Appendix M

The Nature of the Fine Particle and Regional Haze Air Quality Problems in the MANE-VU Region: A Conceptual Description

Prepared for the Ozone Transport Commission
Prepared by NESCAUM
Boston, MA
Final
November 2, 2006

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Executive Summary

Scientific evidence has established a solid link between cardiac and respiratory health risks and transient exposure to ambient fine particle pollution. The same fine particles that are capable of penetrating deep into the lungs are also in the size range that is most efficient at absorbing and scattering visible light, thus impairing visibility. The emission sources, atmospheric chemistry, and meteorological phenomena that influence ambient concentrations of fine particle pollution can act on scales that range from hundreds to thousands of kilometers. Fine particles are not exclusively a secondary pollutant; primary fine particle pollution from local sources can have a significant effect on ambient concentrations in some locations. Fine particles are also not exclusively a summertime pollutant. There are important differences between the meteorological and chemical dynamics that are responsible for high fine particle levels during summer and winter.

In 1997, the U.S. Environmental Protection Agency (USEPA) issued a national ambient air quality standard (NAAQS) for fine particles with an aerodynamic diameter of 2.5 micrometers or less. In 1999, the USEPA followed up with the Regional Haze Rule that enforces a national visibility goal laid out in the Clean Air Act. This will ultimately restore natural visibility to 156 national parks and wilderness areas across the country (called "Class I" areas). To address these Clean Air Act requirements, states will have to develop State Implementation Plans (SIPs) detailing their approaches for reducing fine particle pollution to meet the health-based fine particle NAAQS. They also must develop plans that address the degradation of visibility that exists in various parts of the Northeast (referred to as the Mid-Atlantic/Northeast Visibility Union (MANE-VU) region). As part of this process, the USEPA urges states to include in their SIPs a conceptual description of the pollution problem in their nonattainment and Class I areas. This document provides the conceptual description of the fine particulate and regional haze problems in the MANE-VU states consistent with the USEPA's guidance.

Scientific studies of the regional fine particle problem have uncovered a rich complexity in the interaction of meteorology and topography with fine particle formation and transport. Large scale high pressure systems covering hundreds of thousands of square miles are the source of classic severe fine particle episodes in the eastern United States, particularly in summer. These large, synoptic scale systems create particularly favorable conditions for the oxidation of sulfur dioxide (SO_2) emissions to various forms of sulfate which, in turn, serves to form – or is incorporated into – fine particles that are subsequently transported over large distances. These synoptic scale systems move from west to east across the United States, bringing air pollution emitted by large coal-fired power plants and other sources located outside MANE-VU into the region. This then adds to the pollution burden within MANE-VU on days when MANE-VU's own air pollution sources are themselves contributing to poor air quality. At times, the high pressure systems may stall over the East for days, creating particularly intense fine particle episodes.

In the winter, temperature inversions occur that are effective at concentrating local primary particle emissions at the surface overnight and during early morning hours. This pollution can then be mixed into regionally transported particle pollution (aloft) later in the morning when convection is restored. Additionally, the lower temperature in the winter can shift the chemical equilibrium in the atmosphere slightly toward the production of nitrate particle pollution relative to sulfate formation. As a result, nitrate can become a significant fraction of measured fine particle mass in parts of the eastern U.S. during winter months.

Primary and secondary emissions of carbon-containing compounds (e.g., diesel exhaust, biogenic organic carbon emissions, and anthropogenic volatile organic compound emissions) all contribute to a significant presence of carbonaceous aerosol across the MANE-VU region, which can vary from urban to rural locations and on a seasonal basis. In addition, short range pollution transport exists, with primary and precursor particle pollutants pushed by land, sea, mountain, and valley breezes that can selectively affect relatively local areas. With the knowledge of the different emission sources, transport scales, and seasonal meteorology in various locations adjacent to and within MANE-VU, a conceptual picture of fine particle pollution and its impacts emerges.

The conceptual description that explains elevated regional $PM_{2.5}$ peak concentrations in the summer differs significantly from that which explains the largely urban peaks observed during winter. On average, summertime concentrations of sulfate in the northeastern United States are more than twice that of the next most important fine particle constituent, organic carbon (OC), and more than four times the combined concentration of nitrate and black carbon (BC) constituents. Episodes of high summertime sulfate concentrations are consistent with stagnant meteorological flow conditions upwind of the MANE-VU region and the accumulation of airborne sulfate (via atmospheric oxidation of SO_2) followed by long-range transport of sulfur emissions from industrialized areas within and outside the region.

National assessments have indicated that in the winter, sulfate levels in urban areas are higher than background sulfate levels across the eastern U.S., indicating that the local urban contribution to wintertime sulfate levels is significant relative to the regional sulfate contribution from long-range transport. A network analysis for the winter of 2002 suggests that the local enhancement of sulfate in urban areas of the MANE-VU region ranges from 25 to 40% and that the long-range transport component of $PM_{2.5}$ sulfate is still the dominant contributor in most eastern cities.

In the winter, urban OC and sulfate each account for about a third of the overall $PM_{2.5}$ mass concentration observed in Philadelphia and New York City. Nitrate also makes a significant contribution to urban $PM_{2.5}$ levels observed in the northeastern United States during the winter months. Wintertime concentrations of OC and nitrate in urban areas can be twice the average regional concentrations of these pollutants, indicating the importance of local source contributions. This is likely because winter conditions are more conducive to the formation of local inversion layers which prevent vertical mixing. Under these conditions, emissions from tailpipe, industrial and other local sources become concentrated near the Earth’s surface, adding to background pollution levels associated with regionally transported emissions.

From this conceptual description of fine particle pollution formation and transport into and within MANE-VU, air quality planners need to develop an understanding of what it will take to clean the air in the MANE-VU region. Every air pollution episode is unique in its specific details. The relative influences of the transport pathways and local emissions vary by hour, day, and season. The smaller scale weather patterns that affect pollution accumulation and its transport underscore the importance of local (in-state) controls for SO_2, nitrogen oxides (NO_X) and volatile organic compound (VOC) emissions. Larger synoptic scale weather patterns, and pollution patterns associated with them, support the need for SO_2 and NO_X controls across the broader eastern United States. Studies and characterizations of nocturnal low level jets also support the need for local and regional controls on SO_2 and NO_X sources as locally generated and transported pollution can both be entrained in low level jets formed during nighttime hours. The presence of land, sea, mountain, and valley breezes indicate that there are unique aspects of pollution accumulation and transport that are area-specific and will warrant policy responses at the local and regional levels beyond a one-size-fits-all approach.

The mix of emission controls is also important. Regional fine particle formation is primarily due to SO_2, but NO_X is also important because of its influence on the chemical equilibrium between sulfate and nitrate pollution during winter. While the effect of reductions in anthropogenic VOCs is less well characterized at this time, secondary organic aerosol (SOA) is a major component of fine particles in the region and reductions in anthropogenic sources of OC may have a significant effect on fine particle levels in urban nonattainment areas. Therefore, a combination of localized NO_X and VOC reductions in urban centers with additional SO_2 and NO_X reductions from across a larger region will help to reduce fine particles and precursor pollutants in nonattainment areas as well improve visibility across the entire MANE-VU region.

1. INTRODUCTION

1.1. Background

Fine particle pollution is a persistent public health problem in the Mid-Atlantic/Northeast Visibility Union (MANE-VU) region. Because of its physical structure, fine particulate matter ($PM_{2.5}$) can bypass conductive airways and deliver exogenous materials, such as reactive organic chemicals that adsorb onto the particle core, into the deep lung.[a] Studies of particulate matter (PM) in urban areas have found associations of short- (daily) and long-term (annual and multiyear) exposure to airborne PM as well as $PM_{2.5}$ with cardiopulmonary health outcomes. These effects include increased symptoms, hospital admissions and emergency room visits, and premature death (Pope *et al.* 2004).

In addition to health implications, visibility impairment in the eastern United States is largely due to the presence of light-absorbing and light-scattering fine particles in the atmosphere. The United States Environmental Protection Agency (USEPA) has identified visibility impairment as the best understood of all environmental effects of air pollution (Watson, 2002). A long-established physical and chemical theory relates the interaction of particles and gases in the atmosphere with the transmission of visual information along a sight path from object to observer.

The Clean Air Act requires states that have areas designated “nonattainment” of the fine particle national ambient air quality standard (NAAQS) to submit State Implementation Plans (SIPs) demonstrating how they plan to attain the fine particle NAAQS. [b] The Clean Air Act also contains provisions for the restoration and maintenance of visibility in 156 federal Class I areas.[c] SIPs for dealing with visibility impairment (or regional haze) must include a long-term emissions management strategy aimed at reducing fine particle pollution in these rural areas.

As part of the SIP process for both of these air quality issues, the USEPA urges states to include a conceptual description of the pollution problem. The USEPA has provided guidance on developing a conceptual description, which is contained in Chapter 11 of the document “Guidance on the Use of Models and Other Analyses for

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[a] $PM_{2.5}$ or “fine particles” refer to those particles with a diameter ≤ 2.5 micrometers (μm).

[b] The 1997 $PM_{2.5}$ NAAQS includes a requirement that the three-year average of yearly annual average $PM_{2.5}$ design values must be below 15 $\mu g/m^3$ and a requirement that the three-year average of the 98th percentile 24-hour average concentration must be below 65 $\mu g/m^3$. In October 2006, the USEPA acted to change the daily standard (98th percentile value based on valid 24-hour average concentrations measured at a site) from 65 to 35 $\mu g/m^3$.

[c] The Class I designation applies to national parks exceeding 6,000 acres, wilderness areas and national memorial parks exceeding 5,000 acres, and all international parks that were in existence prior to 1977. In the MANE-VU area, this includes: Acadia National Park, Maine; Brigantine Wilderness (within the Edwin B. Forsythe National Wildlife Refuge), New Jersey; Great Gulf Wilderness, New Hampshire; Lye Brook Wilderness, Vermont; Moosehorn Wilderness (within the Moosehorn National Wildlife Refuge), Maine; Presidential Range – Dry River Wilderness, New Hampshire; and Roosevelt Campobello International Park, New Brunswick.

Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze" (EPA-Draft 3.2, September 2006) (Appendix A of this report reproduces Chapter 11 of the USEPA guidance document). This report provides the MANE-VU states with the basis for their conceptual descriptions, consistent with the USEPA's guidance. In the guidance, the USEPA recommends addressing 13 questions related to $PM_{2.5}$ and eight questions related to visibility to help define the problem in a nonattainment or Class I area. This report addresses these questions, as well as provides some in-depth data and analyses that can assist states in developing conceptual descriptions tailored to their specific areas.

1.2. PM Formation

Fine particles directly emitted into the atmosphere are called "primary" fine particles, and they come from both natural and human sources. These fine particles commonly include unburned carbon particles directly emitted from high-energy processes such as combustion, and particles emitted as combustion-related vapors that condense within seconds of being exhausted to ambient air. Combustion sources include motor vehicles, power generation facilities, industrial facilities, residential wood burning, agricultural burning, and forest fires.

Fine particles are also comprised of "secondary" fine particles, which are formed from precursor gases reacting in the atmosphere or through the addition of PM to pre-existing particles. Although direct nucleation from the gas phase is a contributing factor, most secondary material accumulates on pre-existing particles in the 0.1 to 1.0 micrometer (µm) range and typically account for a significant fraction of the fine PM mass. Examples of secondary particle formation include the conversion of sulfur dioxide (SO_2) to sulfuric acid (H_2SO_4) droplets that further react with ammonia (NH_3) to form various sulfate particles (e.g., ammonium sulfate $(NH_4)_2SO_4$, ammonium bisulfate (NH_4HSO_4), and letovicite ($(NH_4)_3H(SO_4)_2$). The dominant source of SO_2 emissions in the eastern U.S. is fossil fuel combustion, primarily at coal-fired power plants and industrial boilers. Similarly, secondary $PM_{2.5}$ is created by the conversion of nitrogen dioxide (NO_2) to nitric acid (HNO_3) which reacts further with ammonia to form ammonium nitrate (NH_4NO_3) particles. Nitrate particles are formed from the NO_X emitted by power plants, automobiles, industrial boilers, and other combustion sources. Nitrate production in the northeastern U.S. is ammonia-limited and controlled by the availability of sulfate and temperature, especially along the East Coast.[d] While human sources account for most nitrate precursors in the atmosphere, there are some natural sources, including lightning, biological and abiological processes in soils, and stratospheric intrusion. Large sources of ammonia arise from major livestock production and fertilizer application throughout the Midwest, Gulf Coast, mid-Atlantic, and southeastern United States, in addition to the sources of ammonia associated with human activities.

The carbon fraction of fine PM may refer to black carbon (BC) and primary organic and/or secondary organic carbon (OC). Most black carbon is primary, which is

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[d] Ammonia reacts preferentially with sulfuric acid, and if sufficient excess ammonia is available, it can then combine with nitric acid to form particulate nitrate.

also sometimes referred to as elemental carbon (EC) or soot. Black carbon is the light-absorbing carbonaceous material in atmospheric particles caused by the combustion of diesel, wood, and other fuels. Organic carbon includes both primary emissions and secondary organic PM in the atmosphere. Secondary organic particles are formed by reactions involving volatile organic compounds (VOCs), which yield compounds with low saturation vapor pressures that nucleate or condense on existing particles at ambient temperature. Organic carbon in both the gas and solid phase is emitted by automobiles, trucks, and industrial processes, as well as by many types of vegetation. The relative amounts of organic carbon from different sources remain highly uncertain, and data are needed to be able to assess the relative contribution of primary versus secondary and anthropogenic versus biogenic production.

1.3. PM Impacts on Visibility

Under natural atmospheric conditions, the view in the eastern United States would extend about 60 to 80 miles (100 to 130 kilometers) (Malm, 2000). Unfortunately, views of such clarity have become a rare occurrence in the East. As a result of man-made pollution, the average visual range in the eastern half of the country has diminished to about 15-30 miles, approximately one-third the visual range that would be observed under unpolluted natural conditions.

In general, the ability to see distant features in a scenic vista is determined less by the amount of light reaching the observer than by the contrast between those features and their surroundings. For example, the illumination of a light bulb in a greenhouse is barely discernible on a sunny day but would be highly visible at night. Similarly, a mountain peak is easily seen if it appears relatively dark against the sunlit sky. If, on the other hand, a milky haze “fills” the space between the observer and the mountain peak, the contrast between the mountain and its background is diminished as both take on a similar hue (Figure 1-1).

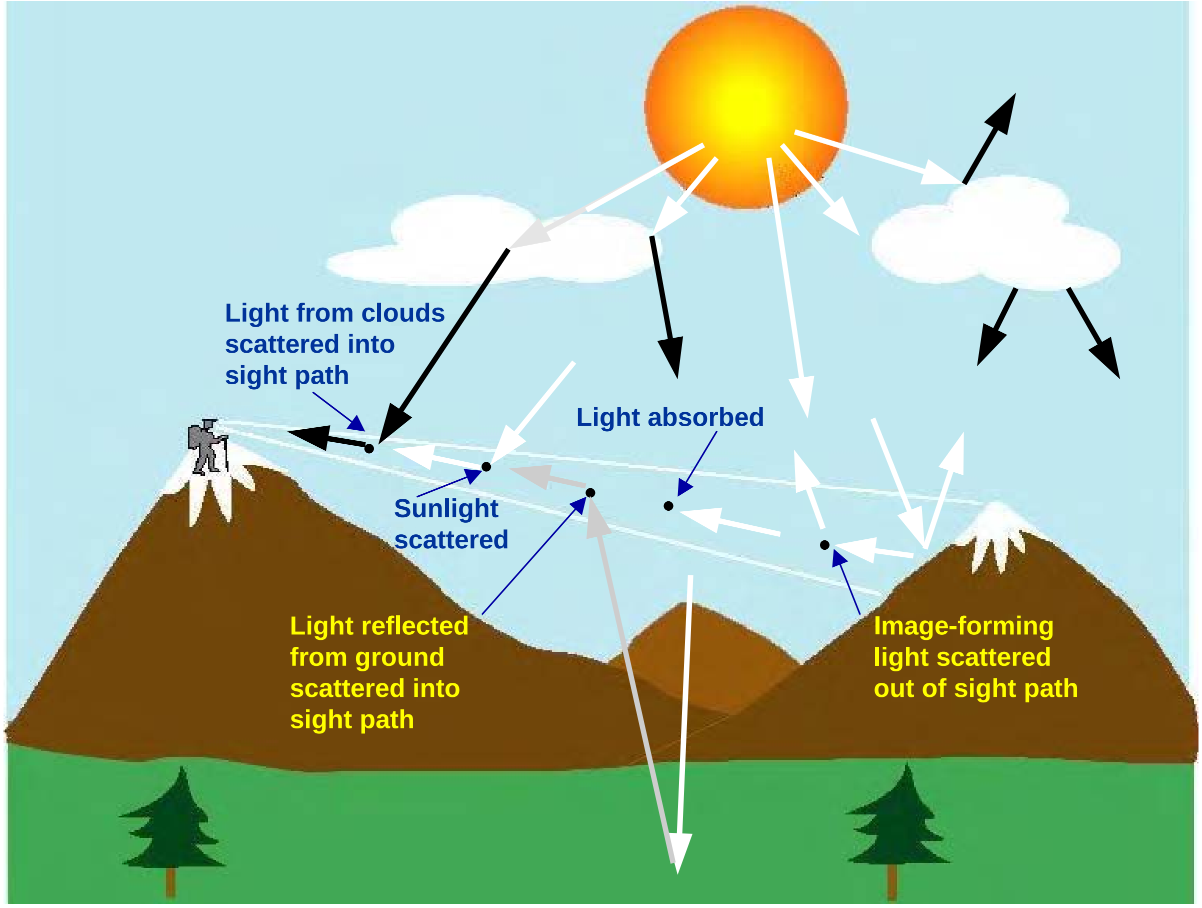
Figure 1-1. View of a good visibility day (left) and a poor visibility day (right) at Acadia National Park, Maine in June 2003.

