appropriate adjustment factors found at www.inflationdata.com.

◊ *Cost of Fuel Switching*: Although fuel switching can be a very effective means of controlling SO_2 emissions (reductions of 50 to 99.9 percent are possible), burning low-sulfur fuel may not be technically feasible or economically practical as an SO_2 control option for every coal-fired boiler. Factors impacting applicability include the characteristics of the plant and the particular type of fuel change being considered. Additionally, switching to a lower-sulfur coal can affect fuel handling systems, boiler performance, PM control effectiveness, and ash handling systems. Oil-fired boilers switching to a lower-sulfur fuel of the same grade (e.g., switching from #6 fuel oil at 2.0% S to #6 fuel oil at 0.5% S) do not typically encounter these issues. (See Part 10.2.3 for a discussion of the costs and issues associated with switching to low-sulfur fuel oil.)

The costs of coal fuel switching, including substitution or blending with a low-sulfur coal, can be attributed to two main factors: the cost of low-sulfur coal compared to higher-sulfur coal (including consideration of the coal's heating value), and the cost of necessary boiler or coal-handling equipment modifications. Many plants will be able to switch from high-sulfur to low-sulfur bituminous coal without serious difficulty, but switching from bituminous to subbituminous coal may require potentially significant investments and modifications to an existing plant. Even if a lower-sulfur fuel is available, it may not be cost competitive if it must be supplied in small quantities or transported long distances from the supplier. It also may be more cost-effective to burn a higher-sulfur fuel supplied by nearby suppliers and to use a post-combustion control device.

Switching from coal combustion to natural gas combustion virtually eliminates SO_2 emissions. It is technically feasible to switch from coal to natural gas; but it is currently uneconomical to consider this option for large ICI boilers because of the required equipment modifications, the fuel quantities necessary, and the generally higher price of natural gas compared to coal.

◊ *Cost of Coal Cleaning*: The World Bank, an organization which assists with economic and technological needs in developing countries, reports that the cost of physically cleaning coal varies from \$1 to \$10 per ton of coal cleaned, depending on the coal quality, the cleaning process used, and the degree of cleaning desired. In most cases, the costs were found to be between \$1 and \$5 per ton of coal cleaned. Coal cleaning typically results in a 20- to 25-percent reduction in SO_2 emissions and increases the heating value of the fuel by a small amount.

◊ *Cost of Combustion Controls*: Dry sorbent injection (DSI) systems have lower capital and operation costs than post-combustion FGD systems because of the simplicity of the DSI design, lower water use needs, and smaller land area requirements. Table 10.6 presents the estimated costs of adding DSI-based SO_2 emission controls to ICI boilers for different boiler sizes, fuel types, and capacity factors.

Table 10.6: Estimated Costs of Dry Sorbent Injection (DSI) for ICI Boilers (2006 dollars)

Fuel	SO_2 Reduction (%)	Capacity Factor (%)	Cost-Effectiveness (\$/ton of SO_2 removed)		
			100 MMBtu/hr	250 MMBTU/hr	1,000 MMBTU/hr
2%-Sulfur Coal	40	14	4,686	3,793	2,979
		50	1,312	1,062	834
		83	772	624	490
3.43%-Sulfur Coal	40	14	2,732	2,212	1,737
		50	765	619	486
		83	450	364	286
2%-Sulfur Coal	85	14	2,205	1,786	1,402
		50	617	500	392
		83	363	294	231
3.43%-Sulfur Coal	85	14	1,286	1,040	818
		50	360	291	229
		83	212	171	134

Note: Data as compiled and presented in Table 4.3 of MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007.

◊ *Cost of FGD*: Installation of post-combustion SO_2 controls in the form of FGD has several impacts on facility operations, maintenance, and waste handling procedures. FGD systems generally require substantial land area for construction of the absorber towers, sorbent tanks, and waste handling equipment. The facility costs therefore depend on the cost and availability of space for construction of the FGD system. In addition, significant quantities of waste material may be generated that require disposal. The costs may be mitigated, however, by utilization of a forced oxidation FGD process that produces commercial-grade gypsum, which may be sold as a raw material for other commercial processes.

Table 10.7 presents the total estimated cost-per-ton of adding FGD-based SO_2 emission controls to ICI boilers for different boiler sizes, fuel types, and capacity factors. There is no indication that these cost data include possible revenues from gypsum sales, which would partially offset the costs of FGD controls.

Carbon dioxide is also emitted as a byproduct of FGD; therefore, the impacts of increased carbon emissions associated with this technology would need to be considered. CO_2 emissions will become more of an issue in the future if they are limited under climate change mitigation strategies. Given the uncertainty of such future strategies, costs related to increased carbon emissions from FGD cannot yet be assessed.

MANE-VU's request for a 28-percent reduction in non-EGU SO_2 emissions allows states flexibility in determining which sources to control, so that the most cost-effective control measures can be adopted and implemented over the next 10 years. Given the wide range of control options and costs available for this purpose, MANE-VU has concluded that the request for a 28-percent reduction in non-EGU SO_2 emissions is reasonable. New Hampshire concurs with this conclusion.

Table 10.7: Estimated Costs of Flue Gas Desulfurization for ICI Boilers (2006 dollars)

Fuel	Technology	SO_2 Reduction (%)	Capacity Factor (%)	Cost-Effectiveness ($/ton of SO_2 removed)		
				100 MMBtu/hr	250 MMBTU/hr	1,000 MMBTU/hr
High-Sulfur Coal [a]	FGD (dry)	40	14	3,781	2,637	1,817
			50	1,379	1,059	828
			83	1,006	814	676
Lower-Sulfur Coal [b]	FGD (dry)	40	14	4,571	3,150	2,119
			50	1,605	1,207	928
			83	1,147	906	744
Coal	FGD (spray dry)	90	14	4,183	2,786	1,601
			50	1,290	899	567
			83	843	607	407
High-Sulfur Coal	FGD (spray dry)	90	14	3,642	2,890	1,909
			50	1,116	875	601
			83	709	563	398
Lower-Sulfur Coal	FGD (wet)	90	14	4,797	3,693	2,426
			50	1,415	1,106	751
			83	892	705	492
Oil [c]	FGD (wet)	90	14	10,843	8,325	5,424
			50	2,269	1,765	1,184
			83	1,371	1,079	740

Note: Data as compiled and presented in Table 4.4 of MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007.

[a] Assumes sulfur content = 3.43% and ash content = 12.71%.

[b] Assumes sulfur content = 2.0% and ash content = 13.2%.

[c] Sulfur content of oil is not specified.

2) Non-EGU SO_2 Emission Reduction Measures outside MANE-VU – Time Necessary for Compliance: For pre- and post-combustion SO_2 emission controls, engineering and construction lead times will vary between 2 and 5 years, depending on the size of the facility and specific control technology selected. Generally, sources are given a 2- to 4- year phase-in period to comply with new rules, as previously described, and states generally have a 2-year period for compliance with RACT rules.

For the purposes of this review, it is assumed that a 2-year period after SIP submittal is adequate for pre-combustion controls (fuel switching or cleaning), and a 3-year period is adequate for the installation of post-combustion controls. MANE-VU has therefore concluded that there is sufficient time between 2008 and 2018 for affected states to adopt emission control requirements and for affected sources to install the necessary controls to meet MANE-VU's requested SO_2 emission reductions from non-EGU sources. New Hampshire concurs with this conclusion.

3) Non-EGU SO_2 Emission Reduction Measures Outside MANE-VU – Energy and Non-Air Quality Environmental Impacts of Compliance: The primary energy impact of pre- or post-combustion control alternatives is a potential increase in electricity usage. Fuel switching and cleaning do not significantly affect the efficiency of the boiler itself, but require additional energy to clean or blend coal. FGD systems typically operate with high-pressure drops across the control equipment and therefore consume significant amounts of electricity to operate blowers and circulation pumps. In addition, some combinations of FGD technology and plant configuration may require flue gas reheating to prevent physical damage to equipment, resulting in higher fuel usage.

The primary non-air environmental impacts of fuel switching derive from transportation of the fuel. Secondary environmental impacts derive from waste disposal and material handling operations (e.g. fugitive dust). For FGD systems, the generation of wastewater and sludge from the SO_2 removal process is a consideration. Wastewater from the FGD systems will increase sulfate, metals, and solids loading at the receiving wastewater treatment facility, resulting in potential impacts to operating cost, energy requirements, and effluent water quality. Processing of the wastewater sludge can require energy for stabilization and/or dewatering, and transporting the dewatered sludge to a landfill has additional environmental implications.

Fuel switching to a low-sulfur distillate fuel oil has a variety of beneficial consequences for ICI boilers. Low-sulfur distillate fuel is cleaner burning and emits less particulate matter, which reduces the rate of fouling of heating units substantially and permits longer time intervals between cleanings. According to a study conducted by NYSERDA (reference 10 in Attachment AA), boiler deposits are reduced by a factor of two by lowering the fuel sulfur content from 1,400 ppm to 500 ppm. These reductions in buildup of deposits result in longer service intervals between cleanings.

Reducing SO_2 emissions from ICI boilers would have positive environmental and health impacts. SO_2 controls would reduce acid deposition, helping to preserve aquatic life, forests, and crops as well as buildings and sculptures made of acid-sensitive materials. These emission reductions would also help to decrease ambient levels of $PM_{2.5}$, a significant contributor to premature morbidity and illness in individuals with heart or lung conditions.

MANE-VU has concluded that the energy and non-air environmental impacts of controlling SO_2 emissions from ICI boilers are justified in light of the beneficial impacts on regional haze, fine particulate air pollution, acid rain, and equipment operation, as described above. New Hampshire concurs with this conclusion.

4) Non-EGU SO_2 Emission Reduction Measures Outside MANE-VU – Remaining Useful Life of Any Potentially Affected Sources: Available information for remaining useful life estimates of ICI boilers indicates a wide range of life expectancies, depending on unit size, capacity factor, and level of maintenance performed. Typical life spans range from about 10 years to over 30 years. However, the remaining useful life of a specific source is highly variable; and older units are not likely to be retrofitted with expensive emission controls. Given the typical range of life expectancies of ICI boilers, the technical options available, and the flexibility that non-MANE-VU states would have to meet the Ask, MANE-VU has concluded that a 28-percent reduction in non-EGU SO_2 emissions is reasonable. New Hampshire concurs with this conclusion.

10.3 Reasonable Progress Goals for Class I Areas in the State

As required under 40 CFR 51.308(d)(1), this regional haze SIP establishes reasonable progress goals for Class I areas in New Hampshire for the 10-year period of the implementation plan ending in 2018. These RPGs are determined from modeling based on implementation of the proposed reasonable measures included in MANE-VU's long-term strategy. Table 10.8 provides a summary of the reasonable progress goals, in deciviews, for New Hampshire's two Class I areas: Great Gulf Wilderness and Presidential Range - Dry River Wilderness.

Table 10.8: Reasonable Progress Goals for Great Gulf Wilderness and Presidential Range - Dry River Wilderness (all values in deciviews)

Visibility Condition	Natural Visibility	2000-2004 Baseline Visibility	RPG (Visibility Expected by 2018)	Visibility Improvement Expected by 2018
20 Percent Worst Days (Average)	12.0	22.8	19.1	3.7
20 Percent Best Days (Average)	3.7	7.7	7.2	0.5

Both natural conditions and baseline visibility for the 5-year period from 2000 through 2004 were calculated in conformance with an alternative method recommended by the IMPROVE Steering Committee. (See Attachment L, "Baseline and Natural Visibility Conditions: Considerations and Proposed Approach to the Calculation of Baseline and Natural Visibility Conditions at MANE-VU Class I Areas," December 2006.) Future progress toward the 2018 visibility target will be calculated in a nationally consistent manner based on 5-year averages in accordance with EPA's "Guidance for Tracking Progress Under the Regional Haze Rule" (EPA-454/B-03-004, September 2003) with adjustments for the alternative method as recommended by the IMPROVE Steering Committee.

40 CFR 51.308(d)(1)(vi) requires that reasonable progress goals represent at least the visibility improvement expected from implementation of other Clean Air Act programs during the applicable planning period. The modeling that formed the basis for reasonable progress goals for MANE-VU Class I Areas included estimation of the effects of all other programs required by the Clean Air Act. MANE-VU's modeling also included the specific control measure assumptions described previously in Subsection 10.2. Additional information may be found in Section 6, Emissions Inventory, and Section 11, Long-Term Strategy, as well as in the documentation for the MANE-VU modeling.

In setting the reasonable progress goals to improve visibility at MANE-VU Class I Areas, New Hampshire recognizes that contributing states will have flexibility to submit SIP revisions and implement various control measures to meet these goals between now and 2018. The overall approach to reducing and preventing emissions that contribute to regional haze allows each state up to 10 years to implement reasonable SO_2 and NO_X control measures as appropriate and necessary.

10.4 Visibility Effects of (Additional) Reasonable Control Measures

MANE-VU's evaluations included modeling to estimate the effects on visibility of the New Hampshire/MANE-VU Ask. The results of this work are summarized below.

NESCAUM performed preliminary modeling as described in the report entitled "MANE-VU Modeling for Reasonable Progress Goals, Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G). NESCAUM also conducted more recent, revised modeling to assess the effects of all haze reduction strategies combined. The latter modeling is described in NESCAUM's "2018 Visibility Projections," May 13, 2008 (Attachment Q).

The NESCAUM modeling demonstrates that significant visibility benefits will accrue from implementation of the additional reasonable control measures described in Subsection 10.2, above. Figures 10.3 and 10.4 describe the results of this modeling. In the first of the two figures, the light yellow bars represent expected visibility at New England Class I Areas in 2018. Comparison of these values with the 2018 "glide slope" values (the plum-colored bars) shows that all areas are expected to experience visibility improvements that meet or exceed the uniform rate of progress calculated for each area. The second figure shows that, for the 20 percent of days having best visibility, expected visibility in 2018 will be better than it is today at all locations.

In conclusion, the reasonable control measures proposed by New Hampshire and the other MANE-VU states are found to be consistent with the stated national goals of preventing further visibility degradation while making measurable progress toward achieving natural visibility conditions in wilderness areas by 2064.

Figure 10.3: Demonstration of Required and Reasonable Visibility Progress for 20 Percent Worst Visibility Days

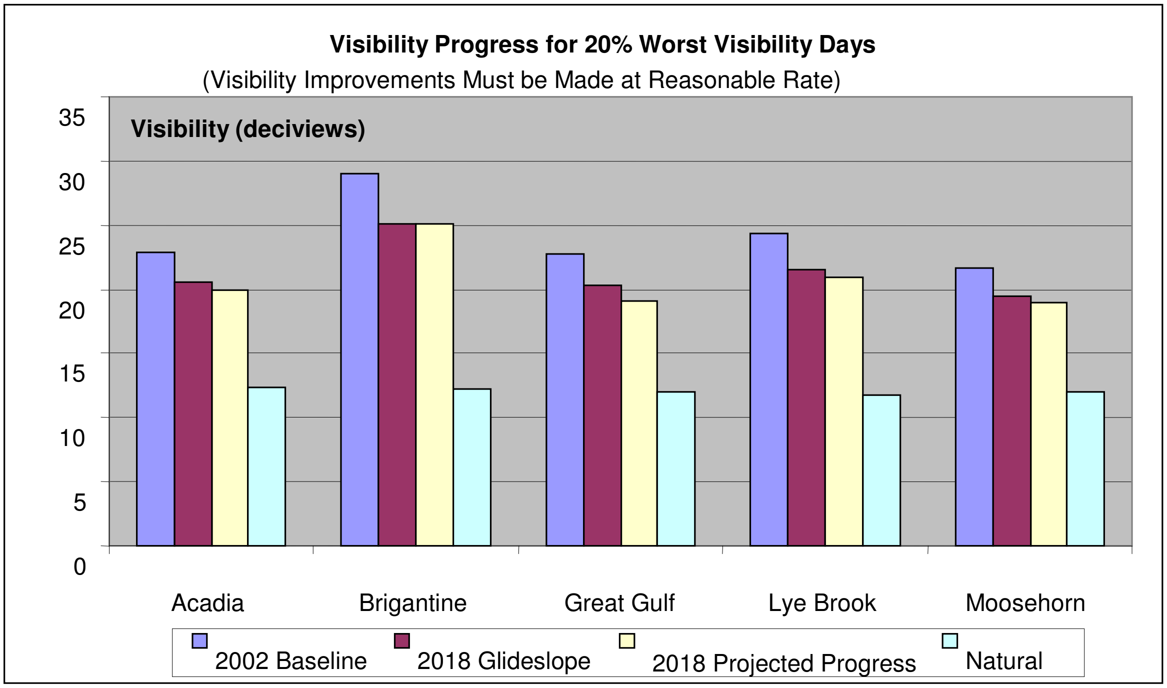
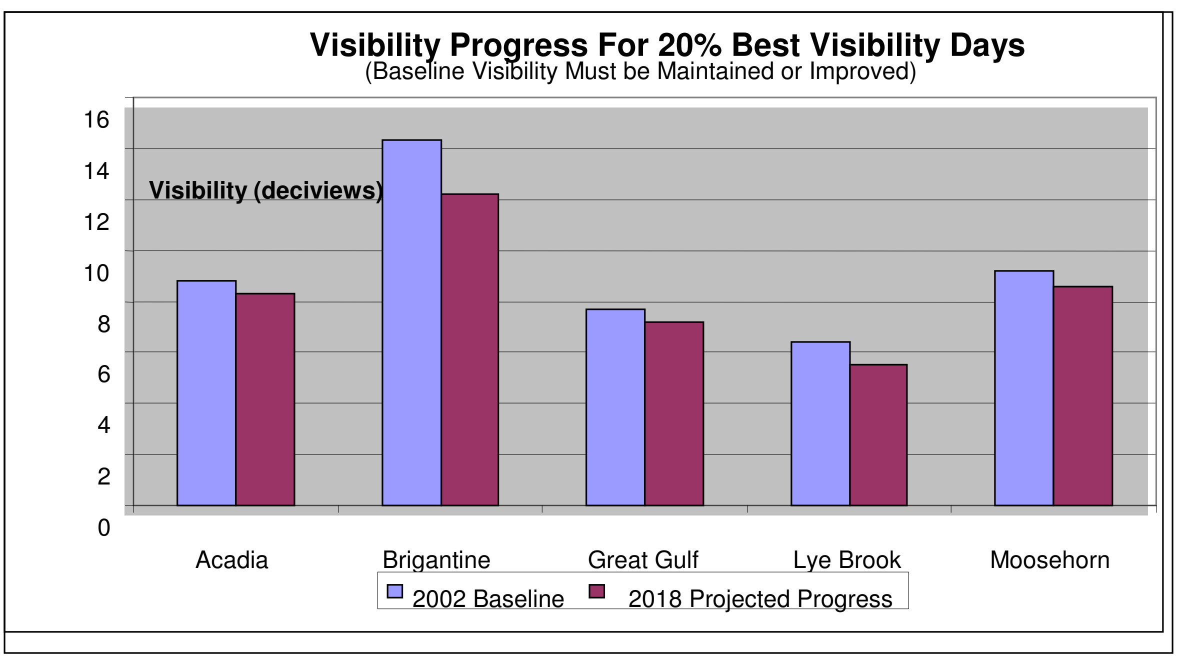


Figure 10.4: Demonstration of Required Maintenance or Improvement of Visibility for 20 Percent Best Visibility Days



References

U.S. Environmental Protection Agency, *National Emission Standards for Hazardous Air*

Pollutants for Industrial/ Commercial/Institutional Boilers and Process Heaters, http://cascade.epa.gov/RightSite/dk_public_collection_detail.htm?ObjectType=dk_docket_collection&cid=OAR-2002-0058&ShowList=items&Action=view (accessed Feb. 25, 2004).

11. LONG-TERM STRATEGY

40 CFR 51.308(d)(3) of the Regional Haze Rule requires the State of New Hampshire to submit a long-term strategy that addresses regional haze visibility impairment for all mandatory Class I federal areas within and outside the state that may be affected by emissions from within the state. Affected areas include the seven designated Class I areas within the MANE-VU region: Great Gulf Wilderness, Presidential Range-Dry River Wilderness, Acadia National Park, Moosehorn Wilderness, Roosevelt Campobello International Park, Lye Brook Wilderness, and Brigantine Wilderness. As presented in Section 3, Regional Planning and Consultation, New Hampshire consulted with other states to develop the coordinated emission management strategies contained in this SIP. The following describes how New Hampshire meets the long-term strategy requirements of the Regional Haze Rule.

New Hampshire's long-term strategy includes enforceable emission limitations, compliance schedules, and other measures necessary to achieve the reasonable progress goals described in Section 10. Additional measures may be reasonable to adopt at a later date after further consideration and review. In developing this long-term strategy, New Hampshire also considered the requirements of the Clean Air Act, Section 110 (a)(2)(D)(i)(II), pertaining to interstate and international transport of pollutants. NHDES has previously addressed this issue in New Hampshire's "Transport SIP Revision," submitted to EPA on March, 11, 2008. As that document observed, states must include provisions in their implementation plans to prohibit any source or activity from emitting air pollutants in amounts that would interfere with another state's ability to prevent significant deterioration of air quality and visibility. The long-term strategy presented herein is designed to protect visibility in New Hampshire as well as areas downwind from New Hampshire.

11.1 Overview of Strategy Development Process

The regional strategy development process identified reasonable measures that would reduce emissions contributing to visibility impairment at Class I areas by 2018 or earlier. The process of identifying potential emission reduction measures and the technical basis for the long-term strategy are discussed in this section. As a MANE-VU member and participant, New Hampshire supported several technical analyses undertaken to assist the MANE-VU states in deciding which regional haze control measures to pursue. These analyses are documented in the following reports:

- NESCAUM, "Contributions to Regional Haze in the Northeast and Mid-Atlantic United States," August 2006, otherwise known as the Contribution Assessment (Attachment B).
- ICF Resources, L.L.C., "Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model®," Final Draft Report, May 30, 2007, otherwise known as the CAIR Plus Report (Attachment BB);

- MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007, otherwise known as the Reasonable Progress Report (Attachment Y);
- NESCAUM, "Five-Factor Analysis of BART-Eligible Sources: Survey of Options for Conducting BART Determinations," June 1, 2007 (Attachment W); and
- NESCAUM, "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities," March 2005, otherwise known as the BART Report (Attachment Z).

MANE-VU reviewed a wide range of potential control measures aimed at reducing regional haze by the 2018 milestone. The process of choosing a set of control measures started in late 2005. OTC selected a contracting firm to assist with the analysis of ozone and regional haze control measure options and provided the contractor with a master list of some 900 potential control measures based on experience and previous state implementation plan work. With the help of an internal OTC Control Measures Workgroup, the contractor narrowed the list of regional haze control measures for further consideration by MANE-VU.

MANE-VU then developed an interim short list of possible control measures for regional haze. The identified control measures can be divided into three general categories:

- Beyond-CAIR sulfate reductions and related control measures targeted at specific electrical generating units (EGUs) in the eastern United States,
- Low-sulfur heating oil for industrial, commercial, institutional (ICI) boilers and residential sources (i.e., boilers and furnaces), and
- Emission controls on ICI boilers (both coal- and oil-fired); lime and cement kilns; residential woodstoves; and outdoor wood burning (including outdoor wood boilers).

The next step was to further refine this list, with the aid of several of the reports named above. The ICF CAIR Plus Report (Attachment BB) documents MANE-VU's assessment of the costs of CAIR and provides a cost analysis for additional SO_2 and NO_X controls in the eastern United States. The Reasonable Progress Report documents the assessment of control measures for EGUs and the other source categories selected for analysis. Further analysis is provided in the second of the two NESCAUM documents referenced above pertaining to Best Available Retrofit Technology (BART) controls.

The beyond-CAIR strategy for EGUs rose to the top of the list because the Contribution Assessment showed that EGU sulfate emissions have, by far, the largest impact on visibility in the MANE-VU Class I Areas. Similarly, a low-sulfur oil strategy gained traction after a NESCAUM-initiated conference with refiners and fuel-oil suppliers concluded that such a strategy could realistically be implemented within the next 10 years. Thus, the low-sulfur heating oil option for the residential and commercial sectors and the control measures option for the oil-fired ICI boiler sector merged into an overall strategy requiring the use of low-sulfur oil. Under this strategy, low-sulfur oil would be required for all residential and commercial heating units and all ICI boilers burning #2, #4, or #6 fuel oils.

During MANE-VU's internal consultation meeting in March 2007, member states reviewed the interim list of control measures to make additional refinements. States determined, for example, that there may be too few coal-fired ICI boilers in MANE-VU for these sources to be included in a regional strategy, but that they could be covered in programs adopted by individual states. The member states also decided that lime and cement kilns, of which there are few in the MANE-VU region, are most likely to be handled via the BART determination process. Residential wood burning and outdoor wood boilers remained on the list for those states where localized visibility impacts are a consideration even though emissions from these sources are primarily organic carbon and direct particulate matter. Finally, it was decided that the issue of outdoor wood burning should be examined further on a state-by-state basis because of concerns related to enforcement and penetration of existing state regulations. New Hampshire is currently considering additional regulation of this sector.

11.2 Technical Basis for Strategy Development

40 CFR 51.308(d)(3)(iii) requires New Hampshire to document the technical basis for the state's apportionment of emission reductions necessary to meet reasonable progress goals in each Class I area affected by New Hampshire's emissions. New Hampshire relied on technical analyses developed by MANE-VU to demonstrate that New Hampshire's emission reductions, when coordinated with those of other states and tribes, are sufficient to achieve reasonable progress goals in Class I areas located in New Hampshire and in other Class I areas affected by emissions originating in New Hampshire.

The emission reductions necessary to meet reasonable progress goals in Class I areas affected by New Hampshire are described in the following documents:

- NESCAUM, "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," December 2006 (Attachment L);
- NESCAUM, "The Nature of the Fine Particle and Regional Haze Air Quality Problems in the MANE-VU Region: A Conceptual Description," Final, November 2, 2006 (Attachment CC);
- NESCAUM, "Contributions to Regional Haze in the Northeast and Mid-Atlantic United States," August 2006, otherwise known as the Contribution Assessment (Attachment B).
- ICF Resources, L.L.C., "Comparison of CAIR and CAIR Plus Proposal Using the Integrated Planning Model®," Final Draft Report, May 30, 2007, otherwise known as the CAIR Plus Report (Attachment BB);
- MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007, otherwise known as the Reasonable Progress Report (Attachment Y);
- NESCAUM, "Five-Factor Analysis of BART-Eligible Sources: Survey of Options for Conducting BART Determinations," June 1, 2007 (Attachment W);
- NESCAUM, "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities," March 2005, otherwise known as the BART Report (Attachment Z);
- NESCAUM, "MANE-VU Modeling for Reasonable Progress Goals: Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G); and

- NESCAUM, "2018 Visibility Projections," May 13, 2008 (Attachment Q).

As described in Subsection 11.1, above, New Hampshire worked with other members of the Ozone Transport Commission and MANE-VU to evaluate a large number of potential emission reduction strategies covering a wide range of sources of SO_2 and other pollutants contributing to regional haze. 40 CFR 51.308(d)(3)(v) requires states to consider several factors in developing their long-term strategies. Operating within this framework and using available information about emissions and potential impacts, the MANE-VU Reasonable Progress Workgroup selected the following source categories for detailed analysis:

- Coal and oil-fired electric generating units (EGUs);
- Point and area source ICI boilers;
- Cement kilns and lime kilns;
- Sources capable of using low-sulfur heating oil; and
- Residential wood combustion and open burning.

These efforts led to the selection of the emission reduction strategies presented in this SIP.

11.3 Existing Commitments / Expected Measures to Reduce Emissions

40 CFR Section 51.308(d)(3)(v)(A) requires New Hampshire to consider emission reductions from ongoing pollution control programs. In developing its long-term strategy, New Hampshire considered air pollution programs being implemented between the 2002 baseline year and 2018. The emission reduction programs described in Parts 11.3.1, 11.3.2, and 11.3.3, below, represent commitments already made by New Hampshire and other states to implement air pollution control measures for EGU point sources, non-EGU point sources, and area sources, respectively. These control measures are the very same measures that were included in the 2018 emissions inventory and used in the modeling. While these control measures were not designed expressly for the purpose of improving visibility, the pollutants they control include those that contribute to visibility impairment in MANE-VU Class I Areas.

MANE-VU's 2018 beyond-on-the-way (BOTW) emissions inventory accounts for emission controls already in place as well as emission controls that are not yet finalized but are likely to achieve additional emission reductions by 2018. The BOTW inventory was developed based on the MANE-VU 2002 Version 3.0 inventory and the MANE-VU 2018 on-the-books/on-the-way (OTB/OTW) inventory. Inventories used for other RPOs reflect anticipated emissions controls that will be in place by 2018. The inventory is termed BOTW because it includes control measures that were developed for ozone SIPs that were not yet on the books in some states. For some states, BOTW also included controls that were under consideration for regional haze SIPs that have not yet been adopted. More information may be found in the following documents:

- MACTEC Federal Programs, Inc., "Development of Emissions Projections for 2009, 2012, and 2018 for NonEGU Point, Area, and Nonroad Sources in the MANE-VU Region," Final Report, February 28, 2007, otherwise known as the Emission Projections Report (Attachment N);
- Alpine Geophysics, LLC, "Documentation of 2018 Emissions from Electric Generating Units in the Eastern United States for MANE-VU's Regional Haze Modeling," Final Report, August 16, 2009 (Attachment H);

- NESCAUM, "MANE-VU Modeling for Reasonable Progress Goals: Model Performance Evaluation, Pollution Apportionment, and Control Measure Benefits," February 7, 2008 (Attachment G); and
- NESCAUM, "2018 Visibility Projections," May 13, 2008 (Attachment Q).

11.3.1 Controls on EGUs Expected by 2018

The following EGU emission reduction programs were included in the modeling used to develop the reasonable progress goals. These programs represent the greatest opportunities for reducing SO_2 emissions at Class I areas in the MANE-VU region and serve as the starting point for MANE-VU's long-term strategy to mitigate regional haze.

***Clean Air Interstate Rule (CAIR)*:** This major federal rule was remanded to EPA to correct deficiencies and has been replaced with the proposed Transport Rule. The original CAIR imposed permanent emissions caps on sulfur dioxide (SO_2) and nitrogen oxides (NO_X) in the eastern United States by 2015. When fully effective, this program was expected to reduce SO_2 emissions in the CAIR region by up to 70 percent. To predict future emissions from EGUs after implementation of CAIR, MANE-VU used the Integrated Planning Model (IPM®)[29]. Adjustments to the IPM output were made to provide a more accurate representation of anticipated controls at specific EGU sources as documented in the Alpine Geophysics report listed above. In making these adjustments, emission controls originating from the following state and regional programs were considered:

***Connecticut EGU Regulations*:** Connecticut adopted the following regulations governing EGU emissions:

- *Regulations of Connecticut State Agencies (RCSA), section 22a-174-19a*, limiting the SO_2 emission rate to 0.33 lb/MMBtu for fossil-fuel-fired EGUs greater than 15 MW that are also Title IV sources (effective, 2007).
- *RCSA, section 22a-174-22*, limiting the non-ozone seasonal NO_X emission rate to 0.15 lb/MMBtu for fossil-fuel-fired EGUs greater than 15 MW (effective, 2007).
- *RCSA, section 22a-199*, limiting the mercury (Hg) emission rate to 0.0000006 lb/MMBtu for all coal-fired EGUs, or alternatively coal-fired EGUs can meet a 90-percent Hg emission reduction (effective, 2008).

***Delaware EGU Regulations*:** Delaware adopted the following regulations governing EGU emissions:

- *Reg. 1144, Control of Stationary Generator Emissions*, requiring emission controls for SO_2, PM, VOC, and NO_X state-wide, effective January 2006.

[30] The IPM model runs also anticipated the implementation of EPA's Clean Air Mercury Rule (CAMR), which was recently vacated by the courts. However, MANE-VU believes that the adjustments made to the predicted SO_2 emissions from electric generating units (EGUs) will have a larger effect on the air quality modeling analysis conducted for this SIP than will the vacatur of the CAMR rule. The emission adjustments were based on states' comments on the actual levels of SO_2 controls expected to be installed in response to state-specific regulations and EPA's CAIR rule. MANE-VU believes these adjustments improve the reliability of both the emissions inventory and modeling results.