Source: CAMNET, http://www.hazecam net

In simple terms, this hazy effect occurs when small particles and certain gaseous molecules in the atmosphere absorb or scatter visible light, thereby reducing the amount of visual “information” that reaches the observer. This occurs to some extent even under natural conditions, primarily as a result of the light scattering effect of individual air molecules (known as Rayleigh scattering[e]) and of naturally occurring aerosols.[f] The substantial visibility impairment caused by manmade pollution, however, is almost entirely attributable to the increased presence of fine particles in the atmosphere.[g]

Figure 1-2 presents a simplified schematic of the way such small particles interact with packets of light or "photons" as they travel from a distant object to an observer. Along the way, particles suspended in the air can deflect or scatter some of the photons out of the sight path. Intervening particles can also absorb photons, similarly removing them from the total amount of light reaching the observer.

Figure 1-2. Schematic of visibility impairment due to light scattering and absorption (adapted from Malm, 2000).



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[e] Because air molecules more effectively scatter light of short wavelengths (i.e., blue light), Rayleigh scattering explains the blue color of the sky.

[f] Atmospheric aerosol is a more general term for fine particles suspended in the atmosphere and refers to any particle (solid or liquid) that is suspended in the atmosphere.

[g] The only light-absorbing *gaseous* pollutant present in the atmosphere at significant concentrations is nitrogen dioxide (NO_2). However, the contribution of NO_2 to overall visibility impacts in the Northeast is negligible and hence its effects are not generally included in this discussion or in standard calculations of visibility impairment.

At the same time, particles in the air can scatter light into the sight path, further diminishing the quality of the view. The extraneous light can include direct sunlight and light reflected off the ground or from clouds. Because it is not coming directly from the scenic element, this light contains no visual information about that element. When the combination of light absorption and light scattering (both into and out of the sight path) occurs in many directions due to the ubiquitous presence of small particles in the atmosphere, the result is commonly described as "haze."

1.4. $PM_{2.5}$ Design Values in the MANE-VU Region

SIP developers use monitoring data in several important ways to support SIP activities. This section as well as Section 1.5 present measurements from the FRM and IMPROVE network needed in establishing SIP requirements. Following USEPA guidance (40CFR Part 50, Appendix N; USEPA, 2003a; USEPA, 2003b), we use these data to preview the Design Values and Baseline Conditions that SIP developers must consider for each nonattainment area and Class I area.

The current annual fine particle National Ambient Air Quality Standard was established in 1997 at 15 $\mu g/m^3$. To meet this standard, the 3-year average of a site's annual mean concentration must not be greater than this level. The current daily standard was set at 65 $\mu g/m^3$ at the 98th percentile level. To meet this standard, the 98th percentile value (of valid measurements recorded at a site) must not be greater than this level. No counties in MANE-VU have been designated nonattainment for the daily standard, however, the USEPA has revised the NAAQS with respect to the 24-hr average concentrations and states will have to comply with the new standard (35 $\mu g/m^3$ at the 98th percentile level) within five years of designations (expected in 2010). Fine particle data from the USEPA's Air Quality System (AQS) database for years 2002 through 2004 were used to determine the attainment status of monitoring sites in MANE-VU.

Table 1-1 shows a summary of areas found to exceed the annual standard (no areas exceed the daily standard). As tabulated, 12 areas fail to achieve the annual standard, with design values ranging from 15.1 to 20.4 $\mu g/m^3$. The nonattainment areas are concentrated in Pennsylvania and the coastal urban corridor. Sulfates and organic carbon represent the largest contributors to these high fine particle levels.

Table 1-1. 2004 $PM_{2.5}$ Design Value for Nonattainment Areas in MANE-VU

State(s)	Nonattainment Area	2004 Annual Design Value	2004 24-hr Design Value
MD	Baltimore	16.3	41
PA	Harrisburg-Lebanon-Carlisle	15.4	41
PA	Johnstown	15.3	40
PA	Lancaster	16.8	42
PA	Liberty-Clairton	20.4	65
MD	Martinsburg, WV-Hagerstown	16.1	39
NY-NJ-CT	New York-N. New Jersey-Long Island	16.8	50
PA-NJ-DE	Philadelphia-Wilmington	15.4	39
PA	Pittsburgh-Beaver Valley	16.5	45
PA	Reading	16.1	42
DC-MD-VA	Washington, DC	15.1	42
PA	York	16.9	43

1.5. Regional haze baseline conditions

The Regional Haze Rule requires states and tribes to submit plans that include calculations of current and estimated baseline and natural visibility conditions. They will use monitoring data from the IMPROVE program as the basis for these calculations. Table 1-2 and Table 1-3 present the five-year average[h] of the 20 percent worst day mass concentrations and 20 percent best day mass concentrations respectively in six Class I areas. Five of these areas are in MANE-VU and one (Shenandoah) is nearby but located in a neighboring regional planning organization (RPO) region.[i] Table 1-4 and Table 1-5 give the corresponding worst day and best day contributions to particle extinction for the six Class I areas. Each of these tables show the relative percent contribution for all six Class I sites. Sulfate and organic carbon dominate the fine mass, with sulfate even more important to particle extinction.

To guide the states in calculating baseline values of reconstructed extinction and for estimating natural visibility conditions, the USEPA released two documents in the fall of 2003 outlining recommended procedures (USEPA 2003a; USEPA 2003b). Recently, the IMPROVE Steering Committee endorsed an alternative method for the calculation of these values. The IMPROVE alternative methods were used, to create Table 1-6, which provides detail on the uniform visibility goals for the 20 percent worst conditions at the six Class 1 areas.

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[h] Great Gulf calculations are based on four years of data (2001-2004).

[i] Note that values presented for Shenandoah, a Class I area in the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) region, are for comparative purposes only. VISTAS will determine uniform rates of progress for areas within its region.

The first column of data in Table 1-6 gives the alternative proposed natural background levels for the worst visibility days at these six sites. MANE-VU has decided to use this approach, at least initially, for 2008 SIP planning purposes (NESCAUM, 2006). The second column shows the baseline visibility conditions on the 20 percent worst visibility days. These values are based on IMPROVE data from the official five-year baseline period (2000-2004) and again were calculated using the IMPROVE alternative approach. Using these baseline and natural background estimates, we derive the uniform rate of progress shown in the third column.[j] The final column displays the interim 2018 progress goal based on 14 years of improvement at the uniform rate.

Table 1-2. Fine mass and percent contribution for 20 percent worst days

20% Worst-day Fine Mass (μg/m³)/% contribution to fine mass					
Site	SO_4	NO_3	OC	EC	Soil
Acadia	6.3/ 56%	0.8/ 7%	3.2/ 28%	0.4/ 4%	0.5/ 5%
Brigantine	11.6/ 56%	1.7/ 8%	5.8/ 28%	0.7/ 3%	1/ 5%
Great Gulf	7.3/ 59%	0.4/ 3%	3.8/ 31%	0.4/ 3%	0.6/ 5%
Lye Brook	8.5/ 58%	1.1/ 7%	3.9/ 27%	0.5/ 3%	0.6/ 4%
Moosehorn	5.7/ 54%	0.7/ 7%	3.4/ 32%	0.4/ 4%	0.4/ 4%
Shenandoah	13.2/ 68%	0.7/ 3%	4.2/ 22%	0.6/ 3%	0.7/ 4%

Table 1-3. Fine mass and percent contribution for 20 percent best days

20% Best-day Fine Mass (μg/m³)/% contribution to fine mass					
Site	SO_4	NO_3	OC	EC	Soil
Acadia	0.8/ 42%	0.1/ 6%	0.8/ 41%	0.1/ 5%	0.1/ 6%
Brigantine	1.8/ 43%	0.5/ 11%	1.5/ 35%	0.2/ 6%	0.2/ 5%
Great Gulf	0.7/ 43%	0.1/ 7%	0.7/ 40%	0.1/ 5%	0.1/ 6%
Lye Brook	0.6/ 44%	0.1/ 11%	0.4/ 33%	0.1/ 5%	0.1/ 7%
Moosehorn	0.8/ 37%	0.1/ 6%	1/ 47%	0.1/ 5%	0.1/ 5%
Shenandoah	1.4/ 45%	0.5/ 16%	1/ 29%	0.2/ 5%	0.2/ 5%

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[j] We calculate the rate of progress as (baseline – natural background)/60 to yield the annual deciview (dv) improvement needed to reach natural background conditions in 2064, starting from the 2004 baseline.

Table 1-4. Particle extinction and percent contribution for 20 percent worst days

20% Worst-day particle extinction (Mm^{-1}) /% Contribution to particle extinction						
Site	SO_4	NO_3	OC	EC	Soil	CM
Acadia	69.2/ 64%	8/ 7%	11.2/ 10%	4.3/ 4%	0.5/ 0%	1.9/ 2%
Brigantine	127.1/ 66%	15.7/ 8%	24.2/ 13%	7/ 4%	1/ 1%	5.4/ 3%
Great Gulf	76.6/ 68%	3/ 3%	14.4/ 13%	3.9/ 3%	0.6/ 1%	3/ 3%
Lye Brook	87.3/ 67%	9.1/ 7%	15.3/ 12%	4.8/ 4%	0.6/ 0%	1.8/ 2%
Moosehorn	58.5/ 60%	6.4/ 7%	11.9/ 12%	4.4/ 5%	0.4/ 0%	2.1/ 3%
Shenandoah	155.5/ 79%	5.8/ 3%	16.1/ 8%	5.7/ 3%	0.7/ 0%	2.5/ 1%

Table 1-5. Particle extinction and percent contribution for 20 percent best days

20% Best-day particle extinction (Mm^{-1}) /% Contribution to particle extinction						
Site	SO_4	NO_3	OC	EC	Soil	CM
Acadia	6.8/ 28%	1.1/ 4%	2.2/ 9%	0.9/ 4%	0.1/ 0%	0.7/ 6%
Brigantine	14.8/ 35%	3.9/ 9%	4.5/ 11%	2.4/ 6%	0.2/ 1%	3.2/ 11%
Great Gulf	5.8/ 27%	1/ 4%	2/ 9%	0.8/ 4%	0.1/ 0%	0.9/ 8%
Lye Brook	4.4/ 23%	1.2/ 6%	1.3/ 7%	0.6/ 3%	0.1/ 0%	0.5/ 6%
Moosehorn	6.7/ 26%	1.1/ 4%	3.1/ 12%	1/ 4%	0.1/ 0%	1.1/ 8%
Shenandoah	11.2/ 36%	4.2/ 13%	2.9/ 9%	1.6/ 5%	0.2/ 1%	1.1/ 5%

Table 1-6. Natural background and baseline calculations for select Class I areas

Site	**20 % Worst Days Natural Background (dv)**	**20% Worst Days Baseline 2000-04(dv)**	**Uniform Rate (dv/yr)**	**Interim Progress Goal 2018 (dv)**	**20% Best Days Baseline 2000-04(dv)**
Acadia	12.54	22.89	0.17	20.47	8.77
Brigantine	12.34	29.01	0.28	25.12	14.33
Great Gulf	12.12	22.82	0.18	20.32	7.66
Lye Brook	11.85	24.44	0.21	21.50	6.37
Moosehorn	12.10	21.72	0.16	19.48	9.15
Dolly Sods	10.45	29.05	0.31	24.71	12.28
James River Face	11.20	29.12	0.30	24.94	14.21
Shenandoah	11.44	29.31	0.30	25.14	10.92

As demonstrated in Table 1-2, the inorganic constituents of fine particles, sulfates and nitrates are the dominant contributors to visibility impairment, accounting for about 80 percent of total particle extinction. Within the MANE-VU sites, the relative split between these two components is ~8 to 1 sulfate to nitrate (at Shenandoah, the average 20 percent worst day contribution of sulfates is even more dominant). Carbonaceous components account for the bulk of the remaining particle extinction, ranging from 12 to nearly 20 percent, mostly in the form of organic carbon. The remaining components add little to the extinction budget on the worst days, with a few percent attributable to coarse mass and around a half percent from fine soil.

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2. A DETAILED LOOK AT FINE PARTICLE POLLUTION AND REGIONAL HAZE IN THE MANE-VU REGION

Developing a conceptual description of fine particle pollution or regional haze requires combining experience and atmospheric-science expertise with multiple data sources and analysis techniques. This includes measured data on ambient pollutant concentrations as well as emission inventory and meteorological data, chemical transport modeling, and observationally based models (NARSTO, 2003). Here, we begin with a conceptual description based on the existing scientific literature and regional data analyses concerning $PM_{2.5}$ and its effect on visibility. This includes numerous review articles and reports on the subject. Subsequent chapters review monitoring data, emissions inventory information, and modeling results to support the conceptual understanding of regional fine particle pollution presented here.

Most past assessments of fine particle pollution and visibility impairment have tended to be national in scope. For purposes of this discussion, we have selectively reviewed the literature in order to present a distinctly eastern U.S. focus. While we already know much about fine particle pollution and visibility impairment and their causes in the MANE-VU region (see NESCAUM, 2001, 2006; NARSTO, 2003; Watson, 2002), significant gaps in understanding remain with respect to the nitrate and organic component of $PM_{2.5}$. While research continues, we have assembled the relevant information that is available to provide an overview of our current understanding of the regional context for $PM_{2.5}$ nonattainment and visibility impairment in the MANE-VU region.

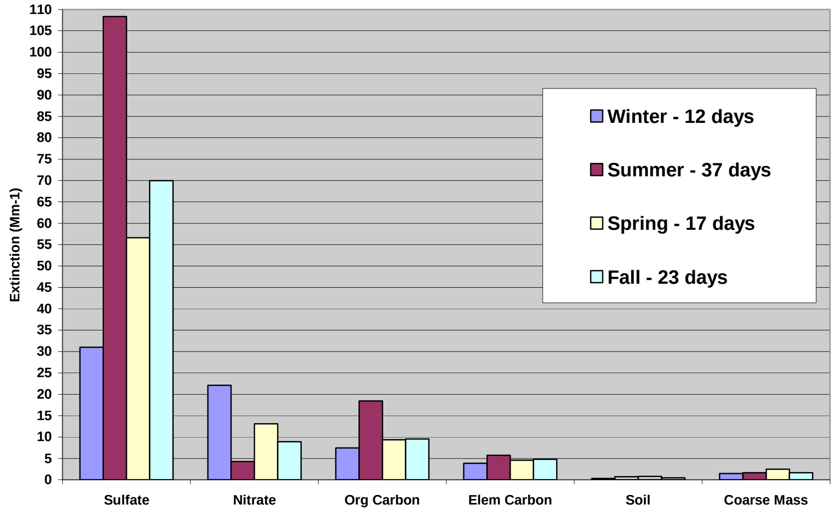
2.1. Chemical composition of particulate matter in the rural MANE-VU region

Sulfate alone accounts for anywhere from one-half to two-thirds of total fine particle mass on high $PM_{2.5}$ days in rural areas of MANE-VU. Even on low $PM_{2.5}$ days, sulfate generally accounts for the largest fraction (40 percent or more) of total fine particle mass in the region (NESCAUM, 2001, 2004b). Sulfate accounts for a major fraction of $PM_{2.5}$, not only in the Northeast but across the eastern United States (NARSTO, 2003).

After sulfate, organic carbon (OC) consistently accounts for the next largest fraction of total fine particle mass. Its contribution typically ranges from 20 to 30 percent of total fine particle mass on the days with the highest levels of $PM_{2.5}$. The fact that the contribution from organic carbon can be as high as 40 percent at the more rural sites on low $PM_{2.5}$ days is likely indicative of the role played by organic emissions from vegetation (so-called “biogenic hydrocarbons”).

Relative contributions to overall fine particle mass from nitrate (NO_3), elemental carbon, and fine soil are all smaller (typically under 10 percent), but the relative ordering among the three species varies with location and season. Figure 2-1 below, reflects the difference between nitrate and organic contributions to rural fine particle concentrations during different seasons (monitoring data for additional sites in the MANE-VU region are in Appendix B).

Figure 2-1. Comparison of contributions during different seasons at Lye Brook W[illegible]rness Area on 20% worst visi~~bility (high $PM_{2.5}$) days (2~~[illegible]00-2003).

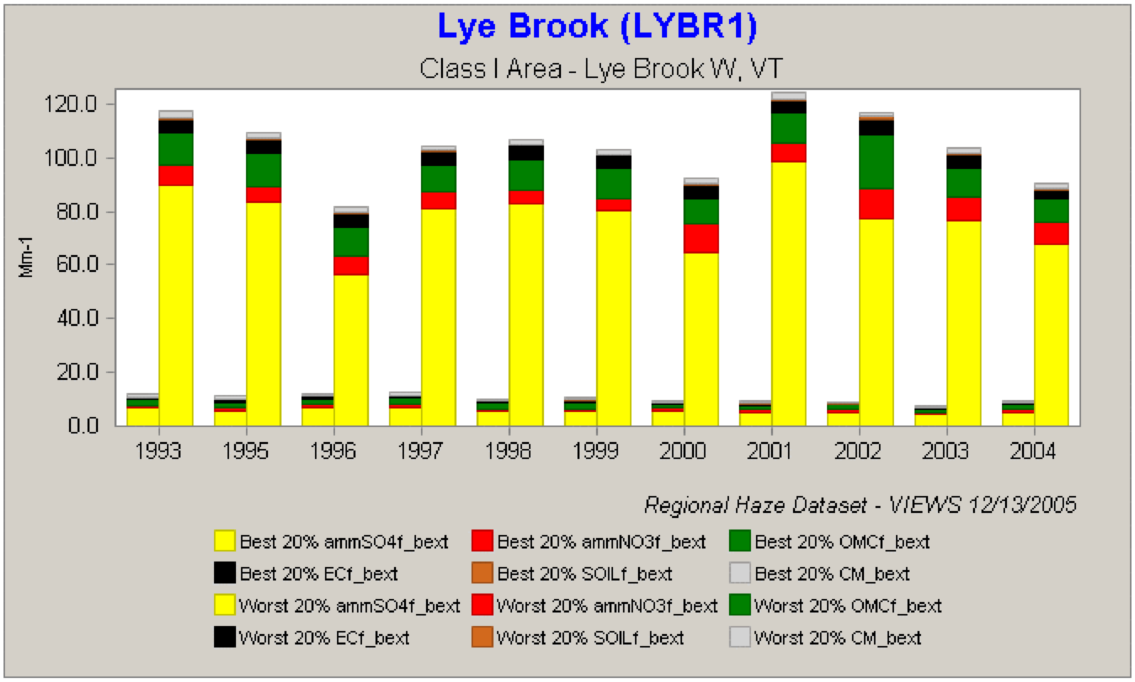


Almost all particle sulfate originates from sulfur dioxide (SO_2) oxidation and typically associates with ammonium (NH_4) in the form of ammonium sulfate ($(NH_4)_2SO_4$). Ninety-five percent of SO_2 emissions are from anthropogenic sources (primarily from fossil fuel combustion), while the majority of ammonium comes from agricultural activities and, to a lesser extent, from transportation sources in some areas (NARSTO, 2003).

Two major chemical pathways produce sulfate from SO_2 in the atmosphere. In the gas phase, production of sulfate involves the oxidation of SO_2 to sulfuric acid (H_2SO_4), ammonium bisulfate (NH_4HSO_4), or ammonium sulfate, depending on the availability of ammonia (NH_3). In the presence of small wet particles (typically much, much smaller than rain drops or even fog), a highly efficient aqueous phase process can oxidize SO_2 to sulfate extremely quickly (~10 percent per hour).

Not only is sulfate the dominant contributor to fine particle mass in the region, it accounts for anywhere from 60 percent to almost 80 percent of the *difference* between fine particle concentrations and extinction on the lowest and highest mass days at rural locations in the northeast and mid-Atlantic states (See Figure 2-2). Notably, at urban locations such as Washington DC, sulfate accounts for only about 40 percent of the difference in average fine particle concentrations for the 20 percent most versus least visibility impaired days (NESCAUM, 2001).

Figure 2-2. Comparison of species contributions on best and worst days at Lye Brook Wilderness Area.



2.2. Rural versus urban chemistry

Contributions to fine particle mass concentrations at rural locations include long-range pollutant transport as well as non-anthropogenic background contributions. Urban areas generally show mean PM$_{2.5}$ levels exceeding those at nearby rural sites. In the Northeast, this difference implies that local urban contributions are roughly 25 percent of the annual mean urban concentrations, with regional aerosol contributing the remaining, and larger, portion (NARSTO, 2003).

This rural versus urban difference in typical concentrations also emerges in a source apportionment analysis of fine particle pollution in Philadelphia (see Chapter 10 of NARSTO, 2003) using two different mathematical models, UNMIX and Positive Matrix Factorization (PMF). This analysis provides additional insight concerning sources of fine particle pollution in urban areas of the densely populated coastal corridor between Washington DC and New England. Specifically, this analysis found the following apportionment of PM$_{2.5}$ mass in the study area:

- Local SO_2 and sulfate: ~ 10 percent
- Regional sulfate: ~ 50 percent
- Residual oil: 4-8 percent
- Soil: 6-7 percent
- Motor vehicles: 25-30 percent

The analysis does not account for biogenic sources, which most likely are embedded in the motor vehicle fraction (NARSTO, 2003). The Philadelphia study suggests that both local pollution from nearby sources and transported “regional” pollution from distant sources contribute to the high sulfate concentrations observed in urban locations along the East Coast on an annual average basis. Summertime sulfate and organic carbon are strongly regional in eastern North America. Typically 75–95 percent of the urban sulfate concentrations and 60–75 percent of the urban OC concentrations arise from cumulative region-wide contributions (NARSTO, 2003). Urban air pollutants are essentially added on top of this regional background. Nitrate plays a noticeably more important role at urban sites compared to northeastern and mid-Atlantic rural monitoring sites, perhaps reflecting a greater contribution from vehicles and other urban pollution sources (NESCAUM, 2001).

It is difficult to discern any significant meaning about the cause of "excess" mass from a single pair of sites. There are many factors that influence the concentrations at a particular site and it is likely that for every pair of sites that shows an urban excess, one could find some pair of locations that might show something similar to an urban "deficit." While paired sites from an urban and a rural location will *typically* show greater concentrations in the urban location and lower levels of pollution in rural areas, great care must be exercised in the interpretation of any two-site analysis such as the comparisons of speciated components of $PM_{2.5}$ presented here. Nonetheless, such comparisons do provide a general feel for the typical chemical composition of $PM_{2.5}$ in the eastern U.S. and the relative differences in chemical composition between rural and more urban locations. More detailed, "network"-wide analyses (e.g., see NESCAUM 2004b; relevant sections are attached in Appendix C to this report) indicate that the results provided are not anomalous of typical urban environments in the MANE-VU region.

Figure 2-3 and Figure 2-4 compare two urban-rural pairs of speciation monitors: the New York nonattainment area (Elizabeth and Chester, New Jersey) and the Boston metropolitan area (Boston and Quabbin Reservoir, Massachusetts). The first three sites are Speciation Trends locations, while the Reservoir site is part of the IMPROVE protocol network.[k]

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[k] To provide a more direct comparison of the differences between the urban and rural sites, only those days for which both monitors in a pair had data were used. Four seasonal averages were computed for 2002, with seasons defined as winter (January, February, December), spring (March, April, May), Summer (June, July, August) and Fall (September, October, November). July 7 was excluded from the analysis because the Quebec forest fires affecting the region on that day would have dominated the summertime averages. The major fine particle species categories considered included ammonium sulfate, ammonium nitrate, organic carbon, elemental carbon, and soil mass. The traditional assumptions about these constituents were made; all sulfate was fully neutralized and a multiplier of 1.4 was used to account for mass of organic carbon. An "other $PM_{2.5}$ mass" category was created to delineate the difference between gravimetric mass determined from the Teflon filter and the reconstructed mass sum of the individual mass constituents. Where no "other" mass is graphed, the sum of the species either equaled or exceeded the directly measured mass. No adjustments were made to account for the different operational definitions of carbon between the IMPROVE and STN networks. Average blank corrections were applied to all samples. In the case of New York City, both rural and urban monitors were STN. The Boston pair reflects not only inter-site differences, but also differences in definition of organic and elemental carbon. However, the general interpretation of the data differences remains consistent. Based on current understanding, the rural elemental carbon would be even lower than what is shown on the graph if it were made consistent with the STN definition of EC. Likewise, the organic carbon value would increase slightly for the rural value, as the

Figure 2-3. New York nonattainment area (Elizabeth, NJ) compared to an upwind background site (Chester, NJ)

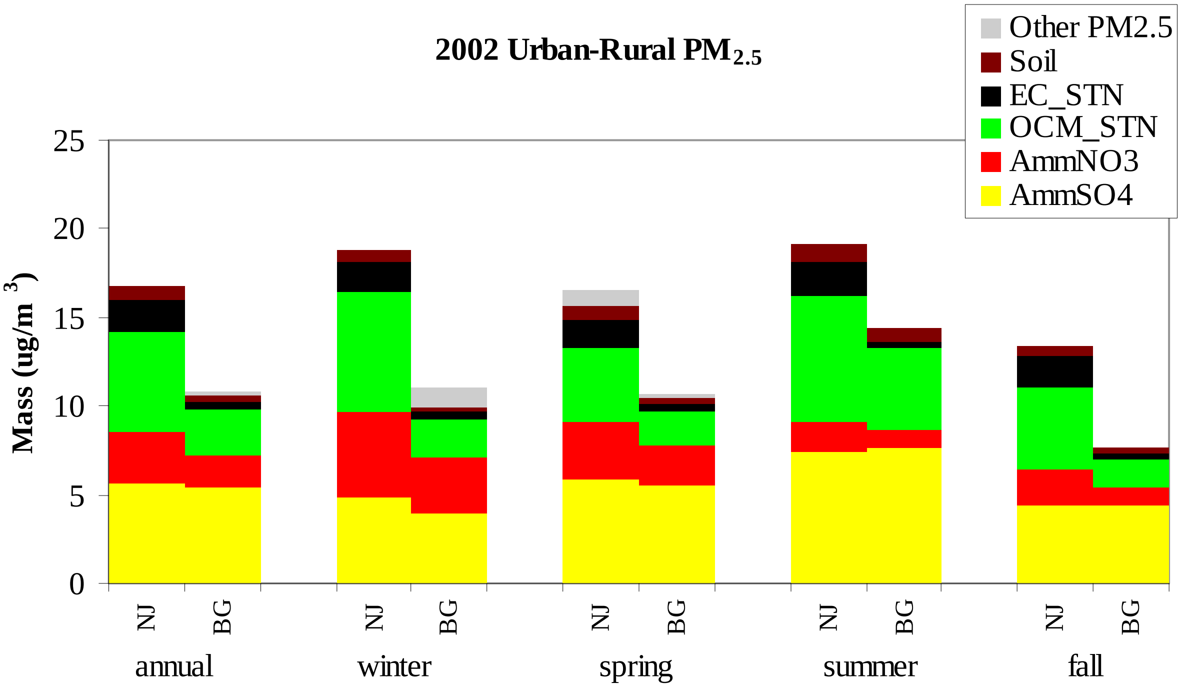
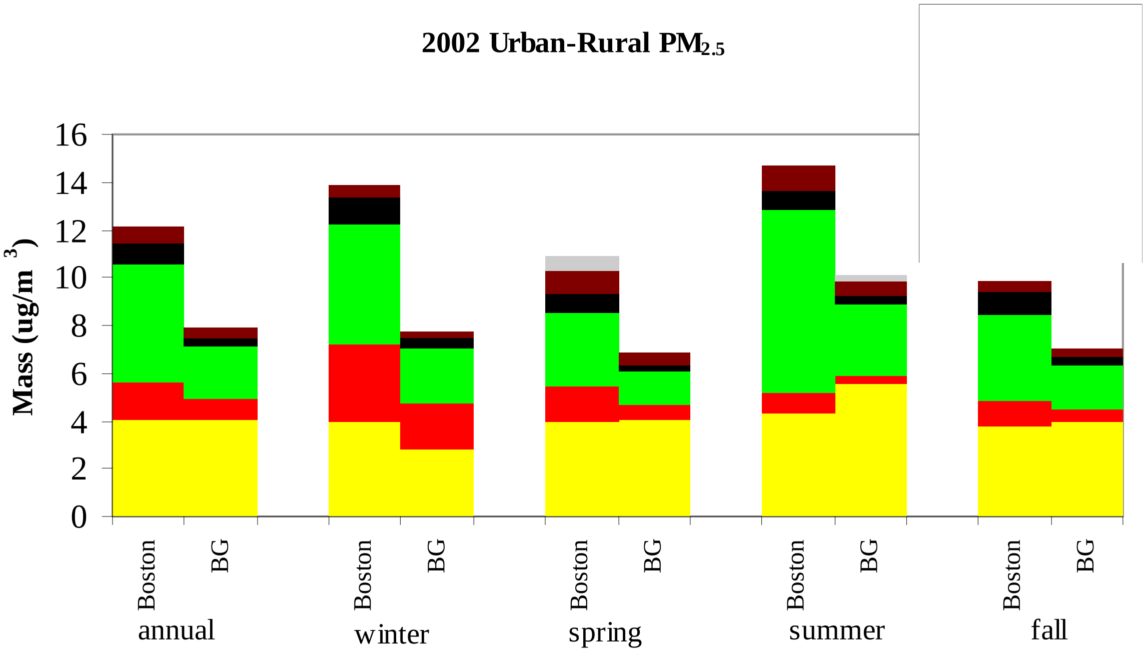


Figure 2-4. Boston urban area (Boston, MA) compared to an upwind background site (Quabbin Reservoir, MA)



EC would be allocated to OC. The urban OC levels are so much greater than those in the rural area that a

The urban-rural differences show consistency for both the New York City nonattainment area and Boston. On an annual scale, the sulfate levels are comparable, with increased mass loading at these urban sites driven primarily by differences in nitrates and carbon with smaller differences in "soil" levels. One interesting aspect of this comparison is the seasonal differences in the urban-rural sulfate split. On an annual basis, sulfate appears to be similar at urban and rural locations (based on these two pair of sites); however, during the colder months, the urban sulfate levels are elevated relative to the rural levels. This behavior is opposite during the summer. During the wintertime, the Northeast urban corridor itself is a substantial source of sulfur emissions. These local emissions can be trapped near the surface during the winter and have a corresponding higher impact on the urban area relative to the rural area.

For both urban and rural areas, the summertime OC levels are significantly greater than wintertime concentrations. Although the oxidation chemistry slows in winter, the cooler temperatures change the phase dynamics, driving more mass into the condensed over the gas phase. This along with more frequent temperature inversions (which limit atmospheric ventilation of the urban boundary layer) can lead to the observed increases in the relative influence of both organic and nitrate levels during winter months. EC, OC, and nitrate all are observed to have higher measured levels in the urban area (but still lower than the comparable summer values measured at the same sites), driven by local sources of these constituents.

2.3. Geographic considerations and attribution of $PM_{2.5}$/haze contributors

In the East, both annual average and maximum daily fine particle concentrations are highest near heavily industrialized areas and population centers. Not surprisingly, given the direct connection between fine particle pollution and haze, the same pattern emerges when one compares measures of light extinction on the most and least visibility impaired days at parks and wilderness areas subject to federal haze regulations in the MANE-VU region (NESCAUM, 2001). An accumulation of particle pollution often results in hazy conditions extending over thousands of square kilometers (km^2) (NARSTO, 2003). Substantial visibility impairment is a frequent occurrence in even the most remote and pristine areas of the MANE-VU region (NESCAUM, 2001).

$PM_{2.5}$ mass declines fairly steadily along a southwest to northeast transect of the MANE-VU region. This decline is consistent with the existence of large fine particle emissions sources (both primary and secondary) to the south and west of MANE-VU. This trend is driven, in large part, by the marked southwest-to-northeast gradient in ambient sulfate concentrations during three seasons of the year as illustrated in Figure 2-5. Wintertime concentrations, by contrast, are far more uniform across the entire region. Figure 2-6 shows that on an annual basis, both total $PM_{2.5}$ and sulfate mass are highest in the southwestern portions of the MANE-VU region (note the different scales for each pollutant). High concentrations of nitrate and organic particle constituents, which play a role in localized wintertime $PM_{2.5}$ episodes, tend to be clustered along the northeastern urban corridor and in other large urban centers.

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slight increase in rural OC makes little difference.

Figure 2-5. 2002 Seasonal average SO$_4$ based on IMPROVE and STN data

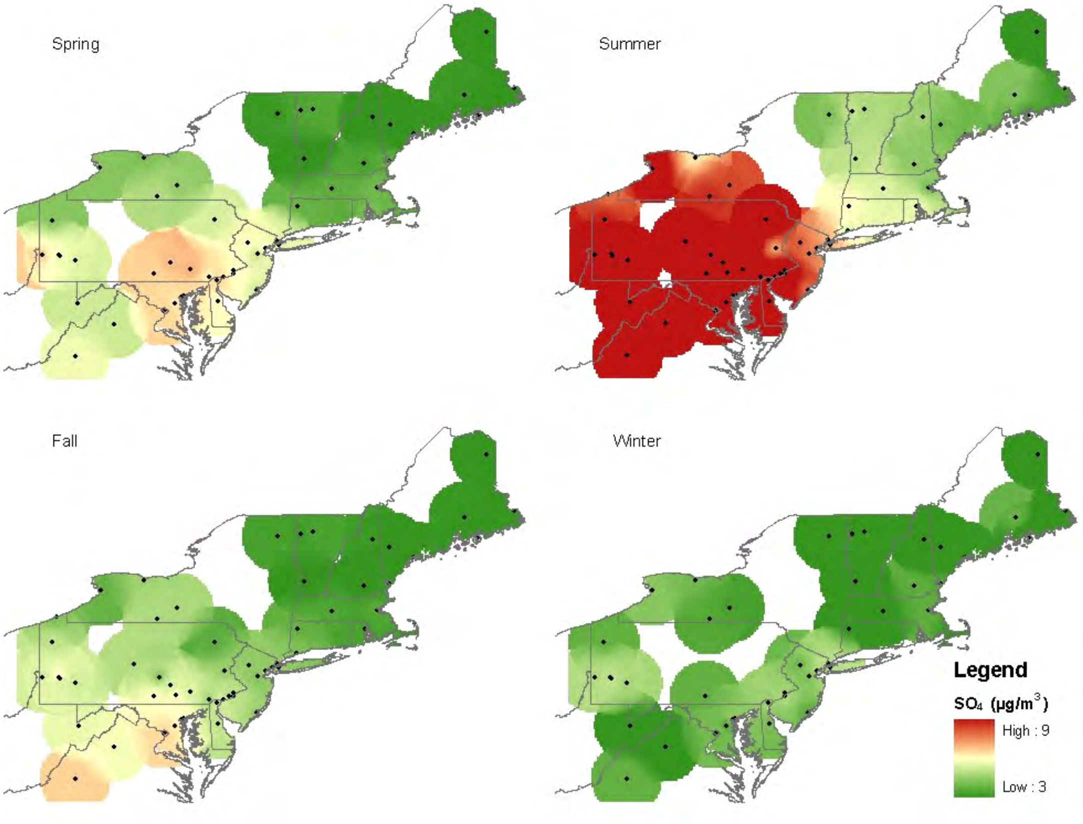
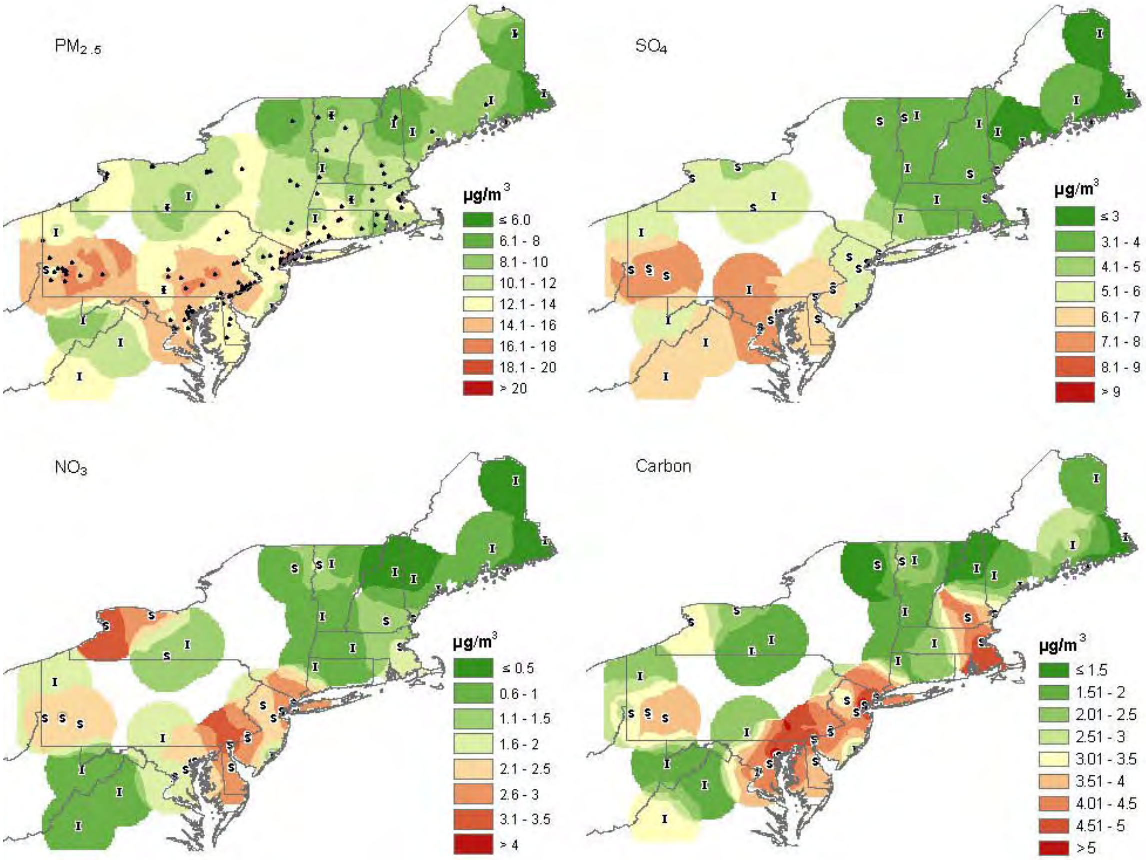


Figure 2-6. 2002 Annual average PM$_{2.5}$, sulfate, nitrate and total carbon for MANE-VU based on IMPROVE (I) and STN (S) data. PM$_{2.5}$ mass data are supplemented by measurements from the FRM network (•).