- *Reg. 1146, Electric Generating Unit (EGU) Multi-Pollutant Regulation,* requiring SO_2 and NO_X emission controls state-wide, effective December 2007. SO_2 reductions will be more than regulation specifies

- *Reg. 1148, Control of Stationary Combustion Turbine Electric Generating Unit Emissions*, requiring SO_2, NO_X, and $PM_{2.5}$ emission controls state-wide, effective January 2007.

Delaware estimates that these regulations will result in the following emission reductions for affected units: SO_2 emissions of 32,630 tons in 2002 will decline to 8,137 tons in 2018 (a 75-percent reduction); NO_X emissions of 8,735tons in 2002 will decline to 3,740 tons in 2018 (a 57-percent reduction).

Also, Delaware anticipates the following reductions resulting from the consent decree with Valero Refinery Delaware City, DE (formerly Motiva, Valero Enterprises): SO_2 emissions of 29,747 tons in 2002 will decline to 608 tons in 2018 (a 98-percent reduction); NO_X emissions in 1,022 in 2002 will decline to 102 tons in 2018 (a 90-percent reduction).

Maine EGU Regulations**:** *Chapter 145, NO_X Control Program*, limits the NO_X emission rate to 0.22 lb/MMBtu for fossil-fuel-fired units greater than 25 MW built before 1995 with a heat input capacity between 250 and 750 MMBtu/hr, and also limits the NO_X emission rate to 0.15 lb/MMBtu for fossil-fuel-fired units greater than 25 MW built before 1995 with a heat input capacity greater than 750 MMBtu/hr (effective, 2007).

Massachusetts EGU Regulations**:** Based on the Massachusetts Department of Environmental Protection's 310 CMR 7.29, *Emissions Standards for Power Plants,* adopted in 2001, six of the largest fossil-fuel-fired power plants in Massachusetts must comply with emissions limitations for NO_X, SO_2, Hg, and CO_2. These regulations will achieve an approximately 50-percent reduction in NO_X emissions and a 50- to 75-percent reduction in SO_2 emissions. Depending on the compliance paths selected, the affected facilities will meet the output-based NO_X and SO_2 standards between 2004 and 2008. This regulation also limits the six grandfathered EGUs to a CO_2 emission rate of 1,800 lb/MWh.

New Hampshire EGU Regulations**:** New Hampshire adopted the following regulations governing EGU emissions (inclusive of the New Hampshire Clean Power Act):

- *Chapter Env-A 2900, Multiple Pollutant Annual Budget Trading and Banking Program*, capping NO_X emissions at 3,644 tons per year, SO_2 emissions at 7,289 tons per year, and CO_2 emissions at 5,425,866 tons CO_2 per year for all existing fossil-fuel-fired steam units by December 31, 2006.

- *Chapter Env-A 3200*, *NO_X Budget Trading Program*, limiting ozone season NO_X emissions on all fossil-fuel-fired EGUs greater than 15 MW to 0.15 lb/MMBtu, effective November 2, 2007.

- *RSA 125-O, Multiple Pollutant Reduction Program*, requiring the installation and operation of a flue gas desulfurization system (scrubber) on PSNH Merrimack Station Units MK1 and MK2 to reduce mercury emissions by at least 80 percent, with the co-benefit of SO_2 emission reductions (90 percent expected minimum).

New Jersey New Source Review Settlement Agreements**:** The New Jersey settlement agreement with PSEG required the following actions for specific EGUs:

- *Bergen Unit #2*: Repower to combined cycle by December 31, 2002.
- *Hudson Unit #2*: Install dry FGD or approved alternative technology by Dec. 31, 2006, to control SO_2 emissions and operate the control technology at all times the unit operates to limit SO_2 emissions to 0.15 lb/MMBtu; install SCR or approved alternative technology by May 1, 2007, to control NO_X emissions and operate the control technology year-round to limit NO_X emissions to 0.1 lb/MMBtu; and install a baghouse or approved alternative technology by May 1, 2007, to control and limit PM emissions to 0.015 lb PM/MMBtu.
- *Mercer Unit #1*: Install dry FGD or approved alternative technology by Dec. 31, 2010, to control SO_2 emissions and operate the control technology at all times the unit operates to limit SO_2 emissions to 0.15 lb/MMBtu; and install SCR or approved alternative technology by 2005 to control NO_X emissions and operate the control technology during ozone season only in 2005 and year-round by May 1, 2006, to limit NO_X emissions to 0.13 lb/MMBtu.
- *Mercer Unit #2*: Install dry FGD or approved alternative technology by Dec. 31, 2012, to control SO_2 emissions and operate the control technology at all times the unit operates to limit SO_2 emissions to 0.15 lb/MMBtu; and install SCR or approved alternative technology by 2004 to control NO_X emissions and operate the control technology during ozone season only in 2004 and year-round by May 1, 2006, to limit NO_X emissions to 0.13 lb/MMBtu.

The New Jersey settlement also requires that units operating an FGD use coal having monthly average sulfur content no greater than 2 percent.

***New York EGU Regulations*:** New York adopted the following regulations governing EGU emissions:

- *Title 6 NYCRR Parts 237, Acid Deposition Reduction NO_X Budget Trading Program*, limits NO_X emissions on all fossil-fuel-fired EGUs greater than 25 MW to a non-ozone season cap of 39,908 tons in 2007.
- *Title 6 NYCRR Parts 238, Acid Deposition Reduction SO_2 Budget Trading Program*, limits SO_2 emissions from all fossil-fuel-fired EGUs greater than 25 MW to an annual cap of 197,046 tons per year starting in 2007 and an annual cap of 131,364 tons per year starting in 2008.

***North Carolina Clean Smokestacks Act*:** Enacted in 2002, this legislation requires that coal-fired EGUs achieve a 77-percent cut in NO_X emissions by 2009 and a 73-percent cut in sulfur dioxide SO_2 emissions by 2013. This act also established annual caps on both SO_2 and NO_X emissions for the two primary utility companies in North Carolina, Duke Energy and Progress Energy. These reductions must be made in North Carolina, and allowances are not saleable.

***Consent Agreements in the VISTAS region*:** The effects of the following consent agreements in the VISTAS states were reflected in the emissions inventories used for those states:

- *Santee Cooper*: A 2004 consent agreement calls for Santee Cooper in South Carolina to install and commence operation of continuous emission control equipment for PM/SO_2/NO_X emissions; comply with system-wide annual PM/SO_2/NO_X emissions limits; agree not to buy, sell, or trade SO_2/NO_X allowances allocated to Santee Cooper

System as a result of this agreement; and to comply with emission unit limits of this agreement.

- *TECO*: Under a settlement agreement, by 2008, Tampa Electric in the state of Florida will install permanent emission control equipment to meet stringent pollution limits; implement a series of interim pollution reduction measures to reduce emissions while the permanent controls are designed and installed; and retire pollution emission allowances that Tampa Electric or others could use, or sell to others, to emit additional NO_X, SO_2, and PM.
- *VEPCO*: Virginia Electric and Power Co. agreed to spend $1.2 billion by 2013 to eliminate 237,000 tons of SO_2 and NO_X emissions each year from eight coal-fired electricity generating plants in Virginia and West Virginia.
- *Gulf Power 7*: A 2002 agreement calls for Gulf Power to upgrade its operation to cut NO_X emission rates by 61 percent at its Crist 7 generating plant by 2007 with major reductions beginning in early 2005. The Crist plant is a significant source of NO_X emissions in the Pensacola, Florida, area.

11.3.2 Controls on Non-EGU Point Sources Expected by 2018

For non-EGU sources within MANE-VU, New Hampshire relied on MANE-VU's Version 3.0 Emission Inventory for 2002. MACTEC conducted an analysis of various control measures as documented in the Emission Projections Report (Attachment N). Control factors were applied to the 2018 MANE-VU inventory for non-EGUs to represent the following national, regional, or state control measures:

- NO_X SIP Call Phase I (NO_X Budget Trading Program) (except ME, NH, VT);
- NO_X SIP Call Phase II (except ME, NH, VT);
- NO_X RACT in 1-hour Ozone SIPs (already included in the 2002 inventory);
- NO_X OTC 2001 Model Rule for ICI Boilers;
- 2-, 4-, 7-, and 10-year MACT Standards;
- Combustion Turbine and RICE MACT (NO_X co-benefits were not included and assumed to be small);
- Industrial Boiler/Process Heater MACT[30]; and
- Refinery Enforcement Initiative (Fluid catalytic cracking units and fluid coking units, process heaters and boilers, flare gas recovery, leak detection and repair, and benzene (wastewater)).

In addition, states provided control measure information about specific non-EGU sources or regulatory programs in their states. MANE-VU used the state-specific data to the extent it was available. For example, several states developed additional control measures in the course of their planning efforts to reduce ozone within the Ozone Transport Region (OTR). These control measures were included by MANE-VU in the inventories used for regional

[30] The inventory was prepared before the MACT for Industrial Boilers and Process Heaters was vacated. Control efficiency was assumed to be 4 percent for SO_2 and 40 percent for PM. The overall effects of including these reductions in the inventory are estimated to be minimal.

haze modeling. (The affected states may or may not have committed to adopting these measures in their ozone SIPs.) For specific states, the ozone-reduction strategies included in the modeling would reduce NO_X emissions from the following non-EGU point sources:

- Asphalt production plants in Connecticut, New Jersey, New York, and the District of Columbia;
- Cement kilns in Maine, Maryland, New York, and Pennsylvania; and
- Glass and fiberglass furnaces in Maryland, Massachusetts, New Jersey, New York, and Pennsylvania.

For other regions, MANE-VU used emission inventory data developed by the RPOs for those regions, including VISTAS's Base G2, MRPO's Base K, and CenRAP's emissions inventory. Non-EGU source controls incorporated into the modeling include those required under the following consent agreements as reflected in the VISTAS inventory:

- *Dupont*: A 2007 agreement calls for E. I. Dupont Nemours & Co.'s James River plant to install dual absorption pollution control equipment by September 1, 2009, resulting in SO_2 emission reductions of approximately 1,000 tons annually. The James River plant is a non-EGU located in the state of Virginia.

- *Stone Container*: A 2004 agreement calls for the West Point Paper Mill in Virginia owned by Smurfit/Stone Container to control SO_2 emissions from its #8 Power Boiler by using a wet scrubber. This control device should result in reductions of over 3,500 tons of SO_2 in 2018.

11.3.3 Controls on Area Sources Expected by 2018

For area sources within MANE-VU, New Hampshire relied on MANE-VU's Version 3.0 Emissions Inventory for 2002. In general, MANE-VU developed the 2018 inventory for area sources by applying growth and control factors to the 2002 Version 3.0 inventory. Area source control factors were developed for the following national or regional control measures:

- The Ozone Transport Commission's VOC Model Rules (for consumer products, architectural and industrial maintenance coatings, portable fuel containers, mobile equipment repair and refinishing, and solvent cleaning);
- Stage I vapor recovery systems at vehicle refueling stations in all New Hampshire counties and Stage II vapor recovery systems at vehicle refueling stations in the four southern counties classified as ozone nonattainment areas (Rockingham, Strafford, Hillsborough, and Merrimack);
- New Jersey post-2002 area source controls; and
- Residential woodstove NSPS.

The following additional control measures were included in the 2018 analysis to reduce NO_X and VOC emissions for the following area source categories for some (identified) states:

- NO_X control measures for combustion of coal; natural gas; and #2, #4, and #6 fuel oils (CT, NJ, and NY only);

- VOC control measures for adhesives and sealants (all MANE-VU states except New Jersey[31] and VT);
- VOC control measures for emulsified and cutback asphalt paving (all MANE-VU states except ME and VT);
- VOC control measures for consumer products (all MANE-VU states except VT); and
- VOC control measures for portable fuel containers (all MANE-VU states except VT).

Some of the area-source control measures listed above may have been developed by states for the primary purpose of reducing ozone within the Ozone Transport Region (OTR) – see Part 11.3.2 for information on other measures included in states' ozone SIPs.

11.3.4 Controls on Mobile Sources Expected by 2018

For the on-road mobile source emission inventory, New Hampshire relied on MANE-VU's Version 3.0 emission inventory, which included the following emission control measures for New Hampshire:

- Use of reformulated gasoline in the four southern counties classified as ozone nonattainment areas: Rockingham, Strafford, Hillsborough, and Merrimack;
- An enhanced safety inspection program, including an anti-tampering inspection for motor vehicles less than 20 years old;
- On-board diagnostics testing for 1996 and newer vehicles in lieu of the anti-tampering inspection;
- Federal On-Board Refueling Vapor Recovery (ORVR) Rule;
- Federal Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Requirements;
- Federal Heavy-Duty Diesel Engine Emission Standards for Trucks and Buses; and
- Federal Emission Standards for Large Industrial Spark-Ignition Engines and Recreational Vehicles

Similar programs in other MANE-VU states were included in the on-road mobile source emission inventory, where applicable. The last four items listed above are federal programs, briefly described here:

***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 to phase out Stage II programs, even in the worst nonattainment areas, once EPA has determined that onboard systems are in widespread use.

[32] New Jersey's emission reductions from control measures for adhesives and sealants apply only to area sources. No reductions for point sources (SCC 4-02-0007-xx) were included to avoid inventory double-counting.

***Tier 2 Motor Vehicle Emissions Standards*:** Tier 2 is a fleet-averaging program modeled after the California LEV II standards. Manufacturers can produce vehicles with emissions ranging from relatively dirty to zero, but the mix of vehicles a manufacturer sells each year must have average NO_X emissions below a specified value. The Tier 2 regulations also require reduced gasoline sulfur levels. The reduction in sulfur levels contributes directly to cleaner air and has additional beneficial effects on vehicle emission control systems. The Tier 2 standards became effective in the 2005 model year and are included in the assumptions used for calculating mobile source emissions inventories used for 2018.

***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 will be phased in together between 2007 and 2010. Sulfur in diesel fuel must be lowered to enable modern pollution-control technology to be effective on the trucks and buses that use this fuel. EPA will require a 97-percent reduction in the sulfur content of highway diesel fuel from its current level of 500 parts per million (low-sulfur diesel) to 15 parts per million (ultra-low sulfur diesel).

***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 non-road 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. Non-road 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.

11.3.5 Controls on Non-Road Sources Expected by 2018

For non-road emission sources, New Hampshire used Version 3.0 of the MANE-VU 2002 Emissions Inventory. Because the NONROAD Model used to develop the non-road source emissions did not include aircraft, commercial marine vessels, and locomotives, MANE-VU's contractor, MACTEC, developed the inventory for these sources. Non-road 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 non-road emission control requirements such as the following:

- "Control of Air Pollution: Determination of Significance for Nonroad Sources and Emissions Standards for New Nonroad Compression Ignition Engines at or above 37 Kilowatts," 59 FR 31306, June 17, 1994.
- "Control of Emissions of Air Pollution from Nonroad Diesel Engines," 63 FR 56967, October 23, 1998.

- "Control of Emissions from Nonroad Large Spark-Ignition Engines and Recreational Engines (Marine and Land-Based)," Final Rule, 67 FR 68241, November 8, 2002.
- "Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel," Final Rule, April, 2004.

As noted above, inventory data for other regions were obtained from those regions' RPOs.

11.4 Additional Reasonable Measures

As required under 40 CFR 51.308(d)(1)(i)(A), New Hampshire and the other MANE-VU states applied four-factor analysis to potential control measures for the purpose of establishing reasonable progress goals (see Subsection 10.2 for detailed description). Reasonable measures include those that the affected states have already committed themselves to implementing, as described in Subsection 11.3, above. In addition, the MANE-VU states have identified other control measures that were found to be reasonable and were included in the modeling that was used to set reasonable progress goals. (These additional measures surpass the "beyond-on-the-way" emission controls and inventories.) All of the control measures – those embodied in the states' commitments to existing or planned programs and the additional reasonable control measures described below – comprise the long-term strategy for improving visibility at MANE-VU Class I Areas.

Specifically, the New Hampshire/MANE-VU long-term strategy includes the following additional measures to reduce pollutants that cause regional haze.

- Timely implementation of BART requirements.
- A 90-percent or greater reduction in sulfur dioxide (SO_2) emissions from each of the EGUs identified by MANE-VU as reasonably anticipated to cause or contribute to impairment of visibility in each mandatory Class I area in the MANE-VU region. (This requirement affects 167 point sources, or stacks, at EGU facilities in the eastern United States.) If it is infeasible to achieve this level of SO_2 reductions from specific EGUs, equivalent alternative measures will be pursued in the affected states.
- Continued evaluation of other control measures, including energy efficiency, alternative clean fuels, MANE-VU's low sulfur fuel oil strategy, 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 combustion.

This suite of additional control measures are those that the MANE-VU states have agreed to pursue for the purpose of mitigating regional haze. The corollary is that the MANE-VU Class I states (Maine, New Hampshire, Vermont, and New Jersey) are asking states outside the MANE-VU region that contribute to visibility impairment inside the region to pursue similar measures. The control measures that non-MANE-VU states choose to pursue may be directed toward the same emission source sectors identified by MANE-VU for its own emission reductions, or they may be equivalent measures targeting other source sectors. Under MANE-VU's long-term strategy, states will be allowed up to ten years to pursue adoption and implementation of proposed control measures. While some measures that states pursue may not represent enforceable commitments immediately, they may become enforceable in the future as new laws are passed, rules are written, and facility permits are issued.

11.4.1 BART

Implementation of the BART provisions of the Regional Haze Rule (40 CFR 51.308(e)) is one of the reasonable strategies included in this SIP. For electrical generating units, EPA determined that CAIR (before its remand) would fulfill BART requirements for this sector. However, New Hampshire's approach is consistent with the MANE-VU long-term strategy; i.e., it goes beyond the original CAIR standards by requiring BART controls on all BART-eligible sources in the state. Proposed control measures for New Hampshire's two BART-eligible sources, both of which are EGUs, are described in Section 9 of this SIP. These two sources are also addressed in MANE-VU's targeted EGU strategy (see Part 11.4.3, below).

To assess the benefits of implementing BART controls for MANE-VU's non-EGU sectors, NESCAUM included in the final 2018 CMAQ modeling analysis anticipated emission reductions for the region's BART-eligible facilities, as described previously in Part 10.2.2 of this SIP. It is anticipated that twelve units at eight BART-eligible sources in MANE-VU would be controlled as a result of BART requirements alone (see Table 10.3).

Note that additional emission reductions will occur at many other BART-eligible facilities within MANE-VU as a result of controls achieved by other programs that serve as BART but are not specifically identified as such (e.g., RACT control measures). While not specifically identified as being attributable to BART, these additional emission reductions were fully accounted for in the 2018 CMAQ modeling.

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

11.4.2 Targeted EGU Strategy

MANE-VU has identified emissions from the top 167 EGU emission points, including three in New Hampshire, that contribute the most to visibility impairment at MANE-VU Class I Areas (see Figure 10.2). Controlling emissions from these contributing facilities is crucial to mitigating haze pollution in wilderness areas and national parks of the Northeast states.

MANE-VU's agreed regional strategy for the EGU source sector is to pursue a 90-percent control level on SO_2 emissions from the 167 identified stacks by 2018. MANE-VU has concluded that pursuing this level of sulfur reduction is both reasonable and cost-effective. For some units, actual SO_2 removal efficiencies would be expected to approach or exceed 95 percent. The costs of SO_2 emission reductions will vary by unit. MANE-VU's Reasonable Progress Report (Attachment Y) summarizes the available control methods and costs, which range from $170 to $5,700 per ton (2006 dollars), depending on site-specific factors such as size of unit, combustion technology used, and type of fuel burned.

As shown in Table 11.1, the three targeted EGUs in New Hampshire are projected to reduce their SO_2 emissions, in the aggregate, by 87 percent between 2002 and 2018.

Table 11.1: Projected SO_2 Emission Reductions from Targeted EGUs in New Hampshire

Facility Name/Unit	Targeted EGU	BART-Eligible	Fuel Type	2002 SO_2 Emissions (tons)	Control Method	SO_2 Emission Reductions (%)	(tons)	2018 SO_2 Emissions (tons)
Merrimack Station MK1	yes	no	coal	9,754	scrubber	90	8,779	975
Merrimack Station MK2	yes	yes	coal	20,902	scrubber	90	18,812	2,090
Newington Station NT1	yes	yes	fuel oil/ natural gas	5,226	0.50 lb/MMBtu SO_2 emission limit	67	3,484	1,742
TOTALS				**35,882**		**87**	**31,075**	**4,807**

Notes: All 2002 values are based on continuous emissions monitoring (CEM) data. For Newington Station, additional SO_2 emission reductions beyond the stated value may occur with a switch to 0.5-percent low-sulfur oil under MANE-VU's low-sulfur oil strategy.

These projections are conservative estimates for at least two reasons:

- The actual performance of scrubbers to be installed on PSNH's Merrimack Station Units MK1 and MK2 is expected to match or exceed MANE-VU's Ask level of 90-percent SO_2 from targeted EGUs. (Note that MANE-VU's Assessment of Control Options for BART-Eligible Sources, Attachment Z references 95-percent control reductions. However, this rate applies to EGUs greater than 200 MW at power plants having capacities above 750-MW, i.e., facilities larger than PSNH's. Also, note that the overall SO_2 control level for the three PSNH units would be greater than stated if the baseline reduction resulting from use of lower-sulfur coal were included in the efficiency calculation.)

- PSNH's Newington Station Unit NT1, being primarily an oil-fired EGU, is expected to have low utilization rates well into the future because of the economics associated with the cost of fuel. In 2007, high fuel costs caused this unit to operate only 5 percent of the time. In fact, the most recent IPM modeling predicts that this unit will be shut down permanently by 2018. (Note that MANE-VU, from the outset, never envisioned that this oil-fired unit would be capable of achieving a control level equal to the presumptive norm for large EGUs.)

Given these considerations, there is a high probability that New Hampshire will actually surpass MANE-VU's goal of a 90-percent overall reduction in SO_2 emissions from targeted EGUs by 2018. However, in the event that New Hampshire is unable to attain this level of emission reductions, equivalency could be demonstrated by alternative methods. For example:

- Credit could be taken for SO_2 emission reductions resulting from the recently completed fuel conversion of Schiller Station Unit 5 from coal to wood and from any similar fuel conversions that might occur for other New Hampshire EGUs in the future.

- Additional SO_2 emission reductions could be achieved before 2018 by requiring all sources that burn residual fuel oil to switch to residual fuel oil with a sulfur content of 0.5-percent (or lower). New Hampshire intends to investigate this possibility further.

The anticipated benefits to regional visibility that will result from using FGD technology on New Hampshire's largest EGUs are an intended consequence of New Hampshire's Multiple Pollutant Reduction Program, which was established by law in RSA Chapter 125-O. This program requires aggressive reductions in SO_2, NO_X, mercury, and carbon dioxide (CO_2) while simultaneously allowing state-level SO_2 credits for over- or early- compliance. Under this program, emission controls for SO_2 and mercury are scheduled to be installed and operational at New Hampshire's PSNH Merrimack Station Units MK1 and MK2 by July 1, 2013. In the meantime, NHDES will continue to evaluate other control measures for EGUs to determine whether it is reasonable to implement additional controls on those sources by that date. NHDES will provide an update on its determinations in New Hampshire's first regional haze SIP progress report.

Several other states within and outside the MANE-VU region have implemented state-specific EGU emission reduction programs that will help MANE-VU meet visibility improvement goals. Many of the state programs that will contribute to meeting the targeted EGU strategy are identified in Part 11.3.1 of this section. Listed below are other states' programs not previously identified that will also contribute to meeting this strategy. These other programs may yield additional benefits by controlling emissions at certain EGUs not listed among the top 167 EGU stacks. The listed programs represent existing commitments by the states and, as such, were included in MANE-VU's most recent modeling.

***Maryland Healthy Air Act*:** Maryland adopted the following requirements governing EGU emissions:

- For NO_X: Phase I (2009) sets unit-specific annual caps totaling 20,216 tons and ozone-season caps totaling 8,900 tons.

  Phase II (2012) sets unit-specific annual caps totaling 16,667 tons and ozone-season caps totaling 7,337 tons.

- For SO_2: Phase I (2010) sets unit-specific annual caps totaling 48,818 tons.

  Phase II (2013) sets unit-specific annual caps totaling 37,235 tons.

- For mercury: Phase I (2010) requires a 12-month-rolling-average minimum removal efficiency of 80 percent.

  Phase II (2013) requires a 12-month-rolling-average minimum removal efficiency of 90 percent.

The specific EGUs included are: Brandon Shores (Units 1 and 2), C.P.Crane (Units 1 and 2), Chalk Point (Units 1, and 2), Dickerson (Units 1, 2, and 3), H.A. Wagner (Units 2 and 3) Morgantown (Units 1 and 2), and R. Paul Smith (Units 3 and 4). No out-of-state trading of emission allowances, no inter-company trading of allowances, and no banking of allowances from year to year were included in the analyses.

***New Jersey Mercury MACT Rule*:** Under this rule all coal-fired EGUs in New Jersey will have a mercury removal efficiency of 90 percent. (Some SO_2 reductions may occur as a co-benefit of mercury emission controls.)

***Consent Agreements in the VISTAS region*:** The following consent agreements in the VISTAS states were reflected in the emissions inventories used for those states:

- *East Kentucky Power Cooperative*: A July 2, 2007, consent agreement between EPA and East Kentucky Power Cooperative (EKPC) requires the utility to reduce its SO_2

emissions by 54,000 tons per year and its NO_X emissions by 8,000 tons per year, by installing and operating selective catalytic reduction (SCR) technology; low-NO_X burners, and PM and mercury continuous emissions monitors at the utility's Spurlock, Dale, and Cooper Plants. According to the EPA, total emissions from the plants will decrease between 50 and 75 percent from 2005 levels. As with all federal consent decrees, EKPC is precluded from using reductions required under other programs to meet the reduction requirements of the consent decree. EKPC is expected to spend $654 million to install pollution controls.

- *American Electric Power*: Under this agreement, American Electric Power (AEP) will spend $4.6 billion dollars for emission controls at sixteen plants located in Indiana, Kentucky, Ohio, Virginia, and West Virginia. These control measures will eliminate 72,000 tons of NO_X emissions each year by 2016 and 174,000 tons of SO_2 emissions each year by 2018 from the affected facilities.

11.5 Source Retirement and Replacement Schedules

40 CFR Section 51.308(d)(3)(v)(D) of the Regional Haze Rule requires New Hampshire to consider source retirement and replacement schedules in developing reasonable progress goals. Source retirement and replacement were considered in developing the 2018 emissions inventory described previously in Subsection 10.3, Reasonable Progress Goals for Class I Areas in the State. See also Table B-5 in the Emission Projections Report (Attachment N).

The following sources in New Hampshire were shut down (or replaced) after the 2002 base year and therefore were not included in the 2018 inventory:

- Batesville Manufacturing, Inc. (Nashua, NH)
- PSNH Schiller Station, Unit No. 5 boiler replacement (Portsmouth, NH)
- Groveton Paperboard, Inc. (Groveton, NH)
- Wausau Paper Printing & Writing, LLC (Groveton, NH)

Since the 2002 and 2018 inventories were developed and the modeling analyses performed, the following major source has also shut down:

- Fraser N.H. LLC (Berlin, NH)

11.6 Measures to Mitigate the Impacts of Construction Activities

40 CFR 51.308(d)(3)(v)(B) of the Regional Haze Rule requires New Hampshire to consider measures to mitigate the impacts of construction activities on regional haze. MANE-VU's consideration of control measures for construction activities is documented in "Technical Support Document on Measures to Mitigate the Visibility Impacts of Construction Activities in the MANE-VU Region," Draft, October 20, 2006," (Attachment DD).

The construction industry is already subject to requirements for controlling pollutants that contribute to visibility impairment. For example, federal regulations require the reduction of SO_2 emissions from construction vehicles. At the state level, New Hampshire's Code of Administrative Rules Env-A 1002, Fugitive Dust, requires the control of direct emissions of particulate matter (primarily crustal material) from mining, transportation, storage, use, and removal activities. These requirements apply to such sources as quarries, unpaved roads, cement plants, construction sites, rock-crushing operations, and general earth-moving activities. Controls may include wet suppression, covering, vacuuming, and other approved means.

MANE-VU's Contribution Assessment (Attachment B) found that, from a regional haze perspective, crustal material generally does not play a major role. On the 20 percent best-visibility days during the 2000-2004 baseline period, crustal material accounted for 6 to 11 percent of particle-related light extinction at MANE-VU Class I Areas. On the 20 percent worst-visibility days, however, the ratio was reduced to 2 to 3 percent. Furthermore, the crustal fraction is largely made up of pollutants of natural origin (e.g., soil or sea salt) that are not targeted under the Regional Haze Rule. 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.

For this regional haze SIP, New Hampshire considered additional measures to mitigate the impacts of construction activities but decided to defer evaluation of further controls. Future deliberations on potential control measures for construction activities and their possible implementation will be documented in the first regional haze SIP progress report in 2013.

11.7 Agricultural and Forestry Smoke Management

40 CFR 51.308(d)(3)(v)(E) requires New Hampshire to consider smoke management techniques related to agricultural and forestry management in developing the long-term strategy. MANE-VU's analysis of smoke management in the context of regional haze is documented in "Technical Support Document on Agricultural and Forestry Smoke Management in the MANE-VU Region, September 1, 2006," (Attachment V).

As that report notes, fires used for resource benefits are of far less significance to the total inventory of fine-particle pollutant emissions than other sources of wood smoke in the region. The largest wood smoke source categories, with respect to $PM_{2.5}$ emissions, are residential wood combustion (73 percent); open burning (15 percent); and industrial, commercial, and institutional wood combustion (9 percent). Unwanted fires involving buildings and wild lands make up only a minor fraction of wood burning emissions and cannot be reasonably addressed in a SIP. Fires that are covered under smoke management plans, including agricultural and prescribed forest burning, constitute less than one percent of total wood smoke emissions in MANE-VU.

Moreover, smoke emissions from all sources represent only a minor fraction of fine-particle mass that is the cause of regional haze. MANE-VU's Contribution Assessment (Attachment B) found that elemental carbon, the main ingredient of smoke, contributed only 3 to 4 percent of fine-particle mass on days of worst and best visibility. Additionally, elemental carbon absorbs light more readily than it scatters light. It is therefore reasonable to conclude that smoke emissions from controlled agricultural and forestry burning contribute, on average, only a small fraction of one percent of total light extinction on days of both good and poor visibility. NHDES has no information to indicate that this situation would change significantly over the next decade.

Nevertheless, New Hampshire intends to consult with the Forest Protection Bureau of the New Hampshire Department of Agriculture and with the New Hampshire Department of Resources and Economic Development (DRED) to consider smoke management in agricultural and forestry practices to address visibility effects at MANE-VU Class I Areas. In addition, New Hampshire will consider ways to improve the inventory of smoke emissions and to achieve a better understanding of the relative importance of agricultural and forestry sources (versus residential wood stoves, in particular) as contributors to regional haze. The results of these efforts will be documented in the first regional haze SIP progress report in 2013.

11.8 Estimated Effects of Long-Term Strategy on Visibility

40 CFR 51.308(d)(3)(v)(G) requires New Hampshire to consider, in developing its long-term strategy, the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy. NESCAUM conducted modeling to evaluate the expected improvements to visibility at affected Class I areas by 2018 as a consequence of implementing MANE-VU's long-term strategy. Those visibility improvements will result, in part, from the efforts identified in this SIP to reduce emissions that originate in New Hampshire.

All Class I states affected by emissions originating in New Hampshire have (or will have) established reasonable progress goals for 2018 for each of their Class I areas. The control measures included in this SIP represent the reasonable efforts of New Hampshire, in conjunction with the efforts of other MANE-VU states, toward achieving the reasonable progress goals established by the affected states.

Based on the most recent MANE-VU modeling, the proposed control measures will reduce sulfate levels at affected Class I areas by about one-third on the worst visibility days and by 6 to 31 percent on the best visibility days by 2018. Nitrate and elemental carbon levels will also show substantial reductions across all areas for both best and worst days, while smaller reductions in organic carbon levels will occur. Small increases are predicted for the fine soil component of regional haze. There is a possibility that the predicted increases in this component are not real but, rather, related to structural differences in the data sets used in the modeling for the baseline and future years. (Specifically, the fire emissions inventory used in VISTAS for the base year relied on an earlier version of fire emissions data than the one used for the 2018 inventory.) No changes are predicted for sea salt because the model does not track this component.

The 2000-2004 visibility readings at affected Class I areas provide the baseline against which future visibility readings will be measured to assess progress deriving from implementation of New Hampshire's regional haze SIP and those of the other MANE-VU states. To determine baseline visibility for affected Class I areas, NHDES used the 2000-2004 IMPROVE monitoring data to calculate the average deciview values for the 20 percent best visibility days and the 20 percent worst visibility days over that period. (Note that both natural conditions and baseline visibility for the 5-year period were calculated in conformance with an alternative method recommended by the IMPROVE Steering Committee – see Subsection 4.1) Thus, the 20 percent best day and 20 percent worst day values represent average visibility conditions for the top and bottom quintiles.

To create the series of visibility graphs which follow, 2018 visibility estimates were made in accordance with EPA modeling guidance. First, 2002 daily average baseline concentrations were multiplied by their corresponding relative reduction factors to obtain 2018 projected concentrations for each day. The 2018 projected concentrations were then used to derive daily visibility in deciviews. As a final step, the deciview values for the 20 percent of days having best visibility were averaged, and the process repeated for the 20 percent of days having worst visibility. The resulting averages represent the projected upper and lower quintiles of visibility in 2018.

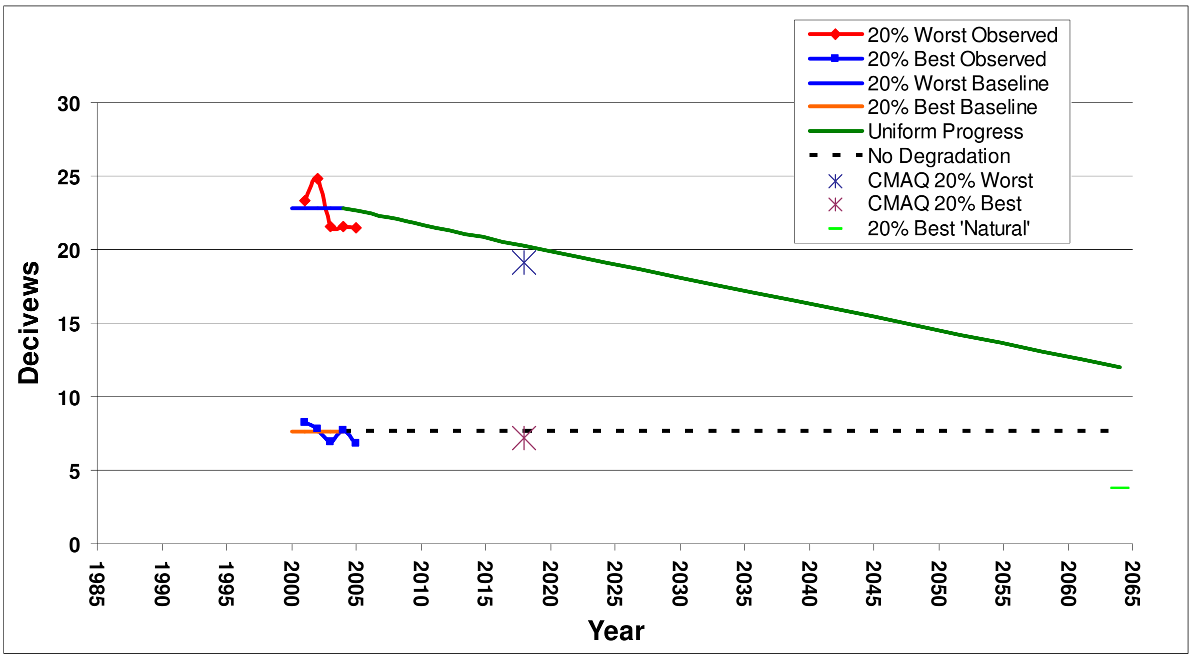
The following is provided to assist with interpretation of the line graphs in Figures 11.1 and Figures 11.3 through 11.5. Note that lower deciview values indicate better visibility.

- The irregular blue line (~) represents the 20 percent best visibility average value as determined from available monitoring data for each year through 2005.
- The irregular red line (~) represents the 20 percent worst visibility average value as determined from available monitoring data for each year through 2005.
- The straight orange line (—) represents the 20 percent best visibility average value as determined from monitoring data for the 5-year period of 2000-2004. (This line represents the *20 percent best visibility baseline condition*.)
- The straight blue line (—) represents the 20 percent worst visibility average value as determined from monitoring data for the 5-year period of 2000-2004. (This line represents the *20 percent worst visibility baseline condition*.)
- The straight broken line (▪▪▪) is a continuation of the 20 percent best visibility baseline, representing the 20 percent best visibility condition as it would be with no further degradation or improvement.
- The straight green line (—) represents the 20 percent worst visibility values that establish the uniform rate of progress for the period 2004-2064. (This line is sometimes referred to as the *uniform progress line*, or *"glide slope."* It was created by linear interpolation between the average 20 percent worst visibility baseline value from 2000-2004 and the 20 percent worst visibility value under natural conditions in 2064. If visibility improvements match this rate of progress, actual visibility will return to natural conditions in 2064. Visibility values used for the calculation of uniform rate of progress may be found in Table 10.1.)
- The light-green dash (–) shown at 2064 represents the theoretical 20 percent best visibility value under natural conditions (i.e., no anthropogenic emissions).
- The purple star (✳) represents the 20 percent best visibility value in 2018 after implementation of MANE-VU's long-term strategy, as predicted by the CMAQ model. (This value is a *reasonable progress goal*.)
- The blue star (✳) represents the 20 percent worst visibility value in 2018 after implementation of MANE-VU's long-term strategy, as predicted by the CMAQ model. (This value is a *reasonable progress goal*.)

Figure 11.1 illustrates predicted visibility improvements at Great Gulf Wilderness. Observe that the blue star lies below the green line, indicating that, by 2018, the long-term strategy of this SIP will result in visibility improvements surpassing the uniform rate of progress on days of worst visibility. Similarly, the position of the purple star below the dashed line indicates that visibility requirements will be met, i.e., there will be no further degradation from baseline conditions on days of best visibility.

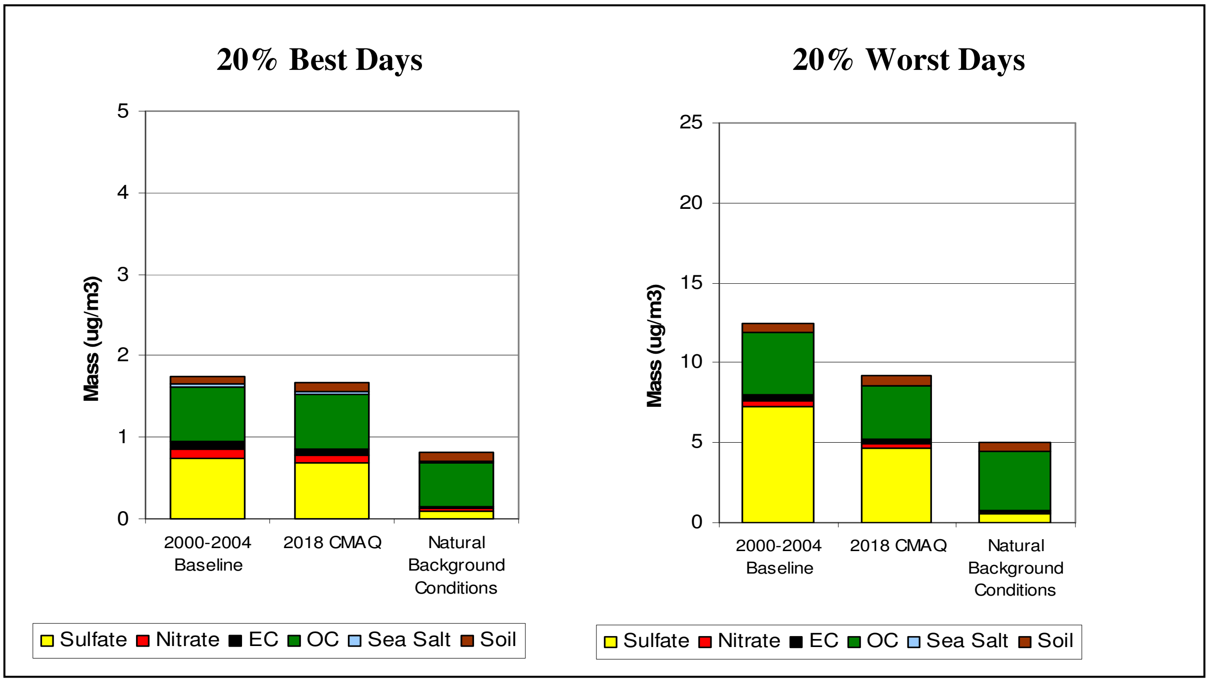
Figure 11.2 presents bar graphs depicting expected improvements in haze-causing pollutant levels at Great Gulf Wilderness. (The data employed for these graphs also apply to Presidential Range - Dry River Wilderness.) The graph on the left shows mass concentrations of visibility-impairing pollutants on days of best visibility for the 2000-2004 baseline period, 2018 modeled year, and natural background condition. The graph on the right is a similar plot for days of worst visibility. The graphs show that almost all of the expected improvements will result from reductions in sulfate concentrations. If the states adhere to MANE-VU's reasonable progress goals, sulfate levels (as a fraction of the total pollutant burden) will fall from about 60 percent in 2000-2004 to no more than 50 percent in 2018 and to less than 10 percent (natural conditions) in 2064.

Figure 11.1: Expected Visibility Improvement at Great Gulf Wilderness Based on Most Recent Projections [32]



[32] The visibility improvement estimate for Great Gulf Wilderness also serves as an estimate for Presidential Range - Dry River Wilderness.

Figure 11.2: Expected Improvements in Pollutant Concentrations at Great Gulf Wilderness on Best and Worst Days



Figures 11.3 through 11.6 are line graphs showing anticipated visibility improvements for the other New England Class I Areas. All locations are projected to meet or exceed their uniform-rate-of-progress goals for 2018. In addition, all areas are expected to see improvements in best-day visibility relative to baseline values.

Figure 11.3: Expected Visibility Improvement at Acadia National Park Based on Most Recent Projections

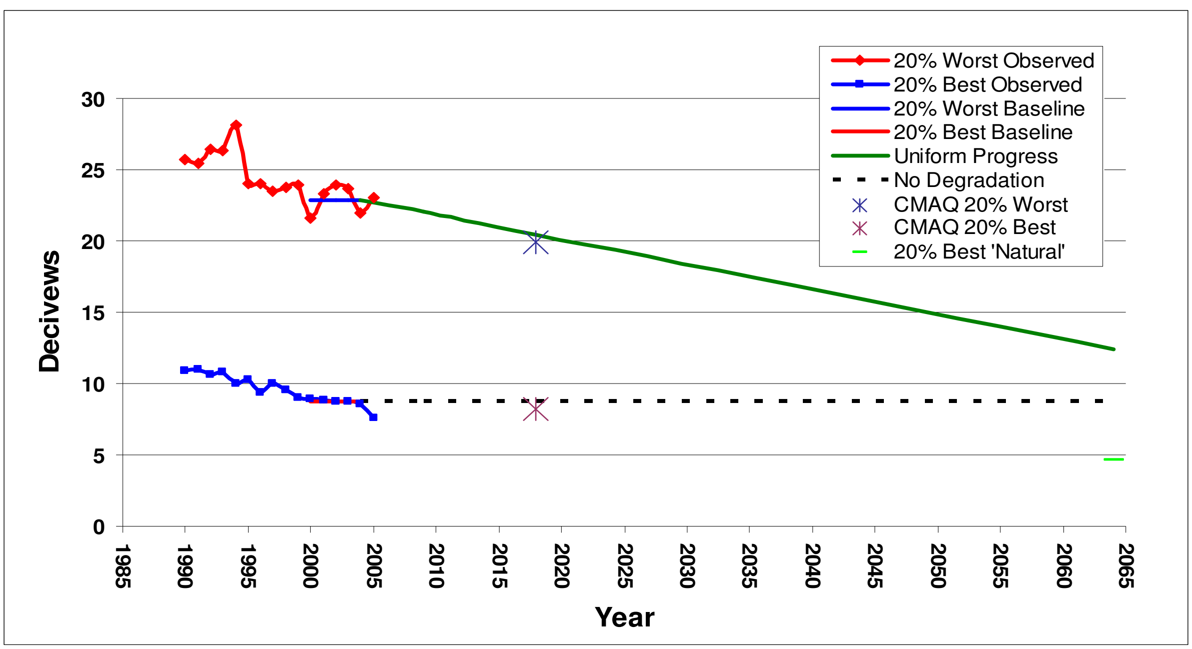


Figure 11.4: Expected Visibility Improvement at Lye Brook Wilderness Based on Most Recent Projections

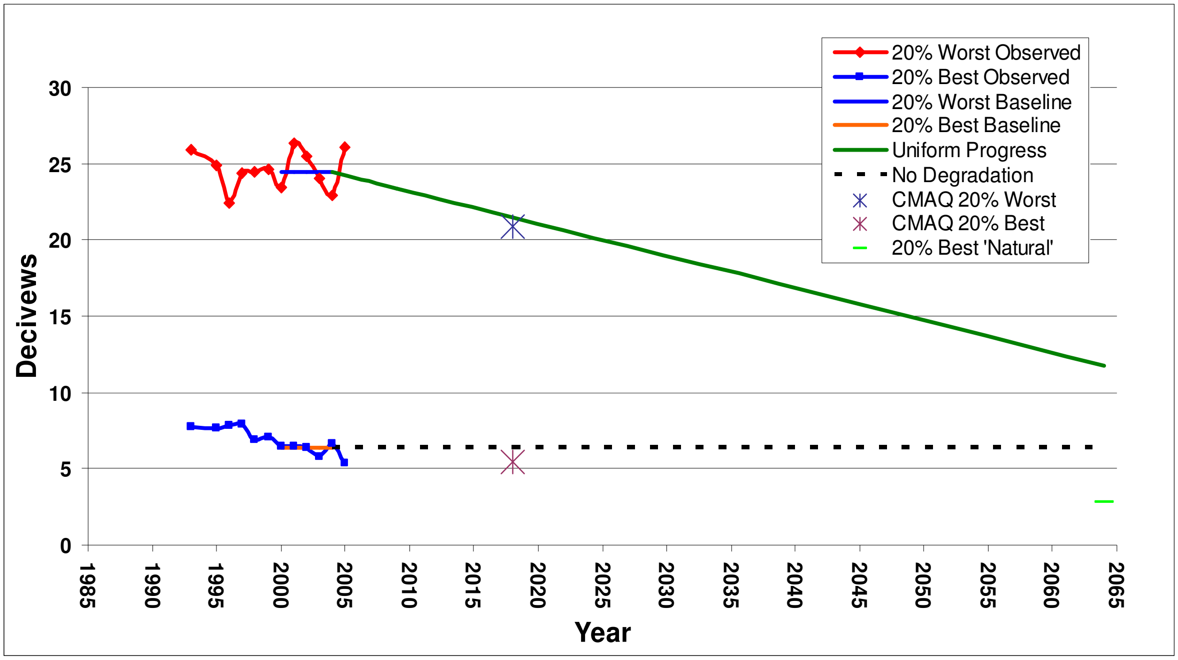
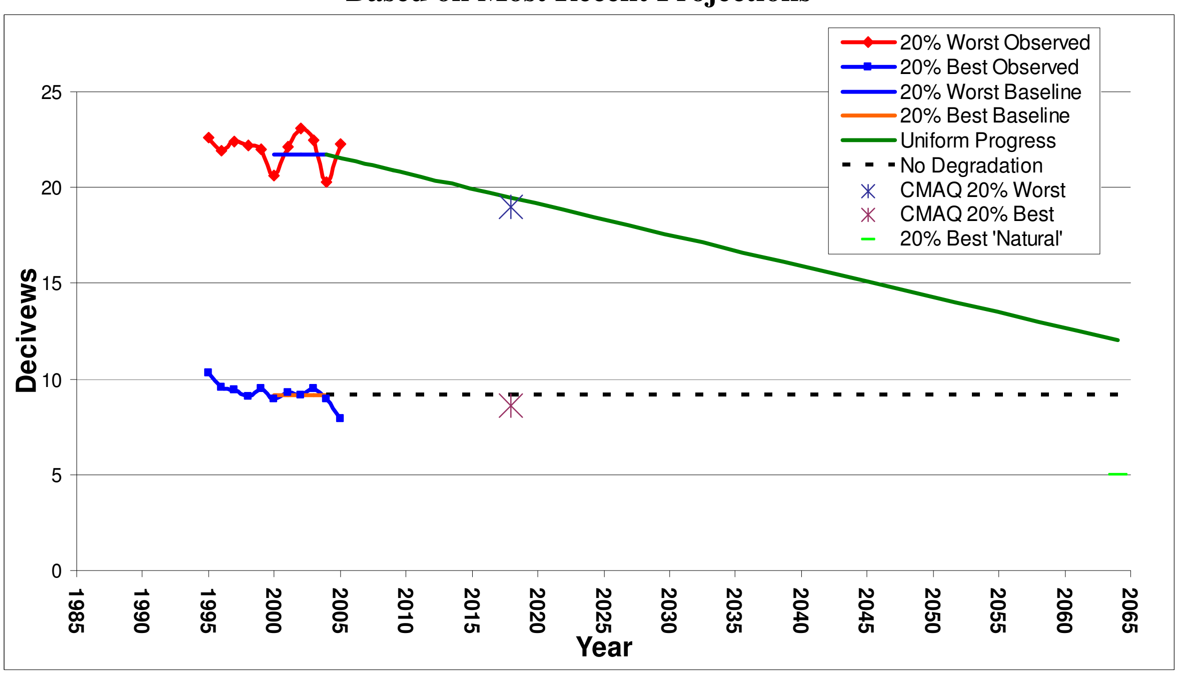


Figure 11.5: Expected Visibility Improvement at Moosehorn National Wildlife Refuge Based on Most Recent Projections [33]



[34] The visibility improvement estimate for Moosehorn Wilderness also serves as an estimate for Roosevelt/Campobello International Park.

The data points for predicted visibility in 2018 (the stars in Figures 11.1 and 11.3 through 11.5) omit the potential visibility benefits of a low-sulfur fuel oil strategy. This omission reflects the fact that New Hampshire was unable to adopt legislation for such a strategy within the allotted timeframe for submittal of regional haze SIPs. To obtain the 2018 predicted visibility values, NHDES adjusted MANE-VU's most recent ("Best and Final") modeling results by removing the visibility benefits associated with the low-sulfur fuel oil strategy (S1 and S2). In Table 11.2, this adjustment is represented mathematically by adding the isolated S1 and S2 visibility improvement increments to the most recent modeling results.

The incremental visibility benefits were previously identified in Table 5-1 of the Modeling for Reasonable Progress report (Attachment G). The described method conservatively assumes that the maximum benefits of the low-sulfur fuel strategy would occur on worst visibility days. Thus, in Table 11.2, the adjusted 2018 visibility estimates for 20% worst visibility days are likely to be on the high side.

Table 11.2: Adjusted Visibility Estimates for 20 Percent Worst Visibility Days (deciviews)

	Great Gulf	Acadia	Lye Brook	Moosehorn
2000-2004 Baseline	22.82	22.89	24.45	21.72
2018 Most Recent Modeling	19.1	19.4	20.9	19.0
Isolated S1 Low-Sulfur Oil Strategy*	0.12	0.41	0.16	0.30
Isolated S2 Low-Sulfur Oil Strategy**	0.01	0.05	0.01	0.04
Adjusted 2018 Most Recent Modeling	19.23	19.86	21.07	19.34
2018 Rate of Progress Goal	20.3	20.5	21.5	19.4

Note: Adjusted visibility calculations were performed only for Class I areas for which New Hampshire was found to significantly contribute.

* S1 Low-Sulfur Oil matches Phase 1 of the MANE-VU Low-Sulfur Oil Strategy (500 ppm for #2 distillate fuel oil, 0.25%S for #4 residual fuel oil, and 0.5%S for #6 residual fuel oil).

** S2 Low-Sulfur Oil matches Phase 2 of the MANE-VU Low-Sulfur Oil Strategy (further reduction to 15ppm for #2 distillate oil).

11.9 New Hampshire's Share of Emission Reductions

40 CFR 51.308(d)(3)(ii) of the Regional Haze Rule requires New Hampshire to demonstrate that its implementation plan includes all measures necessary to obtain its share of emission reductions needed to meet the reasonable progress goals. The modeling analyses referenced in Subsection 11.8, above, demonstrate that the New Hampshire/MANE-VU long-term strategy is sufficient to meet these visibility goals.

The basis for the long-term strategy is a statement adopted by MANE-VU on June 20, 2007 (see Part 3.3.3, The MANE-VU "Ask"). This document provides that each state will have up to 10 years to pursue adoption and implementation of reasonable control measures for NO_X and SO_2 emission reductions. New Hampshire's regional haze SIP is wholly consistent with this long-term strategy. **To meet its obligation, New Hampshire agrees to pursue the following general and specific emission reduction measures**:

- Timely implementation of BART requirements at the two BART-eligible units in the state: PSNH Merrimack Station Unit MK2 and PSNH Newington Station Unit NT1;
- Emission controls on targeted in-state EGUs that contribute to visibility impairment at Class I areas in the region – more specifically, compliance with New Hampshire law RSA 125-O, Multiple Pollutant Reduction Program, which mandates the installation of scrubbers on PSNH Merrimack Station Units MK1 and MK2 by July 1, 2013, to control SO_2 and mercury emissions. These controls will reduce SO_2 emissions at these units by at least 90 percent from 2002 levels. It is anticipated that the scrubber will be optimized for mercury emission reductions and therefore may not meet the 95 percent SO_2 reduction rate that is typical for scrubbers. However, the 90-percent minimum requirement effectively means that actual SO_2 emission reductions must *exceed* 90 percent on average. To the extent that these higher rates can be realized, they will be applied against the less than 90-percent SO_2 reduction expected at Newington station in order to fulfill the state's commitment to MANE-VU's targeted EGU strategy.
- Continued evaluation of other possible control measures for haze-causing emissions, including participation in MANE-VU's low-sulfur fuel oil strategy by 2018.

Implementation of the long-term strategy will produce significant changes in New Hampshire's emissions inventory by the end of the first planning period, 2018. Changes to the emissions inventory will also occur as a result of population growth; changes in land use and transportation; development of industrial, energy, and natural resources; and other air pollution control measures not directly related to regional haze. However, it is the expected reductions in SO_2 emissions that will have the greatest effect on visibility improvement at MANE-VU Class I Areas; and those reductions will be largely due to implementation of the control measures incorporated into this SIP. (As a precursor to sulfate, SO_2 emissions are responsible for most of the fine-particle mass on the haziest days at MANE-VU Class I Areas. See Section 8, Understanding the Sources of Haze-Causing Pollutants.)

Current and projected SO_2 emissions for the various source categories in New Hampshire and, for comparison, all of MANE-VU are summarized in Tables 11.2 and 11.3. These emissions represent the majority of all haze-causing pollutants originating within the state and region. Further information on New Hampshire's emissions inventory, including other pollutants that contribute to visibility impairment, is available in Section 6, Emissions Inventory.

Table 11.3: SO_2 Emissions from Point, Area, and Mobile Sources in New Hampshire (tpy)

Source Category	Baseline 2002	Most Recent Projected 2018*	Low-Sulfur Fuel Strategy 2018**	Adjusted Projected 2018***
Area	7,072	972	6,449	7,421
Non-EGU Point	2,436	1,084	2,030	3,114
EGU Point	44,124	10,766	–	10,766
On-Road Mobile	777	537	–	537
Non-Road Mobile	891	246	–	246
TOTAL	55,300	13,605	8,479	22,084
Percent Reduction 2002-2018				**60.1**

* From MANE-VU's 2018 "Best and Final" modeling emissions inventory.
** Projected emission reductions for MANE-VUs's low-sulfur fuel strategy.
*** Projected 2018 emissions without MANE-VU's low-sulfur fuel strategy.

Table 11.4: SO_2 Emission from Point, Area, and Mobile Sources in all of MANE-VU (tpy)

Source Category	Baseline 2002	Most Recent Projected 2018*	Low-Sulfur Fuel Strategy 2018**	Adjusted Projected 2018***
Area	286,921	129,656	175,984	305,640
Non-EGU Point	264,377	211,320	59,114	270,434
EGU Point	1,643,257	386,584	–	386,584
On-Road Mobile	40,090	8,757	–	8,757
Non-Road Mobile	57,257	8,643	–	8,643
TOTAL	2,291,902	744,960	235,098	980,058
Percent Reduction 2002-2018				**57.2**

* From MANE-VU's 2018 "Best and Final" modeling emissions inventory.
** Projected emission reductions for MANE-VUs's low-sulfur fuel strategy.
*** Projected 2018 emissions without MANE-VU's low-sulfur fuel strategy.

The projected overall reduction of 60 percent for SO_2 emissions originating in New Hampshire exceeds by a small amount the projected average reduction of 57 percent for all of MANE-VU. These estimates exclude the projected benefits of MANE-VU's low-sulfur fuel strategy. When New Hampshire's future participation in the low-sulfur fuel strategy is counted, it is expected that New Hampshire's actual emission reductions in 2018 will approach 80 percent. As mentioned in Subsection 11.8, above, New Hampshire was unable to adopt legislation for the low-sulfur fuel strategy within the required timeframe for this SIP submittal; consequently, NHDES is not currently seeking credit for expected emission reductions from this control measure.

(Note: The emissions in Tables 11.3 and 11.4 under the column heading Most Recent Projected 2018 came from MANE-VU's 2018 "Best and Final" modeling emissions inventories that were used in the final visibility modeling as document in Attachment Q. The projected emissions and modeling incorporate the additional reasonable control measures of the long-term strategy: BART, targeted EGUs, and the low-sulfur fuel. The values in the two tables reflect the assumptions used at the time the modeling was performed and are not adjusted for revisions made to the BART analyses after the MANE-VU visibility modeling was completed. For Unit NT1 specifically, the visibility modeling assumed a 50% reduction in SO_2 emissions. However, at a BART control level of 67% (see Table 9.3), the emission reductions for this unit would be greater than assumed for the final visibility modeling.)

11.10 Emission Limitations and Compliance Schedules

40 CFR 51.308(d)(3)(v)(C) requires New Hampshire to establish emission limitations and compliance schedules to meet reasonable progress goals. While emission limitations and compliance schedules are already in place for some New Hampshire control measures outlined in Subsections 11.3 and 11.4, other such provisions will need to be established by

law (Revised Statutes Annotated, RSA) or codified in New Hampshire Rules Governing the Control of Air Pollution (Env-A 100-4800); specifically:

- ***Best Available Retrofit Technology (BART)*****:** The emission limitations and compliance schedule for New Hampshire's two BART-eligible sources are detailed in Section 9. The BART emission limitations will be enforceable through a combination of existing permit conditions and administrative rules, including Chapter Env-A 2300, Mitigation of Regional Haze (Attachment GG). New emission limitations created by this rule will be effective on July 1, 2013. All BART provisions will have this date as the compliance deadline.

- ***Emission Reductions from Specific EGUs*****:** PSNH Merrimack Station Units MK1 and MK2 and PSNH Newington Station Unit NT1 are included in MANE-VU's targeted EGU strategy. The Merrimack plant is required by New Hampshire law to install a flue gas desulfurization system (scrubber) to remove SO_2 and other major pollutants by July 1, 2013 (see temporary permit for Units MK1 and MK2, Attachment EE). This control measure will simultaneously satisfy BART requirements for Unit MK2. PSNH Newington Station Unit NT1, which is also subject to BART limitations, will find it necessary to control fuel sulfur levels in order to achieve a more stringent SO_2 emission limit than is currently allowed (see BART Analyses for Sources in New Hampshire, Attachment X, and Title V operating permit, Attachment II).

NHDES will continue to evaluate all measures included in the long-term strategy to ascertain whether they remain reasonable for New Hampshire to implement by the end of the SIP planning period (2018) and will formalize that determination with the submission of the first regional haze SIP progress report in 2013. **New Hampshire intends to adopt all reasonable control measures as expeditiously as practicable, in a manner consistent with state law, so that they may be in place by the indicated compliance dates.**

11.11 Enforceability of Emission Limitations and Control Measures

40 CFR 51.308(d)(3)(v)(F) requires New Hampshire to ensure that emission limitations and control measures used to meet reasonable progress goals are enforceable. All control measures incorporated into law or codified in administrative rules will be enforceable. Any facility subject to state or federal permit requirements, including BART-eligible and Title V facilities, will be required to comply with the specific permit conditions that reference the applicable provisions of those laws and rules.

In New Hampshire, the authority to create rules, issue permits, and enforce laws related to regional haze are established in RSA 125-C, Air Pollution Control. Under RSA 125-C:6, Powers and Duties of the Commissioner, the NHDES Commissioner is authorized to enforce the state's air laws, establish a permit program, accept and administer grants, and exercise all incidental powers necessary to carry out the statutory obligations.

Sections of New Hampshire law of particular relevance to the regional haze SIP are:

- RSA 125-C:4, Rulemaking Authority; Subpoena Power, which establishes requirements by which the Commissioner shall adopt rules related (but not limited) to:
  - primary and secondary ambient air quality standards;
  - prevention, control, abatement, and limitation of air pollution;

- procedures to meet air pollution emergencies,
- establishment and operation of a statewide permit system;
- notification and public hearings on permit applications;
- fees and procedures for permit application and review; and
- procedures for air testing/monitoring and recordkeeping;

and which authorizes the Commissioner to issue subpoenas requiring the attendance of witnesses, production of evidence, and taking of testimony as he may deem necessary.

- RSA 125-C:11, Permit Required, which authorizes the creation of a permit program and the issuance of permits requiring specific emission control measures, including enforceable emission limitations;
- RSA 125-C:12, Administrative Requirements, which authorizes the Commissioner to collect fees to recover the costs of reviewing and acting upon permit applications and enforcing the terms of permits issued; and
- RSA 125-C: 15, Enforcement, which authorizes NHDES to issue orders to correct violations of RSA 125-C and establishes the legal authority for the enforcement of New Hampshire Rules Governing the Control of Air Pollution (Env-A 100–4800).

The New Hampshire rules provide for enforceable emission control measures and compliance schedules to meet the applicable requirements of the Clean Air Act and rules promulgated by EPA. The New Hampshire rules also define the permit program and fee structure for stationary sources, to ensure that national ambient air quality standards are achieved; specifically:

- Chapter Env-A 600, Statewide Permit System (effective 4-26-03, 7-28-04, 6-8-06, 4-3-08, and 4-22-09), provides for the issuance of temporary permits, state permits to operate, and Title V operating permits. Part Env-A 619 of this chapter addresses the prevention of significant deterioration of air quality and visibility protection, in accordance with the requirements of 40 CFR 51.166, 40 CFR 52.21 and RSA 125-C.
- Chapter Env-A, 700 Permit Fee System (effective 4-26-03 and 6-26-04) provides for the payment of fees to cover the reasonable costs of administering the permit program and of implementing and enforcing the terms and conditions of any permit.

With respect to specific control measures for visibility improvement under the Regional Haze Rule, the following enforceable provisions will apply:

- PSNH Merrimack Station Units MK1 and MK2 are required to install an FGD system by July 1, 2013, to achieve major emission reductions in SO_2 and other pollutants as established under New Hampshire law RSA 125-O, Multiple Pollutant Reduction Program, and as set forth in Temporary Permit No. TP-0008, reissued August 2, 2010 (Attachment EE).
- PSNH Newington Station Unit NT1 will be required to meet a new SO_2 emission limit of 0.50 lb/MMBtu by July 1, 2013, for any fuel or combination of fuels burned, as provided in administrative rule Env-A 2300, Mitigation of Regional Haze (Attachment GG).

Ultimately, New Hampshire's Regional Haze SIP depends on implementation of enforceable emission limitations and control measures, both within the state and in other states identified as contributing to visibility impairment at New Hampshire's Class I Areas. Because New Hampshire has no jurisdiction over other states' actions, the attainment of regional progress goals will, to a large extent, be predicated on the good-faith efforts of contributing upwind states to meet their fair share of emission reductions through implementation of their own enforceable control measures. While New Hampshire can provide assurances regarding the implementation of in-state emission controls, the bulk of regional-haze-causing pollutants over New Hampshire will continue to come from out-of-state sources.