While these figures provide some preliminary context for identifying sources contributing to the region's particulate matter and visibility problems, they say nothing about the relative efficiency of a state's or region's emissions in contributing to the problem. It is clear that distance from the emissions source matters. Local, nearby sources are exceedingly important and sources within about 200 km are much more efficient (on a per ton emitted basis) at producing pollution impacts at eastern Class I sites such as Shenandoah National Park than emissions sources farther away (USNPS, 2003). In general, the "reach" of sulfate air pollution resulting from SO_2 emissions is longest (650–950 km). The reach of ammonia emissions or reduced nitrogen relative to nutrient deposition is the shortest (around 400 km), while oxides of nitrogen and sulfur — in terms of their impacts with respect to acidic deposition — have a reach between 550–650 km and 600–700 km, respectively (USNPS, 2003).

Monitoring evidence indicates that non-urban visibility impairment in eastern North America is predominantly due to sulfate particles, with organic particles generally second in importance (NARSTO, 2003). This makes sense, given the "long reach" of SO_2 emissions once they are chemically transformed into sulfate and given the ubiquitous nature of OC sources in the East. The poorest visibility conditions occur in highly industrialized areas encompassing and adjacent to the Ohio River and Tennessee Valleys. These areas feature large coal-burning power stations, steel mills, and other large emissions sources. Average fine particle concentrations and visibility conditions are also poor in the highly populated and industrialized mid-Atlantic seaboard but improve gradually northeast of New York City (Watson, 2002).

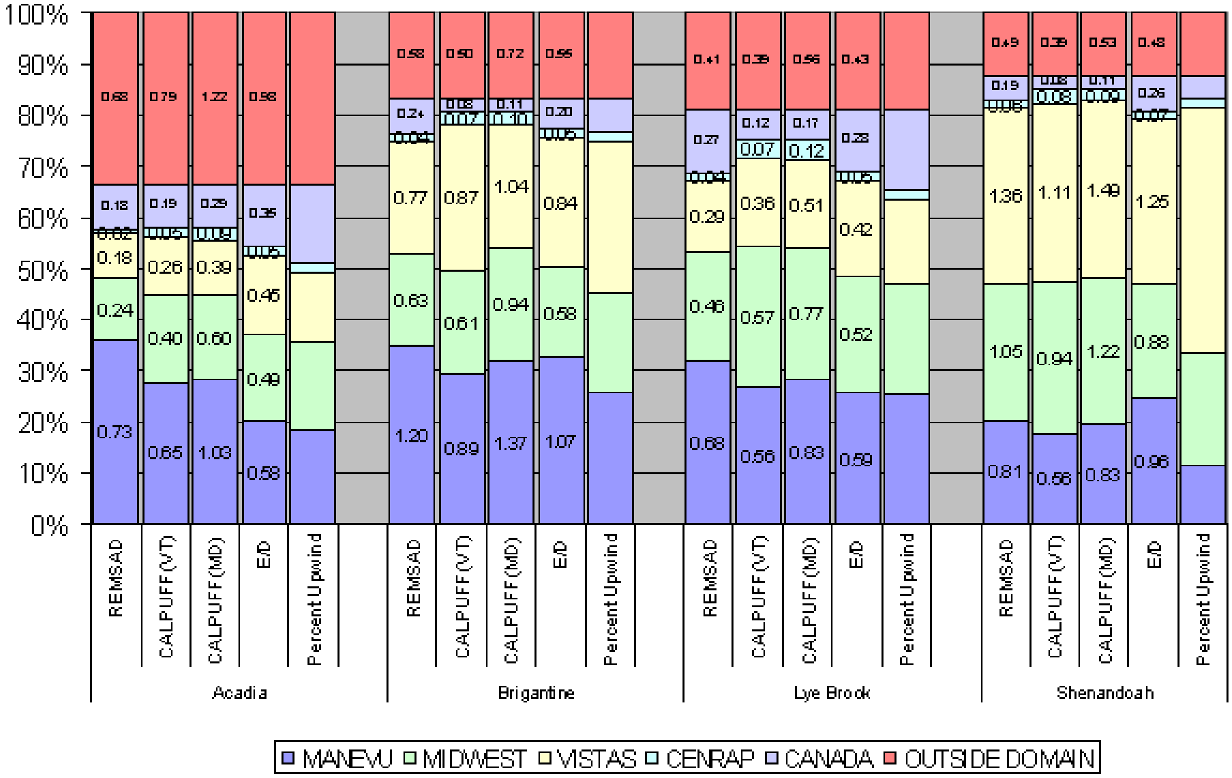
A review of source apportionment and ensemble trajectory analyses conducted by USEPA (2003) found that all back trajectory analyses for eastern sites associated sulfate with the Ohio River Valley area. These studies also are frequently able to associate other types of industrial pollutants (e.g., copper or zinc smelting, steel production, etc.) with known source areas, lending credibility to their performance. Several studies in the USEPA review noted transport across the Canadian border, specifically sulfates from the midwestern United States into Canada, and smelter emissions from Canada into the northeastern United States.

A recent, comprehensive analysis of air quality problems at Shenandoah National Park conducted by the U.S. National Park Service (USNPS, 2003) focused on contributions to particulate pollution and visibility impairment south of the MANE-VU region. In descending order of importance, the Park Service analysis determined that Ohio, Virginia, West Virginia, Pennsylvania, and Kentucky comprise the top five of 13 key states contributing to ambient sulfate concentrations and haze impacts at the park. West Virginia, Ohio, Virginia, Pennsylvania, and Kentucky comprise the top five contributing states with respect to sulfur deposition impacts at the park. Finally, Virginia, West Virginia, Ohio, Pennsylvania, and North Carolina were found to be the top five states contributing to deposition impacts from oxidized nitrogen at the park (USNPS, 2003).

In sum, the Park Service found that emission sources located within a 200 km (125 mile) radius of Shenandoah cause greater visibility and acidic deposition impacts at the park, on a per ton basis, than do more distant emissions sources (USNPS, 2003). When mapping deposition and concentration patterns for all three pollutants using contour lines, the resulting geographic pattern shows a definite eastward tilt in the area of highest impact. This is the result of prevailing wind patterns, which tend to transport most airborne pollutants in an arc[1] from the north-northeast to the east. The Park Service found, for example, that emissions originating in the Ohio River Valley end up three times farther to the east than to the west (USNPS, 2003).

The recent sulfate attribution work completed by MANE-VU (NESCAUM, 2006) finds that a variety of different states contribute to observed sulfate in rural locations across the MANE-VU region, but that in the southwest portions of the region, neighboring RPOs contribute to a more significant degree relative to rural areas in the Northeast. Figure 2-7 shows relative contributions of RPOs to sulfate at three MANE-VU Class I areas and one VISTAS Class I area based on a variety of analysis methods. Figure 2-8 shows the individual state contributions to sulfate at Brigantine Wilderness Area on the New Jersey coast according to tagged REMSAD modeling.

Figure 2-7. 2002 Annual average contribution to $PM_{2.5}$ sulfate as determined by multiple analysis methods for four Class I areas spanning MANE-VU and Virginia



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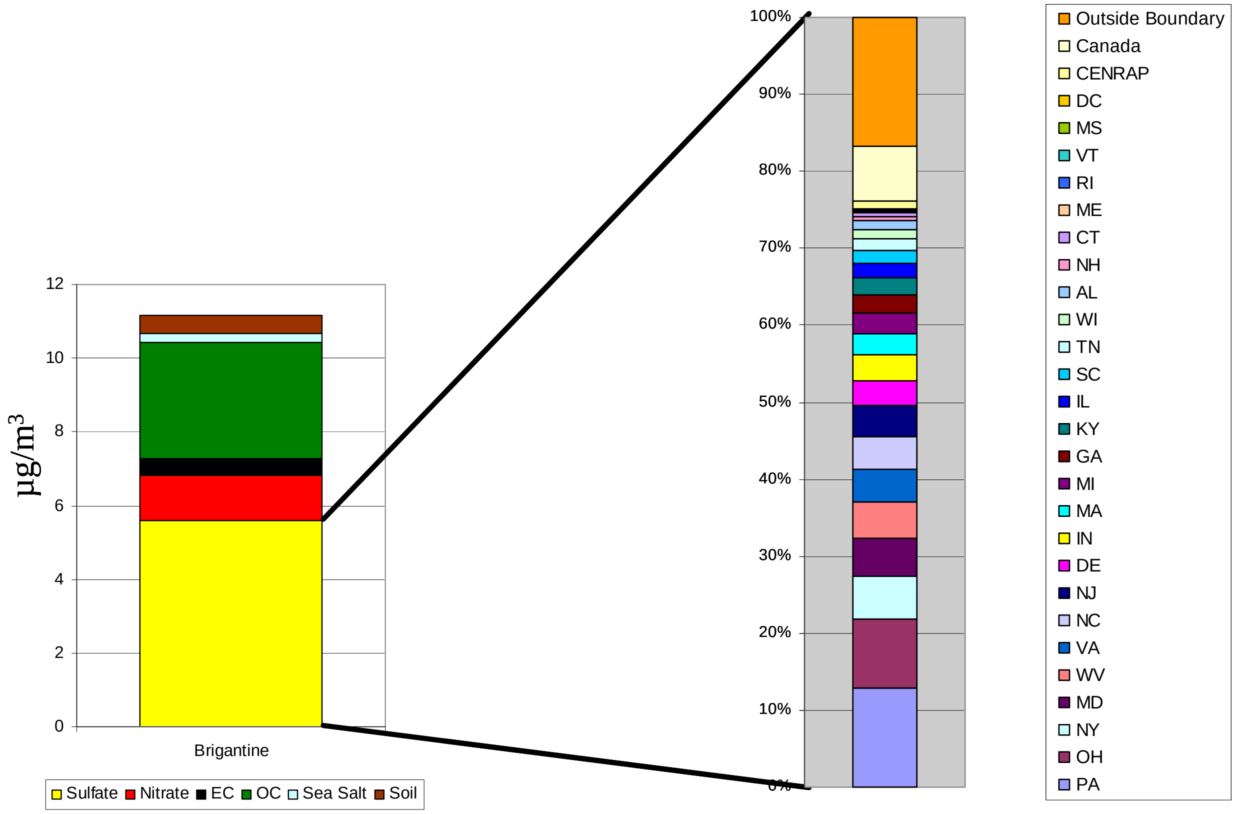
[1] The prevailing winds are eastward to northeast. This leads to greater pollution transport to the east-northeast relative to other directions.

Figure 2-8. 2002 Annual average mass contribution to $PM_{2.5}$ at Brigantine Wilderness in New Jersey (IMPROVE) and sulfate contributions as determined by tagged REMSAD model simulations (NESCAUM, 2006)



2000-2004 average IMPROVE mass

REMSAD 2002 average contributions to sulfate

2.4. CAIR Modeling

The CAIR modeling by the USEPA provides information on the upwind areas (by state) contributing to downwind nonattainment for $PM_{2.5}$ in MANE-VU counties. Table 2-1 presents the upwind states significantly contributing to $PM_{2.5}$ nonattainment in counties within MANE-VU during 2001, according to significance criteria used by the USEPA (USEPA, 2005, from Table VII-3). The states listed in the table as significantly contributing to downwind nonattainment in MANE-VU counties include states outside of MANE-VU, indicating the broad regional scale of the $PM_{2.5}$ transport problem.

Table 2-2 provides the maximum contribution from each state to annual average $PM_{2.5}$ nonattainment in a downwind state (not necessarily restricted to MANE-VU nonattainment counties) based on CAIR modeling.

Table 2-1. Upwind states that make a significant contribution to $PM_{2.5}$ in each downwind nonattainment county (2001 modeling).

Downwind State/County		Upwind States									
DE	New Castle	MD/DC	MI	NY	OH	PA	VA	WV			
DC	District of Columbia	NC	OH	PA	VA	WV					
MD	Anne Arundel	NC	OH	PA	VA	WV					
MD	Baltimore City	NC	OH	PA	VA	WV					
NJ	Union	MD/DC	MI	NY	OH	PA	WV				
NY	New York	MD/DC	OH	PA	WV						
PA	Allegheny	IL	IN	KY	MI	OH	WV				
PA	Beaver	IN	MI	OH	WV						
PA	Berks	MD/DC	MI	NY	OH	VA	WV				
PA	Cambria	IN	MD/DC	MI	OH	WV					
PA	Dauphin	MD/DC	MI	OH	VA	WV					
PA	Delaware	MD/DC	MI	OH	VA	WV					
PA	Lancaster	IN	MD/DC	MI	NY	OH	VA	WV			
PA	Philadelphia	MD/DC	MI	OH	VA	WV					
PA	Washington	IN	KY	MI	OH	WV					
PA	Westmoreland	IN	KY	MD/DC	MI	OH	WV				
PA	York	MD/DC	MI	OH	VA	WV					

Table 2-2. Maximum downwind $PM_{2.5}$ contribution ($\mu g/m^3$) for each of the 37 upwind states (2001 data).

Upwind State	Maximum Downwind Contribution	Upwind State	Maximum Downwind Contribution
Alabama	0.98	Nebraska	0.07
Arkansas	0.19	New Hampshire	<0.05
Connecticut	<0.05	New Jersey	0.13
Delaware	0.14	New York	0.34
Florida	0.45	North Carolina	0.31
Georgia	1.27	North Dakota	0.11
Illinois	1.02	Ohio	1.67
Indiana	0.91	Oklahoma	0.12
Iowa	0.28	Pennsylvania	0.89
Kansas	0.11	Rhode Island	<0.05
Kentucky	0.9	South Carolina	0.4
Louisiana	0.25	South Dakota	<0.05
Maine	<0.05	Tennessee	0.65
Maryland/DC	0.69	Texas	0.29
Massachusetts	0.07	Vermont	<0.05
Michigan	0.62	Virginia	0.44
Minnesota	0.21	West Virginia	0.84
Mississippi	0.23	Wisconsin	0.56
Missouri	1.07		

2.5. Seasonal differences

Eastern and western coastal regions of the United States and Canada show marked seasonality in the concentration and composition of fine particle pollution, while central interior regions do not (NARSTO, 2003). While MANE-VU extends inland as far as the Pennsylvania and Ohio border, the majority of $PM_{2.5}$ NAAQS nonattainment areas and Class I areas affected by the Regional Haze Rule cluster along the East Coast and thus typically show strong seasonal influences. Maximum $PM_{2.5}$ concentrations typically occur during the summer over most of the rural Northeast, with observed summer values for rural areas in the region, on average, twice those of winter. In urban locations, summertime and wintertime $PM_{2.5}$ levels are more comparable and whether one season dominates over the other is more of a function of inter-annual variability of meteorology and fire activity (i.e., summertime fire activity can push average $PM_{2.5}$ values higher in some years). As described below, the reason for the wintertime strength of $PM_{2.5}$ levels in urban areas is related to the greater concentration of local pollution that accumulates when temperature inversions are present, significantly boosting the wintertime $PM_{2.5}$ levels. Winter nitrate concentrations are generally higher than those observed in summer and, as mentioned above, urban concentrations typically exceed rural concentrations year-round. In addition, local mobile source carbon grows in importance during wintertime. Hence, in some large urban areas such as Philadelphia and New York City, peak concentrations of $PM_{2.5}$ can occur in winter.

The conceptual descriptions that explain elevated regional $PM_{2.5}$ peak concentrations in the summer differs significantly from those that explain the largely urban peaks observed during winter. On average, summertime concentrations of sulfate in the northeastern United States are more than twice that of the next most important fine particle constituent, OC, and more than four times the combined concentration of nitrate and black carbon (BC) constituents (NARSTO, 2003). Episodes of high summertime sulfate concentrations are consistent with stagnant meteorological flow conditions upwind of MANE-VU and the accumulation of airborne sulfate (via atmospheric oxidation of SO_2) followed by long-range transport of sulfur emissions from industrialized areas within and outside the region.