11.12 Prevention of Significant Deterioration

Part Env-A 619 of Chapter Env-A 600 of New Hampshire's Rules spells out the Prevention of Significant Deterioration (PSD) requirements of the Statewide Permit System. PSD is applicable to all major sources (or existing sources making a major modification) located in an area that is in attainment of the National Ambient Air Quality Standards. A major source is an emissions source that has the potential to emit more than 100 tons per year of any pollutant. One of the purposes of the PSD program is to protect air quality in national parks, wilderness areas, and other areas of special natural, scenic, or historic value. The PSD permitting process requires a technical air quality analysis and additional analyses to assess the potential impacts on soils, vegetation, and visibility at Class I areas.

PSD permit applicants are required to conduct such analyses, and may do so in consultation with NHDES and the relevant Federal Land Manager (FLM). Recommended procedures for evaluating the impacts of a proposed PSD source on air quality and visibility at Class I areas are provided in NHDES' "Guidance and Procedure for Performing Air Quality Modeling in New Hampshire," July 2006. New major sources and existing sources making major modifications will be constructed and operated so as not to degrade air quality or visibility. The PSD permitting program, as set for under Env-A 619, is an integral part of New Hampshire's long-term strategy for meeting its regional haze goals.

12. Administrative Details

NHDES held two public hearings related to New Hampshire's Regional Haze SIP Revision:

- On May 25, 2009, NHDES published in a statewide newspaper, the Manchester, NH, *Union Leader*, a public notice soliciting comment on New Hampshire's Regional Haze SIP Revision. The notice also announced the opportunity to request a public hearing for the SIP revision. A public hearing was held at NHDES headquarters on Wednesday, June 24, 2009.

- On November 19, 2010, NHDES published in a statewide newspaper, the Manchester, NH, *Union Leader*, a public notice soliciting comment on New Hampshire's proposed revision to the State Implementation Plan to add administrative rule Env-A 2300, Mitigation of Regional Haze. A public hearing on this SIP revision was held at NHDES headquarters on December 20, 2010.

Copies of the public notices are presented in Attachment JJ. Documentation certifying the public process is provided in Attachment KK. Evidence of legal authority to create and submit these SIP revisions may be found in Attachment LL.

NHDES received written comments on the SIP from EPA and the Federal Land Managers.

NHDES also received written comments from the Appalachian Mountain Club and the Sierra Club. NHDES has addressed all comments in the SIP revision. Comments from EPA and the FLMs, and NHDES's formal responses to those comments, are included in Attachment I. Comments from the AMC and the Sierra Club, and responses to those comments, are included in Attachment J.

BART Analysis for
PSNH Merrimack Station Unit MK2

January 14, 2011

Amended August 26, 2011

BART Analysis for
PSNH Merrimack Station Unit MK2

1. INTRODUCTION

PSNH Merrimack Station has two coal-fired steam-generating boilers that operate nearly full time to meet baseload electric demand. Unit MK2 is a wet-bottom, cyclone-type boiler with a heat input rating of 3,473 MMBtu/hr and an electrical output of 320 MW. Installed in 1968, this generating unit is equipped with selective catalytic reduction to remove oxides of nitrogen (NO_X) formed during the combustion process. Two electrostatic precipitators operate in series to capture particulate matter (PM) in the flue gases. Also, construction is nearing completion on a limestone forced oxidation scrubber system that will reduce sulfur dioxide (SO_2) emissions. Retrofit options for this unit are limited because the facility already has controls in place for these major pollutants of concern. Only a few emission control technologies are compatible with the type of boiler design employed, and space for new retrofits is very limited.

2. CURRENTLY AVAILABLE RETROFIT TECHNOLOGIES, POTENTIAL COSTS, AND OTHER ENVIRONMENTAL AND ENERGY IMPACTS

2.1 Retrofit Technologies for NO_X Control

Because of the current boiler design, the only NO_X emission control technology options available and potentially applicable to Unit MK2 are selective non-catalytic reduction and selective catalytic reduction.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion technology that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_X in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected, the mixing of the reagent in the flue gas, the residence time of the reagent within the required temperature window, the ratio of reagent to NO_X, and the sulfur concentration in the flue gas. (Sulfur in the flue gas, originating from the sulfur content of the fuel, can combine with ammonia to form solid sulfur compounds such as ammonium bisulfate that may become deposited in downstream equipment.) NO_X reductions of 35 to 60 percent have been achieved through the use of SNCR on coal-fired boilers operating in the United States.

Selective Catalytic Reduction (SCR)

SCR is another post-combustion technology that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_X to nitrogen and water. The SCR reactor can be located at various positions in the process, including upstream of an air heater and particulate control device, or downstream of an air heater, particulate control device, and flue gas desulfurization system. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia-to-NO_X ratio, inlet NO_X concentration, space velocity, catalyst design, and catalyst condition. NO_X emission reductions of about 75 to 90 percent have been obtained with SCR on coal-fired boilers operating in the U.S.

2.1.1 Potential Costs of NO_X Controls

The estimated costs of NO_X emission controls for SNCR and SCR at Merrimack Station Unit MK2 are presented in Table 2-1. These estimates are based on assumptions used in EPA's Integrated Planning Model for the EPA Base Case 2006 (V.3.0), for retrofitting an electric generating unit (EGU) the size of Unit MK2. For SNCR, the total annual cost is estimated to be about \$5,110,000, or \$593/ton of NO_X removed. For an SCR system, the total annual cost is estimated to be \$5,070,000, or \$312/ton. Stated costs are for year-round operation.

Table 2-1. Estimated NO_X Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
SNCR	12.1	3,880,000	4,780,000	5,110,000	593
SCR	117.8	37,710,000	1,910,000	5,070,000	312

Estimates are derived from USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006. Costs are scaled for boiler size. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 320-MW unit with 80% capacity factor and 2,243 million kWh annual generation. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on an estimated 8,613 tons of NO_X removed for SNCR and an estimated 16,269 tons of NO_X removed for SCR.

Because Unit MK2 already has SCR controls in place, the listed costs serve for comparative purposes only. In 1998, PSNH estimated that its SCR costs would be about \$400/ton for year-round operation and about \$600/ton for operation limited to the ozone season (May 1 through September 30). These costs are approximately equal to \$530/ton and \$790/ton, respectively, in 2008 dollars. PSNH currently operates Unit MK2 full time in order to meet NO_X RACT requirements.

Year-round operation is EPA's presumptive norm for BART (applicable to EGUs of 750 MW capacity or greater) for units that already have seasonally operated SCRs. Assuming that operating costs are proportional to operating time, the difference in cost between year-round and seasonal SCR operation for Unit MK2 is about \$3,300,000, based on PSNH's 1998 cost estimates. The cost differential could be about half that amount, if based on the more recent generic estimates presented in Table 2-1.

2.1.2 Other Environmental and Energy Impacts of NO_X Controls

SNCR and SCR both use urea or anhydrous ammonia. Ammonia is a regulated toxic air pollutant in New Hampshire. Facilities using these technologies must limit their ammonia emissions, which may be released either in their flue gases or as fugitive emissions from the handling and storage of urea or anhydrous ammonia. A facility must also maintain a risk management plan if the quantities of stored ammonia exceed the applicable regulatory threshold.

Ammonia from SNCR that becomes entrained in the fly ash may affect the resale value or disposal cost of the ash. Ammonia in the flue gas may produce a more visible plume, depending on the ammonia concentration in the gas stream. High ammonia concentrations in the boiler from SNCR can react with sulfate to form ammonium bisulfate, which deposits on the economizer, air heater, and other surfaces. Ammonium bisulfate can also plug filter bags in a baghouse. SNCR may generate nitrous oxide emissions, a greenhouse gas.

With SCR, the formation of ammonium bisulfate may be exacerbated by the ability of this catalyst-based technology to oxidize SO_2 to SO_3, resulting in higher sulfate concentrations than would otherwise exist. Ammonium bisulfate formation can be reduced by controlling excess ammonia and using catalysts that minimize SO_2 oxidation. The air heater and other surfaces where the ammonia bisulfate may deposit must be acid washed periodically. Acid washing helps to maintain the efficiency of the air heater and prevents plugging to allow the free flow of flue gases through it. An SCR may also require a fan upgrade to overcome additional pressure drop across the catalyst. The increase in fan capacity consumes a small amount of energy. (In the case of Unit MK2, the existing fan was sufficient to accommodate the additional pressure drop.)

NO_X emission reductions provide environmental and public health benefits beyond visibility improvement – most notably, reductions in acid rain and ground-level ozone. NO_X is a chemical precursor to ozone formation and is one of the primary compounds contributing directly to acid rain formation. A decrease in acid rain production improves water quality and the health of ecosystems sensitive to low pH.

2.2 Retrofit Technologies for PM Control

PM control technologies available and potentially applicable to Unit MK2 are electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers.

Electrostatic Precipitators (ESPs)

Electrostatic precipitators capture particles through the use of electrodes, which are electrical conductors used to make contact with non-metallic parts of a circuit. An ESP consists of a small-diameter negatively charged electrode (usually a set of individual wires or a grid) and a grounded positively charged plate. In operation, a strong electric charge from the negatively charged electrode sets up a one-directional electric field. When particle-laden gases pass through this electric field, the particles become charged and are then drawn to the positive collecting surface (the plate), where they are neutralized. The particles are then collected by washing or knocking the plate, causing the particles to fall into a collection hopper. Existing electrostatic precipitators are typically 40 to 60 percent efficient. New or rebuilt ESPs can achieve collection efficiencies of more than 99 percent.

For older units, options for upgrading an ESP system include: replacement of existing control systems with modern electronic controllers; replacement of old-style wire and plate systems inside the ESP with new, rigid electrode systems; addition of new ESP fields; or addition of entire new units (in series). The feasibility of any particular upgrade will be influenced by spatial limitations or design constraints on a case-by-case basis.

Fabric Filters

Fabric filtration devices, or baghouses, incorporate multiple fabric filters/bags inside a containment structure. These devices work on the same principal as a vacuum cleaner bag.

The particle removal efficiency of the fabric filter system depends on a variety of particle and operational parameters. The physical characteristics of particle size distribution, particle cohesion, and particle electrical resistivity are important variables. Operational parameters affecting collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, and cleaning intensity. The structure of the fabric filter, filter composition, and bag properties also affect collection efficiency. Collection efficiencies of baghouses may exceed 99 percent.

Mechanical Collectors and Particle Scrubbers

Mechanical collectors, such as cyclones, are most effective at collecting coarse particulate matter (i.e., particles with a diameter of 10 micrometers or larger). Finer particles escape cyclones along with the flue gases. For this reason, mechanical collectors are generally most useful when used in conjunction with other pollution control equipment. The typical collection efficiency of mechanical collectors is about 85 percent for larger particle sizes.

Scrubbing systems involve the injection of water and/or chemicals into the flue gas to wash unwanted pollutants from the gas stream through physical or chemical absorption/adsorption. Scrubbing systems have been shown to reduce PM_{10} emissions by 50 to 60 percent but are generally less effective for removal of fine particles.

Because mechanical collectors and particle scrubbers are more costly and less efficient than other control options (i.e., ESPs, baghouses), these lower-performing technologies are rarely used today for removing particulate matter from power plant emissions. Consequently, mechanical collectors and scrubbers are not considered further in this analysis for the control of PM emissions.

2.2.1 Potential Costs of PM Controls

Table 2-2 presents cost data for PM controls as developed from NESCAUM's *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. Approximate cost ranges are provided for two types of ESPs and two types of fabric filters applicable to a retrofit installation the size of Unit MK2. Capital and operating costs are based on flue gas flow rates in actual cubic feet per minute (acfm).

Table 2-2. Estimated PM Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost ($)	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
Dry ESP	73-194	23.3-62.1 million	1.1-1.9 million	3.0-7.1 million	100-240
Wet ESP	73-194	23.3-62.1 million	0.6-1.6 million	2.6-6.8 million	90-230
Fabric filter – reverse air	82-194	26.4-62.1 million	1.6-2.4 million	3.8-7.6 million	130-260
Fabric filter – pulse jet	58-194	18.6-62.1 million	2.2-3.1 million	3.7-8.3 million	130-280

Reference: NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 320-MW unit with 80% capacity factor and flue gas flow rate of 1.36 million acfm. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on 29,850 tons of PM removed for ESPs and 29,759 tons of PM removed for fabric filters.

The costs for ESPs and fabric filters are of similar magnitude, with total annual costs ranging from about $2.6 million to $8.3 million, or $90 to $280 per ton of PM removed. Because Unit MK2 already has two dry ESPs installed and operating, the tabulated costs are useful for comparative purposes only. For facilities with existing ESPs, typical equipment replacement costs to upgrade performance may be in the range of $10,000 to $30,000 per MW. (M. Sankey and R. Mastropietro, "Electrostatic Upgrade Strategy: Get the Most From What You Have," Hamon Research-Cottrell, Inc., April, 1997.)

2.2.2 Other Environmental and Energy Impacts of PM Controls

PM controls collect particulate matter, or fly ash, suspended in the flue gases. In some cases, the fly ash is injected back into the boiler, an arrangement that improves boiler efficiency by recapturing the residual heating value of the fly ash. If the fly ash is not reinjected, it must be either landfilled or reclaimed, e.g., as a supplement in concrete production or as a component in other manufactured products.

2.3 Retrofit Technologies for SO_2 Control

SO_2 control technologies available and potentially applicable to Unit MK2 are scrubber systems for flue gas desulfurization, and use of low-sulfur coal.

Flue Gas Desulfurization

Scrubber systems use chemical reagents to "scrub" or "wash" unwanted pollutants from a gas stream. Flue gas desulfurization (FGD) processes based on this technology concept are classified as either wet or dry. Wet scrubbers are more commonly used at power plants to control acid gas emissions. Scrubbers of all types may be effective for the removal of particulate matter, mercury, sulfur dioxide, and other air pollutants.

In the wet FGD process, an alkaline reagent is applied in liquid or slurry form to absorb SO_2 in the flue gas. A PM control device is always located upstream of a wet scrubber. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. Wet regenerative (meaning the reagent material can be treated and reused) FGD processes are an attractive option because they allow higher sulfur removal rates and produce minimal wastewater discharges.

For coal-fired power plants, the reagent is usually lime or limestone; and the reaction product is calcium sulfite or calcium sulfate. The solid compounds are collected and removed in downstream process equipment. Calcium sulfate (gypsum) sludge produced in FGDs can be recycled into saleable byproducts such as wallboard, concrete, and fertilizer. Sulfate products that are not recycled must be landfilled.

SO_2 removal efficiencies for existing wet limestone scrubbers range from 31 to 97 percent with an average of 78 percent (NESCAUM, "Assessment of Control Technology Options for BART-Eligible Sources," March 2005). For new FGD systems installed at large (>750 MW) coal-fired power plants, the presumptive norm is 95 percent reduction of SO_2 emissions (USEPA, Appendix Y to Part 51 – Guidelines for BART Determinations under the Regional Haze Rule).

Dry (or semi-dry) FGD processes are similar in concept to wet FGD processes but do not saturate the flue gas stream with moisture. Dry scrubbers are of two general types: dry sorbent injection and spray dryers. With the former, an alkaline reagent such as hydrated lime or soda ash is injected directly into the flue gas stream to neutralize the acid gases. In spray dryers, the flue gas stream is passed through an absorber tower in which the acid gases are absorbed by an atomized alkaline slurry. The SO_2 removal efficiencies range from 40 to 60 percent for existing dry injection systems and from 60 to 95 percent for existing lime spray dryer systems (NESCAUM, 2005). A PM control device (ESP or fabric filter) is always installed downstream of a dry or semi-dry scrubber to remove the sorbent from the flue gas.

Low-Sulfur Coal

Because SO_2 emissions are directly related to the sulfur content of the fuel burned, reducing the amount of sulfur in the fuel reduces SO_2 emissions. Usually, for operational reasons, a facility cannot make a complete switch from one fuel type to another. Instead, the facility may be able to blend different fuels to obtain a lower-sulfur mix that emits less SO_2 upon combustion – for example, blending low-sulfur bituminous or subbituminous coal with a high-sulfur bituminous coal. The feasibility of fuel switching or blending depends on the physical characteristics of the plant (including boiler type), and significant modifications to systems and equipment may be necessary to accommodate the change in fuels. Switching to a lower-sulfur coal can affect coal handling and preparation systems, ash handling systems, boiler performance, and the effectiveness of PM emission controls. To meet federal acid rain requirements, many facilities have switched to lower-sulfur coals, resulting in SO_2 emission reductions of 50 to 80 percent.

2.3.1 Potential Costs of SO_2 Controls

PSNH Merrimack Station is required by New Hampshire law to install an FGD system to reduce mercury emissions (with SO_2 removal as a co-benefit) at both Unit MK1 (not a BART-eligible unit) and Unit MK2 (a BART-eligible unit). A company estimate for the project placed the capital cost at $457 million, or $1,055/kW (both amounts in 2008$) to install a wet limestone FGD system. Using 2002 baseline emissions of 30,657 tons of SO_2 from Units MK1 and MK2 combined, and a minimum capture efficiency of 90 percent for this pollutant, the annualized capital cost translates to about $1,400 per ton of SO_2 removed.

The project cost is said to be in line with the costs of multiple-unit scrubber installations occurring elsewhere in the country. However, PSNH's estimated cost per kilowatt is at least triple the cost range for FGD systems as reported in MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007 (see Reasonable Progress Report, Attachment Y). The PSNH estimated cost is also more than double the estimate of $300/kW to $500/kW as reported in a 2008 survey of FGD systems (George W. Sharp, "What's That Scrubber Going to Cost?," *Power*, March 1, 2009). The higher cost-per-kW for Unit MK2 may reflect industry-wide increases in raw material, manufacturing, and construction costs but may also reflect site-specific factors such as unit size, type, and difficulty of retrofit.

The costs of switching to lower-sulfur coal at PSNH Merrimack Station would rest on the incremental cost of purchasing the lower-sulfur material at prevailing market prices. Even if a lower-sulfur coal is available at reasonable additional cost, operational considerations related to the physical characteristics of Unit MK2 may dictate the choice of coal for this unit. (Only certain types of coal can be used in wet-bottom, cyclone boilers; and lower-sulfur coals have already been tested and adopted for regular use at this facility.) Commodity spot prices for coal vary considerably. For example, from late March to early May 2009, the price spread between Northern Appalachia coal (<3.0 SO_2) and Central Appalachia coal (1.2 SO_2) ranged from $10 to $25 per ton (source: Energy Information Administration, http://www.eia.doe.gov/fuelcoal.html).

2.3.2 Other Environmental and Energy Impacts of SO_2 Controls

An FGD system typically operates with high pressure drops across the control equipment, requiring increased energy usage for blowers and circulation pumps. Some configurations of FGD systems also require flue gas reheating to prevent operational problems (including physical damage to equipment), resulting in higher fuel usage per unit of net electrical generation. Documentation for EPA's Integrated Planning Model (IPM®) indicates that a wet FGD system reduces the generating capacity of the unit by about 2 percent.

Flue gas desulfurization has impacts on the operation of solid waste and wastewater management systems. In addition to removing SO_2, the FGD process removes mercury and other metals and solids. Often, gypsum produced in a limestone FGD process is recycled or sold to cement manufacturers; otherwise, the sludge must be stabilized and placed in an approved landfill. Gypsum must be dewatered before it can be handled, resulting in a wastewater stream that requires treatment. This wastewater stream increases the sulfates, metals, and solids loadings on the receiving wastewater treatment plant. Sometimes an additional clarifier is required to remove wastewater solids coming from the FGD system.

Wet FGDs increase the amount of water vapor entrained in the flue gas. The result is a lower stack exit temperature and a more visible plume at the stack outlet.

3. DISCUSSION OF CURRENT POLLUTION CONTROL EQUIPMENT AND EMISSIONS

3.1 Discussion of Current NO_X Emissions and Controls

In 1994, PSNH installed an SCR system on Unit MK2, the first such system to be used on a coal-fired, wet-bottom, cyclone boiler in the United States. The SCR was designed to meet NO_X Reasonably Available Control Technology (RACT) limits. Specifically, Unit MK2 is subject to a NO_X RACT Order limit of 15.4 tons per calendar day and a second NO_X RACT Order limit of 29.1 tons per calendar day for combined emissions from Units MK1 and MK2. The facility must also meet a less stringent federal acid rain program limit of 0.86 lb NO_X/MMBtu. PSNH has a monetary incentive to surpass the NO_X RACT requirements because further emission reductions allow the utility to accumulate DERs. Actual NO_X emissions for Unit MK2 were reported as 2,871 tons in baseline year 2002.

Since January 2001, the SCR on Unit MK2 has reduced NO_X emissions to between 0.15 and 0.37 lb/MMBtu (calendar monthly average), with a few excursions outside this range. (Note that the existing NO_X RACT limit of 15.4 tons per calendar day is mathematically equivalent to 0.37 lb/MMBtu.) Data available from the period of 1993 to early 1995, prior to operation of the SCR, provide a baseline for uncontrolled NO_X emissions in the range of 2.0 to 2.5

lb/MMBtu. Taken together, this information indicates that Unit MK2 achieves a control level that exceeds 85 percent most of the time and frequently surpasses 90 percent.

3.2 Discussion of Current PM Emissions and Controls

PSNH Merrimack Station Unit MK2 has two electrostatic precipitators (ESPs), dry type, operating in combination with a fly ash reinjection system. The ESPs have been upgraded with state-of-the-art electronic controls. Installation of the ESPs has reduced PM emissions from this unit by about 99 percent, based on a review of 2002 emissions data. The current air permit for the facility requires that Unit MK2 meet a total suspended particulate (filterable TSP) limit of 0.227 lb/MMBtu and a TSP emissions cap of 3,458.6 tons/year. However, the 0.227 lb/MMBtu rate does not reflect the true capabilities of the ESPs to control particulate emissions. Stack testing on three separate dates in 1999 and 2000 found actual TSP emissions to be 0.043, 0.041, and 0.021 lb/MMBtu after controls. The most recent test, in May 2009, produced an emission rate of 0.032 lb/MMBtu. Total TSP emissions from this unit were 210 tons in 2002.

3.3 Discussion of Current SO_2 Emissions and Controls

New Hampshire law requires PSNH Merrimack Station to install and operate a scrubber system for both Unit MK1 and Unit MK2 by July 1, 2013. While the primary intent of this law is to reduce mercury emissions from the company's coal-fired power plants, a major co-benefit is SO_2 removal. Pursuant to this statutory obligation, New Hampshire issued a permit to PSNH on March 9, 2009, for the construction of a wet, limestone-based FGD system to control mercury and SO_2 emissions at Merrimack Station. The permit requires an SO_2 control level of at least 90 percent for Unit MK2. The specific language of the permit states as follows:

> Beginning on July 1, 2013,…SO_2 emissions shall be controlled to 10 percent of the uncontrolled SO_2 emission rate (90 percent SO_2 removal)…The Owner shall submit a report no later than December 31, 2014 that includes the calendar month average SO_2 emission rates at the inlet and outlet of the FGD and the corresponding calendar month average emissions reductions during the preceding 12 months of operation,…DES will use this data to establish the maximum sustainable rate of SO_2 emissions reductions for MK2. The maximum sustainable rate is the highest rate of reductions that can be achieved 100 percent of the time...This established rate shall be incorporated as a permit condition for MK2. Under no circumstances shall the SO_2 removal efficiency for MK2 be less than 90 percent.

These permit conditions effectively require that actual SO_2 removal efficiencies *exceed* 90 percent on average for Unit MK2. This plant must also meet general regulations for coal-burning devices that limit the sulfur content of the coal to 2.0 pounds per million BTU gross heat content averaged over any consecutive 3-month period, and 2.8 pounds per million BTU gross heat content at any time. Since 2002, the facility has operated well within these fuel limits. More specifically, PSNH has worked to control coal sulfur content to reduce SO_2 emissions and minimize the purchase of SO_2 allowances. Because the particular boiler design does not permit the burning of straight low-sulfur coal, the company blends coals to bring average sulfur content to a level that is consistent with sustainable boiler operations.

PSNH must also meet a fleet-wide SO_2 emissions cap of 55,150 tons/year effective for all electrical generating units at its Merrimack, Newington, and Schiller Stations. In 2002, actual SO_2 emissions from Unit MK2 were 20,902 tons.

4. REMAINING USEFUL LIFE OF UNIT

Where a reasonable control option is available for a BART-eligible unit, the unit should be controlled in a manner consistent with BART and the expected useful life of the unit. Originally, electric generating units were estimated to have a life expectancy of 30 to 40 years, but many units are lasting 50 years or more. In many cases, it is less expensive to keep existing units operating than to build replacement facilities and/or new transmission lines. Merrimack Station Unit MK2 was built in 1968. PSNH's commitment to install new emission controls on this unit demonstrates the company's belief that this unit is capable of supplying electricity to the region for many years beyond the present.

5. DEGREE OF VISIBILITY IMPROVEMENT ANTICIPATED FROM BART

5.1 CALPUFF Modeling Analysis

The New Hampshire Department of Environmental Services (NHDES) conducted a CALPUFF modeling analysis to assess the anticipated visibility effects of BART controls at PSNH Merrimack Station Unit MK2. Visibility can be quantified using deciviews (dv), a logarithmic unit of measure to describe increments of visibility change that are just perceptible to the human eye. NHDES conducted a set of CALPUFF runs for Unit MK2 under controlled and uncontrolled conditions. Before considering the findings of this modeling work, it is useful to review the results of the BART eligibility modeling performed by the Mid-Atlantic/Northeast Visibility Union (MANE-VU).

In previous modeling, MANE-VU used CALPUFF to assist in the identification of BART-eligible sources. This modeling assumed natural visibility conditions (about 7 dv) to produce the most conservative results possible, thereby minimizing the number of sources that would "model out" of BART requirements. Under these conditions, uncontrolled emissions from Unit MK2 produce theoretical CALPUFF worst-case impacts of 2.24 dv at Acadia National Park. EPA considers it acceptable to exempt sources when this form of conservative modeling indicates that a source produces less than 0.5 dv of impact. MANE-VU considers an exemption level of 0.2 to 0.3 dv to be more appropriate but prefers, and has applied, an even more conservative exemption level of 0.1 dv. CALPUFF modeling results for baseline emissions from Unit MK2 exceed all of these exemption levels.

The BART assessment modeling provides a comparison of visibility impacts from current allowable emissions with those from the post-control emission level (or levels) being assessed. Results are tabulated for the average of the 20% worst natural visibility (about 11.7 to 12.4 dv) and 20% worst baseline visibility (about 22.8 dv) modeled days at each nearby Class I area. For any pair of control levels evaluated, the difference in the level of impairment predicted is the degree of improvement in visibility expected.

Rather than use CALPOST to manipulate background deciview calculations, NHDES normalized CALPUFF modeling results and then applied predicted concentrations to a logarithmic best-fit equation to the actual observed $PM_{2.5}$-to-deciview relationship measured at Acadia NP, Great Gulf NWR, and Lye Brook NWR. Thus, CALPUFF was applied in a relative way using real observed data as the basis. At this point, a number of background visibility scenarios could be calculated from the resulting PM-extinction-to-deciview equation. In accordance with BART guidance, the natural visibility condition (about 7 dv) was used for exemption purposes, and 20% worst natural and 20% worst baseline visibility were used for assessment of BART control effectiveness. The CALPUFF-predicted visibility benefits from BART controls on 20% worst natural and 20% worst baseline visibility days are as follows:

Table 5-1. CALPUFF Modeling Results for Merrimack Station Unit MK2: Visibility Improvements from BART Controls

On the 20% Worst Natural Visibilty Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	90% with FGD	1.07	0.83	**0.17**
NOx	Additional 25% with SCR upgrade	0.21	0.18	**0.10**
PM	90% with upgraded controls	0.16	0.12	**0.03**
On the 20% Worst Baseline Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	90% with FGD	**0.26**	**0.20**	0.03
NOx	Additional 25% with SCR upgrade	**0.07**	**0.06**	0.03
PM	90% with upgraded controls	**0.07**	**0.05**	<0.01*

* below sensitivity limit of model

Note: Values in **boldface** are considered as having greater validity in the modeling estimation of maximum visibility benefits from BART controls.

While the full impact of Unit MK2 was predicted to be as large as 2.24 dv at Acadia National Park under natural conditions, the predicted visibility benefit from a 90% reduction in sulfur emissions at Unit MK2 on the most visibility-impaired days is only 0.26 dv. At first this result may appear to be too low; however, on further examination, it is found that CALPUFF predicts the same amount of sulfate from Unit MK2 reaching Acadia under both best and worst visibility conditions. The difference is that there is greater than an order of magnitude more sulfate coming from other sources on the 20% worst visibility days, raising the background concentrations to much higher levels. Because the deciview scale is logarithmic, the same mass reduction of 0.259 $\mu g/m^3$ of sulfate from this one source results in wide differences in deciview impacts for different background visibility conditions at opposite ends of the range.

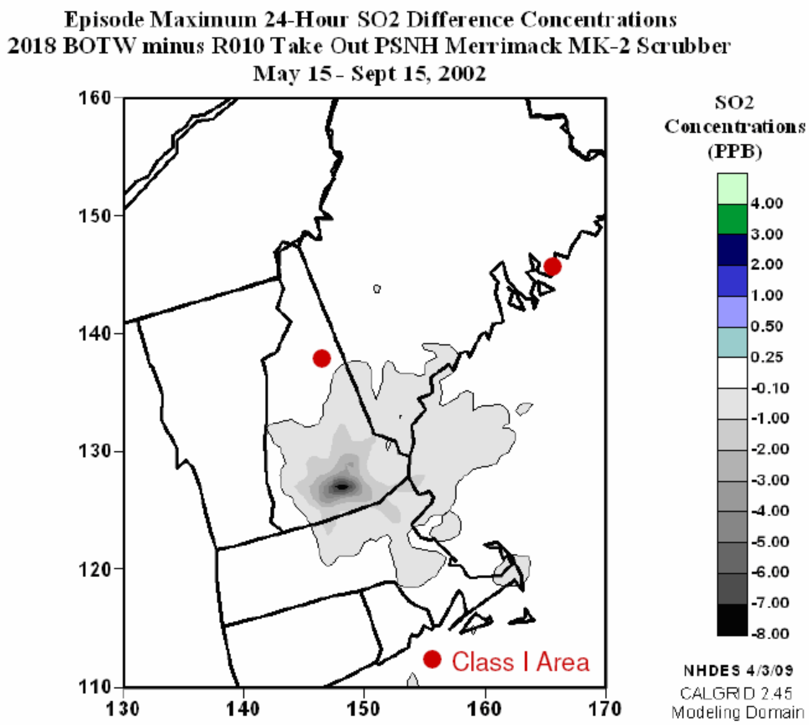
5.1 CALGRID Modeling Analysis

NHDES also conducted a screening-level analysis of the anticipated visibility effects of BART controls at PSNH Merrimack Station Unit MK2. Specifically, one modeling run using the CALGRID photochemical air quality model was performed to assess the effects of installing an FGD system on Unit MK2. The simulation covered the full summer modeling episode (from May 15 to September 15, 2002) and used MANE-VU's 2018 beyond-on-the-way (BOTW) emissions inventory scenario as a baseline. The BOTW emissions scenario reflects controls from potential new regulations that may be necessary to attain National Ambient Air Quality Standards and other regional air quality goals, beyond those regulations that are already "on the books" or "on the way."

The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutants within the region. NHDES post-processed the modeled concentration reductions to estimate the corresponding visibility improvements at nearby Class I areas (i.e., concentration impacts were converted to visibility impacts).

Based on the CALGRID modeling results, the installation of scrubber technology with 90% removal efficiency on Unit MK2 is expected to reduce near-stack maximum predicted 24-hour average SO_2 concentration impacts by up to 21 $\mu g/m^3$ (8 ppb by volume; see Figure 5-1) and maximum predicted 24-hour average $PM_{2.5}$ concentration impacts by up to 1 $\mu g/m^3$. The largest modeled pollutant concentration reductions occur within a 50-kilometer radius of the facility. For the affected Class I areas (located 100 to 500 kilometers away), reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, are expected to yield a nominal improvement in visibility (about 0.1 deciview) on direct-impact hazy days.

Figure 5-1



NHDES's use of CALGRID differs somewhat from EPA's preferred methodology. CALPUFF is EPA's preferred model for performing long-range visibility assessments of individual sources to distant Class I areas, in part because it is considered to be a conservative model or one that is capable of estimating worst-case impacts rather than expected impacts. This makes CALPUFF ideally suited to screening BART sources for exemption purposes because it is likely to identify virtually all sources that could provide visibility benefits when their emissions are controlled.

CALGRID is a sister program to CALPUFF and shares much of the same chemistry; however, it works as a gridded model rather than a puff tracking model, and it has the advantage of easily tracking 20% worst visibility days and cumulative impacts by modeling all source sectors. NHDES chose to use CALGRID for screening since it is much easier to track the dynamics of impacts from single sources to multiple Class I areas on targeted days, rather than just applying the maximum impact conditions that may or may not be associated with 20% worst days. While the CALPUFF model's CALPOST post-processor has an option for application on 20% worst natural visibility days, it does not in fact isolate those 20% worst natural visibility days for analysis. It simply changes the background values the model uses to adjust what it estimates to be appropriate background levels. It does not account for wind directions that may be preferentially included or excluded on such days.

The above analyses indicate that CALPUFF and CALGRID have aligned better in their predictions than might be expected. This result may be attributed to the similar chemistry used in both models and to the specific circumstances of this case in which the prevailing wind direction on the 20% worst visibility days carries Unit MK2 emissions directly toward Class I areas such as Acadia National Park. The big discrepancy occurs under best visibility days, when CALGRID (correctly) does not align the source to receptor, but CALPUFF (incorrectly) applies wind directions for worst visibility days to the best day calculations.

6. DETERMINATION OF BART

Based on the completed review and evaluation of existing and potential control measures for PSNH Merrimack Station Unit MK2, it is determined that the NO_X, PM, and SO_2 controls described below represent Best Available Retrofit Technology for this unit.

6.1 Selecting a Pollution Control Plan for NO_X

PSNH currently operates an SCR system on Unit MK2. This system was installed in 1994 to meet the requirements of NO_X RACT and the ozone season NO_X budget program. SNCR is the only other control technology available for controlling NO_X emissions from this unit. SCR yields higher NO_X removal rates and is more cost-effective than SNCR. For units that already have seasonally operated SCRs, year-round operation is EPA's presumptive norm for BART. PSNH estimated, in 1998, that the existing SCR system could be operated year-round at a cost of $494 per ton of NO_X removed.

For an early-generation SCR that has received previous retrofits to improve its performance, further upgrades to this NO_X control system appear to be impractical and would yield negligible (generally less than 0.1 dv) improvement in visibility. Additional upgrades would require major redesign and construction at a location where physical space is already constrained. Capital costs would be comparable to installing a new SCR and would achieve only marginal additional reductions in NO_X emissions. Because Unit MK2 has an existing SCR system designed to meet other air program requirements that could be operated year-round at reasonable cost, full-time operation of the existing SCR is considered to be BART for NO_X control on this unit.

EPA has provided presumptive BART emission rates that are broadly applicable to power plants larger than 750 MW but are not necessarily representative of smaller EGUs like Unit MK2. In the case of Unit MK2, the cyclone boiler has a relatively high uncontrolled NO_X emission rate (≥2.0 lb/MMBtu); so it follows that the controlled emission rate, even at 90 percent control efficiency, would be above the presumptive norm of 0.10 lb/MMBtu applicable to larger EGUs of its type. The past decade of emissions records for Unit MK2 shows monthly average NO_X emission rates normally ranging between 50 and 100 percent of the RACT limit. The existing NO_X RACT limit of 15.4 ton/day, equivalent to of 0.37 lb/MMBtu*, corresponds to a NO_X control rate of approximately 85 percent.

PSNH has described operational and infrastructural changes that would be needed in order to allow the company to guarantee a NO_X performance level lower than the current effective limit of 0.37 lb/MMBtu (see Supporting Documentation, attached). This could be accomplished by increasing the frequency of maintenance cleanings and accelerating the rate of catalyst replacement to ensure a high level of NOx reduction capability at all times. The four major cost components would be:

1. The direct costs of extra inspections and maintenance cleanings for the air heater and SCR system,
2. The cost of purchased replacement power covering the periods of additional scheduled maintenance outages,
3. The cost of extra catalyst (early catalyst replacement), and
4. The increased cost of purchased replacement power associated with reduced flexibility to operate at partial load.

Calculations performed by PSNH assume a NOx emission rate of 0.8 lb/MMBtu during partial load operation. This relatively high emission rate means that, the lower the emission limit is set, the smaller must be the total time of partial load operation as a percentage of total operating time. As the emission limit is set lower, outage time would necessarily have to increase to prevent excessive emissions (that would otherwise occur under partial load operation). Replacement power at such times would represent an unavoidable cost.

Taking into account all of the described cost factors, PSNH has estimated that a reduction in the NO_X emission limit to 0.30 lb/MMBtu (an effective reduction of 0.07 lb/MMBtu) would have an incremental cost of approximately $800 per ton of NO_X removed and would result in a *potential* incremental emission reduction of about 1,000 tons per year. The indicated cost per ton falls within the generally regarded cost-effective range. At the same time, PSNH has estimated that further reduction of the NOx emission limit to 0.25-0.30 lb/MMBtu would yield diminishing returns, with the incremental cost per ton approximately one order of magnitude higher. NHDES concurs that such additional costs are not justifiable given the fact of negligible visibility benefit. When the historical performance of Unit MK2 is considered alongside the operational factors and estimated costs to achieve a higher performance level, NHDES finds that a NO_X emission rate of 0.30 lb/MMBtu reasonably represents the sustainable performance capabilities of this unit and is also appropriate as a BART control level for NO_X on a 30-day rolling average basis.

6.2 Selecting a Pollution Control Plan for PM

PSNH currently operates two ESPs in series on Unit MK2. Mechanical collectors (cyclones) are effective only for coarse particle removal and would be impractical as a retrofit for Unit MK2, where the more efficient ESPs already exist. Fabric filters have performance levels

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* The 0.37 lb/MMBtu NO_X emission rate for MK2 is calculated from its maximum heat input rate of 3,473 MMBtu/hr and the applicable NO_X RACT limit of 15.4 tons per day, as follows:

$[(15.4 \text{ tons/day} \times 1 \text{ day/24 hr}) \times 2{,}000 \text{ lb/ton}] \div 3{,}473 \text{ MMBtu/hr} = 0.37 \text{ lb/MMBtu}$

comparable to ESPs and are a suitable PM control technology for power plant emissions. However, fabric filters are also impractical as a retrofit for Unit MK2 under present circumstances: ESPs already exist, physical space at the facility is limited, and the addition of an FGD system is now in progress.

The existing ESPs were previously upgraded to include state-of-the-art electronic controls. Further upgrading would require either major equipment substitutions or the addition of a third ESP in series with the two existing units. Adding a third ESP might be physically impossible because of the aforementioned spatial limitations following past improvements to emission control systems. To undertake either major equipment replacement or installation of a third ESP, if it could be done at all, would require a major capital expenditure. Typical equipment replacement costs for ESP upgrades may be in the range of $10,000 to $30,000 per MW. For Unit MK2, additional costs of this magnitude are not easily justified when weighed against the visibility improvement (less than 0.1 dv on the 20 percent worst visibility days) that would be realized.

The current PM emission limit for Unit MK2 is not reflective of the performance capabilities of the existing ESPs. However, the volume of available stack test data is insufficient to establish a conclusive, long-term BART performance level of 0.04 lb/MMBtu or lower for this unit. New Hampshire has adopted a new administrative rule that will hold TSP emissions to a maximum of 0.08 lb/MMBtu but will apply this limitation more broadly than BART requires. The new PM emission limit will affect both of Merrimack Station's coal-fired utility boilers – Unit MK1 (not a BART-eligible facility) and Unit MK2 – as explained below.

In the new rule, Units MK1 and MK2 are placed within a regulatory "bubble" for the purposes of TSP compliance. This arrangement serves both necessity and convenience because the two units will share a common stack. The following procedure was used to calculate the maximum allowable emission rate for the combined source:

1. For BART-eligible Unit MK2, the maximum heat input rating of 3,473 MMBtu/hr was multiplied by MANE-VU's lowest presumptive control level for TSP emissions, 0.02 lb/MMBtu, to obtain an emission rate of 69.46 lb/hr.

2. For non-BART Unit MK1, the maximum heat input rating of 1,238 MMBtu/hr was multiplied by the unit's permitted TSP limit, 0.27 lb/MMBtu, to determine an emission rate of 334.26 lb/hr.

3. The individual emission rates were summed to yield a total maximum emission rate of 403.72 lb/hr. This value was divided by the total maximum heat input rate, 4,711 MMBtu/hr, to obtain the new TSP emission limitation of 0.08 lb/MMBtu (rounded down from 0.086 lb/MMBtu).

By including Unit MK1 in the rule, the allowable TSP emissions from the two coal-fired units combined will be less than the allowable emissions would be if the limit for Unit MK1 remained separate and unchanged, and the limit for Unit MK2 were reduced to 0.04 lb/MMBtu, its approximate performance capability from actual stack test data.[†]

[†] For the bubble concept, the combined emission rate = 0.08 lb/MMBtu × 4,711MMBtu/hr = 377 lb/hr. For the stand-alone alternative, the sum of the individual emission rates = (0.04 lb/MMBtu × 3,473 MMBtu/hr) + (0.27 lb/MMBtu × 1,238 MMBtu/hr) = 473 lb/hr.

It is concluded that the existing ESPs, operating in conjunction with the FGD process, will provide the most cost-effective controls for particulate emissions. Continued operation of the existing ESPs, controlled to emission rates not exceeding the new emission limit described above, represents BART for PM control on Unit MK2.

6.3 Selecting a Pollution Control Plan for SO_2

PSNH Merrimack Station is installing a flue gas desulfurization system to remove mercury emissions in compliance with New Hampshire law. As a co-benefit, the FGD system is expected to remove more than 90 percent of SO_2 emissions. Because this installation is already mandated and because it will attain SO_2 removal rates approaching the BART presumptive norm of 95 percent (generally applicable to facilities larger than Merrimack Station), the FGD system is considered to be BART for SO_2 control on Unit MK2. (Note that, at an installed cost exceeding $1,000/kW, the FGD system being added to this facility is more expensive than the industry average and might not be viewed as cost-effective if its only purpose were to satisfy BART requirements.)

7. SUMMARY AND CONCLUSIONS

Table 7-1 summarizes Best Available Retrofit Technology for PSNH Merrimack Station Unit MK2 for the pollutants NO_X, PM, and SO_2. The summary includes existing controls that have been determined to meet or exceed BART requirements as well as changes in progress that are consistent with BART requirements. NHDES has already issued a temporary permit (construction permit) for the installation of the flue gas desulfurization system and is not requiring additional control technology for Merrimack Station at this time in order to comply with BART.

Table 7-1. Summary of BART Determinations for Unit MK2

Pollutant	Current Emission Controls	Additional Emission Controls in Progress	BART Controls	BART Emission Limit
NO_X	SCR	None	SCR	0.30 lb/MMBtu, 30-day rolling average
PM	Two ESPs in series	None	Two ESPs in series	0.08 lb/MMBtu total suspended particulate (TSP)
SO_2	Fuel sulfur limits set at 2.0 lb sulfur/MMBtu (averaged over 3 mos.) and 2.8 lb sulfur/MMBtu at any time	Flue gas desulfurization (FGD), with required SO_2 percent reduction set at maximum sustainable rate, but not less than 90% on a calendar monthly average basis	Flue gas desulfurization (FGD), with required SO_2 percent reduction set at maximum sustainable rate, but not less than 90% on a calendar monthly average basis; existing fuel sulfur limits to remain in effect	10% of uncontrolled SO_2 emissions, calendar monthly average

NEW HAMPSHIRE BART ANALYSIS: Merrimack Station Unit MK2 (320 MW)

Pollutant	Emission Control Technology	Control Level	Uncontrolled Emissions ton/yr	Controlled Emissions ton/yr	Emission Reductions ton/yr	Estimated Cost of Emission Controls[7]						
							Capital $	Capital $/kW	O&M $/yr	Total Annual $/yr	Average $/ton	Ref.
NO_X	SCR (existing)	85%	19,140 [1]	2,871 [2]	16,269		37,710,186	118	1,910,432	5,069,414	312	8
	SNCR	45%	19,140 [1]	10,527	8,613		3,876,771	12	4,781,136	5,105,893	593	8
PM	2 ESPs (existing)	99+%	30,060 [2]	210 [2]	29,850	min.	23,280,363	73	1,086,417	2,571,006	86	9
						max.	62,080,967	194	1,940,030	7,140,553	239	
	Fabric Filters	99%	30,060 [2]	301	29,759	min.	18,624,290	58	2,172,834	3,732,991	125	9
						max.	62,080,967	194	3,104,048	8,304,571	279	
SO_2	Lower-S coal (existing)	40% [3]	—	—	—		—	—	—	—	—	
	FGD	90% [4]	20,902 [5]	2,090	18,812 [6]		457,000,000	1,055	unknown	unknown	unknown	10

1 Estimated.

2 2002 (baseline) emissions as taken from NHDES data summary derived from facility's annual emissions statement.

3 Estimated average reduction in fuel sulfur content with use of lower-S coal, resulting in equivalent reduction in SO_2 emissions.

4 Additional control level on emissions after existing controls have been applied; overall control level with use of lower-S coal is estimated to be 40 + 90(1 - 0.40) = 94%

5 2002 (baseline) emissions with use of lower-sulfur coal at ~1.0 % S by weight.

6 Reductions from baseline emissions.

7 All cost estimates adjusted to 2008$.

8 USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

9 NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

10 FGD capital cost is PSNH's estimate (2008$) for Units MK1 (113 MW) and MK2 (320 MW) combined.

Merrimack Station Unit MK2: NO_X Controls

Plant type	wet-bottom, cyclone, coal-fired boiler	
Generation capacity	320	MW
Maximum heat Input	3,473	MMBtu/hr
Capacity factor	80	%
Annual hours	8,760	hr/yr
Annual production	2,242,560,000	kWh/yr

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	7,180	6,703	7,462	7,280	7,577	7,477	6,519
Total Heat Input*	22,013,513	22,006,524	24,024,382	23,795,575	25,328,218	25,448,437	18,282,000
Capacity factor**	72.4%	72.3%	79.0%	78.2%	83.3%	83.6%	60.1%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004$

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M	Scaled Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
SCR	111.48	103.46	33,108,152	2,773,470	0.74	0.69	219,771	0.67	0.65	1,457,518	1,677,289	4,450,759	16,269	274
SNCR	11.04	10.64	3,403,662	285,125	0.16	0.15	49,328	1.46	1.85	4,148,332	4,197,661	4,482,786	8,613	520

Costs: 2008$ 2004$ → 2008$ 1.139 multiplier

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M	Scaled Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
SCR	126.98	117.84	37,710,186	3,158,982	0.84	0.78	250,319	0.76	0.74	1,660,113	1,910,432	5,069,414	16,269	312
SNCR	12.57	12.11	3,876,771	324,757	0.18	0.18	56,185	1.66	2.11	4,724,951	4,781,136	5,105,893	8,613	593

Cost Reference:

USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Merrimack Station Unit MK2: PM Controls

Plant type	wet-bottom, cyclone, coal-fired boiler	
Capacity	320	MW
Maximum heat Input	3,473	MMBtu/hr
Capacity factor	80	%
Annual hours	8,760	hr/yr
Annual production	2,242,560,000	kWh/yr
Flue gas flow rate	1,362,620	acfm

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	7,180	6,703	7,462	7,280	7,577	7,477	6,519
Total Heat Input*	22,013,513	22,006,524	24,024,382	23,795,575	25,328,218	25,448,437	18,282,000
Capacity factor**	72.4%	72.3%	79.0%	78.2%	83.3%	83.6%	60.1%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004$

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	15.00	20,439,300	1,712,200	0.25	0.45	953,834	2,666,034	29,850	89
	max.	40.00	54,504,800	4,565,867	0.65	0.60	1,703,275	6,269,142	29,850	210
Wet ESP	min.	15.00	20,439,300	1,712,200	0.15	0.25	545,048	2,257,248	29,850	76
	max.	40.00	54,504,800	4,565,867	0.50	0.50	1,362,620	5,928,487	29,850	199
Fabric Filter - Reverse Air	min.	17.00	23,164,540	1,940,494	0.35	0.70	1,430,751	3,371,245	29,759	113
	max.	40.00	54,504,800	4,565,867	0.75	0.80	2,112,061	6,677,928	29,759	224
Fabric Filter - Pulse Jet	min.	12.00	16,351,440	1,369,760	0.50	0.90	1,907,668	3,277,428	29,759	110
	max.	40.00	54,504,800	4,565,867	0.90	1.10	2,725,240	7,291,107	29,759	245

Cost Reference:

NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Costs: 2008$ 2004$ → 2008$ 1.139 multiplier

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	17.09	23,280,363	1,950,196	0.28	0.51	1,086,417	3,036,613	29,850	102
	max.	45.56	62,080,967	5,200,523	0.74	0.68	1,940,030	7,140,553	29,850	239
Wet ESP	min.	17.09	23,280,363	1,950,196	0.17	0.28	620,810	2,571,006	29,850	86
	max.	45.56	62,080,967	5,200,523	0.57	0.57	1,552,024	6,752,547	29,850	226
Fabric Filter - Reverse Air	min.	19.36	26,384,411	2,210,222	0.40	0.80	1,629,625	3,839,848	29,759	129
	max.	45.56	62,080,967	5,200,523	0.85	0.91	2,405,637	7,606,160	29,759	256
Fabric Filter - Pulse Jet	min.	13.67	18,624,290	1,560,157	0.57	1.03	2,172,834	3,732,991	29,759	125
	max.	45.56	62,080,967	5,200,523	1.03	1.25	3,104,048	8,304,571	29,759	279

BART Analysis for
PSNH Newington Station Unit NT1

January 14, 2011

Amended August 26, 2011

BART Analysis for
PSNH Newington Station Unit NT1

1. INTRODUCTION

Unit NT1 is the sole electrical generating unit at PSNH Newington Station. It operates at irregular times, principally during periods of peak electric demand. Power is derived from an oil- and/or natural-gas-fired steam-generating boiler with a heat input rating of 4,350 MMBtu/hr and an electrical output of 400 MW. Installed in 1968, the boiler is equipped with low-NOx burners, an overfire air system, and water injection to minimize the formation of oxides of nitrogen (NO_X) during the combustion process. The facility also has an electrostatic precipitator (ESP) to capture particulate matter (PM) in the flue gases. Partial control of SO_2 emissions is provided by sulfur content limits on the fuel oil.

2. CURRENTLY AVAILABLE RETROFIT TECHNOLOGIES, POTENTIAL COSTS, AND OTHER ENVIRONMENTAL AND ENERGY IMPACTS

2.1 Retrofit Technologies for NO_X Control

NO_X emission control technology options available and potentially applicable to Unit NT1 are combustion controls, selective non-catalytic reduction, and selective catalytic reduction.

Combustion Controls

Controls on the combustion process can reduce NO_X formation by as much 75 percent. Combustion controls or firing practices include such measures as staged combustion, limiting excess air, providing overfire air, recirculating the flue gases, using low-NO_X burners, and injecting water or steam.

Operating with low excess air involves restricting the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compatible boiler operation. Because less oxygen is introduced into the combustion zone, NO_X formation is inhibited. Adjustments to the air supply may affect normal boiler operation and may reduce operational flexibility. The effectiveness of limiting excess air varies from boiler to boiler, but typical NO_X reductions are 10 to 25 percent from uncontrolled levels.

Overfire air (OFA) is a method where some of the total combustion air is diverted from the burners and injected through ports above the top burner level. This staged combustion reduces fuel-based NO_X formation in the oxygen-deficient primary combustion zone and limits thermal NO_X formation because of the lower peak flame temperature (i.e., combustion occurs over a larger portion of the furnace). For oil-fired boilers, OFA typically reduces NO_X emissions by 15 to 45 percent.

Flue gas recirculation (FGR) involves reinjecting a portion of the cooled flue gas into the combustion chamber. FGR dilutes the oxygen concentration in the combustion zone and depresses peak flame temperature by adding a large amount of cooled gas to the fuel-air mixture, resulting in less thermal NO_X formation. FGR reduces NO_X emissions by about 40 to 60 percent in oil-fired boilers.

Low-NO_X burners (LNB) are designed to control fuel/air mixing and increase heat dissipation. These alternative burners can be installed on new boilers or retrofitted on older units. LNB technology integrates staged combustion in the burner. A typical LNB creates a fuel-rich primary combustion zone, thus lowering the formation of fuel-based NO_X. At the same time, limited combustion air reduces the flame temperature, minimizing the formation of thermal NO_X. Combustion is completed in a lower-temperature, fuel-lean zone. LNB retrofits have been shown to reduce NO_X formation by 30 to 55 percent.

Water or steam can be injected into the boiler combustion zone to reduce the peak flame temperature, with a corresponding reduction in thermal NO_X formation. Water/steam injection can reduce NO_X emissions by as much as 75 percent in gas-fired boilers and slightly less in oil-fired boilers.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion technology that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_X in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected, the mixing of the reagent in the flue gas, the residence time of the reagent within the required temperature window, the ratio of reagent to NO_X, and the sulfur concentration in the flue gas. (Sulfur in the flue gas, originating from the sulfur content of the fuel, can combine with ammonia to form solid sulfur compounds such as ammonium bisulfate that may become deposited in downstream equipment.) There is limited commercial experience with SNCR from which to judge its effectiveness for oil-fired boilers. NO_X reductions of 35 to 60 percent have been achieved through the use of SNCR on some oil-fired boilers operating in the United States.

Selective Catalytic Reduction (SCR)

SCR is another post-combustion technology that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_X to nitrogen and water. The SCR reactor can be located at various positions in the process, including upstream of an air heater and particulate control device, or downstream of an air heater, particulate control device, and flue gas desulfurization system. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia-to-NO_X ratio, inlet NO_X concentration, space velocity, catalyst design, and catalyst condition. NO_X emission reductions of about 75 to 90 percent have been obtained with SCR on coal-fired boilers operating in the U.S. Although there is little experience with SCR systems on oil-fired boilers, SCR retrofits for oil-fired EGUs using the latest technology would be expected to achieve NO_X control efficiencies toward the upper end of this range.

2.1.1 Potential Costs of NO_X Controls

The estimated costs of NO_X emission controls at Newington Station Unit NT1 are presented in Table 2-1. These estimates are based on assumptions used in EPA's Integrated Planning Model for the EPA Base Case 2006 (V.3.0), for retrofitting an electric generating unit

(EGU) the size of Unit NT1. For low-NO_X burners, the total annual cost is estimated to be about $830,000, or $1,470 per ton of NO_X removed. With the addition of overfire air, this cost rises to $1,130,000, or $1,600 per ton. For SNCR, the total annual cost is estimated to be $730,000, or $1,030 per ton. For SCR, the total annual cost doubles to $1,410,000; but the unit cost is only moderately higher at $1,180 per ton of NO_X removed. Because Unit NT1 is primarily a peak-load generator, these estimates are based on a 20-percent capacity factor.

Table 2-1. Estimated NO_X Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
LNB	21.9	7,900,000	170,000	830,000	1,470
LNB+OFA	29.8	10,700,000	230,000	1,130,000	1,600
SNCR	12.3	3,300,000	450,000	730,000	1,030
SCR	36.7	11,500,000	440,000	1,410,000	1,180

Estimates are derived from USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006. Costs are scaled for boiler size. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 400-MW unit with 20% capacity factor and 701million kWh annual generation. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on the following estimates of NO_X removed: 563 tons for LNB; 704 tons for LNB+OFA; 704 tons for SNCR; and 1,196 tons for SCR.

Low-NO_X burners have previously been reported to operate in a cost range of $200 to $500 per ton of NO_X removed (NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005); however, this cost range is likely to be more relevant to larger plants operating at higher capacity factors than Newington Station.

2.1.2 Other Environmental and Energy Impacts of NO_X Controls

SNCR and SCR both use urea or anhydrous ammonia. Ammonia is a regulated toxic air pollutant in New Hampshire. Facilities using these technologies must limit their ammonia emissions, which may be released either in their flue gases or as fugitive emissions from the handling and storage of urea or anhydrous ammonia. A facility must also maintain a risk management plan if the quantities of stored ammonia exceed the applicable regulatory threshold.

Ammonia from SNCR that becomes entrained in the fly ash may affect the resale value or disposal cost of the ash. Ammonia in the flue gas may produce a more visible plume, depending on the ammonia concentration in the gas stream. High ammonia concentrations in the boiler from SNCR can react with sulfate to form ammonium bisulfate, which deposits on the economizer, air heater, and other surfaces. Ammonium bisulfate can also plug filter bags in a baghouse. SNCR may generate nitrous oxide emissions, a greenhouse gas.

With SCR, the formation of ammonium bisulfate may be exacerbated by the ability of this catalyst-based technology to oxidize SO_2 to SO_3, resulting in higher sulfate concentrations than would otherwise exist. Ammonium bisulfate formation can be reduced by controlling excess ammonia and using catalysts that minimize SO_2 oxidation. The air heater and other surfaces where the ammonia bisulfate may deposit must be acid washed periodically. Acid washing helps to maintain the efficiency of the air heater and prevents plugging to allow the free flow of flue gases through it. An SCR may also require a fan upgrade to overcome extra pressure drop across the catalyst. The increase in fan capacity consumes a small amount of energy.

NO_X emission reductions provide environmental and public health benefits beyond visibility improvement – most notably, reductions in acid rain and ground-level ozone. NO_X is a chemical precursor to ozone formation and is one of the primary compounds contributing directly to acid rain formation. A decrease in acid rain production improves water quality and the health of ecosystems sensitive to low pH.

2.2 Retrofit Technologies for PM Control

PM control technologies available and potentially applicable to Unit NT1 are electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers.

Electrostatic Precipitators (ESPs)

Electrostatic precipitators capture particles through the use of electrodes, which are electrical conductors used to make contact with non-metallic parts of a circuit. An ESP consists of a small-diameter negatively charged electrode (usually a set of individual wires or a grid) and a grounded positively charged plate. In operation, a strong electric charge from the negatively charged electrode sets up a one-directional electric field. When particle-laden gases pass through this electric field, the particles become charged and are then drawn to the positive collecting surface (the plate), where they are neutralized. The particles are then collected by washing or knocking the plate, causing the particles to fall into a collection hopper. Existing electrostatic precipitators are typically 40 to 60 percent efficient. New or rebuilt ESPs can achieve collection efficiencies of more than 99 percent.

For older units, options for upgrading an ESP system include: replacement of existing control systems with modern electronic controllers; replacement of old-style wire and plate systems inside the ESP with new, rigid electrode systems; addition of new ESP fields; or addition of entire new units (in series). The feasibility of any particular upgrade will be influenced by spatial limitations or design constraints on a case-by-case basis.

Fabric Filters

Fabric filtration devices, or baghouses, incorporate multiple fabric filters/bags inside a containment structure. These devices work on the same principal as a vacuum cleaner bag. The particle removal efficiency of the fabric filter system depends on a variety of particle and operational parameters. The physical characteristics of particle size distribution, particle cohesion, and particle electrical resistivity are important variables. Operational parameters affecting collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, and cleaning intensity. The structure of the fabric filter, filter composition, and bag properties also affect collection efficiency. Collection efficiencies of baghouses may exceed 99 percent.

Mechanical Collectors and Particle Scrubbers

Mechanical collectors, such as cyclones, are most effective at collecting coarse particulate matter (i.e., particles with a diameter of 10 micrometers or larger). Finer particles escape cyclones along with the flue gases. For this reason, mechanical collectors are generally most useful when used in conjunction with other pollution control equipment. The typical collection efficiency of mechanical collectors is about 85 percent for larger particle sizes.

Scrubbing systems involve the injection of water and/or chemicals into the flue gas to wash unwanted pollutants from the gas stream through physical or chemical absorption/adsorption. Scrubbing systems have been shown to reduce PM_{10} emissions by 50 to 60 percent but are generally less effective for removal of fine particles.

Because mechanical collectors and particle scrubbers are more costly and less efficient than other control options (i.e., ESPs, baghouses), these lower-performing technologies are rarely used today for removing particulate matter from power plant emissions. Consequently, mechanical collectors and scrubbers are not considered further in this analysis for the control of PM emissions.

2.2.1 Potential Costs of PM Controls

Table 2-2 presents cost data for PM controls as developed from NESCAUM's *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. Approximate cost ranges are provided for two types of ESPs and two types of fabric filters applicable to a retrofit installation the size of Unit NT1. Capital and operating costs are based on flue gas flow rates in actual cubic feet per minute (acfm).

Table 2-2. PM Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost ($)	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
Dry ESP	73-194	29.3-78.1 million	1.4-2.4 million	3.8-9.0 million	27,000-63,000
Wet ESP	73-194	29.3-78.1 million	0.8-2.0 million	3.2-8.5 million	23,000-60,000
Fabric filter – reverse air	82-194	33.2-78.1 million	2.0-3.0 million	4.8-9.6 million	14,000-29,000
Fabric filter – pulse jet	58-194	23.4-78.1 million	2.7-3.9 million	4.7-10.4 million	14,000-31,000

Reference: NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. (Note that these costs were developed for coal-fired boilers.) All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 400-MW unit with 20% capacity factor and flue gas flow rate of 1.71 million acfm. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on 142 tons of PM removed for ESPs and 335 tons of PM removed for fabric filters.

The costs for ESPs and fabric filters are of similar magnitude, with total annual costs ranging from about \$3.2 million to \$10.4 million, or \$14,000 to \$63,000 per ton of PM removed. Because Unit NT1 already has an ESP installed and operating, the tabulated costs are useful for comparative purposes only. For facilities with existing ESPs, typical equipment replacement costs to upgrade performance may be in the range of \$10,000 to \$30,000 per MW. (M. Sankey and R. Mastropietro, "Electrostatic Upgrade Strategy: Get the Most From What You Have," Hamon Research-Cottrell, Inc., April, 1997.)

2.2.2 Other Environmental and Energy Impacts of PM Controls

PM controls collect particulate matter, or fly ash, suspended in the flue gases. In some cases, the fly ash is injected back into the boiler, an arrangement that improves boiler efficiency by recapturing the residual heating value of the fly ash. If the fly ash is not reinjected, it must be either landfilled or reclaimed, e.g., as a supplement in concrete production or as a component in other manufactured products.

2.3 Retrofit Technologies for SO_2 Control

SO_2 control technologies available and potentially applicable to Unit NT1 are scrubber systems for flue gas desulfurization, and use of low-sulfur coal.

Flue Gas Desulfurization

Scrubber systems use chemical reagents to “scrub” or “wash” unwanted pollutants from a gas stream. Flue gas desulfurization (FGD) processes based on this technology concept are classified as either wet or dry. Wet scrubbers are more commonly used at power plants to control acid gas emissions. Scrubbers of all types may be effective for the removal of particulate matter, mercury, sulfur dioxide, and other air pollutants.

In the wet FGD process, an alkaline reagent is applied in liquid or slurry form to absorb SO_2 in the flue gas. A PM control device is always located upstream of a wet scrubber. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. Wet regenerative (meaning the reagent material can be treated and reused) FGD processes are an attractive option because they allow higher sulfur removal rates and produce minimal wastewater discharges.

For coal-fired power plants, the reagent is usually lime or limestone; and the reaction product is calcium sulfite or calcium sulfate. The solid compounds are collected and removed in downstream process equipment. Calcium sulfate (gypsum) sludge produced in FGDs can be recycled into saleable byproducts such as wallboard, concrete, and fertilizer. Sulfate products that are not recycled must be landfilled.

SO_2 removal efficiencies for existing wet limestone scrubbers range from 31 to 97 percent with an average of 78 percent (NESCAUM, “Assessment of Control Technology Options for BART-Eligible Sources,” March 2005). For new FGD systems installed at large (>750 MW) coal-fired power plants, the presumptive norm is 95 percent reduction of SO_2 emissions (USEPA, Appendix Y to Part 51 – Guidelines for BART Determinations under the Regional Haze Rule). While experience with FGD systems on smaller, oil-fired EGUs is generally lacking, it is anticipated that such installations would perform at a similar level, achieving SO_2 removal efficiencies of 90 percent or greater.