National assessments (NARSTO, 2003) have indicated that in the winter, sulfate levels in urban areas are almost twice as high as background sulfate levels across the eastern U.S., indicating that the local urban contribution to wintertime sulfate levels is comparable in magnitude to the regional sulfate contribution from long-range transport. MANE-VU’s network analysis for the winter of 2002 suggests that the local enhancement of sulfate in urban areas of MANE-VU is somewhat less with ranges from 25 to 40% and that the long-range transport component of $PM_{2.5}$ sulfate is still the dominant contributor in most eastern cities.

In the winter, urban OC and sulfate each account for about a third of the overall $PM_{2.5}$ mass concentration observed in Philadelphia and New York City. Nitrate also makes a significant contribution to urban $PM_{2.5}$ levels observed in the northeastern United States during the winter months. Wintertime concentrations of OC and NO_3 in urban areas can be twice the average regional concentrations of these pollutants, indicating the importance of local source contributions (NARSTO, 2003). This is likely because winter conditions are more conducive to the formation of local inversion layers that prevent vertical mixing. Under these conditions, emissions from tailpipe, industrial, and other local sources become concentrated near the Earth's surface, adding to background pollution levels associated with regionally transported emissions.

It is worth noting that while sulfate plays a significant role in episodes of elevated particle pollution during summer and winter months, the processes by which sulfate forms may vary seasonally. Nearly every source apportionment study reviewed by USEPA (2003) identified secondary sulfate originating from coal combustion sources as the largest or one of the largest contributors to overall fine particle mass in the region. It often accounted for more than 50 percent of $PM_{2.5}$ mass at some locations during some seasons. In a few cases, source apportionment studies identified a known local source of sulfate, but most assessments (in conjunction with back trajectory analysis) have pointed to coal-fired power plants in the Midwest as an important source for regional sulfate. Studies with multiple years of data have also tended to identify a distinguishable chemical "signature" for winter versus summer sources of sulfate, with the summer version typically accounting for a greater share of overall fine particle mass. Researchers have speculated that the two profiles represent two extremes in the chemical transformation processes that occur in the atmosphere between the source regions where emissions are released and downwind receptor sites. We note that while coal combustion is often referred to as the "sulfate source" because of the dominance of its sulfate contribution, coal combustion is often a source of significant amounts of organic carbon and is usually the single largest source of selenium (Se) and other heavy metal trace elements (USEPA, 2003).

Figure 2-9. Moving 60-day average of fine aerosol mass concentrations based on long-term data from two northeastern cities

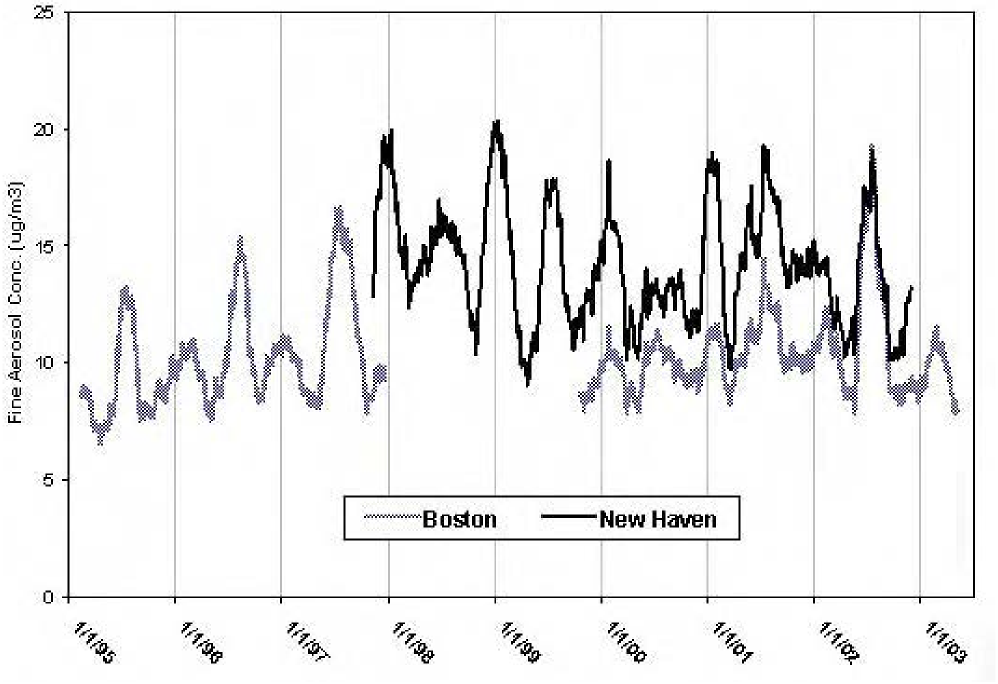
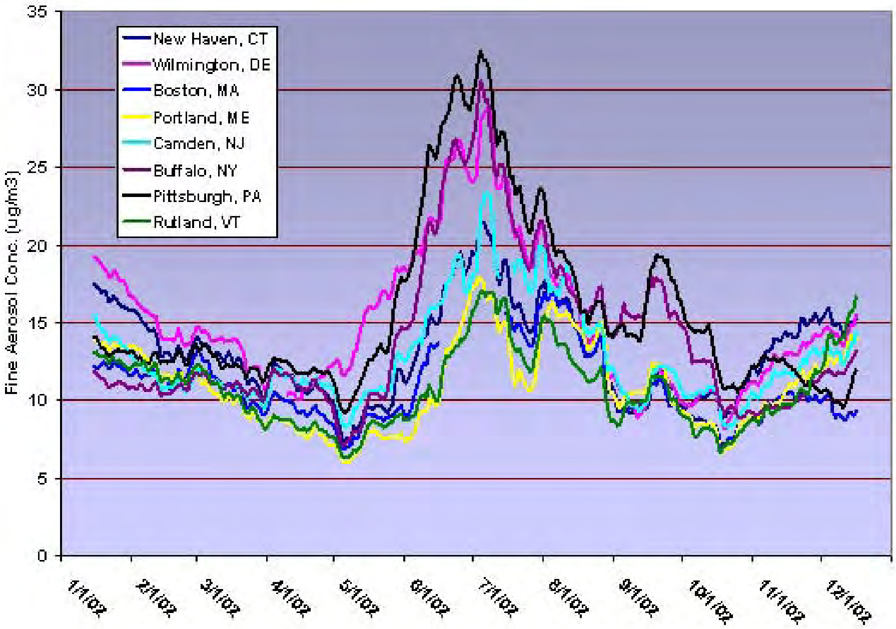


Figure 2-10. The 30-day average $PM_{2.5}$ concentrations from 8 northeastern cities during 2002



In general, fine particle concentrations in MANE-VU are highest during the warmest (summer) months but also exhibit a secondary peak during the coldest (winter) months that can dominate during some years, particularly in urban locations. This bimodal seasonal distribution of peak values is readily apparent in Figure 2-9. The figure shows the smoothed 60-day running average of fine particle mass concentrations using continuous monitoring data from two northeastern cities over a period of several years.

Figure 2-10 also demonstrates this bimodal pattern. Though slightly more difficult to discern in just a single year's worth of data, a "W" pattern does emerge at almost all sites across the region during 2002 with the winter peak somewhat lower than the summer peak at most sites. Urban monitors in Wilmington, Delaware and New Haven, Connecticut have wintertime peak values approaching those of summer.

In the summertime, MANE-VU sites repeatedly experience sulfate events due to transport from regions to the south and west. During such events, both rural and urban sites throughout MANE-VU record high (i.e., >15 µg/m^3) daily average $PM_{2.5}$ concentrations. Meteorological conditions during the summer frequently allow for summer "stagnation" events when very low wind speeds and warm temperatures (upwind and over MANE-VU) allow pollution levels to build in an air mass as it slowly moves across the continent. During these events, atmospheric ventilation is poor and local emission sources add to the burden of transported pollution with the result that concentrations throughout the region (both rural and urban) are relatively uniform. Generally, there are enough of these events to drive the difference between urban and rural sites down to less than 1 µg/m^3 during the warm or hot months of the year. As a result, concentrations of fine particles aloft will often be higher than at ground-level during the summertime, especially at rural monitoring sites. Thus, when atmospheric "mixing" occurs during summer[m] mornings (primarily 7 to 11 a.m.), fine particle concentrations at ground-level can actually increase (see Hartford, CT or Camden, NJ in Figure 2-11).

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[m] Here we define summer as May, June, July and August.

Figure 2-11. Mean hourly fine aerosol concentrations during 2002 summer months

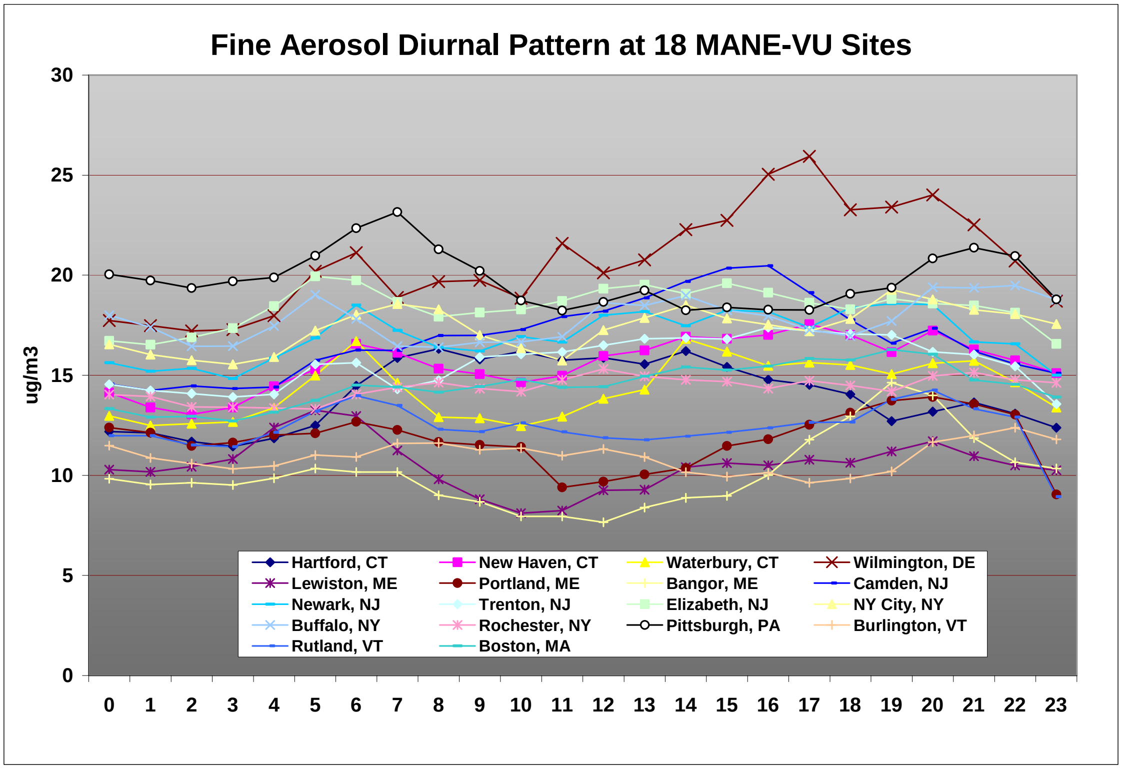
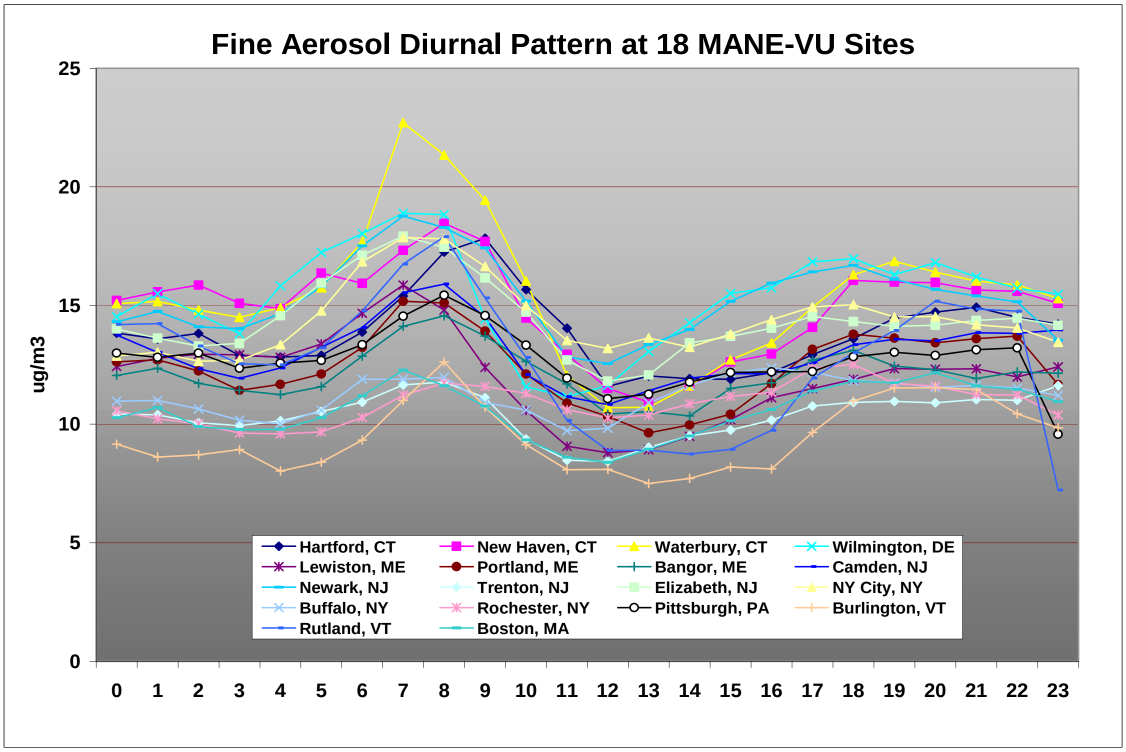


Figure 2-12. Mean hourly fine aerosol concentrations during 2002 winter months



During the wintertime, strong inversions frequently trap local emissions overnight and during the early morning, resulting in elevated urban concentrations. These inversions occur when the Earth's surface loses thermal energy by radiating it into the atmosphere (especially on clear nights). The result is a cold, stable layer of air near the ground. At sunrise, local emissions (both mobile and stationary) begin increasing in strength and build-up in the stable ground layer (which may extend only 100 meters or less above the ground). Increasing solar radiation during the period between 10 a.m. and noon typically breaks this cycle by warming the ground layer so that it can rise and mix with air aloft. Because the air aloft during wintertime is typically less polluted than the surface layer, this mixing tends to reduce ground-level particle concentrations (see Figure 2-12). This diurnal cycle generally drives wintertime particle concentrations, although the occasional persistent temperature inversion can have the effect of trapping and concentrating local emissions over a period of several days, thereby producing a significant wintertime pollution episode.

Rural areas experience the same temperature inversions but have relatively fewer local emissions sources so that wintertime concentrations in rural locations tend to be lower than those in nearby urban areas. Medium and long-range fine particle transport events do occur during the winter but to a far lesser extent than in the summertime. In sum, it is the interplay between local and distant sources together with seasonal meteorological conditions that drives the observed 3–4 $\mu g/m^3$ wintertime urban-rural difference in $PM_{2.5}$ concentrations.

Visually hazy summer days in the Northeast can appear quite different from hazy winter days. The milky, uniform visibility impairment shown in Figure 2-13 is typical of summertime regional haze events in the Northeast. During the winter, by comparison, reduced convection and the frequent occurrence of shallow inversion layers often creates a layered haze with a brownish tinge, as shown in Figure 2-14. This visual difference suggests seasonal variation in the relative contribution of different gaseous and particle constituents during the summer versus winter months (NESCAUM, 2001). Rural and inland areas tend not to experience these layered haze episodes as frequently due to the lack of local emission sources in most rural areas (valleys with high wood smoke contributions are an exception).

Overall (regional) differences in summer versus winter particle mass concentrations and corresponding visibility impairment (as measured by light extinction) are largely driven by seasonal variation in sulfate mass concentrations. This is because winter meteorological conditions are less conducive to the oxidation of sulfate from SO_2 (as borne out by the previously cited source apportionment studies). In addition, seasonal differences in long-range transport patterns from upwind SO_2 source regions may be a factor.

The greater presence of nitrate during the cold season is a consequence of the chemical properties of ammonium nitrate. Ammonia bonds more weakly to nitrate than it does to sulfate, and ammonium nitrate tends to dissociate at higher temperatures. Consequently, ammonium nitrate becomes more stable at lower temperatures and hence contributes more to $PM_{2.5}$ mass and light extinction during the winter months relative to the summer (NESCAUM, 2001).

Figure 2-13. Summertime at Mt. Washington

Clean Day **Typical Haze Event**

Figure 2-14. Wintertime in Boston

Clean Day **Typical Haze Event**

2.6. Summary

The presence of fine particulate matter in ambient air significantly degrades public health and obscures visibility during most parts of the year at sites across the MANE-VU region. Particle pollution generally, and its sulfate component specifically, constitute the principle driver for regional visibility impacts. While the broad region experiences visibility impairment, it is most severe in the southern and western portions of MANE-VU that are closest to large power plant SO_2 sources in the Ohio River and Tennessee Valleys.

Summer visibility impairment is driven by the presence of regional sulfate, whereas winter visibility depends on a combination of regional and local influences coupled with local meteorological conditions (inversions) that lead to the concentrated build-up of pollution.

Sulfate is the key particle constituent from the standpoint of designing control strategies to improve visibility conditions in the northeastern United States. Significant further reductions in ambient sulfate levels are achievable, though they will require more than proportional reductions in SO_2 emissions.

Long-range pollutant transport and local pollutant emissions are important, especially along the eastern seaboard, so one must also look beyond the achievement of further sulfate reductions. During the winter months, in particular, consideration also needs to be given to reducing urban sources of SO_2, NO_X and OC (NARSTO, 2003) .