Dry (or semi-dry) FGD processes are similar in concept to wet FGD processes but do not saturate the flue gas stream with moisture. Dry scrubbers are of two general types: dry sorbent injection and spray dryers. With the former, an alkaline reagent such as hydrated lime or soda ash is injected directly into the flue gas stream to neutralize the acid gases. In spray dryers, the flue gas stream is passed through an absorber tower in which the acid gases are absorbed by an atomized alkaline slurry. The SO_2 removal efficiencies range from 40 to 60 percent for existing dry injection systems and from 60 to 95 percent for existing lime spray dryer systems (NESCAUM, 2005). A PM control device (ESP or fabric filter) is always installed downstream of a dry or semi-dry scrubber to remove the sorbent from the flue gas.

Low-Sulfur Fuels

Because SO_2 emissions are directly related to the sulfur content of the fuel burned, reducing the amount of sulfur in the fuel reduces SO_2 emissions. For facilities that burn fuel oil, switching to a lower-sulfur fuel may be a cost-effective control option. Switching from high-sulfur residual fuel oil to low-sulfur residual fuel oil or low-sulfur distillate fuel oil is one possible control strategy. For facilities that have the option to replace fuel oil with natural gas or can co-fire with natural gas, increasing the use of natural gas is another effective control strategy. Sulfur dioxide emissions from burning natural gas are negligible in comparison to those from burning fuel oil. When substituting natural gas for fuel oil, the resulting SO_2 emission reductions are roughly proportional to the fraction of natural gas burned on a Btu-equivalent basis.

2.3.1 Potential Costs of SO_2 Controls

There is little or no experience with, or cost data on, flue gas desulfurization at oil-fired power plants. However, the technology is similar to FGD for coal-fired plants. Therefore, the costs of an FGD system for PSNH Newington Station may be crudely approximated by extrapolating from the costs of FGD for PSNH Merrimack Station.

The flue gas desulfurization system at Merrimack Station is being installed to reduce mercury emissions (with SO_2 removal as a co-benefit) at its two coal-fired boilers. These units have a combined generating capacity of 433 MW, or slightly greater than the capacity of Newington Station Unit NT1. The company's capital cost estimate for the wet limestone FGD system is $457 million, or $1,055/kW (both amounts in 2008$), which is said to be in line with project costs for multiple-unit scrubber installations occurring elsewhere in the United States. However, PSNH's estimated cost per kilowatt is at least triple the cost range for FGD systems as reported in MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007 (see Reasonable Progress Report, Attachment Y). The PSNH estimated cost is also more than double the estimate of $300/kW to $500/kW as reported in a 2008 survey of FGD systems (George W. Sharp, "What's That Scrubber Going to Cost?," *Power*, March 1, 2009). The higher cost-per-kW for Unit MK2 may reflect industry-wide increases in raw material, manufacturing, and construction costs but may also reflect site-specific factors such as unit size, type, and difficulty of retrofit.

Using the latest Merrimack Station estimate of $1,055/kW for scaling purposes, the total capital cost of a wet limestone FGD system for Newington Station Unit NT1 would be roughly $422,000,000. Much caution is necessary in relating this number to the Newington facility: Note that the cost of FGD on oil-fired boilers previously has been estimated to be about *twice* the cost of FGD on coal-fired boilers of comparable size (NESCAUM, 2005).

The costs of switching to a low-sulfur fuel oil at Unit NT1 would depend on the incremental costs of purchasing the lower-sulfur product at prevailing market prices. The long-term price differential between 1.0%-sulfur (low-S) residual fuel oil and 2.0%-sulfur residual fuel oil is estimated to be about 7.5 cents/gallon. The differential between 0.5%-sulfur (ultra-low-S) residual fuel oil and 2.0%-sulfur residual fuel oil is estimated to be about twice this amount, or 15 cents/gallon (both estimates in 2008$ based on Energy Information Agency compiled price data for the period 1983-2008.) Using these unit prices, the total cost of switching to low-S residual fuel oil is approximately $3.3 million per year, or $1,900 per ton of SO_2 emissions removed; and the cost of switching to ultra-low-S residual fuel oil is approximately $6.6 million per year, or also $1,900 per ton of SO_2 emissions removed (both estimates based on 2002 actual fuel oil usage; note that fuel oil usage in 2006-2009 has been below 2002 levels). These results imply that the costs of switching fuel oils may be relatively constant on a $/ton basis as long as supplies are adequate.

Table 2-3 summarizes the approximate costs of flue gas desulfurization and fuel switching as SO_2 control options for PSNH Newington Station Unit NT1. The costs for switching from 2.0%-S residual fuel oil to 1.0%-S or 0.5%-S residual fuel oil are listed. At any given time, the actual cost of fuel switching would vary in proportion to the applicable fuel price differential.

Table 2-3. SO_2 Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
FGD	1,055	422,000,000	unknown	unknown	unknown
Switch to 1.0%-S oil	—	—	3,300,000	3,300,000	$1,900
Switch to 0.5%-S oil	—	—	6,600,000	6,600,000	$1,900

Capital cost estimate for FGD is based on reported cost per kilowatt-hour for FGD system at PSNH Merrimack Station. Actual costs for Newington Station could be much higher. O&M costs for fuel switching are based on 2002 annual fuel usage of 44,140,000 gallons and estimated fuel price differential of 7.5 or 15 ¢/gallon for substitution of 1.0%-S or 0.5%-S residual fuel oil, respectively.

In a similar analysis performed independently by PSNH (see attached letter), the company has estimated the costs of fuel switching based on historical fuel prices for the period 2002-2009 as compiled by Platts[‡]. Table 2-4 reproduces the fuel oil prices used by PSNH:

Table 2-4. Historical Fuel Oil Prices, 2002-2009 ($/barrel)

Year	2%S Oil	1%S Oil	0.7%S Oil	0.5%S Oil	0.3%S Oil
2002	21.20	22.45	23.26	23.80	25.25
2003	24.95	27.48	29.26	30.45	32.63
2004	25.25	27.92	30.04	31.46	34.53
2005	37.00	41.00	44.00	46.00	50.10
2006	45.50	46.30	48.46	49.90	54.12
2007	53.70	53.45	56.54	58.60	62.86
2008	75.25	77.80	81.10	83.30	92.16
2009	49.90	50.75	51.98	52.80	55.83

Source: Platts. 2009 data include costs through 9/09.

‡ Platts, a division of The McGraw-Hill Companies, is a provider of energy information services.

Using this historical fuel price record and PSNH's calculated SO_2 emission reductions from fuel switching, the New Hampshire Department of Environmental Services (NHDES) has prepared alternate estimates of the increased costs of fuel switching from 2.0%-S residual fuel oil to 1.0%-S or 0.5%-S residual fuel oil, and other variations, in Table 2-5. Costs are listed in terms of \$/barrel, \$/hour, and \$/ton. This analysis produces somewhat less conservative (lower) estimates of the cost of fuel switching than the \$1,900/ton estimate given above. In either analysis, the cost-effectiveness of switching to 0.5%-sulfur residual fuel oil appears reasonable as long as supplies remain stable. Switching to 0.3%-sulfur fuel oil could also prove reasonable in the future if prices were to stay within their recent historical range and future supplies could be assured.

Table 2-5. Costs of Fuel Switching Based on Historical Fuel Oil Prices

Fuel Switch	SO_2 Emission Reduction* (lb/hr)	Increased Cost (\$/barrel)		Increased Cost (\$/hour)**		\$/ton of SO_2 Removed***	
		low	high	low	high	low	high
→ 2% to 1%	***5,228.7***	***0***	***4***	***0***	***2,692***	***0***	***1,030***
1% to 0.7%	1,470.3	1	3.3	673	2,222	414	3,022
0.7% to 0.5%	957.0	1	2.2	673	1,482	586	3,095
0.5% to 0.3%	935.3	3	9	2,020	6,059	2,967	12,957
2% to 0.7%	6,699.0	2	7	1,34	4,712	402	1,407
→ 2% to 0.5%	***7,656.0***	***3***	***9***	***2,019***	***6,058***	***528***	***1,583***
2% to 0.3%	8,591.3	4	17	2,692	11,444	627	2,664

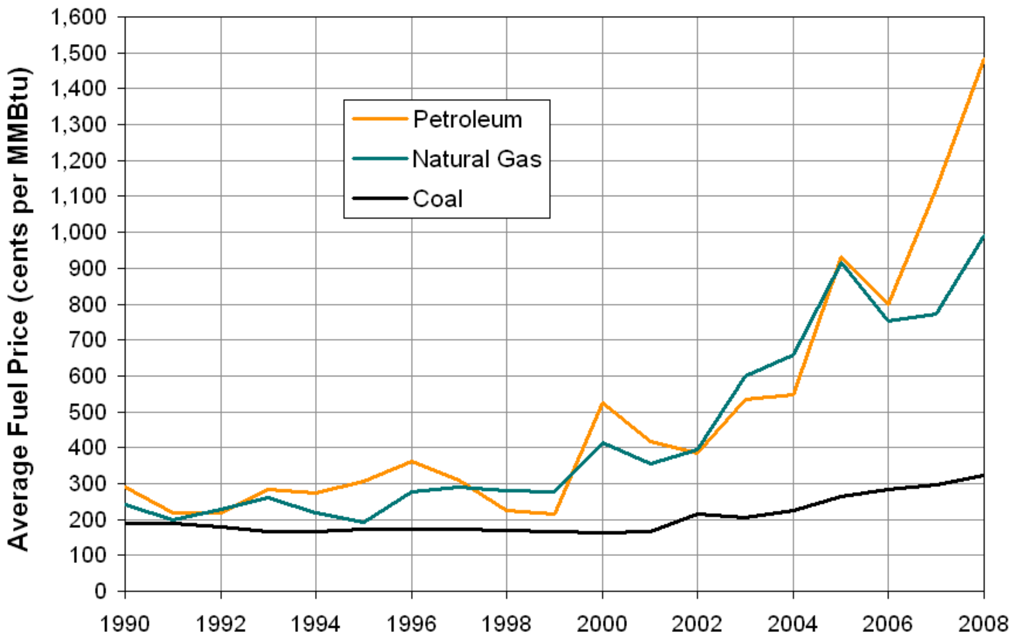
* Calculated reduction, from PSNH letter dated December 4, 2009.
** \$/barrel ÷ 42 gal/barrel ÷ 0.153846 MMBtu/gal × MMBtu/hr = \$/hr
*** \$/hr ÷ lb/hr × 2000 lb/ton = \$/ton

Besides switching residual fuel oils to reduce SO_2 emissions, other proposed options include replacing 2.0%-S residual fuel oil with low-sulfur distillate fuel oil or natural gas. Although distillate fuel oil is sometimes used during startup of Unit NT1, the boiler is not designed to operate routinely on this fuel; and retrofitting the boiler for this purpose would involve major capital expenditure. Burner replacements to combust distillate fuel oil could exceed \$20 to \$30 million (approximately \$1 to 2 million per burner) in direct capital costs, not including the additional costs of engineering and any required auxiliary equipment.

The cost determinations associated with using natural gas are more complicated. Unit NT1 can be fired with either natural gas or liquid fuel (i.e., residual fuel oil or biofuel), or it can be co-fired with both types of fuel at the same time. However, because of physical limitations to the boiler's design, the unit cannot operate at full capacity when fueled solely by natural gas. In order to reach maximum heat input, the boiler must either use liquid fuel or be co-fired with both fuel types. (Unit NT1 can operate at up to about 50 percent of maximum heat input from natural gas, with no corresponding limitation on liquid fuel.) Firing Unit NT1 entirely with natural gas might be technically feasible but would require more than just burner replacements: it would require modifications to other major boiler components or replacement of the entire boiler. Such measures cannot be economically justified. However, using natural gas – to the extent that Unit NT1 can burn this fuel with existing equipment – remains a viable option as long as the cost of this fuel is competitive with the cost of residual fuel oil and biofuel.

Volatile energy commodity prices in recent years and the uncertainty of future fuel prices make it difficult to provide a useful estimate of the cost of substituting natural gas for residual fuel oil. As seen in Figure 2-1, past prices of natural gas and petroleum fuels, on a BTU-equivalent basis, exhibit similar trends; but the price differentials show wide variation from year to year. Consequently, no cost estimate for this fuel switching option is presented.

Figure 2-1. Comparison of Fossil Fuel Prices for Electric Generation in New England (1990-2008)



Data source: Energy Information Administration, Form EIA-923, "Power Plant Operations Report."
http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html

2.3.2 Other Environmental and Energy Impacts of SO_2 Controls

An FGD system typically operates with high pressure drops across the control equipment, requiring increased energy usage for blowers and circulation pumps. Some configurations of FGD systems also require flue gas reheating to prevent operational problems (including physical damage to equipment), resulting in higher fuel usage per unit of net electrical generation. Documentation for EPA's Integrated Planning Model (IPM®) indicates that a wet FGD system reduces the generating capacity of the unit by about 2 percent.

Flue gas desulfurization has impacts on the operation of solid waste and wastewater management systems. In addition to removing SO_2, the FGD process removes mercury and other metals and solids. Often, gypsum produced in a limestone FGD process is recycled or sold to cement manufacturers; otherwise, the sludge must be stabilized and placed in an approved landfill. Gypsum must be dewatered before it can be handled, resulting in a wastewater stream that requires treatment. This wastewater stream increases the sulfates, metals, and solids loadings on the receiving wastewater treatment plant. Sometimes an additional clarifier is required to remove wastewater solids coming from the FGD system.

Wet FGDs increase the amount of water vapor entrained in the flue gas. The result is a lower stack exit temperature and a more visible plume at the stack outlet.
Switching to lower-sulfur fuel oil generally reduces boiler maintenance requirements because less particulate matter is emitted. With fewer material deposits occurring on internal boiler surfaces, the intervals between cleanings/outages can be longer. Also, because lower-sulfur oil reduces the formation of sulfuric acid emissions, corrosion is reduced and equipment life is extended.

3. DISCUSSION OF CURRENT POLLUTION CONTROL EQUIPMENT AND EMISSIONS

3.1 Discussion of Current NO_X Emissions and Controls

PSNH Newington Station Unit NT1 currently operates with low-NOx burners, an overfire air system, and water injection to minimize NO_X formation. For compliance with NO_X RACT requirements, the facility's existing air permit limits NO_X emissions from this unit to a daily average of 0.35 lb/MMBtu when burning oil and 0.25 lb/MMBtu when burning a combination of oil and gas. NHDES reviewed emissions data for Unit NT1 for the period from 2003 to 2005, when more than 99 percent of the gross heat input came from residual fuel oil. Monthly average NO_X emissions ranged between 0.21 and 0.30 lb/MMBtu. These values compare favorably with the facility's NO_X RACT limits. Actual NO_X emissions from this unit were 943 tons in 2002.

3.2 Discussion of Current PM Emissions and Controls

Unit NT1 has an electrostatic precipitator to capture PM emissions. In an EPA inspection report on this unit from December 15, 1989, a table of design values for the ESP listed a particulate removal efficiency of 93 percent. It is unknown whether the stated efficiency is representative of actual long-term performance. The facility's air permit (TV-OP-054, March 9, 2007; administrative amendment, December 17, 2007) sets an emission limit of 0.22 lb/MMBtu total suspended particulate matter (filterable TSP). The single available stack test on Unit NT1 measured a controlled TSP emission rate of 0.058 lb/MMBtu, which is well below the permit limit. The tested emission rate lies within the expected range for a properly operating ESP at a plant like Newington and may serve as a better measure of performance than any stated efficiency for this control device. Actual TSP emissions from Unit NT1 were 198 tons in 2002.

3.3 Discussion of Current SO_2 Emissions and Controls

Sulfur dioxide emissions are partially controlled at PSNH Newington Station by existing limits on fuel oil sulfur content. Permitted fuel sulfur limits are 2.0% sulfur by weight for No. 6 fuel oil and 0.4% sulfur by weight for No. 2 fuel oil. Unit NT1 does not have an individual limitation on sulfur dioxide emissions but is subject to an annual cap of 55,150 tons of SO_2 for all electrical generating units at PSNH's Merrimack, Newington, and Schiller Stations combined. Actual SO_2 emissions from Unit NT1 were 5,226 tons in 2002. The average sulfur content of No. 6 fuel oil burned that year was 1.2% by weight, which is typical of values from the most recent decade. In 2009, the average was 1.0%.

4. REMAINING USEFUL LIFE OF UNIT

Where a reasonable control option is available for a BART-eligible unit, the unit should be controlled in a manner consistent with BART and the expected useful life of the unit. Originally, electric generating units were estimated to have a life expectancy of 30 to 40 years, but many units are lasting 50 years or more. In many cases, it is less expensive to keep existing units operating than to build replacement facilities and/or new transmission lines. Newington Station Unit NT1 was built in 1969. However, because this facility runs primarily on fuel oil, its remaining useful life may depend more on future commodity supplies/prices and other external factors than on the longevity of plant equipment.

5. DEGREE OF VISIBILITY IMPROVEMENT ANTICIPATED FROM BART

5.1 CALPUFF Modeling Analysis

NHDES performed a set of CALPUFF model runs for the New Hampshire BART-eligible sources under controlled and uncontrolled conditions. The same methodologies used for the CALPUFF modeling work for Merrimack Station Unit MK2 were applied to the modeling for Newington Station Unit NT1.

In previous modeling, MANE-VU used CALPUFF to assist in the identification of BART-eligible sources. This modeling assumed natural visibility conditions (about 7 dv) to produce the most conservative results possible, thereby minimizing the number of sources that would "model out" of BART requirements. Under these conditions, uncontrolled emissions from Unit NT1 produce theoretical CALPUFF worst-case impacts of 1.22 dv at Acadia National Park. EPA considers it acceptable to exempt sources when this form of conservative modeling indicates that a source produces less than 0.5 dv of impact. MANE-VU considers an exemption level of 0.2 to 0.3 dv to be more appropriate but prefers, and has applied, an even more conservative exemption level of 0.1 dv. CALPUFF modeling results for baseline emissions from Unit NT1 exceed all of these exemption levels. The CALPUFF-predicted visibility benefits from BART controls on 20% worst natural and 20% worst baseline visibility days are presented in Table 5-1.

As seen in the table, more benefit would result generally from SO_2 emission reductions than NOx emission reductions. This finding reinforces MANE-VU's early determination that SO_2 was the primary target pollutant for maximizing visibility improvements. NO_X, while also an important visibility impairing pollutant, reacts with ammonia less preferentially than does SO_2 and is also less hydrophilic than SO_2. As a result, NO_X has a lower rate of formation of haze-causing particles and impairs visibility less effectively than a similar mass of SO_2.

Table 5-1. CALPUFF Modeling Results for Newington Station Unit NT1:
Visibility Improvements from BART Controls

On the 20% Worst Natural Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	FGD (90% sulfur reduction*)	0.57	0.45	**0.09**
	1.0%-S residual fuel oil (50% sulfur reduction*)	0.30	0.24	**0.05**
	0.5%-S residual fuel oil (75% sulfur reduction*)	0.46	0.36	**0.07**
	0.3%-S residual fuel oil (85% sulfur reduction*)	0.52	0.40	**0.08**
	0.50 lb SO_2/MMbtu (77% sulfur reduction*)	0.47	0.37	**0.08**
	Switch from 0.50 lb SO_2/MMbtu emission limit to 0.3%S residual fuel oil	*<0.05*	*0.03*	***<0.01****
NOx	SNCR (25% NOx reduction**)	0.11	0.10	**0.04**
	SCR (78% NOx reduction**)	0.34	0.30	**0.12**
PM	Baghouse (85% PM reduction**)	0.05	0.04	**0.01**
On the 20% Worst Baseline Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	FGD (90% sulfur reduction*)	**0.13**	**0.10**	<0.01***
	1.0%-S residual fuel oil (50% sulfur reduction*)	**0.07**	**0.06**	<0.01***
	0.5%-S residual fuel oil (75% sulfur reduction*)	**0.11**	**0.09**	0.01
	0.3%-S residual fuel oil (85% sulfur reduction*)	**0.13**	**0.10**	0.01
	0.50 lb SO_2/MMbtu (77% sulfur reduction*)	**0.11**	**0.09**	0.01
	Switch from 0.50 lb SO_2/MMbtu emission limit to 0.3%S residual fuel oil	***0.01***	***0.01***	*<0.01****
NOx	SNCR (25% NOx reduction**)	**0.04**	**0.03**	0.01
	SCR (78% NOx reduction**)	**0.11**	**0.10**	0.03
PM	Baghouse (85% PM reduction**)	**0.02**	**0.02**	<0.01***

* from maximum permitted level
** from baseline level with existing controls
*** below sensitivity limit of model

Note: Values in **boldface** are considered as having greater validity in the modeling estimation of maximum visibility benefits from BART controls.

5.1 CALGRID Modeling Analysis

NHDES also conducted a screening-level analysis of the anticipated visibility effects of BART controls at PSNH Newington Station Unit NT1. Specifically, one modeling run using the CALGRID photochemical air quality model was performed to assess the effects of switching to lower-sulfur fuel for this unit. The simulation covered the full summer modeling episode (from May 15 to September 15, 2002) with MANE-VU's 2018 beyond-on-the-way (BOTW) emissions inventory scenario as a baseline.

The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutants within the region. NHDES post-processed the modeled concentration reductions to estimate the corresponding visibility improvements at nearby Class I areas (i.e., concentration impacts were converted to visibility impacts).

Based on the CALGRID modeling results, switching to lower-sulfur fuel oil for Unit NT1 is expected to reduce near-stack maximum predicted 24-hour average SO_2 concentration impacts by about 1.4 $\mu g/m^3$. Reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, would yield negligible visibility improvement at the affected Class I areas.

6. DETERMINATION OF BART

Based on the completed review and evaluation of existing and potential control measures for PSNH Newington Station Unit NT1, it is determined that the NO_X, PM, and SO_2 controls described below represent Best Available Retrofit Technology for this unit.

6.1 Selecting a Pollution Control Plan for NO_X

Use of low excess air reduces NO_X emissions but can often result in greater PM and/or CO emissions. Many of the NO_X reduction benefits acquired through the implementation of low excess air are already being achieved at Unit NT1 through the use of low-NOx burners, overfire air, and water injection; so the application of low excess air would be redundant in this case. Flue gas recirculation reduces the peak flame temperature in much the same way as overfire air and has the additional benefit of reducing the oxygen content in the combustion zone, leading to further reductions in NO_X formation. Because Unit NT1 operates with an existing overfire air system, and because this boiler has already been modified by the installation of natural gas lances, FGR is economically impractical and might also be physically infeasible.

The NO_X emission reductions being achieved at Unit NT1 through the use of combustion control technologies are a substantial improvement over no controls. Retrofitting the facility with SCR or SNCR would reduce NO_X emissions by an additional 300 to 700 tons per year. Despite the sizeable emission reductions that SCR or SNCR would provide, with annualized costs of \$0.7 to \$1.3 million, neither technology option could be implemented cost-effectively. Note that these dollar amounts do not include the significant additional costs of redesigning Newington Station's layout to address spatial constraints. Also, the estimated costs are based on 2002 emission levels, when the plant's capacity factor was around 20 percent. With the capacity factor having fallen to less than 10 percent over the period 2006-

2009, it is difficult to justify additional technology retrofits to reduce NO_X emissions at this facility today. This conclusion is reinforced by the small improvement in visibility that might be obtained with such retrofits on the few occasions when meteorological conditions would indicate maximum impacts.

Another consideration with SCR or SNCR is flue gas and fugitive ammonia emissions. Based on past operation of Unit NT1 and on typical ammonia "slip" rates, it is estimated that fugitive ammonia emissions with either technology would be in the vicinity of 32 tons annually. Ammonia is a regulated toxic air toxic pollutant in New Hampshire and is also a significant contributor to visibility impairment. However, the issue is not so much the magnitude of ammonia slip, toxicity, or visibility impairment as the fact that ammonia slip would occur at all. On balance, this is a relatively minor negative to be weighed in the context of other factors.

Based on all of these considerations, NHDES finds that SCR and SNCR are not cost-effective as Best Available Retrofit Technology for NO_X control at this facility and will not be evaluated further. The existing NO_X controls, which include low-NOx burners, overfire air, and water injection, are determined to fulfill BART requirements for Newington Station Unit NT1.

Because additional retrofits are not proposed, completion of the BART assessment for Unit NT1 becomes a matter of ascertaining this facility's long-term performance capability with existing equipment. NHDES reviewed emissions data for Unit NT1 for the period from 2003 to 2005, when more than 99 percent of the gross heat input came from residual fuel oil. Monthly average NO_X emissions ranged between 0.21 and 0.30 lb/MMBtu. These values compare favorably with the facility's NO_X RACT limit of 0.25 lb/MMBtu, daily average, when burning natural gas and 0.35 lb/MMBtu, daily average, when burning fuel oil. However, the extent of the data record is insufficient to demonstrate that the facility could sustainably meet more restrictive emission limits than these. The current NO_X RACT limitations for Unit NT1 are therefore considered to represent BART control levels.

6.2 Selecting a Pollution Control Plan for PM

PSNH currently operates an electrostatic precipitator on Unit NT1. ESPs perform with removal efficiency rates similar to those of fabric filters but operate at about half the cost for plants of this size. Although it may be technically feasible to improve performance of the existing ESP through some form of upgrade, it is difficult to justify any major capital expense at this facility in light of its recent operating history. Since 2006, the plant's capacity factor has been below 10 percent. In consideration of the facts that Unit NT1 already operates a fully functional ESP, that additional capital outlay for PM control cannot be economically justified at this time, and that any resulting benefit to visibility would be negligible, it is determined that the existing ESP fulfills BART requirements.

The single available stack test on this unit indicates that the ESP yields controlled TSP emission rates in the vicinity of 0.06 lb/MMBtu versus a currently permitted rate of 0.22 lb/MMBtu. The extent of the data record is insufficient to support consideration of a BART performance level more restrictive than the existing permit limit. The facility's Title V operating permit requires that a compliance stack test for PM emissions be performed on Unit NT1 before the permit expires on March 31, 2012. NHDES will review the stack test results to ascertain the unit's performance and incorporate any new limit into a permit amendment by the permit expiration date, as appropriate. The permit expiration date precedes the effective date of proposed BART control measures by fifteen months.

6.3 Selecting a Pollution Control Plan for SO_2

Flue gas desulfurization is a potential SO_2 control option for PSNH Newington Station Unit NT1. However, the cost per ton for FGD on oil-fired boilers is estimated to be about twice the cost of this technology on coal-fired boilers and could well exceed $1,000/kW for Newington Station. Given the high costs of this option, it is apparent that FGD would be uneconomical as a retrofit for a peak-demand plant the size of Unit NT1.

Use of a lower-sulfur fuel is a practical option for controlling SO_2 emissions at Newington Station. When natural gas is available at reasonable cost relative to residual fuel oil, natural gas is the preferred fuel because of its very low sulfur content. Otherwise, use of low-sulfur residual fuel oil is a reasonable option. For relatively minor increases in the cost of fuel, switching to 1.0%-sulfur or 0.5%-sulfur residual fuel oil would provide significant reductions in fuel sulfur content with proportional reductions in SO_2 emissions.

When not firing exclusively on natural gas, Newington Station Unit NT1 has traditionally burned No. 6 fuel residual fuel oil at 2.0 percent (nominal) sulfur content. From 2002 to 2009, the actual average annual sulfur content of the fuel oil ranged between 1.03 and 1.54 percent by weight, with no significant trend (average fuel sulfur content was 1.21 percent in 2002). For New Hampshire's BART analysis of this plant, the following fuel sulfur values were assumed:

Nominal %S (permit limitation)	Assumed Actual %S (chemical assay)
2.0	1.2
1.0	0.8
0.5	0.4

Under these assumptions, switching from 2.0 %S (nominal) to 1.0 %S (nominal) residual fuel oil would produce a one-third reduction in sulfur dioxide emissions, and switching to 0.5 %S (nominal) residual fuel oil would produce a two-thirds reduction in sulfur dioxide emissions at this facility.

The proposed fuel switching could be accomplished without capital expense and would have predictable costs tied directly to fuel consumption and fuel price differentials. The cost per ton would be no more than about $1,900 (historical fuel prices suggest a range of $0 to $2,000 per ton). At the 2002 production level of 700 million kilowatt-hours, estimated annual costs (long-term average, 2008$) for switching to 1.0% or 0.5% residual fuel oil would be about $3.3 or $6.6 million (equivalent to $0.0047 or $0.0094 per kWh), respectively. The cost per kilowatt-hour would vary more or less in proportion to the fuel price differential and would not change significantly with increases or decreases in production level.

While fuel availability is always a consideration, supplies should not be a significant factor in obtaining fuels whose sulfur content is as low as 0.5 percent. Residual fuel oil at 1.0% sulfur is already widely distributed within the region; and there is greater assurance today of the availability 0.5%-sulfur residual fuel oil than in 2008, when New Hampshire began

drafting its BART determinations. Maine, Massachusetts, New Jersey, and other states within MANE-VU are moving toward or already require the use of 0.5%-sulfur residual fuel oil, thus ensuring the presence of a regional market for this commodity.
NHDES considered the possible use of 0.3%-sulfur residual fuel oil for Unit NT1; but this fuel has had only very limited use within the northern New England region, and its future availability and price remain uncertain. More specifically, the fact that some plants in Connecticut are using 0.3%-sulfur residual fuel oil today does not guarantee the availability of this fuel in northern New England, which obtains its bulk oil shipments through different ports.

For Unit NT1, the possible use of low-sulfur residual fuel oil is complicated by the plant's low capacity factor and existing fuel stocks and storage facilities. The plant now has a sizeable quantity of higher-sulfur residual fuel oil in storage tanks on site. Because there is no practical way to offload and replace the existing inventory with a lower-sulfur residual fuel oil, the existing stock of higher-sulfur fuel oil would have to be used up before requiring that Unit NT1 be fired exclusively with low-sulfur fuel oil. Also, it is anticipated that the plant will continue to have a low utilization rate and capacity factor in the coming years (its capacity factor was less than 7 percent in 2009). Given this scenario, depletion of the existing stock of residual fuel oil could take more than a year, or substantially longer if the facility co-fires with natural gas to reduce sulfur dioxide emissions.

EPA has suggested greater use of natural gas and/or low-sulfur distillate fuel oil for Unit NT1 in place of residual fuel oil. The substitution of No. 2 distillate fuel oil for No. 6 residual fuel oil would not be practical for this facility for two major reasons: the high cost of burner replacements needed to implement this option, and the plant's low utilization rate and capacity factor. Unit NT1 would produce relatively few kilowatt-hours of generation through which to recover capital costs.

Greater use of natural gas is a reasonable option when its price is competitive with that of residual fuel oil. Recent years have witnessed sudden and dramatic swings in the price of natural gas relative to fuel oil as supply/demand has shifted. While the future price and availability of natural gas remain difficult to discern, the market for natural gas is expected to expand amid global concerns about carbon emissions and a visible renaissance in gas exploration and development.

Unit NT1 has considerable operational flexibility with respect to fuel selection. The boiler can be fired with either natural gas or liquid fuel as the only fuel, or it can be co-fired with both fuel types simultaneously. However, because of physical limitations to the boiler's design, the unit can operate at no more than about 50 percent of maximum heat input when fueled solely by natural gas. There is already a natural incentive for PSNH to operate Unit NT1 with natural gas as much as possible whenever the price of this fuel is competitive with or less than the price of liquid fuels.

In recognition of the dual-fuel capability of Unit NT1, NHDES has developed for this facility a requirement by rule establishing a new sulfur dioxide emission limitation of 0.50 lb/MMBtu[§] applicable to any fuel type or mix. The recently adopted rule (Attachment GG)

[§] This limit is calculated using USEPA's published AP-42 emission factor for SO_2 of 150(S) lb SO_2/1000 gallons. Assuming 0.5% fuel sulfur content by weight and a heating value of 150,000 Btu/gallon for No. 6 fuel oil, the SO_2 emission rate would be $150 \times 0.5 = 0.075$ lb/gallon, and the SO_2 emission factor would be 0.075

will allow the facility the flexibility to burn natural gas and/or fuel oil in any feasible ratio, depending on market conditions.

New Hampshire's new rule will cause a substantial reduction in SO_2 emissions from Unit NT1 regardless of fuel type while rendering unnecessary any need to speculate on the direction of relative fuel supplies and prices. For the first regional haze progress report, due no later than December 17, 2012, NHDES will review fuel usage, fuel supplies, fuel prices, and plant utilization/capacity factors to determine whether the fuel sulfur limitation described above is still appropriate as BART control for Unit NT1. Should the review indicate a different BART control level, the facility's Title V operating permit will be amended as necessary before its expiration date of March 31, 2012, fifteen months prior to the effective date of proposed BART control measures. The use of low- or ultra-low-sulfur residual fuel oil will be reconsidered as part of this review. Looking beyond 2012, a possible further reduction in the sulfur content of fuel oil burned at this facility would be consistent with MANE-VU's plan to reduce sulfur levels to 0.25-0.5% for all residual fuel oils throughout the region by 2018 (refer to "Statement of the Mid-Atlantic/ Northeast Visibility Union (MANE-VU) Concerning a Course of Action within MANE-VU toward Assuring Reasonable Progress," June 20, 2007, included in Attachment E).

7. SUMMARY AND CONCLUSIONS

Table 7-1 summarizes Best Available Retrofit Technology for PSNH Newington Station Unit NT1 for the pollutants NO_X, PM, and SO_2. The summary includes existing controls that have been determined to fulfill BART requirements as well as new operating conditions consistent with BART requirements. A more stringent sulfur dioxide emission limitation, established by a rule change, will require the facility to reduce average fuel sulfur content through appropriate adjustments to its fuel mix.

Table 7-1. Summary of BART Determinations for Unit NT1

Pollutant	Current Emission Controls	BART Controls	BART Emission Limit
NO_X	Low-NOx burners, overfire air, and water injection	Low-NOx burners, overfire air, and water injection	0.35 lb/MMBtu (oil) and 0.25 lb/MMBtu (oil/gas), daily avg. (= RACT limit)
PM	ESP	ESP	0.22 lb/MMBtu total suspended particulate (TSP)
SO_2	2.0% sulfur content limit on residual fuel oil; 0.4% sulfur content limit on distillate fuel oil	SO_2 emission limitation of 0.50 lb/MMBtu, applicable to any fuel type or mix	0.50 lb/MMBtu, 30-day rolling average

lb/gallon ÷ 150,000 BTU/gallon × 10^6 = 0.5 lb/MMBtu.

NEW HAMPSHIRE BART ANALYSIS: Newington Station Unit NT1 (400 MW)

Pollutant	Emission Control Technology	Approx. Control Level	Uncontrolled Emissions ton/yr	Controlled Emissions ton/yr	Emission Reductions ton/yr	Estimated Cost of Emission Controls[6] Capital $	Capital $/kW	O&M $/yr	Total Annual $/yr	Average $/ton	Ref./ Note
NO_X	Combustion Controls (existing)	33%	1,407 [1]	943 [2]	464	—	—	—	—	—	
	LNB (typical)	40%	1,407 [1]	844	563	7,905,617	20	167,052	829,306	1,473	7
	LNB+OFA (typical)	50%	1,407 [1]	704	704	10,732,574	27	228,215	1,127,283	1,602	7
	SCR	85%	1,407 [1]	211	1,196	11,510,100	37	441,685	1,405,886	1,175	7
	SNCR	50%	1,407 [1]	704	704	3,298,475	12	451,026	727,339	1,034	7
PM	ESP (existing)	42%	338 [2]	196 [2]	142	—	—	—	—	—	
	Fabric Filters	99%	338 [2]	3	335	min. 23,426,952	59	2,733,144	4,695,620	14,033	8
						max. 78,089,840	195	3,904,492	10,446,078	31,218	
SO_2	2.0%-S oil (existing)	0% [3]	5,226 [2]	—	—	—	—	—	—	—	
	Switch to 1.0%-S oil	33% [4]	5,226 [2]	3,484	1,742	—	—	—	3,310,808	1,901	9
	Switch to 0.5%-S oil	67% [5]	5,226 [2]	1,742	3,484	—	—	—	6,621,615	1,901	10
	FGD	90%	5,226 [2]	523	4,703	422,000,000	1,055	unknown	unknown	unknown	11

1 Estimated.

2 2002 (baseline) emissions reported in NHDES data summary as derived from facility's annual emissions statement.

3 Actual average fuel sulfur content was ~1.2% in 2002. Over period 2002-09, average annual values ranged from 1.03 to 1.54% S with no significant trend.

4 Based on an assumed average fuel sulfur content of 0.8%.

5 Based on an assumed average fuel sulfur content of 0.4%.

6 All cost estimates adjusted to 2008$.

7 USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

8 NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

9 Stated costs represent premium for purchasing 1.0%-S oil at estimated price differential of 7.5¢/gal.

10 Stated costs represent premium for purchasing 0.5%-S oil at estimated price differential of 15¢/gal.

11 Based on $/kW estimated capital cost for comparable controls at Merrimack Station.

Newington Station Unit NT1: NO_X Controls

Plant type	oil- or natural-gas-fired boiler	
Capacity	400	MW
Maximum heat Input	4,350	MMBtu/hr
Capacity factor	20	%
Annual hours	8,760	hr/yr
Annual production	700,800,000	kWh/yr

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	3,085	6,606	6,300	4,187	1,282	1,374	548
Total Heat Input*	7,223,832	26,414,481	22,477,521	16,060,698	3,600,581	4,303,867	1,231,841
Capacity factor**	19.0%	69.3%	59.0%	42.1%	9.4%	11.3%	3.2%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004$

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
LNB	19.24	17.4	6,940,840	581,434	0.29	0.26	104,618	0.06	42,048	146,666	728,100	563	1,293
LNB+OFA	26.12	23.6	9,422,804	789,348	0.40	0.36	144,300	0.08	56,064	200,364	989,713	704	1,406
SCR	32.20	25.26	10,105,443	846,533	0.99	0.78	310,695	0.11	77,088	387,783	1,234,316	1,196	1,032
SNCR	10.80	7.24	2,895,939	242,593	0.17	0.11	45,584	0.50	350,400	395,984	638,577	704	907

Costs: 2008$ 2004$ → 2008$ 1.139 multiplier

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
LNB	21.91	19.76	7,905,617	662,254	0.33	0.30	119,160	0.07	47,893	167,052	829,306	563	1,473
LNB+OFA	29.75	26.83	10,732,574	899,068	0.46	0.41	164,358	0.09	63,857	228,215	1,127,283	704	1,602
SCR	36.68	28.78	11,510,100	964,201	1.13	0.88	353,882	0.13	87,803	441,685	1,405,886	1,196	1,175
SNCR	12.30	8.25	3,298,475	276,313	0.19	0.13	51,920	0.57	399,106	451,026	727,339	704	1,034

Cost Reference:

USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

Note: Cost estimates for LNB and LNB+OFA are based on referenced values for coal-fired plants; actual costs could be greater for oil- or gas-fired units.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Newington Station Unit NT1: PM Controls

Plant type	oil- or natural-gas-fired boiler	
Capacity	400	MW
Maximum heat Input	4,350	MMBtu/hr
Capacity factor	20	%
Annual hours	8,760	hr/yr
Annual production	700,800,000	kWh/yr
Flue gas flow rate	1,714,000	acfm

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	3,085	6,606	6,300	4,187	1,282	1,374	548
Total Heat Input*	7,223,832	26,414,481	22,477,521	16,060,698	3,600,581	4,303,867	1,231,841
Capacity factor**	19.0%	69.3%	59.0%	42.1%	9.4%	11.3%	3.2%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

2004$

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	15.00	25,710,000	2,153,727	0.25	0.45	1,199,800	3,353,527	142	23,616
	max.	40.00	68,560,000	5,743,271	0.65	0.60	2,142,500	7,885,771	142	55,534
Wet ESP	min.	15.00	25,710,000	2,153,727	0.15	0.25	685,600	2,839,327	142	19,995
	max.	40.00	68,560,000	5,743,271	0.50	0.50	1,714,000	7,457,271	142	52,516
Fabric Filter - Reverse Air	min.	17.00	29,138,000	2,440,890	0.35	0.70	1,799,700	4,240,590	335	12,673
	max.	40.00	68,560,000	5,743,271	0.75	0.80	2,656,700	8,399,971	335	25,103
Fabric Filter - Pulse Jet	min.	12.00	20,568,000	1,722,981	0.50	0.90	2,399,600	4,122,581	335	12,320
	max.	40.00	68,560,000	5,743,271	0.90	1.10	3,428,000	9,171,271	335	27,408

Cost Reference:

NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Costs: 2008$ 2004$ → 2008$ 1.139 multiplier

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	17.09	29,283,690	2,453,095	0.28	0.51	1,366,572	3,819,667	142	26,899
	max.	45.56	78,089,840	6,541,586	0.74	0.68	2,440,308	8,981,893	142	63,253
Wet ESP	min.	17.09	29,283,690	2,453,095	0.17	0.28	780,898	3,233,993	142	22,775
	max.	45.56	78,089,840	6,541,586	0.57	0.57	1,952,246	8,493,832	142	59,816
Fabric Filter - Reverse Air	min.	19.36	33,188,182	2,780,174	0.40	0.80	2,049,858	4,830,032	335	14,434
	max.	45.56	78,089,840	6,541,586	0.85	0.91	3,025,981	9,567,567	335	28,592
Fabric Filter - Pulse Jet	min.	13.67	23,426,952	1,962,476	0.57	1.03	2,733,144	4,695,620	335	14,033
	max.	45.56	78,089,840	6,541,586	1.03	1.25	3,904,492	10,446,078	335	31,218

Newington Station Unit NT1: SO_2 Controls

SO_2 Control Cost Calculations for Switching from #6 Fuel Oil @ 2.0% S to Lower-Sulfur Fuel Oils @ 1.0 or 0.5% S:

Fuel Type	Maximum (Nominal) Fuel Sulfur[1]	Actual Fuel Sulfur	Annual Fuel Usage[4]	Annual SO_2 Emissions	Switch to Lower-S Fuel	Annual SO_2 Emission Reductions[7]	Blended Fuel Price Differential[8]		SO_2 Control Cost
	%S by wt	%S by wt	gal/yr	ton/yr	%S by wt	ton/yr	¢/gal	$/yr	$/ton removed
#6 Residual Oil	2.0	1.2 [2]	44,144,100	5,226 [5]	—	—	—	—	—
#6 ULS Residual Oil	1.0	0.8 [3]	44,144,100	3,484 [6]	2.0 to 1.0%	1,742	7.5 [9]	$3,310,808	$1,901
#6 ULS Residual Oil	0.5	0.4 [3]	44,144,100	1,742 [6]	2.0 to 0.5%	3,484	15.0 [10]	$6,621,615	$1,901

1 Maximum allowable sulfur content of specified fuel.

2 Actual average sulfur content of fuel burned in 2002. In the period 2002-09, average annual values ranged from 1.03 to 1.54% S with no significant trend.

3 Assumed average sulfur content of specified fuel as assayed.

4 Actual fuel usage in 2002.

5 Actual 2002 emissions from CEM data.

6 Estimated emissions based on stated fuel usage and estimated average sulfur content of specified fuel.

7 Estimated emission reductions after switch to specified lower-sulfur fuel.

8 Estimated price difference between residual oil @ >1.0%S and residual oil @ ≤1%S, based on EIA fuel price data for all U.S. locations, 1983-2008.

9 Estimated price difference between fuel @ 1.2%S (2002 actual) and fuel @ 0.8%S actual (1.0% nominal).

10 Estimated price difference between fuel @ 1.2%S (2002 actual) and fuel @ 0.4%S actual (0.5% nominal).

SO_2 Control Cost Calculations for Flue Gas Desulfurization:

As an approximation, assume that FGD capital cost for Newington Station would be comparable to that for Merrimack Station on a $/kW basis.

Merrimack Station has an estimated capital cost of $1,055/kW, based on PSNH's 2008 estimate of $457 million for Unit MK1 (113 MW) and Unit MK2 (320 MW) combined.

Newington Station Unit NT1 has a generating capacity of 400 MW (=400,000 kW).

Estimated capital cost for FGD on Unit NT1 = 400,000 kW × $1,055/kW = $422,000,000.

Enclosure to Letter from PSNH to DES ARD, dated 12/4/09

NOTE: This sheet is a re-creation of PSNH's tables, with formulas inserted and additional calculations. All changes and additions to the original are shown in blue.

Assumptions Used to Calculate Incremental Cost Estimates*

(A) % sulfur	AP-42** SO2 lb/1000gal	AP-42*** SO2 lb/mmbtu	(B) SO2 lb/mmbtu	(C) Max Gross Heat Input mmbtu/hr	(D) SO2 lb/hr	(E) Reduction in SO2 lb/hr	Fuel Switch	increased cost/barrel**** low	increased cost/barrel**** high	increased cost/hr***** low	increased cost/hr***** high	$/ton SO2 Reduced low	$/ton SO2 Reduced high
2.0	314.0	2.041	2.288	4,350	9,952.8								
1.0	157.0	1.021	1.086	4,350	4,724.1	5,228.7	2% to 1%	$0.00	$4.00	$0.00	$2,692.86	$0	$1,030
0.7	109.9	0.714	0.748	4,350	3,253.8	1,470.3	1% to 0.7%	$1.00	$3.30	$673.21	$2,221.61	$414	$3,022
0.5	78.5	0.510	0.528	4,350	2,296.8	957.0	0.7% to 0.5%	$1.00	$2.20	$673.21	$1,481.07	$586	$3,095
0.3	47.1	0.306	0.313	4,350	1,361.6	935.3	0.5% to 0.3%	$3.00	$9.00	$2,019.64	$6,058.93	$2,967	$12,957
				4,350		5,228.7	2% to 1%	$0.00	$4.00	$0.00	$2,692.86	$0	$1,030
				4,350		6,699.0	2% to 0.7%	$2.00	$7.00	$1,346.43	$4,712.50	$402	$1,407
				4,350		7,656.0	2% to 0.5%	$3.00	$9.00	$2,019.64	$6,058.93	$528	$1,583
				4,350		8,591.3	2% to 0.3%	$4.00	$17.00	$2,692.86	$11,444.65	$627	$2,664

(A) % sulfur in the fuel oil
(B) SO2 lb/mmBtu emission rate, calculated based on %S and 153,846 btu/gal
(C) Maximum gross heat input rate from permit
(D) SO2 lb/hr emission rate, calculated = B * C
(E) Lbs of SO2 reduced per hour

** Source: USEPA, Compilation of Air Pollutant Emission Factors, AP-42, 5th Ed., Vol. 1. Section 1.3 - Fuel Oil Combustion (9/98)
*** Based on fuel heating value of 153,846 BTU/gal
**** From historical fuel cost table, approximate.
***** $/barrel ÷ 42 gal/barrel ÷ 0.153846 mmBTU/gal × mmBTU/hr = $/hr

	Actual Fuel Use #6 oil (barrels)	Historical Fuel Cost 2%S Oil ($/barrel)	1%S Oil ($/barrel)	0.7%S Oil ($/barrel)	0.5%S Oil ($/barrel)	0.3%S Oil ($/barrel)
2002	1,051,050	$21.20	$22.45	$23.26	$23.80	$25.25
2003	3,425,217	$24.95	$27.48	$29.26	$30.45	$32.63
2004	3,099,258	$25.25	$27.92	$30.04	$31.46	$34.53
2005	2,027,172	$37.00	$41.00	$44.00	$46.00	$50.10
2006	392,922	$45.50	$46.30	$48.46	$49.90	$54.12
2007	529,092	$53.70	$53.45	$56.54	$58.60	$62.86
2008	201,172	$75.25	$77.80	$81.10	$83.30	$92.16
2009	118,246	$49.90	$50.75	$51.98	$52.80	$55.83

Historical fuel cost data from Platts 2002-2009.
2009 data includes costs through 9/09 only.

*Estimates calculated illustrate cost increases based on assumptions relied upon.

chm
12/08/09

Supporting Documentation for BART Analyses

- PSNH Correspondence, December 4, 2009
- PSNH Correspondence, July 9, 2010
- PSNH Correspondence, August 16, 2010
- PSNH Correspondence, December 15, 2010

Public Service of New Hampshire

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The Northeast Utilities System

John M. MacDonald
Vice President - Generation

December 4, 2009

Mr. Robert R. Scott, Director
Air Resources Division
Dept. of Environmental Services
29 Hazen Drive, PO Box 95
Concord, NH 03302-0095

Public Service Company of New Hampshire
Request for Additional Information for Determination of
Best Available Retrofit Technology (BART) for the NH Regional Haze SIP

Dear Mr. Scott:

In response to your request, dated November 17, 2009, for additional information necessary to finalize the NH Department of Environmental Services, Air Resources Division's response to comments received from the U.S. Environmental Protection Agency and Federal Land Managers specific to DES' Best Available Retrofit Technology (BART) demonstration, Public Service Company of New Hampshire is submitting the enclosed information.

As you know, PSNH did not submit written comments specific to DES' BART determination presented at the public hearing on June 24, 2009, because PSNH was in agreement with that determination. PSNH is interested in understanding the basis of any significant changes to the BART determination and would raise objection to overly stringent BART limits that provide minimal environmental benefit yet increase costs and expose PSNH's generating facilities to permit exceedances during the course of normal operation of the units.

<u>Incremental Cost Estimates of SO2 Reductions at Newington Unit NT1</u>

In order to estimate incremental costs associated with varying grades of oil, PSNH evaluated historical fuel cost data provided by Platts for the period of 2002 through September 2009. Considering the inevitable inaccuracies in trying to predict future fuel prices, PSNH has calculated incremental cost estimates for illustrative purposes using the more recent historical fuel cost data (2005-2009).

As illustrated on the enclosed spreadsheet, PSNH has estimated the incremental costs, on a dollar per ton basis, of sulfur dioxide reductions at Newington Station, Unit NT1 to be as follows:

2% sulfur content by weight to 1% sulfur content by weight	\$1,030 per ton SO2 reduced
1% sulfur content by weight to 0.7% sulfur content by weight	\$2,949 per ton SO2 reduced
0.7% sulfur content by weight to 0.5% sulfur content by weight	\$7,203 per ton SO2 reduced
0.5% sulfur content by weight to 0.3% sulfur content by weight	\$12,957 per ton SO2 reduced

Assumptions Used to Produce Estimated Incremental Costs

The assumptions used to estimate incremental costs include historical fuel prices, maximum gross heat input rate of Unit NT1, SO2 emission rates in lb/mmBtu and lb/hr for each grade of fuel, and tons of SO2 reduced. Capacity factor of Unit NT1 is not necessary to calculate incremental costs on a dollar per ton reduced basis. The SO2 emission rates were derived from the sulfur content of the fuel, the heating value of the fuel, and the maximum gross heat input rate of Unit NT1. The tons of SO2 reduced were calculated using the delta in SO2 emissions between each fuel type on a lb/hr basis which was calculated using the SO2 lb/mmBtu emission rate for each grade of fuel and the maximum gross heat input rate of Unit NT1 as contained in Newington Station's Title V Operating Permit, TV-OP-054.

Additional Costs Associated with Fuel Storage Upgrades at Newington Station

At the present time, PSNH is hopeful that the current fuel storage and delivery system, including configuration and storage capacity, is adequate to handle varying grades of oil if required in the future. As a result, PSNH has not calculated additional costs associated with fuel storage upgrades.

MK Unit #2 Boiler and SCR Operations

The SCR has a temperature permissive that must be met in order for the SCR to be put in service or kept in service. During start-ups, shut-downs, and low load operation of Merrimack Unit #2, the temperature is lower than that permissive temperature and the SCR cannot be operated. As an example, Merrimack Unit 2 typically has 10 to 15 outages per year, in addition to approximately 8 low load operating periods per year. The timing of these conditions is not predictable and this estimate of occurrences provided reflects historical performance. Examples of low load situations include, but are not limited to: forced and planned outage start ups and shutdowns, loss of one of any equipment pair where both pieces of equipment are necessary for full load operation and the loss of one results in half load operation (such as Forced Draft Fans, Condensate Pumps), loss of the Main Boiler Feed Pump, loss of coal feeders, condenser waterbox cleaning, etc. Any condition which requires the unit be at loads below 230 mw net, causing the temperature to be below the SCR permissive will result in the SCR not able to be put in service. This load point may increase with the new, more efficient HP/IP turbine.

In addition to boiler operations and load conditions that affect SCR operation, malfunctions of the SCR system and/or associated equipment can also affect the operation of the SCR. Malfunctions of the SCR system and/or associated equipment can result in partial or complete reduction of SCR performance.

As part of normal service, the SCR catalyst becomes coated with flyash. Blinding of the catalyst with flyash can cause the SCR process control settings (often referred to as the setpoint) to have to be increased (less NOx conversion), as the reagent distribution becomes less uniform and as less catalyst is exposed to the flue gas. The SCR is cleaned as needed during outages, and sootblowers are used on line.

Reagent injection grid nozzles, being in the flue gas path, can become fouled with deposits. This can affect reagent distribution, compounding the effect of a fouled catalyst, for example. The reagent injection grid is cleaned, as needed, during outages. Also, reagent delivery disruption can occur and on-site storage is limited.

Also as a catalyst ages, it becomes less reactive. This causes a reduction in ability for NOx conversion to take place. This in itself does not typically result in higher NOx emission because the SCR has four layers of catalyst, staggered in age. However, it will compound the effect of a fouled catalyst, for example.

The uncontrolled NOx rate at reduced load and during start ups and shut-downs is typically 1.0 - 1.5 lb NOx/mmBTU. The uncontrolled NOx rate at normal full load is as high as 2.66 lb NOx/mmBTU, with an average of 2.4 lb NOx/mmBTU.

The SCR is unable to perform continually at its maximum capability due to these concerns. As a result, PSNH needs flexibility to operate the SCR based on current operating conditions.

In closing, PSNH would like to reiterate its opinion that changes to DES' BART determination that result in more stringent emissions limitations create concerns relative to increased costs and decreased operational flexibility.

Please contact Laurel L. Brown, Senior Environmental Analyst – Generation, at 634-2331 if you would like additional information or would like to meet to discuss the enclosed information further.

Sincerely,

John M. MacDonald
Vice President – Generation

Enclosure

Assumptions Used to Calculate Incremental Cost Estimates*

(A) % sulfur	(B) SO2 lb/mmbtu	(C) Max Gross Heat Input mmbtu/hr	(D) SO2 lb/hr	(E) Reduction in SO2 lb/hr
2.0	2.288	4,350	9,952.8	
1.0	1.086	4,350	4,724.1	5,228.7
0.7	0.748	4,350	3,253.8	1,470.3
0.5	0.528	4,350	2,296.8	957.0
0.3	0.313	4,350	1,361.6	935.3

	increased cost/barrel low	increased cost/barrel high	increased cost/hr low	increased cost/hr high	$/ton SO2 Reduced
2% to 1%	0	$ 4.00	0	$ 2,692.86	$ 1,030
1% to 0.7%	$ 1.00	$ 3.30	$ 673.21	$ 2,167.75	$ 2,949
0.7% to 0.5%	$ 1.00	$ 2.20	$ 673.21	$ 3,446.86	$ 7,203
0.5% to 0.3%	$ 3.00	$ 9.00	$ 2,019.64	$ 6,058.93	$ 12,957

(A) % sulfur in the fuel oil
(B) SO2 lb/mmBtu emission rate, calculated based on %S and 153,846 btu/gal
(C) Maximum gross heat input rate from permit
(D) SO2 lb/hr emission rate, calculated = B * C
(E) Lbs of SO2 reduced per hour

	Actual Fuel Use	Historical Fuel Cost				
	#6 oil (barrels)	2%S oil ($/barrel)	1%S oil ($/barrel)	0.7%S oil ($/barrel)	0.5%S oil ($/barrel)	0.3%S oil ($/barrel)
2002	1,051,050	$ 21.20	$ 22.45	$ 23.26	$ 23.80	$ 25.25
2003	3,425,217	$ 24.95	$ 27.48	$ 29.26	$ 30.45	$ 32.63
2004	3,099,258	$ 25.25	$ 27.92	$ 30.04	$ 31.46	$ 34.53
2005	2,027,172	$ 37.00	$ 41.00	$ 44.00	$ 46.00	$ 50.10
2006	392,922	$ 45.50	$ 46.30	$ 48.46	$ 49.90	$ 54.12
2007	529,092	$ 53.70	$ 53.45	$ 56.54	$ 58.60	$ 62.86
2008	201,172	$ 75.25	$ 77.80	$ 81.10	$ 83.30	$ 92.16
2009	118,246	$ 49.90	$ 50.75	$ 51.98	$ 52.80	$ 55.83

Historical fuel cost data from Platts 2002-2009
2009 data includes costs through 9/09 only.

* Estimates calculated illustrate cost increases based on assumptions relied upon.

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The Northeast Utilities System

CONFIDENTIAL

Released per Nov 3, 2010 Letter to PSNH

July 9, 2010

Rcvd via e-mail on July 16, 2010

Michele Roberge
Administrator, Permitting and Environmental Health Bureau
NH Department of Environmental Services, Air Resources Division
29 Hazen Drive
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JUL 16 2010

AIR RESOURCES DIVISION

CONFIDENTIAL BUSINESS INFORMATION

Public Service of New Hampshire
Best Available Retrofit Technology (BART)
Response to Request for Additional Information

Dear Ms. Roberge:

As requested, PSNH provides the following information to support the Merrimack Unit #2 (MK2) NOx limits and the Newington (NT1) fuel oil sulfur content for New Hampshire's Regional Haze SIP. We are providing this information as confidential business information since it contains various operating scenarios and financial costs which are competitively sensitive in nature and could be harmful if disclosed.

Merrimack Station Unit #2: Merrimack Station was the first investor owned utility in the nation to install an SCR to achieve NOx reductions. Given the operation of the SCR, it is PSNH's position that maintaining operational flexibility is a critical priority in order to ensure continued and cost-effective compliance while simultaneously achieving significant reductions in NOx emissions. The following information summarizes the primary drivers and the associated costs that would be incurred in ensuring attainment of NOx emissions rates lower than the current NOx emission limits set in the NH Regional Haze SIP

1. Operating Temperature of SCR

As previously provided, the SCR has a temperature permissive that must be met in order for the SCR to be put in service or kept in service. During start-ups, shut-downs, and low load operation of Merrimack Unit #2, the temperature is lower than that permissive temperature and the SCR cannot be operated. For example, Merrimack Unit 2 typically has 10 to 15 outages per year and approximately 8 low load operations per year. During these events, SCR operating temperatures are less than the permissive temperature rendering the SCR inoperable. The timing of these events is not predictable; the estimate of occurrences provided reflects historical performance.

Examples of low load situations include, but are not limited to, the following:

- Forced and planned outage start ups and shutdowns;

- Loss of one of any equipment pair. Both pieces are necessary for full load operation and the loss of one results in half load operation (such as forced draft fans, condensate pumps);
- Loss of the main boiler feed pump;
- Loss of coal feeders, condenser waterbox cleaning, etc.; and
- Any condition which results in the flue gas temperatures to be below the SCR permissive temperature will result in the SCR not able to be put in service.

2. Malfunction and Fouling of the SCR and/or Associated Equipment

In addition to boiler operations and load conditions that affect SCR operation, malfunctions of the SCR system and/or associated equipment can also affect the operation of the SCR. Malfunctions of the SCR system and/or associated equipment can result in partial or complete reduction of SCR performance.

Also as part of normal service, the SCR performance degrades over time. One reason this occurs is due to blinding of the catalyst with fly ash. This condition will cause the SCR process control settings to compensate by increasing SCR loading to maintain the set point. This is necessary because the reagent distribution becomes less uniform as less surface area of the catalyst is exposed to the flue gas. To manage this condition from developing to the point that a maintenance outage is necessary, the SCR is cleaned on-line utilizing soot blowers and cleaned during outages, as needed. Increased SCR loading will lead to more frequent maintenance outages. Reagent injection grid nozzles are directly exposed to the flue gas and become fouled over time. This can affect reagent distribution, compounding the effect of a fouled catalyst. The reagent injection grid is cleaned, as needed, during outages. Also as catalyst ages, it becomes less reactive. This causes a reduction in ability for NOx conversion to take place. This in itself does not typically result in higher NOx emissions because the SCR has four layers of catalyst, intentionally staggered in age. However, it will compound the effect of a fouled catalyst and can result in the SCR being unable to perform continually at its maximum capability. As a result, PSNH needs flexibility to operate the SCR based on current operating conditions. Currently the SCR averages greater than 86% efficiency. The uncontrolled NOx rate at normal full load is as high as 2.66 lb NOx/mmBTU, with an average of 2.4 lb NOx/mmBTU. The uncontrolled NOx rate at reduced load and during start ups and shut-downs is typically 1.0 - 1.5 lb NOx/mmBTU.

With these short-term challenging operational conditions, PSNH's greatest concern is ensuring consistent compliance. We have reviewed historical data and concluded that start-ups and shut downs can significantly impact both a calendar month and a rolling 30-day average emission rate by up to 0.04 lb NOx/mmBTU. If there is more than 1 outage during the averaging period, the impact to the average emission rate could be as high as 0.08 lb NOx/mmBTU. To allow for this potential operating occurrence, Merrimack Station would need to operate to maintain a much lower average NOx rate. Reviewing the historical monthly averages, this leaves little margin for typical operating fluctuations in NOx controls. For example, if a unit is off for a longer period of time, there are less valid operating days available to be included in average rate. This analysis is particularly interesting, because in this specific scenario, the total tons of emissions are less than full load operation for the same averaging period, but could have a high emission rate. An extreme example of this scenario was observed in August 2009 when the monthly average emission rate was 0.813 lb NOx/mmBTU and yet total emissions for that month were approximately 1 ton. This was primarily due the unit operating only a short amount of time in that month.

3. Potential Costs Associated with Proposed Reduction in NOx emission rate

Merrimack Station will need to consider a number of additional compliance efforts if not provided the necessary flexibility to deal with short-term events as described above and the operational restrictions of the SCR. Each has an additional cost as outlined below.

There will be increased maintenance costs to maintain peak NOx reduction capability. For example, air heater cleanings will be required more frequently because of increased loading of the SCR. This scenario results in additional maintenance costs and replacement power costs associated with the required outages.

Maintenance (Cleaning) Costs: $30,000 to $100,000 per cleaning

Replacement Power Costs: The table below uses an assumption of ~ $30/mwhr difference between the cost of Merrimack Station and the market cost. This number can vary greatly depending on energy market prices.

Duration of Cleaning/Outage	Replacement Power Cost per Outage	Number of outages per year	Total Cost per Year
Short (3 days)	$720,000	1 2 3 4	$720,000 $1,440,000 $2,160,000 $2,880,000
Mid (4.5 days)	$1,100,000	1 2 3	$1,100,000 $2,200,000 $3,300,000
Long (6 days)	$1,400,000	1 2	$1,400,000 $2,800,000

If air heater washings were routinely necessary to comply with a step change in the NOx rate, the cost per ton of NOx reduction would be extremely costly, as illustrated below. This cost can increase greatly if an air heater cleaning was completed during a high priced market.

Emission Rate Lb NOx/mm BTU	NOx tons emitted per year	Incremental tons per year	Incremental tons per day
0.37	5628.34		
0.34	5171.99	456.35	1.25

Duration of Cleaning/Outage	Replacement Power Cost per Outage	Incremental tons per year	Cost per Ton
Short (3 days)	$720,000	456.35	$1,578
Mid (4.5 days)	$1,100,000	456.35	$2,410
Long (6 days)	$1,400,000	456.35	$3,068

Examples of other compliance measures that would be necessary include accelerating the catalyst replacement in the SCR management plan. Currently, one layer of catalyst is exchanged every 2 years. To revise this plan by exchanging one layer every year would result in a project expense of approximately $2 million every other year. Increasing the frequency of catalyst replacement would result in approximately $12 million over the period 2013 thru 2025. This revised replacement plan would not likely result in additional total reduced tons of NOx for the year, but rather help manage the brief periodic increased emission rates associated with the events described above.

It should be reiterated that these compliance measures are focused solely on the shorter duration events that typically occur at lower loads with less heat input and for a discreet period of time-- and thus do not result in the emission of a significant amount NOx emissions. For example, the flexibility of partial load operation during high demand periods is important to the electrical reliability of the grid and can significantly protect customers from high energy costs during these peak events. It would not be in the public interest to require the unit to come off line since such action would be extremely costly to both reliability and to customers. A half day of no operation when energy prices are over $100mwh will be $250,000, $350,000 or greater; a cost that would yield a NOx reduction of only approximately 10 – 15 tons.