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3. MANE-VU EMISSION INVENTORY CHARACTERISTICS FOR FINE PARTICLES

The pollutants that affect fine particle formation and visibility are sulfur oxides (SO_X), NO_X, VOCs, ammonia (NH_3), and particles with an aerodynamic diameter less than or equal to 10 and 2.5 µm (i.e., primary PM_{10} and $PM_{2.5}$). The emissions dataset illustrated in this section is the 2002 MANE-VU Version 2 regional haze emissions inventory. The MANE-VU regional haze emissions inventory version 3.0, released in April 2006, has superseded version 2 for modeling purposes.

3.1. Emissions inventory characteristics

3.1.1. Sulfur dioxide (SO_2)

SO_2 is the primary precursor pollutant for sulfate particles. Ammonium sulfate particles are the largest contributor to $PM_{2.5}$ mass on an annual average basis at MANE-VU nonattainment sites. It also accounts for more than 50 percent of particle-related light extinction at northeastern Class I areas on the clearest days and for as much as or more than 80 percent on the haziest days. Hence, SO_2 emissions are an obvious target of opportunity for both addressing $PM_{2.5}$ nonattainment and for reducing regional haze in the eastern United States. Combustion of coal and, to a substantially 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, 2001).

Figure 3-1 shows SO_2 emissions trends in MANE-VU states[n] extracted from the National Emissions Inventories (NEI) for the years 1996, 1999 (MARAMA, 2004), and the 2002 MANE-VU inventory. Most of the states (with the exception of Maryland) show declines in year 2002 annual SO_2 emissions as compared to 1996 emissions. Some of the states show an increase in 1999 followed by a decline in 2002 and others show consistent declines throughout the entire period. The upward trend in emissions after 1996 probably reflects electricity demand growth during the late 1990s combined with the availability of banked SO_2 emissions allowances from initial over-compliance with control requirements in Phase 1 of the USEPA Acid Rain Program. This led to relatively low market prices for allowances later in the decade, which encouraged utilities to purchase allowances rather than implement new controls as electricity output expanded. The observed decline in the 2002 SO_2 emissions inventory reflects implementation of the second phase of the USEPA Acid Rain Program, which in 2000 further reduced allowable emissions and extended emissions limits to more power plants.

Figure 3-2 shows the percent contribution from different source categories to overall annual 2002 SO_2 emissions in MANE-VU states. The chart shows that point sources dominate SO_2 emissions, which primarily consist of stationary combustion sources for generating electricity, industrial energy, and heat. Smaller stationary combustion sources called "area sources" (primarily commercial and residential heating)

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[n] The description of MANE-VU state inventories discussed throughout this section does not include the portion of Virginia in the Washington, DC metropolitan area.

are another important source category in MANE-VU states. By contrast, on-road and non-road mobile sources make only a relatively small contribution to overall SO_2 emissions in the region (NESCAUM, 2001).

Figure 3-1. State level sulfur dioxide emissions

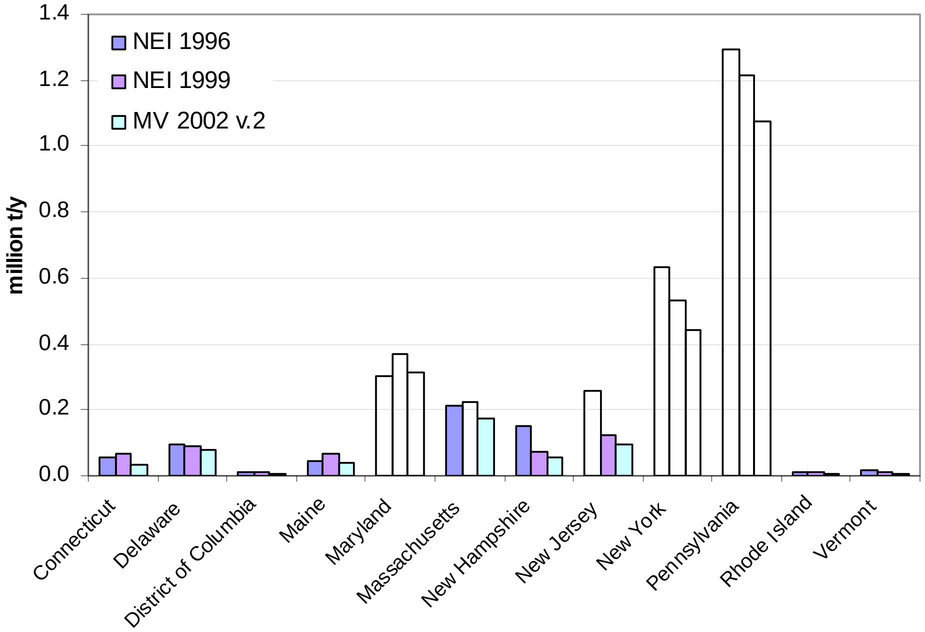


Figure 3-2. 2002 MANE-VU state SO_2 inventories

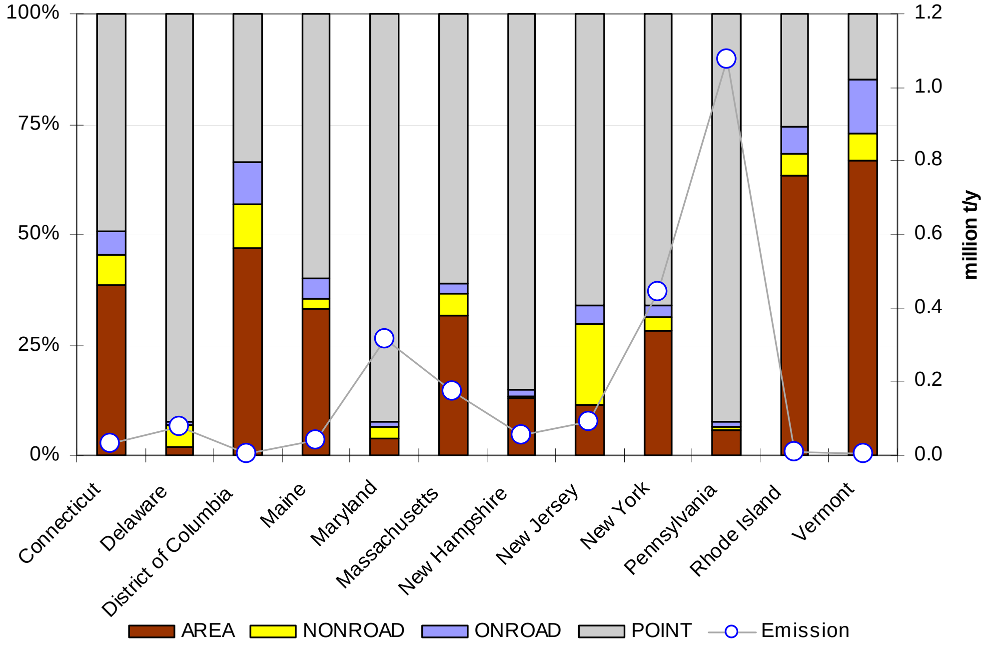


Figure Key: Bars = Percentage fractions of four source categories; Circles = Annual emissions amount in 10^6 tons per year. Note that Version 2 of the MANE-VU inventory was used and the Virginia portion of the Washington, DC metropolitan area is not shown in the figure.

3.1.2. Volatile organic compounds (VOCs)

Existing emission inventories generally refer to VOCs based on their historical contribution to ozone formation. From a fine particle perspective, VOCs (also referred to as hydrocarbons) are of concern because they can react in the atmosphere to form secondary organic aerosol (SOA) as a result of condensation and oxidation processes. The SOA component of fine particles also obscures visibility, but this component has a smaller impact on visibility (on a per unit mass basis) relative to sulfate or nitrate, which have an affinity for water that allows them to significantly “grow” as particles under humid conditions. Nonetheless, organic carbon typically has the second largest visibility impact at most Class I sites next to sulfate, given its large mass contribution.

As shown in Figure 3-3, the VOC inventory is dominated by mobile and area sources. Most VOC emissions in MANE-VU, however, come from natural sources, which are not shown in the figure. Among the human-caused VOC emissions, on-road mobile sources of VOCs include exhaust emissions from gasoline passenger vehicles and diesel-powered heavy-duty vehicles as well as evaporative emissions from transportation fuels. VOC emissions may also originate from a variety of area sources (including solvents, architectural coatings, and dry cleaners) as well as from some point sources (e.g., industrial facilities and petroleum refineries).

Naturally occurring (biogenic) VOC emissions are caused by the release of natural organic compounds from plants in warm weather. Natural, or biogenic, VOCs contribute significantly to fine particle formation. Biogenic VOCs are not included in Figure 3-3, but nationally, they represent roughly two-thirds of all annual VOC emissions (USEPA, 2006). Biogenic emissions are extremely difficult to estimate, as it requires modeling the behavior of many plants as well as their responses to the environment.

With regard to fine particle formation, understanding the transport dynamics and source regions for organic carbon is likely to be more complex than for sulfate. This is partly because of the large number and variety of VOC species, the fact that their transport characteristics vary widely, and the fact that a given species may undergo numerous complex chemical reactions in the atmosphere. Thus, the organic carbon contribution to fine particles in the East is likely to include manmade pollution transported from a distance, manmade pollution from nearby sources, and biogenic emissions, especially terpenes from coniferous forests.

For fine particles derived from organic carbon, the oxidation of hydrocarbon molecules containing seven or more carbon atoms is generally the most significant pathway for their formation (Odum *et al.*, 1997). Recent research, however, suggests that smaller reactive hydrocarbons like isoprene not only contribute significantly to ground-level ozone, which may indirectly impact organic aerosol formation, but also contribute directly to ambient organic aerosol through heterogeneous processes (Claeys et al., 2004; Kroll et al., 2005).

Figure 3-3. 2002 MANE-VU state VOC inventories

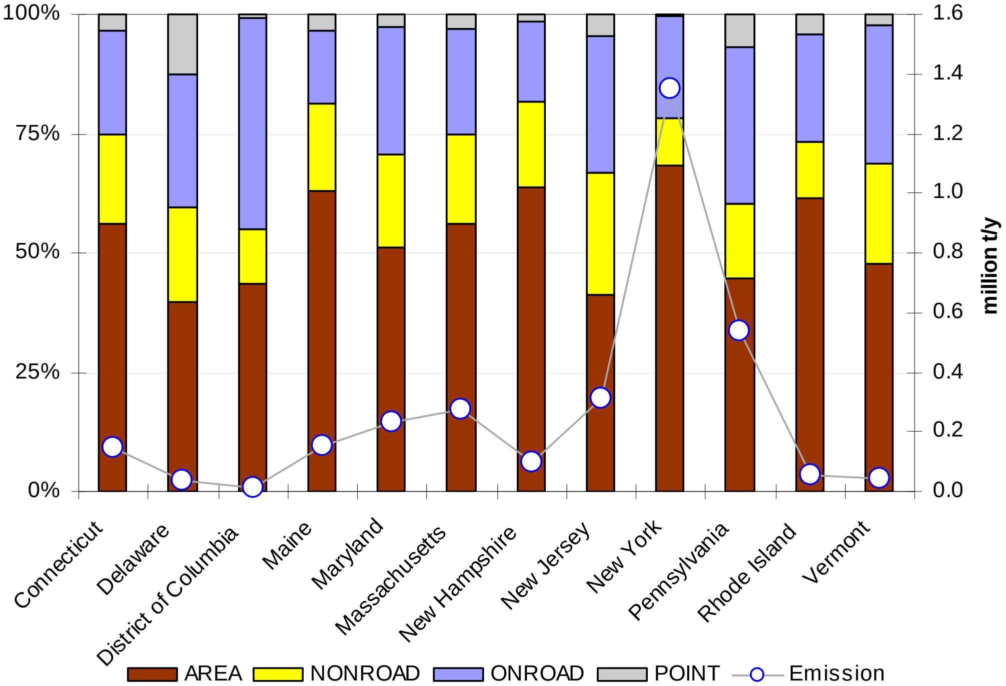


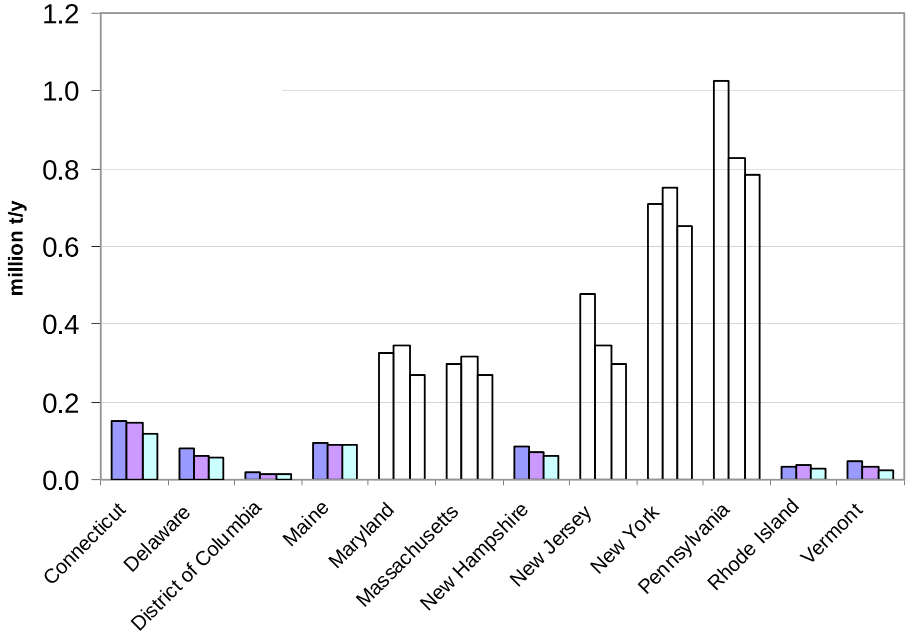
Figure key: Bars = Percentage fractions of four source categories; Circles = Annual emissions amount in 10^6 tons per year. Note that Version 2 of the MANE-VU inventory was used and the Virginia portion of the Washington, DC metropolitan area is not shown in the figure. Biogenic VOCs are not included in this figure.

3.1.3. Oxides of nitrogen (NO_X)

NO_X emissions contribute directly to $PM_{2.5}$ nonattainment and visibility impairment in the eastern U.S. by forming nitrate particles. Nitrate generally accounts for a substantially smaller fraction of fine particle mass and related light extinction than sulfate and organic carbon regionally in MANE-VU. Notably, nitrate may play a more important role at urban sites 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, 2001).

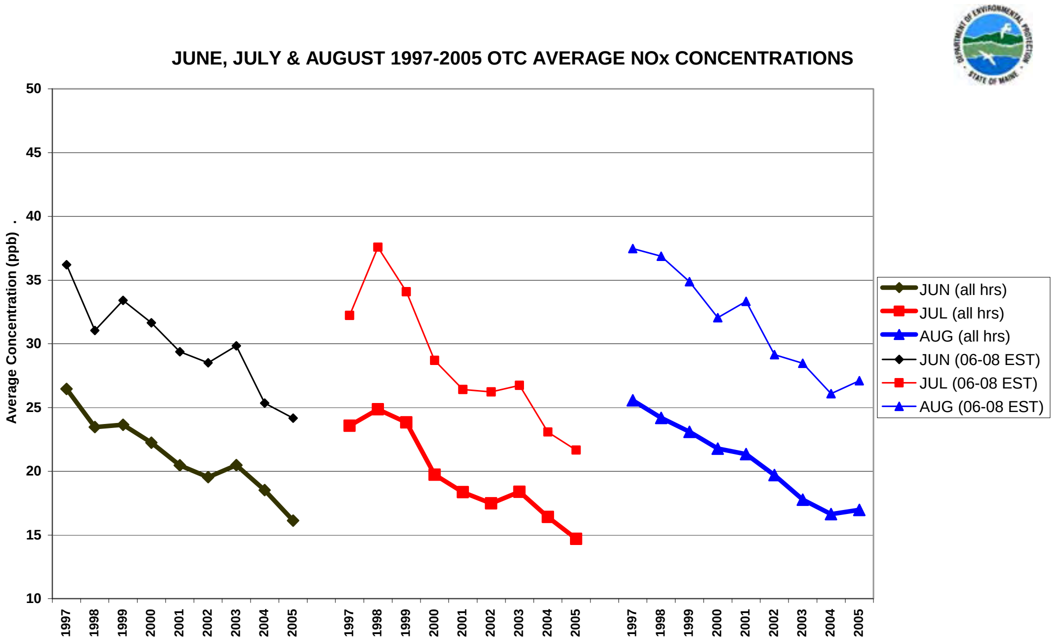
Figure 3-4 shows NO_X emissions in MANE-VU at the state level. Since 1980, nationwide emissions of NO_X from all sources have shown little change. In fact, emissions increased by 2 percent between 1989 and 1998 (USEPA, 2000a). This increase is most likely due to industrial sources and the transportation sector, as power plant combustion sources have implemented modest emissions reductions during the same time period. Most states in MANE-VU experienced declining NO_X emissions from 1996 through 2002, except Massachusetts, Maryland, New York, and Rhode Island, which show an increase in NO_X emissions in 1999 before declining to levels below 1996 emissions in 2002.

Figure 3-4. State level nitrogen oxides emissions



Monitored ambient NO_X trends during the summer from 1997 to 2005 corroborate the downward trend in NO_X emissions seen in the emissions inventories for MANE-VU. As seen in Figure 3-5, the 24-hour (lower trend lines) and 6 a.m.-8 a.m. (upper trend lines) NO_X concentrations indicate decreases in NO_X over this time period in MANE-VU. The NO_X reductions likely come from decreasing vehicle NO_X emissions due to more stringent motor vehicle standards as well as NO_X reductions from MANE-VU NO_X Budget Program and the NO_X SIP Call (mainly power plants).

Figure 3-5. Plot of monitored NO_X trends in MANE-VU during 1997-2005



Note: Upper trend lines correspond to NO_X measured from 0600-0800 EST in the morning. Lower trend lines correspond to NO_X measured over entire day (created by Tom Downs, Maine Department of Environmental Protection).

Power plants and mobile sources 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. The electric sector plays an even larger role, however, in parts of the industrial Midwest where high NO_X emissions have a particularly significant power plant contribution. By contrast, mobile sources dominate the NO_X inventories for more urbanized mid-Atlantic and New England states to a far greater extent, as shown in Figure 3-6. In these states, on-road mobile sources — a category that mainly includes highway vehicles — represent the most significant NO_X source category. Emissions from non-road (i.e., off-highway) mobile sources, primarily diesel-fired engines, also represent a substantial fraction of the inventory.

Figure 3-6. 2002 MANE-VU state NO_X inventories

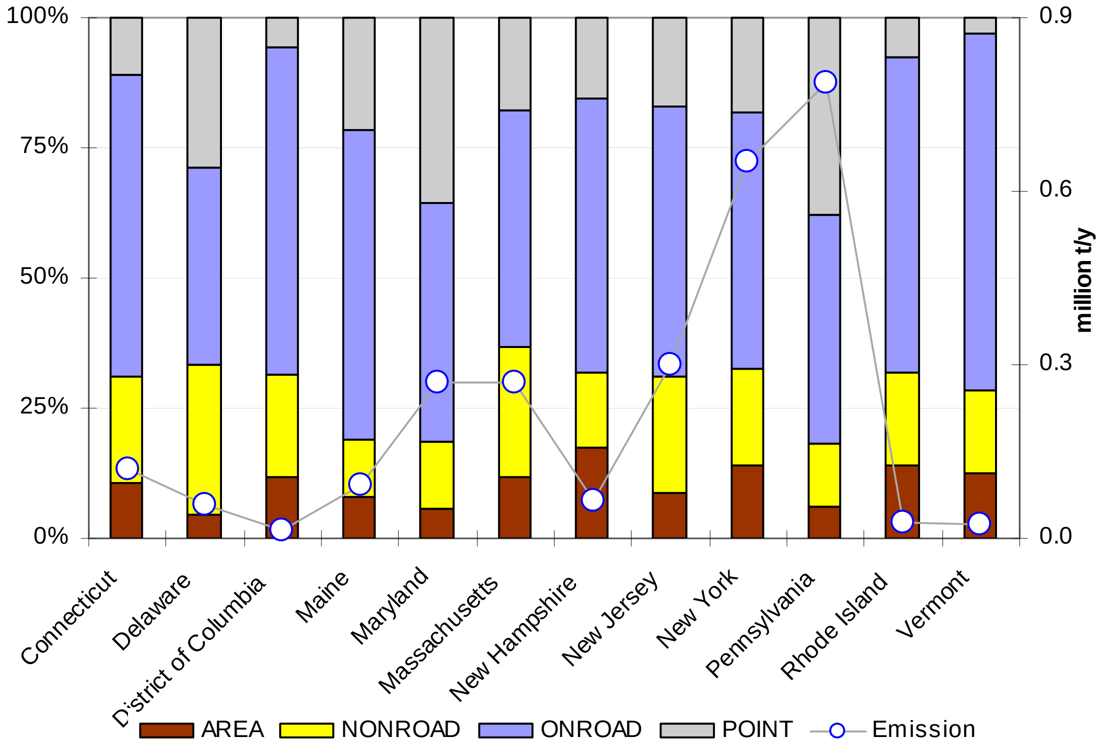


Figure key: Bars = Percentage fractions of four source categories; Circles = Annual emissions amount in 10^6 tons per year. Note that Version 2 of the MANE-VU inventory was used and the Virginia portion of the Washington, DC metropolitan area is not shown in the figure.

3.1.4. 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 like SO_2 and NO_X) also contribute to fine particle levels in the atmosphere. For regulatory purposes, we make a distinction between particles with an aerodynamic diameter less than or equal to 10 micrometers and smaller particles with an aerodynamic diameter less than or equal to 2.5 micrometers (i.e., primary PM_{10} and $PM_{2.5}$, respectively).

Figure 3-7 and Figure 3-8 show PM_{10} and $PM_{2.5}$ emissions for MANE-VU states for the years 1996, 1999, and 2002. Note that, as opposed to the other constituents of PM, the 2002 inventory values for PM_{10} are drawn from the 2002 NEI. Most states show a steady decline in annual PM_{10} emissions over this time period. By contrast, emission trends for primary $PM_{2.5}$ are 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 transport 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 before including in modeling analyses.

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), it accounted for 6 to 11 percent of particle-related light extinction at MANE-VU Class 1 sites. On the 20 percent worst-visibility days, however, crustal material generally plays a much smaller role relative to other haze-forming pollutants, ranging from 2 to 3 percent. Moreover, the crustal fraction includes material of natural origin (such as soil or sea salt) that is not targeted under USEPA’s Regional Haze Rule. Of course, the crustal fraction can be influenced by certain human activities, such as 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 sites, control measures targeted at crustal material may prove beneficial.

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

Current emissions inventories for the entire MANE-VU area indicate residential wood combustion represents 25 percent of primary fine particulate emissions in the region. This implies that rural sources can play an important role in addition to the contribution from the region’s many highly populated urban areas. An important consideration in this regard is that residential wood combustion occurs primarily in the winter months, while managed or prescribed burning activities occur largely in other seasons. The latter category includes agricultural field-burning activities, prescribed burning of forested areas, and other burning activities such as construction waste burning. Limiting burning to times when favorable meteorological conditions can efficiently disperse resulting emissions can manage many of these types of sources.

Figure 3-7. State level primary PM$_{10}$ emissions

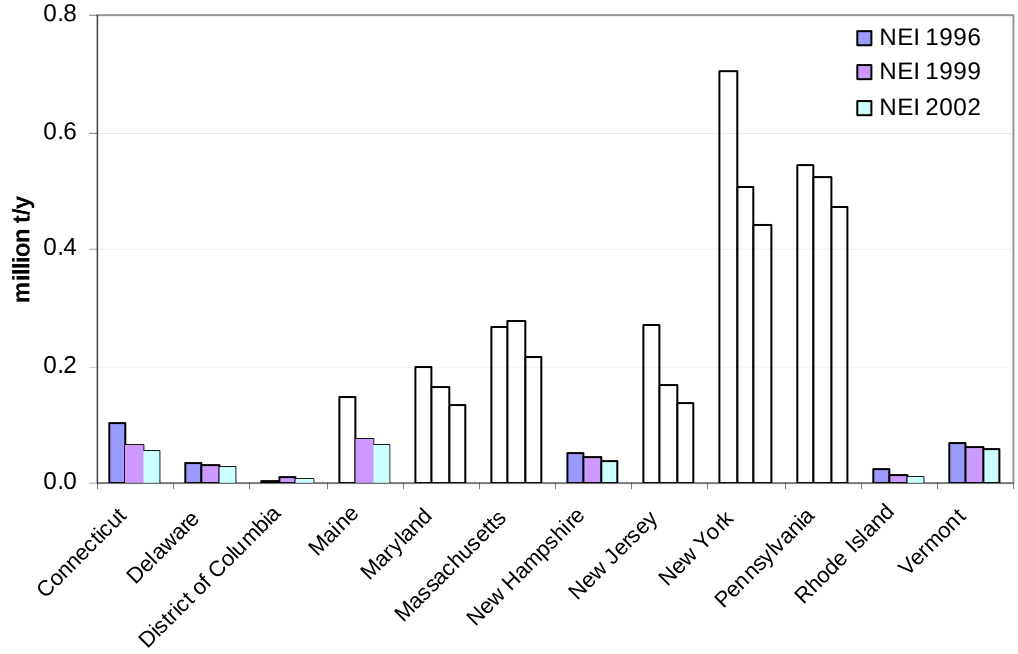


Figure 3-8. State level primary PM$_{2.5}$ emissions

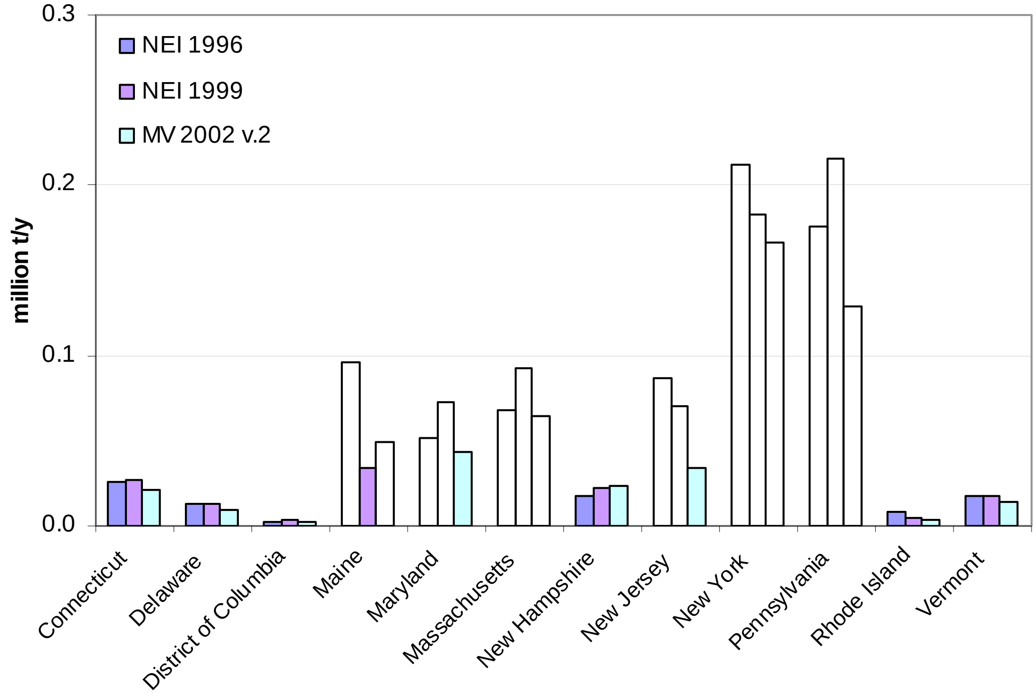


Figure 3-9 and Figure 3-10 show that area and mobile sources dominate primary PM emissions. (The NEI inventory categorizes residential wood combustion and some other combustion sources as area sources.) The relative contribution of point sources is larger in the primary PM$_{2.5}$ inventory than in the primary PM$_{10}$ inventory since the crustal component (which consists mainly of larger or “coarse-mode” particles) contributes mostly to overall PM_{10} levels. At the same time, pollution control equipment commonly installed at large point sources is usually more efficient at capturing coarse-mode particles.

Figure 3-9. 2002 MANE-VU state primary PM_{10} inventories

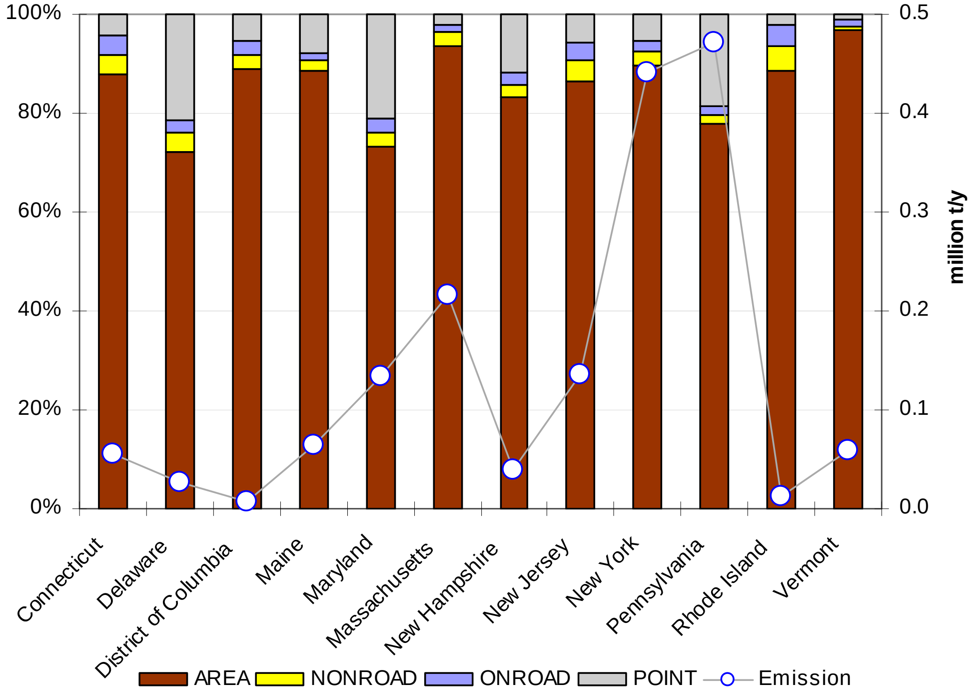


Figure 3-10. 2002 MANE-VU state primary $PM_{2.5}$ inventories

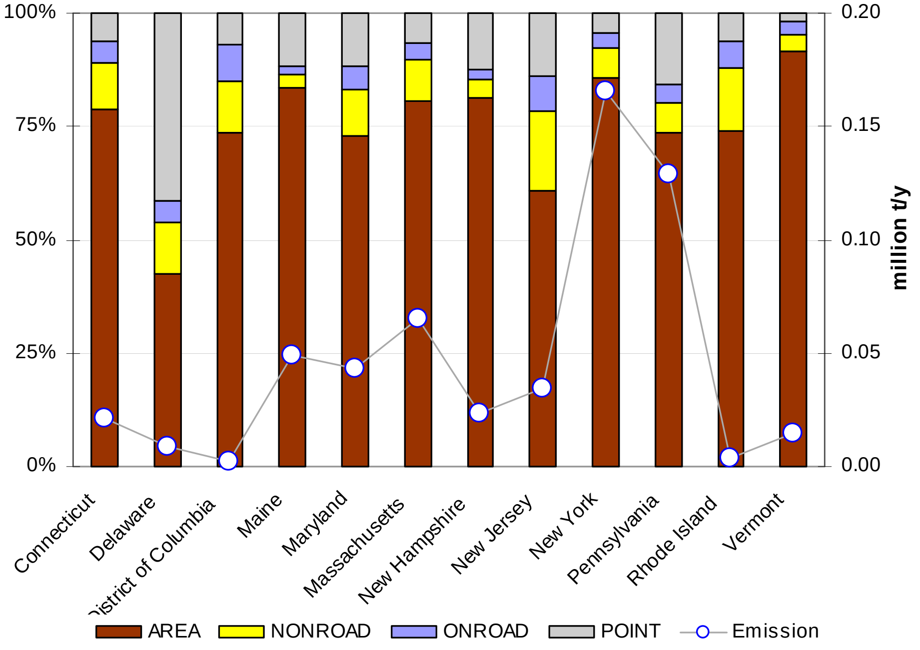


Figure key: Bars = Percentage fractions of four source categories; Circles = Annual emissions amount in 10^6 tons per year. Note that Version 2 of the MANE-VU inventory was used and the Virginia portion of the Washington, DC metropolitan area is not shown in the figure.

3.1.5. Ammonia emissions (NH_3)

Knowledge of ammonia emission sources will be necessary in developing effective regional haze reduction strategies because of the importance of ammonium sulfate and ammonium nitrate in determining overall fine particle mass and light scattering. According to 1998 estimates, livestock and agriculture fertilizer use accounted for approximately 85 percent of all ammonia emissions to the atmosphere (USEPA, 2000b). We need, however, better ammonia inventory data for the photochemical models used to simulate fine particle formation and transport in the eastern United States. Because the USEPA does not regulate ammonia as a criteria pollutant or as a criteria pollutant precursor, these data do not presently exist at the same level of detail or certainty as for NO_X and SO_2.

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 extremely beneficial because a more-than-proportional reduction in fine particle mass can result. Ansari and Pandis (1998) showed that a one $\mu g/m^3$ reduction in ammonium ion could result in up to a four $\mu g/m^3$ 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. 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.

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

Figure 3-11 shows that estimated ammonia emissions were fairly stable in the 1996, 1999, and 2002 NEI for MANE-VU states, with some increases observed for Massachusetts, New Jersey and New York. Area and on-road mobile sources dominate the ammonia inventory, according to Figure 3-12. Specifically, emissions from agricultural sources and livestock production account for the largest share of estimated ammonia emissions in MANE-VU, except in the District of Columbia. The two remaining sources with a significant emissions contribution are wastewater treatment systems and gasoline exhaust from highway vehicles.