This discussion demonstrates that the implementation of a calendar month and rolling 30 day lb/mmbtu NOx emission rate can result in significant cost to our customers with little environmental benefit. To avoid permit exceedences due to a short-term NOx rate excursion, would require running the SCR harder, more frequent air heater cleaning, extended outages, and forced outages.

Replacement power cost associated with outages:

	Cost delta with the Market	Total cost of Outage for customers	Cost per Ton *
1 day	$30	$239,040	$15,936
	$40	$318,720	$21,248
	$50	$398,400	$26,560
2 days	$30	$478,080	$15,936
	$40	$637,440	$21,248
	$50	$796,800	$26,560

*assumes saving of 15 tons per day

As you are aware, Merrimack Station has aggressively reduced NOx emissions for the past 15 years. The total annual emissions reflect that laudable effort. Going forward, Merrimack Station anticipates continuing that effort, while maximizing customer value and providing reliable, affordable power, but to do that successfully, we do require operational flexibility. It is critical to understand that such operational flexibility will ensure consistent compliance with the monthly average emission rate while not significantly increasing total NOx emissions.

Newington Station- additional fuel oil information

In your June 15, 2010 email, you also requested information regarding Newington Station's current oil stocks, storage capacity, fuel usage rates, and operational considerations and costs associated with switching to lower sulfur fuels required by the NH Regional Haze SIP. That information is provided below.

Please describe the current oil stocks (type and quantity) and storage capabilities.

Newington Station has the capacity to store approximately 732,500 barrels (31 million gallons) of fuel oil in four separate above ground storage tanks (identified as NT-1, NT-2, SR-2, and SR-3). Currently, these four tanks contain approximately 485,000 barrels (20 million gallons) of No. 6 fuel oil with an average sulfur concentration of approximately 1%.

How many hours of operation would this supply at current usage rates? What are the rates that this estimate is based on?

Due to various economic conditions, including the rising cost of No. 6 fuel oil, lower natural gas prices and electric demand, Newington Station has burned only a limited volume of oil in the past couple years. Current conditions are not expected to change considerably in the short term, therefore, Newington does not anticipate consuming a significant volume of oil in the next couple of years.

It is difficult to assess how long it would take to deplete this fuel oil inventory since fuel oil usage is dependent on market conditions and the demand for electricity. Newington Station will choose the fuel or blend of fuel (oil, natural gas, or natural gas and oil) based on the desired electrical output and the cost of fuel. As you are aware, Newington Station will use the most cost effective fuel to maintain its electric costs for the customer.

In an effort to understand how this inventory relates to future operating conditions, PSNH has looked at different operating scenarios to estimate the length of time it may take to deplete this inventory. The scenarios include different operating loads, a fuel mix of 75% natural gas and 25% fuel oil, and an operating capacity factor of 5% (see table below). Although, PSNH can not reliably predict with any certainty how Newington Station will operate in the next couple years, for purposes of this evaluation, PSNH has assumed an average output level of 150 MW with a heat rate of 11,750 Btu/kWh, 75% natural gas/25% oil blend, and a capacity factor of 5%.

Based on current fuel oil inventory levels, and the scenario presented above, Newington Station would deplete its existing fuel supply in 16 years.

MW	Btu/kWh	Btu/gal Oil	Capacity Factor %	BBl/yr	75% gas/25% oil BBl/yr	Projected depletion of current inventory (yrs)
400	10,793	153,846	5	292,645	73,161	7
150	11,750	153,846	5	119,533	29,883	16
100	13,860	153,846	5	93,951	23,488	21
60	16,560	153,846	5	67,352	16,838	29

Note:
Assuming an average output level of 150 MW with a heat rate of 11,750 Btu/kWh, a 75%/25% gas/oil blend, and a capacity factor of 5%, the current inventory would be depleted in 16 years. This scenario is Newington Station's best estimate based on current operating history.

What are the specific operational considerations in switching to 0.3% S oil that do or do not make it feasible and costly?

PSNH understands that the Regional Haze SIP will require Newington Station to burn 0.5% or 0.3 % sulfur oil as part of its compliance strategy as early as 2013. In order to prepare for this requirement, Newington Station would need to have the available capacity to store the lower sulfur oil. Due to a variety of factors that affect the availability and cost of natural gas, PSNH believes it would be necessary to empty one of the larger bulk fuel oil storage tanks, at a minimum, to provide the storage capacity of the lower sulfur fuel. Our largest tanks (NT1 and NT-2) currently contain approximately 160,000 barrels each of fuel oil. Based on the likely operating scenario presented above, it will take more than 5 years to empty one of the larger tanks.

In this scenario, Newington would either need to operate and utilize the on-hand fuel or sell some of its current inventory if an acceptable process could be identified. It is difficult to estimate what the cost to PSNH would be if this were required, since the value of this oil in 3 years is unknown.

PSNH currently knows of no way other than consuming oil in the unit to dispose/deplete our current inventory. Although offloading oil from the tanks to a barge or ship is being considered, Newington's oil terminal was designed to accept deliveries of oil from fuel vessels and was not designed to load vessels from the oil tanks. Newington Station also does not have the capability for loading trucks from the oil tanks. Any risk to personnel safety or the environment would need to be fully eliminated to consider a transfer of oil to a vessel or truck. Therefore, at this point, it is assumed that Newington Station would be required to burn the oil in the unit at a potential incremental cost to NH customers. Consistent with the numbers above, to burn 160,000 barrels of oil to empty one of the larger tanks, the unit would have to operate an equivalent of 24 hours/day for approximately 10 days at 400 MWs. Also, as stated above, due to economic conditions, Newington Station has been reserved to protect customers from high priced market excursions. If we assume consumption of the inventory of oil is required, then it will be necessary for Newington to operate at rates higher than market rates. In this case, based on an incremental cost of $80 per MWH, the total cost to customers will be approximately $8 million. This is a significant cost to customers which has no associated environmental benefit.

Blending this higher sulfur fuel with lower sulfur fuel or natural gas over time is a more cost effective option and will not result is greater emissions as compared to a targeted depletion effort described in the above scenario. Although it is possible to consider the depletion of current fuel oil inventories by blending with natural gas, natural gas is not always available and could not be relied upon as a sole compliance option.

What are the estimated costs of making the switch; both capital and operating costs?

As presented in our earlier December 4, 2009 letter, the cost to PSNH in going from a 1% sulfur oil to a 0.5% sulfur oil could be as high as $42/bbl (based on fuel oil prices from 2005-2009). Similarly, the cost to PSNH in going from 1% sulfur oil to 0.3% sulfur oil could be as high as $51/bbl. Using the same operating scenario presented above, this equates to an additional cost to PSNH customers of $1.2 million/year for the use 0.5% sulfur fuel and $1.5 million/year for the use 0.3%.

PSNH would be happy to meet with you and your staff to discuss the information provided above. If you have questions or require additional information, please contact me at 634-2440 or Sheila Burke at 634-2512.

Sincerely,

Elizabeth H. Tillotson

Elizabeth H. Tillotson
Technical Business Manager -- Generation

cc:
Sheila Burke, Generation Staff
Tara Olson, Newington Station

Released Per Nov 3, 2010 Letter to PSNH

August 16, 2010

CONFIDENTIAL BUSINESS INFORMATION

Public Service of New Hampshire
Best Available Retrofit Technology (BART)
Response to Request for Additional Information

SUPPLEMENTAL INFORMATION to PSNH's July 16 Letter, Response to Request for Additional Information re: BART

As requested, PSNH provides the following information to support the Merrimack Unit #2 (MK2) NOx limits for New Hampshire's Regional Haze SIP. We are providing this information as confidential business information since it contains various operating scenarios and financial costs which are competitively sensitive in nature and could be harmful if disclosed.

Merrimack Station Unit #2: Merrimack Station was the first investor owned utility in the nation to install an SCR to achieve NOx reductions. Given the operation of the SCR, it is PSNH's position that maintaining operational flexibility is a critical priority in order to ensure continued and cost-effective compliance while simultaneously achieving significant reductions in NOx emissions. The following information summarizes the primary drivers behind the increased costs that would be incurred in ensuring attainment of NOx emissions rates lower than the current NOx emission limits set in the NH Regional Haze SIP.

1- Operational Impacts

Based on historical data MK2 typically has 10 to 15 outages per year and approximately 8 low load operations per year. During these events, SCR operating temperatures are reduced and in some instances below the SCR permissive temperature limit. The SCR temperature permissive must be met in order for the SCR to be put in service or kept in service. During start-ups, shut-downs, and partial load operation the temperature could be lower than the permissive temperature and the SCR cannot be operated. In most cases the timing of these events is not predictable.

Examples of low load situations include, but are not limited to, the following:

- Forced and planned outage start ups and shutdowns;
- Loss of one of any equipment pair. Both pieces are necessary for full load operation and the loss of one results in half load operation (such as forced draft fans, condensate pumps);
- Loss of the main boiler feed pump;
- Loss of coal feeders, condenser waterbox cleaning, etc.; and
- Any condition which results in the flue gas temperatures to be below the SCR permissive temperature will result in the SCR not able to be put in service.

A more stringent limit could result in the unnecessary shutdown of the unit rather than operating at partial load. An example of this scenario has occurred in the past when a critical pump failed which restricted full load operation. While the pump was repaired the unit remained operating but at a reduced capacity, the duration of this event was approximately 240 hours. PSNH's customers received significant benefit from this partial load operation. Replacement power costs associated with this type of event are shown in the Table 1.

Replacement Power Costs: The table below uses an assumption of $30/mwhr difference between the cost of MK2 and the market cost. This number can vary greatly depending on energy market prices.

Table 1a. Cost Associated with De-rate Flexibility at 0.37 lb/MMBtu Assumes 0.64 tons per hr				
Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	Avoided Replacement Power Cost	Cost per ton
240 hr	132 MW	200 MW	$1,440,000	$0
100 hr	132 MW	200 MW	$ 600,000	$0
50 hr	132 MW	200 MW	$ 300,000	$0

Table 1b. Cost Associated with limited De-rate Flexibility at 0.34 lb/MMBtu Assumes 0.59 ton per hr				
Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	**Un-avoided** Replacement Power Cost	Cost per ton
240 hr	132 MW	200 MW	$1,440,000	$10,169
100 hr	132 MW	200 MW	$ 600,000	$10,169
50 hr	132 MW	200 MW	$ 300,000	$10,169

The opportunity for partial load operation during high demand periods would be even more costly to both reliability and to customers. The example mentioned above resulted in a long duration of partial load operation but it is important to note that during periods of high energy prices a much shorter event could also have significant cost. For example, assuming a $100 per MWh market price, operating at 200MW partial load for a period of 12-hours would avoid $240,000 of replacement power cost. During this period a NOx reduction of approximately 7 tons would be realized which equates to $34,000 per ton NOx. Under some of these scenarios partial load operation would be eliminated to ensure consistent compliance with the proposed NOx limit reduction.

2 – Maintenance Impacts

PSNH's highest priority is ensuring compliance with all emission limits. PSNH has reviewed historical data and concluded that start-ups, shut downs partial load operating conditions and upsets can significantly impact a calendar month average emission rate. To account for these events PSNH operates NOx control equipment to maintain a NOx emission rate of approximately 0.25 lb/MMBtu calendar month average. In order to ensure compliance with the 15.4 ton/day limit or the equivalent 0.37 lb/MMBtu emission rate, PSNH targets a 0.15 lb/MMBtu difference between the average NOx emission rate and the specific limit. Further limitations would impact operation and increase incremental maintenance and capital cost.

In addition to boiler operation and load conditions that affect SCR operation, malfunctions of the SCR system and/or associated equipment can also affect the operation of the SCR. Malfunctions of the SCR system and/or associated equipment can result in partial or complete reduction of SCR performance.

Also, as part of normal service, the SCR performance degrades overtime. One reason this occurs is due to blinding of the catalyst with fly ash. This condition will cause the SCR process control settings to compensate by increasing SCR loading to maintain the set point. This is necessary because the reagent distribution becomes less uniform as less surface area of the catalyst is exposed to the flue gas. To manage this condition from developing to the point that a maintenance outage is necessary, the SCR is cleaned on-line utilizing soot blowers and cleaned during outages, as needed. Increased SCR loading could lead to more frequent maintenance outages. It is anticipated that a minimum of three additional SCR cleanings and air heater washes would be necessary to maintain compliance with the 0.34 lb/MMBtu proposed NOx limit. Cleanings are expected cost between $30,000 and $100,000 as noted below in item 3. Replacement power costs associated with the necessary maintenance outages are also described in item 3 below.

Additionally, reagent injection grid nozzles are directly exposed to the flue gas and become fouled over time. This can affect reagent distribution, compounding the effect of blinded catalyst. The reagent injection grid is cleaned, as needed, during outages. Also as catalyst ages, it becomes less reactive. This causes a reduction in ability for NOx conversion to take place. This in itself does not typically result in higher NOx emissions because the SCR has four layers of catalyst, intentionally staggered in age. However, increased loading of the SCR catalyst would be necessary to maintain compliance with the proposed reduction in NOx limit and accelerate catalyst degradation. For example, the SCR is unable to perform continually at its maximum capability. As a result, PSNH needs flexibility to operate the SCR based on current operating conditions. Currently the SCR averages greater than 86% efficiency.

Each catalyst layer has an anticipated functional life of 8 years and each layer is staggered in age to accommodate replacing one layer every 24 –months. Further NOx limitation would increase loading of the SCR and could result in accelerated catalyst degradation requiring premature replacement. This would result in a loss of investment. Even if minor catalyst degradation occurred reducing the catalyst useful life from 8 years to 7.5 years the replacement schedule would need to be adjusted. The change in replacement schedule is necessary because catalyst replacement projects must coincide with MK2's overhaul schedule which is on a 12-month cycle. PSNH would incur a loss of investment of approximately $143,000 annually due to the early replacement. It is also important to note that the revised replacement plan would result in minimal reductions to the total reduced tons of NOx for the year, but rather be put in place to avoid the periodic increased emission rates at the end of the catalyst life. As shown below in Table 2, PSNH believes minimal catalyst replacement and maintenance cost are associated with the 0.37 lb/MMBtu rates provided certain exceptions for start-up and shutdown and malfunctions.

Table 2. Incremental Maintenance and Capital Cost				
Emission Limit (lb/MMBtu)	Calendar Month Control Target (lb/MMBtu)	Annual Loss of Investment of SCR Catalyst	Increase Maintenance (Cost of Air heater and SCR Maintenance)	Predicted Incremental Cost
0.37	0.22	$0	$0	$0
0.34	0.19	$143,000	$195,000	$338,000

3 –Replacement Power Costs associated with the Proposed Reduction in NOx Emission Rate

Merrimack Station will need to consider a number of additional compliance efforts if not provided the necessary flexibility to deal with short-term events as described above and the operational restrictions of the SCR. Each has an additional cost as outlined below.

There will be increased maintenance costs to maintain peak NOx reduction capability. For example, air heater and SCR cleanings will be required more frequently because of increased loading of the SCR. This results in additional maintenance costs and replacement power costs associated with the required outages. It is anticipated that at least one additional 4.5 day (mid) maintenance outage would be necessary to maintain compliance with the 0.34 lb/MMBtu proposed limit. In addition to the maintenance outage additional cleaning will be completed as a proactive measure during forced outages resulting in delayed start-ups. Outage duration is from time offline until the unit is phased.

If air heater washing were completed to comply with a step change in the NOx rate as shown below, the cost per ton of NOx reduction would be extremely costly. Again this number can increase greatly if an air heater cleaning was completed during a high priced market.

Table 3. **Potential** Emission Summary (8760 hrs)		
Emission Rate Lb NOx/mm BTU	NOx tons emitted per year	Incremental reduction in **Potential** emissions tons per year
0.37	5628.34	0
0.34	5171.99	456

Maintenance (Cleaning) Costs: $30,000 to $100,000 per cleaning

Replacement Power Costs: The table below uses an assumption of $30/mwhr difference between the cost of MK2 and the market cost. This number can vary greatly depending on energy market prices.

Table 5. Impact of 0.34 lb/MMBtu Limit	
Duration of Cleaning/Outage	Replacement Power Cost per Outage
Short (3 days)	$720,000
Mid (4.5 days)	$1,100,000
Long (6 days)	$1,400,000

It should be reiterated that these compliance measures are focused solely on the shorter duration events that typically occur at lower loads with less heat input and for a discreet period of time thus do not result in the emission of a significant amount of NOx emissions. To meet the proposed rates of 0.34 lb NOx/MMBtu, under the conditions referenced above, PSNH may be forced to shutdown for air heater/SCR cleaning and also may be forced to shutdown rather than operate at partial load. Each of these aforementioned scenarios has significant cost as described above.

Also, with out exceptions for short term operational conditions additional incremental costs may be incurred when considering a calendar month averaging period. PSNH may be forced to delay start-up to maintain a 0.34 lb/MMBtu calendar month average. It is important to note that start-up shutdowns, and partial load operating scenarios may bias a lb/MMBtu rate but typical result in low tonnage emission total. To manage for this situation it may be necessary for PSNH to adjust the current operating strategy by delaying start-ups or to prevent a short operating periods during the calendar month. Table 6., below illustrates the potential cost with delaying an outage start-up.

Table 6. Replacement power cost associated with delayed start-up			
	Cost delta with the Market	Total cost of Outage for customers	Cost per Ton *
1 day	$30 $40 $50	$239,040 $318,720 $398,400	$15,936 $21,248 $26,560
2 days	$30 $40 $50	$478,080 $637,440 $796,800	$31,872 $42,496 $53,120

*assumes saving of 15 tons per day

4 - Summary of Analysis

Merrimack Station has had a program in place to reduce NOx emissions for the past 15 years. The reductions in total annual emissions reflect that laudable effort. Going forward, Merrimack Station anticipates continuing that effort, while maximizing customer value and providing reliable and affordable power. It is critical to understand adjusting the NOx rate will significantly increase the incremental costs of compliance without significantly decreasing total NOx emissions. This effort will have virtually no effect on MK2's actual emissions and is focused on limiting MK2's potential emission which results in eliminating operational flexibility and increasing operating costs. Table 7. below is a summary of the incremental costs that PSNH will incur when considering the 0.34 lb/MMBtu proposed NOx emission rate.

Table 7. Summary of Additional Predicted Annual Cost

Emission Limit (lb/MMBtu)	Calendar Month Control Target (lb/MMBtu)	Loss of Investment of SCR Catalyst per year	Un-avoidable Replacement Power cost (Partial Load) @ 240 hrs	Increase Maintenance (Cost of Air heater and SCR Maintenance) 3 per year	Replacement Power Cost For Maintenance Outage at $30 MWH	Delayed start-up to clean SCR and Air Heater 2days (One day each for two outages)	Incremental reduction in **Potential** tons per year	Predicted Incremental Cost Increase $/yr	Cost per ton
0.37	0.22	$0	$0	$0	$0	$0	0	$0	$0
0.34	0.19	$143,000	$1,440,000	$195,000	$1,100,000	$478,080	456	$3,356,080	$7,359

This analysis demonstrates that the implementation of a 0.34 lb/MMBtu or more stringent rate will result in significant cost to our customers with little environmental benefit. This is true because a lb/MMBtu rate could result in running the SCR harder, more frequent air heater cleaning, extended outages, and forced outages, and limit partial load operation.

PSNH would be happy to meet with you and your staff to discuss the information provided above. If you have questions or require additional information, please contact Lynn Tillotson at 634-2440 or Sheila Burke at 634-2512.

cc:
Elizabeth H. Tillotson, TBM, Generation Staff
Sheila Burke, Generation Staff
Tara Olson, Newington Station

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The Northeast Utilities System

December 15, 2010

Robert Scott
Director
NH Department of Environmental Services, Air Resources Division
29 Hazen Drive
PO Box 95
Concord, NH 03302-0095

Public Service of New Hampshire
Best Available Retrofit Technology (BART)
Response to Request for Additional Information

Dear Mr. Scott:

As requested in your December 8, 2010 letter, PSNH provides the following additional information to support the Merrimack Unit #2 (MK2) NOx limits for New Hampshire's Regional Haze SIP.

Merrimack Station Unit #2:

Merrimack Station was the first investor owned utility in the nation to install an SCR to achieve NOx reductions. Given the operation of the SCR, it is PSNH's position that maintaining operational flexibility is a critical priority in order to ensure continued and cost-effective compliance while simultaneously achieving significant reductions in NOx emissions. The following information summarizes the primary drivers behind the increased costs that would be incurred in ensuring attainment of NOx emissions rates lower than the current NOx emission limits set in the NH Regional Haze SIP.

This submittal will analyze the 0.30 lb/MMBtu emission rate averaged on a 30-day rolling basis as well as the impact of a more stringent limit. A 30-day rolling average is defined as the arithmetic average of all hourly rates for the current boiler operating day and the previous 29 boiler operating day[1]. This definition is consistent with November 22, 2010 comments provided by EPA pertaining to the draft rule.

[1] *Boiler operating day* for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. (40 CFR 60 Subpart Da)

The summary of the analysis is provided in the following table, all supporting calculations and basis for this determination are detailed in the items below.

Summary of Analysis			
Emission Limit (lb/MMBtu)	Incremental reduction in **Potential** tons per year[2]	Predicted Incremental Cost Increase $/yr	Cost per ton
0.37	0	$0	$0
0.30	1,065	$880,000	$826
0.25 – 0.30	380	$2,888,000	$7,600

1- Operational Impacts

Based on historical data MK2 typically has 10 to 15 outages per year and approximately 8 low load operations per year. During these events, SCR operating temperatures are reduced and in some instances below the SCR permissive temperature limit. The SCR temperature permissive must be met in order for the SCR to be put in service or kept in service. During start-ups, shut-downs, and partial load operation the temperature could be lower than the permissive temperature and the SCR cannot be operated.

Examples of low load situations include, but are not limited to, the following:

- Forced and planned outage start ups and shutdowns;
- Loss of one of any equipment pair. Both pieces are necessary for full load operation and the loss of one results in half load operation (such as forced draft fans, condensate pumps);
- Loss of the main boiler feed pump;
- Loss of coal feeders, condenser waterbox cleaning, etc.; and
- Any condition which results in the flue gas temperatures to be below the SCR permissive temperature will result in the SCR not able to be put in service.

The ability to manage these events is beneficial to our customers. Adequate flexibility allows the high cost of replacement power to be minimized. Limiting operational flexibility could result in the unnecessary shutdown of the unit rather than operating at partial load. Tables 1a. and 1b. below demonstrate the replacement power cost associated with a 0.30 lb/MMBtu, 30-day rolling average emission rate. The opportunity for partial load operation during high demand periods would be even more valuable to both reliability and to customers.

[2] Incremental reduction of Potential emissions is the calculated mean of the 0.25-0.30 range.

Replacement Power Costs: The table below uses an assumption of \$30/mwhr difference between the cost of MK2 and the market cost.

Table 1a. Cost Associated with De-rate Flexibility at 0.37 lb/MMBtu Assumes 0.64 tons per hr			
Avoided Cost			
Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	Avoided Replacement Power Cost
240 hr	132 MW	200 MW	\$1,440,000
100 hr	132 MW	200 MW	\$600,000
50 hr	132 MW	200 MW	\$300,000

Table 1b. Cost Associated with limited De-rate Flexibility at 0.30 lb/MMBtu Assumes 0.51 ton per hr			
Un-Avoided Cost			
Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	Un-avoided Replacement Power Cost
240 hr	132 MW	200 MW	\$1,440,000
Avoided Cost			
Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	Avoided Replacement Power Cost
100 hr	132MW	200 MW	\$600,000
50 hr	132MW	200 MW	\$300,000

The table is based on a steady state NOx emission rate of 0.22 lb/MMBtu and a NOx emission rate of 0.8 lb/MMBtu during partial load operation. The maximum number of days MK2 can operate in a partial load is 4.2 days (100 hrs) when considering a 0.30 lb/MMBtu 30-day rolling emission limit.

It should be noted previous submittals did not consider the rolling averaging method, because the existing Data Acquisition and Handling System (DAHS) is not configured for this averaging period. Based on EPA comments of the proposed Env-A 2300 Rule, PSNH has consulted the software vendor which supplies the DAHS and is reviewing the best available option to manage this averaging period. Current method of achieving this is through a new "Smart Reporting" software trial program. PSNH is confident in working with the vendor that the rolling average period will be achievable. Preliminary information suggests that implementing the new software has an estimated cost of \$10,000 and an annual recurring cost of \$2,000.

2 – Maintenance Impacts

Calendar Month Analysis (Previously Submitted):

PSNH's highest priority is ensuring compliance with all emission limits. PSNH has reviewed historical data and concluded that start-ups, shut downs partial load operating conditions and upsets can significantly impact average emission rates. PSNH's current method of operation to account for these events is to operate NOx control equipment to maintain an emission rate of approximately 0.25 lb/MMBtu calendar month average to ensure compliance with the 15.4 ton/day limit or the equivalent 0.37 lb/MMBtu emission rate. This method of operation results in approximately a 0.15 lb/MMBtu difference between the average NOx emission rate and the limit, this allows for operational flexibility as described above (i.e. start-up, shutdown, partial load operation etc). Further limitations based on a calendar month would impact operation and increase incremental maintenance and capital cost. For complete breakdown of the costs represented in Table 2a. and a calendar month analysis reference PSNH's August 16, 2010, submittal.

Table 2a. Incremental Maintenance and Capital Cost				
Emission Limit (lb/MMBtu)	**Calendar** Month Control Target (lb/MMBtu)	Annual Loss of Investment of SCR Catalyst	Increase Maintenance (Cost of Air heater and SCR Maintenance)	Predicted Incremental Cost
0.37	0.22	$0	$0	$0
0.34	0.19	$143,000	$195,000	$338,000

30-Day Rolling Average analysis:

In addition to the above analysis and based on EPA comments to the draft rule and DES's request for additional information, PSNH further analyzed the impact of changing its current method which is based on a calendar month average and reviewed a 30-day rolling emission limit, as well as the incremental cost associated with this limit. PSNH agrees with EPA that the 30-day rolling average method addresses flexibility for start-up, shutdown, emergency and malfunction. However, additional flexibility is necessary to maintain short term partial load capability.

PSNH has determined that a 0.30 lb/MMBtu emission rate on a 30-day rolling average will accommodate reasonably anticipated operating scenarios while achieving approximately 20% reduction in potential emissions. The maintenance costs that will be incurred by complying with this limit is estimated to be $30,000 per year, and can be attributed to additional cleaning and inspection of the SCR and air heater. PSNH also analyzed more stringent limits and determined costs similar to those represented in Table 2a above would be incurred. The increase cost associated with a more stringent limit can be attributed to the cascading effect of increased loading of the SCR.

Increased loading of the SCR results in the following conditions each more impactful as loading increases. More detail associated with these conditions can be found in the August 16, 2010, PSNH submittal.

1) Blinding of Catalyst;
2) More Frequent Maintenance Outages;
3) Fouled reagent distribution nozzles;
4) Accelerated catalyst derogation; and
5) Loss of Investment of catalyst.

Table 2b Incremental Maintenance and Capital Cost based on 30-day Rolling Average			
Emission Limit (lb/MMBtu)	Annual Loss of Investment of SCR Catalyst	Increase Maintenance (Cost of Air heater and SCR Maintenance)	Predicted Incremental Cost
0.37	$0	$0	$0
0.30	$0	$30,000	$30,000
0.25-0.30	$143,000	$195,000	$338,000

As noted in condition 2 above there will likely be additional maintenance outages to ensure optimum SCR performance. Replacement power costs that customers would incur from an additional maintenance outage are described in Item 3.

3 – Replacement Power Costs associated with more stringent limit than 0.30 lb/MMBtu NOx Emission Rate

Merrimack Station will need to consider a number of additional compliance efforts if not provided the necessary flexibility to deal with events as described above.

Increased maintenance costs to maintain peak NOx reduction capability could be signifcant. For example, air heater and SCR cleanings will be required more frequently because of increased loading of the SCR. This results in additional maintenance costs and replacement power costs associated with the required outages. In addition to the maintenance outages additional cleaning will be completed as a proactive measure during forced outages resulting in delayed start-ups. Outage duration is from time offline until the unit is phased.

If air heater washing were completed to comply with a step change in the NOx rate as shown below, the cost per ton of NOx reduction would be extremely costly. Again this number can increase greatly if an air heater cleaning was completed during a high priced market.

Table 3. Impact of more stringent Limit	
Duration of Cleaning/Outage	Replacement Power Cost per Outage
Short (3 days)	$720,000
Mid (4.5 days)	$1,100,000
Long (6 days)	$1,400,000

Replacement Power Costs: The table uses an assumption of $30/mwhr difference between the cost of MK2 and the market cost. This number can vary greatly depending on energy market prices.

It should be reiterated to meet more stringent emission rate than 0.30 lb NOx/MMBtu, under the conditions referenced above, PSNH may be forced to shutdown for air heater/SCR cleaning and also may be forced to shutdown rather than operate at partial load. Each of these aforementioned scenarios has significant cost as described above in Table 5.

4 - Summary of Analysis

Merrimack Station has aggressively reduced NOx emissions for the past 15 years. The total annual emissions reflect that laudable effort. Going forward, Merrimack Station anticipates continuing that effort, while maximizing customer value and providing reliable and affordable power. Table 4. below is a detailed summary of the incremental costs that PSNH will incur when considering the 0.30 lb/MMBtu proposed NOx emission rate and a more stringent limit.

Table 4. Summary of Additional Predicted Annual Cost[3]

Emission Limit (lb/MMBtu)	**Un-avoidable** Replacement Power cost (Partial Load) @ 240 hrs	New DAHS Implementation	Increase Maintenance (Cost of Air heater and SCR Maintenance 3 per year	Loss of investment of the SCR Catlyst	Replacement Power Cost For Maintenance Outage at $30 MWH	Delayed start-up to clean SCR and Air Heater (Two days)	Incremental reduction in **Potential** tons per year	Predicted Incremental Cost Increase $/yr	Cost per ton
0.37	$0	$0	$0	$0	$0	$0	0	$0	$0
0.30	$840,000	$10,000	$30,000	$0	$0	$0	1,065	$880,000	$826
0.25-0.30	$1,440,000	$10,000	$165,000	$143,000	$1,100,000	$0	380	$2,888,000	$7,600

[3] Values represented in Table 4 are net values.

PSNH understand the cost per ton of complying with the 0.30 lb/MMBtu calculated on a 30-day rolling average is under the BART threshold and is willing to accept this limit, which results in approximately 20% reduction of MK2's potential NOx emissions. This analysis demonstrates that the implementation of a more stringent limit than 0.30 lb/MMBtu will result in significant cost to our customers with little environmental benefit. With running the SCR harder, more frequent air heater cleaning, extended outages, and forced outages, and limit partial load operation.

If you have questions or require additional information, please contact me at 634-2440 or Sheila Burke at 634-2512.

Sincerely,

Elizabeth H. Tillotson

Elizabeth H. Tillotson
Technical Business Manager – Generation

cc:
Sheila Burke, Generation Staff
David Cribbie, Generation Staff

The State of New Hampshire
DEPARTMENT OF ENVIRONMENTAL SERVICES

Thomas S. Burack, Commissioner

November 29, 2011

Mr. Curt Spalding
Regional Administrator
USEPA New England, Region I
5 Post Office Square, Suite 100
Boston, MA 02109-3912

Re: Revision to New Hampshire's State Implementation Plan to Meet the Requirements of the Clean Air Act, Section 169A, Protection of Visibility (Regional Haze)

Dear Administrator Spalding:

On August 26, 2011, the New Hampshire Department of Environmental Services (NHDES) submitted amendments to the State Implementation Plan (SIP) revision pertaining to protection of visibility and regional haze. It has come to our attention that EPA may not have received the updated BART analyses (Attachment X), which were intended to accompany that submittal. Hence, as Governor John Lynch's designee, I am submitting herewith the amended BART analyses for PSNH Merrimack Station MK2 and PSNH Newington Station Unit NT1 as components of the subject SIP revision.

The submitted changes are minor in scope and limited to Section 5, "Degree of Visibility Improvement Anticipated from BART," for each of the BART analyses. The revised text and tables are now consistent with Section 9 of the main regional haze SIP revision document submitted last August.

If you have any questions regarding this submittal, please contact Jeff Underhill at (603) 271-1102.

Sincerely,

Robert R. Scott
Director
Air Resources Division

rrs/blh
enclosure: Amended BART Analyses (Attachment X), NH Regional Haze SIP Revision

cc: Anne Arnold, USEPA Region I
Anne McWilliams, USEPA Region I
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