Figure 3-11. State level ammonia emissions

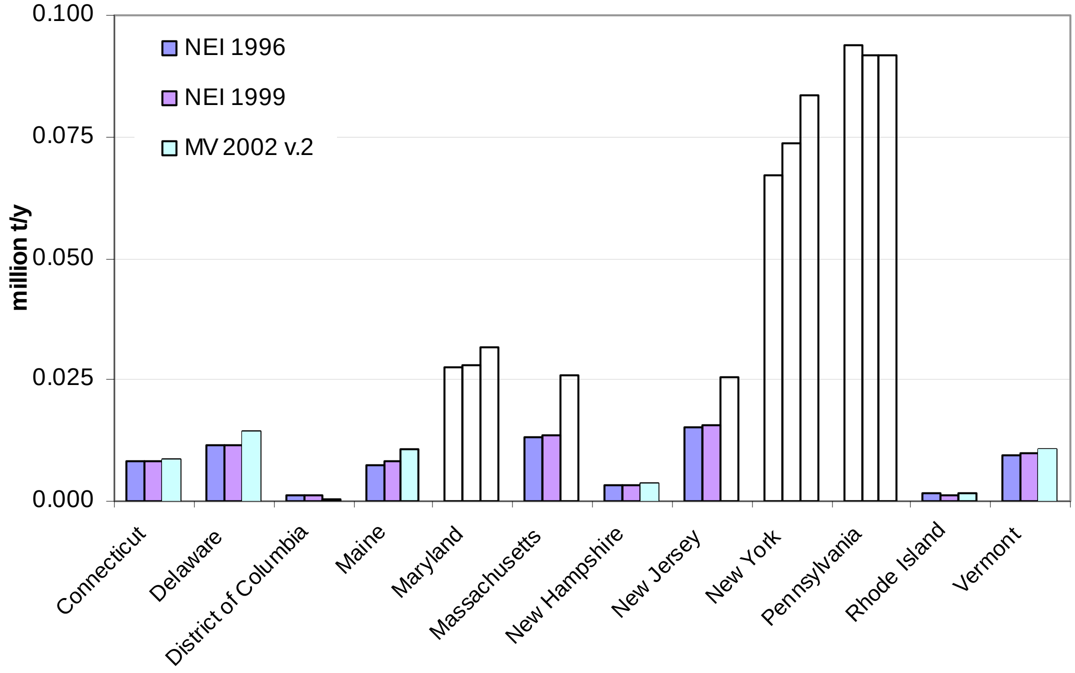


Figure 3-12. 2002 MANE-VU state NH_3 inventories

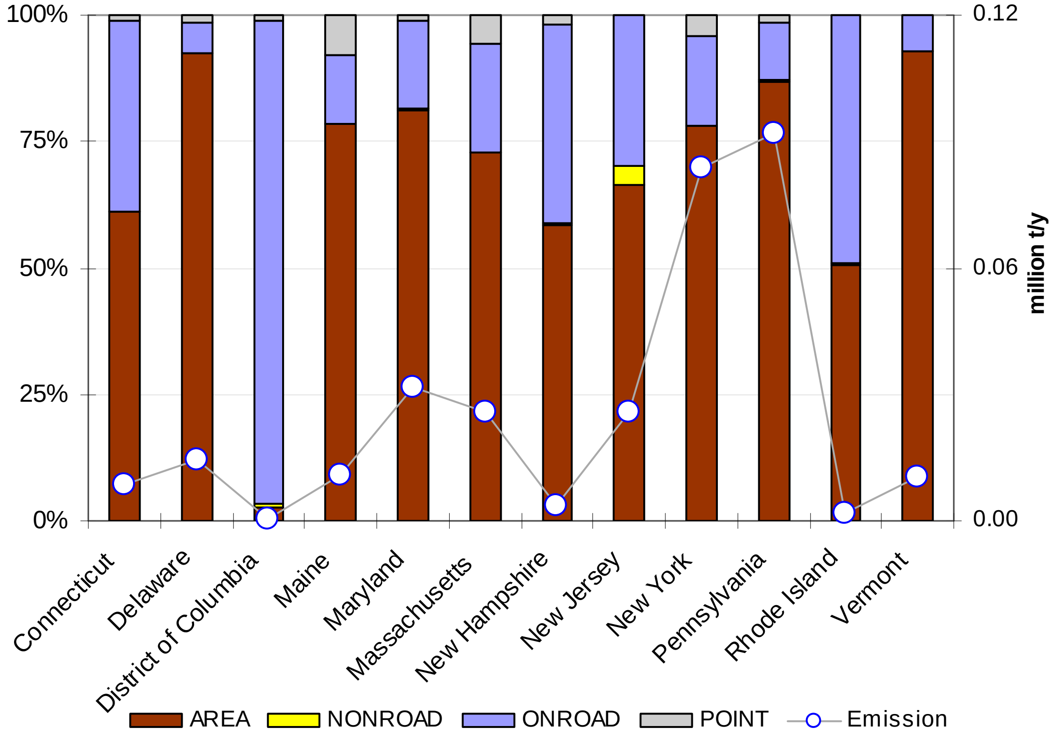


Figure key: Bars = Percentage fractions of four source categories; Circles = Annual emissions amount in 10^6 tons per year. Note that Version 2 of the MANE-VU inventory was used and the Virginia portion of the Washington, DC metropolitan area is not shown in the figure.

3.2. Emissions inventory characteristics outside MANE-VU

SO_2, NO_X and VOC emissions from within MANE-VU are only one component of the emissions contributing to fine particles affecting the MANE-VU region. As regional modeling for the CAIR has shown, emission sources, primarily of SO_2 and NO_X, located outside MANE-VU can significantly contribute to particle sulfate and nitrate transported into the MANE-VU region. Here we present regional emissions information grouped by the three eastern RPOs – MANE-VU, VISTAS (Visibility Improvement State and Tribal Association of the Southeast), and the MWRPO (Midwest RPO). Table 3-1 lists the states in each RPO.

The inventory information is extracted from the USEPA final 2002 National Emissions Inventory (NEI). For consistency, the MANE-VU information here also comes from the 2002 NEI rather than from the MANE-VU Version 2 regional haze emissions inventory described in Section 3.1. The differences between the inventories are not great, as the NEI and the MANE-VU Version 2 inventory are both based on the same inventory information provided by the states.

Table 3-1. Eastern U.S. RPOs and their state members

RPO	State
MWRPO	Illinois
MWRPO	Indiana
MWRPO	Michigan
MWRPO	Ohio
MWRPO	Wisconsin
MANE-VU	Connecticut
MANE-VU	Delaware
MANE-VU	District of Columbia
MANE-VU	Maine
MANE-VU	Maryland
MANE-VU	Massachusetts
MANE-VU	New Hampshire
MANE-VU	New Jersey
MANE-VU	New York
MANE-VU	Pennsylvania
MANE-VU	Rhode Island
MANE-VU	Vermont
VISTAS	Alabama
VISTAS	Florida
VISTAS	Georgia
VISTAS	Kentucky
VISTAS	Mississippi
VISTAS	North Carolina
VISTAS	South Carolina
VISTAS	Tennessee
VISTAS	Virginia
VISTAS	West Virginia

Table 3-2 presents SO_2 emissions by source sector and RPO for the eastern United States. The NO_X emissions by source sector and RPO are presented in Table 3-3 and VOC emissions in Table 3-4. Regionally, SO_2 emissions are more important with respect to regional particle formation and transport. NO_X emissions play an important role in determining the equilibrium between ammonium sulfate and ammonium nitrate formation, especially during winter. VOC emissions contribute to secondary organic aerosol formation.

Table 3-2. SO_2 emissions in eastern RPOs (tons/yr)

RPO	Point	Area	On-road	Non-road	Total
MWRPO	3,336,967	133,415	49,191	82,307	3,601,880
MANE-VU	1,924,573	353,176	39,368	74,566	2,391,683
VISTAS	4,349,437	448,023	83,001	91,307	4,971,769

Table 3-3. NO_X emissions in eastern RPOs (tons/yr)

RPO	Point	Area	On-road	Non-road	Total
MWRPO	1,437,284	184,790	1,290,178	723,844	3,636,096
MANE-VU	680,975	268,997	1,297,357	534,454	2,781,783
VISTAS	2,094,228	266,848	2,160,601	812,615	5,334,293

Table 3-4. VOC emissions in eastern RPOs (tons/yr)

RPO	Point	Area	On-road	Non-road	Total
MWRPO	234,938	1,182,186	660,010	492,027	2,569,160
MANE-VU	93,691	1,798,158	793,541	494,115	3,179,504
VISTAS	458,740	2,047,359	1,314,979	609,539	4,430,617

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USEPA. *2002 Final National Emissions Inventory (NEI)*, available online: ftp://ftp.epa.gov/EmisInventory/2002finalnei/, 2006 (accessed October 10, 2006) [The 2002 NEI reports national annual emissions for total anthropogenic VOC emissions as 16.8 million tons, and total biogenic VOC emissions as 41.8 million tons].

4. WHAT WILL IT TAKE TO CLEAN THE AIR?

In this chapter we build on the conceptual description of fine particle formation and impacts in the MANE-VU region by looking at a typical fine particle pollution event and the meteorological and chemical conditions which contributed to its formation. As an illustration of how the conceptual elements laid out in Chapter 2 and 3 contribute to a pollution event under real-world circumstances, we examine a pollution event from 2002. We examine this event from two perspectives: (1) the broad spatial patterns of the formation and transport of particle air pollution and (2) the chronological sequence of events at a few discrete points where high temporal resolution monitoring was in place. We then proceed to examine likely emission reduction strategies that should be considered in light of the conceptual understanding of fine particle formation and transport developed in this report.

4.1. Meteorological and Pollution Overview of August 8-16, 2002

Annual and seasonal statistics are useful for understanding the general patterns of air pollution in our region, but it is also instructive to review specific high $PM_{2.5}$ episodes in order to shed more light on the meteorological circumstances under which high ambient concentrations of $PM_{2.5}$ are able to form from emitted precursor pollutants. Here we present an analysis of the high $PM_{2.5}$ and regional haze episode of August 2002 by reviewing surface maps from the period to provide a synoptic overview of major weather systems that were influencing air quality across the Northeast U.S. during that time.

Figure 4-1 through Figure 4-3, respectively, show eight-panel displays of afternoon fine particle concentrations as well as surface weather maps and back trajectories from 12Z (8 a.m. EDT) each day. The following chronology of events combines the meteorological insights with $PM_{2.5}$ concentration information to provide a basic storyline for analysis.

A slow-moving high pressure system centered over the Great Lakes set up northerly flow over MANE-VU on August 8. The high drifted southeast-ward and became extended over several days bringing high temperatures to the region. Calm conditions west of MANE-VU on August 10 were pivotal in the formation of fine aerosol concentrations, which began building in the Ohio River Valley. Over the next four days, concentrations in MANE-VU climbed into the 60-90 $\mu g/m^3$ range over a wide area before being swept out to sea by a series of frontal passages beginning on August 15.

8/8 – A high pressure system over the Great Lakes produces NW-N prevailing surface winds (~4-8 mph) throughout the region. Maximum daily temperatures approach or exceed 80° F.

8/9 – Wind speeds fall off but direction remains NW-N as the high moves into the central portion of MANE-VU. Temperatures rise as cloud cover declines.

8/10 – The high reaches the East Coast and stalls. Temperatures (except in northern-most areas) reach 90° F while surface-level winds turn to more southerly directions. Calm conditions through the morning hours in the lower Ohio River Valley promote creation of haze noted in surface observations.

8/11 – Circulation around the high (now near Cape Hatteras) becomes well established. Peak temperatures are in the low to mid-90's. Morning winds are light-to-calm in the area east of the Mississippi – the area of haze now reaches from Michigan to northern Texas and eastward to West Virginia and eastern Tennessee. A surface-level trough descends from north of the Great Lakes during the day, passes eastward through the Ohio River Valley and stalls over the Allegheny Mountains and southward.

8/12 – Temperatures exceed 90º F throughout MANE-VU except in coastal ME. The area of concentrated haze has pushed eastward and now extends from central ME to central PA. Haze builds throughout the day as circulation forces it to channel NE between the stalled trough and a cold front approaching from the Midwest.

8/13 – Calm conditions prevail as the trough reaches coastal NJ by 8 a.m. Generally clear skies allow temperatures to reach the mid-90's everywhere except in coastal ME. Dew points, which had been rising since 8/8, reach the upper 60's. Peak hourly fine aerosol concentrations are greater than 40 $\mu g/m^3$ everywhere in MANE-VU and exceed 90 $\mu g/m^3$ in some locations. By 8 p.m., showers associated with the approaching cold front have reached into Ohio.

8/14 – By 8 a.m. the trough has dissipated and the high is moving offshore. Dew points remain in the upper 60's and peak temperatures reach into the 90's everywhere and top 100 in several locations. Increased ventilation causes aerosol concentrations to drop throughout the day everywhere except ME where some locations peak above 60 $\mu g/m^3$ after midnight.

8/15 – The approaching cold front and associated showers fall apart during the morning hours. By 8 p.m., a new batch of moderate rain has intruded deeply into the region from the SW and has virtually pushed the haze out of the MANE-VU region.

8/16 – A new high building in over the upper Midwest pushes the remains of the showers out of the Northeast.

Figure 4-1. Spatially interpolated maps of fine particle concentrations August 9 – 16, 2002

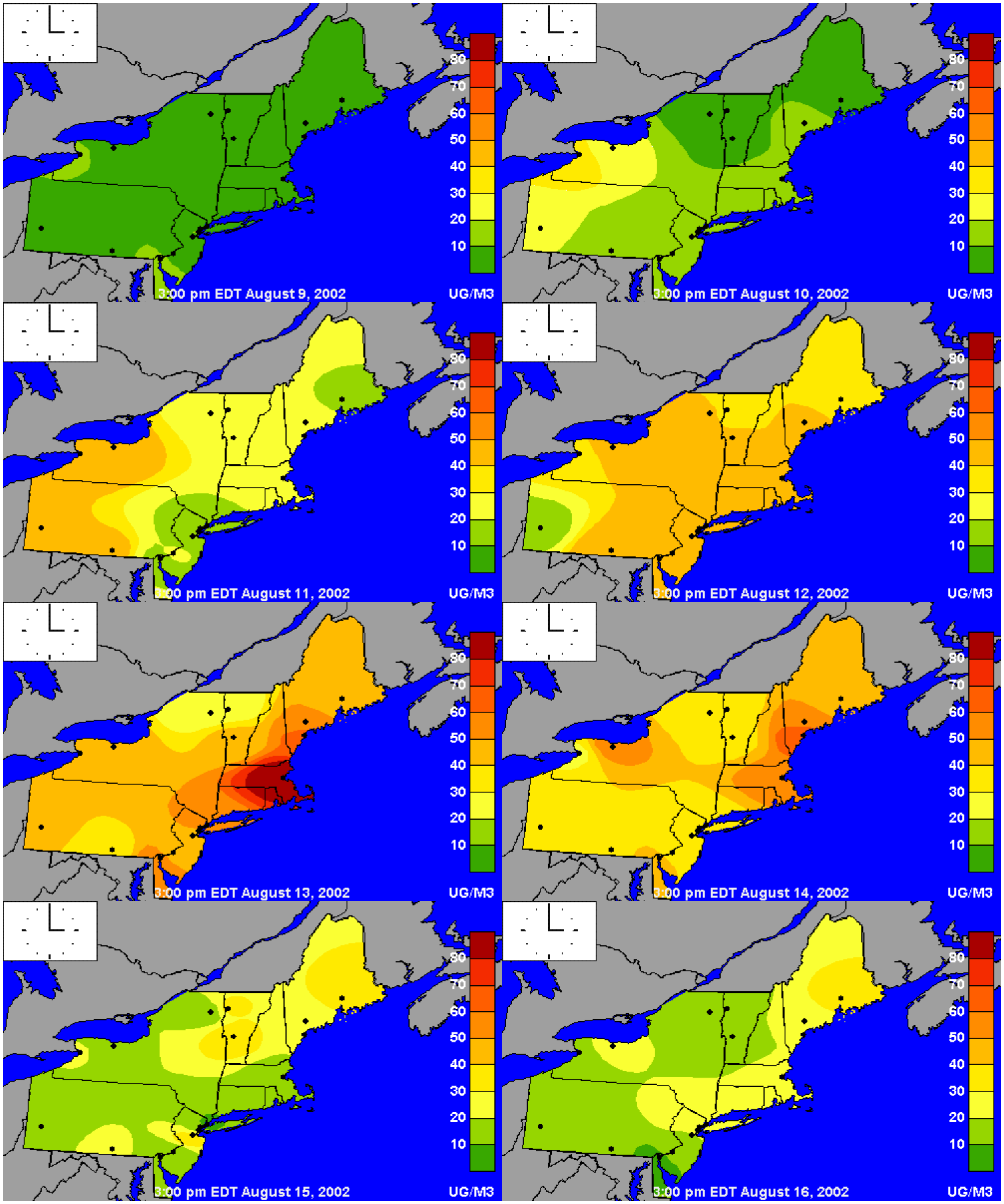
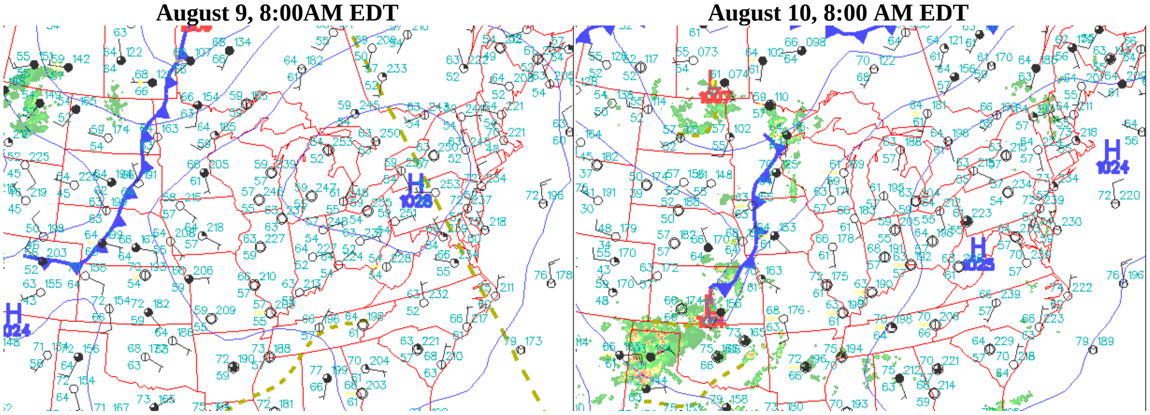
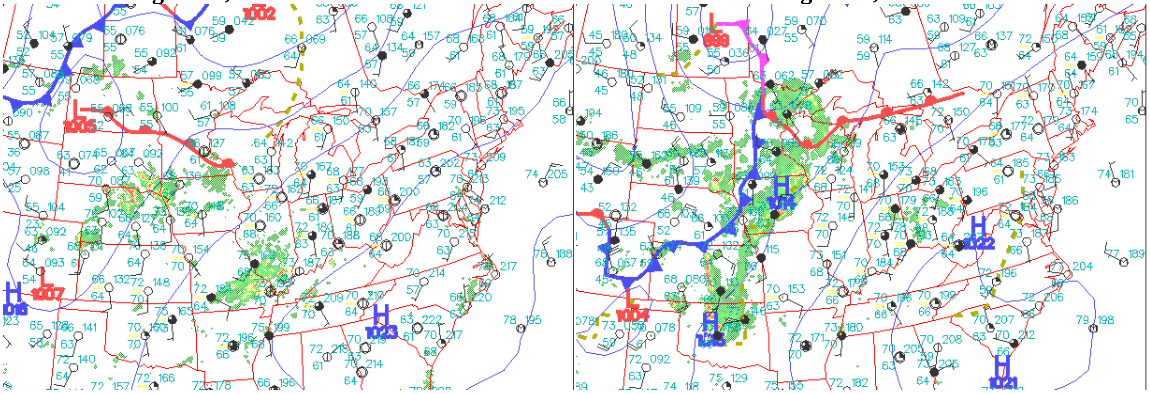


Figure 4-2. Surface weather maps for August 9-16, 2002

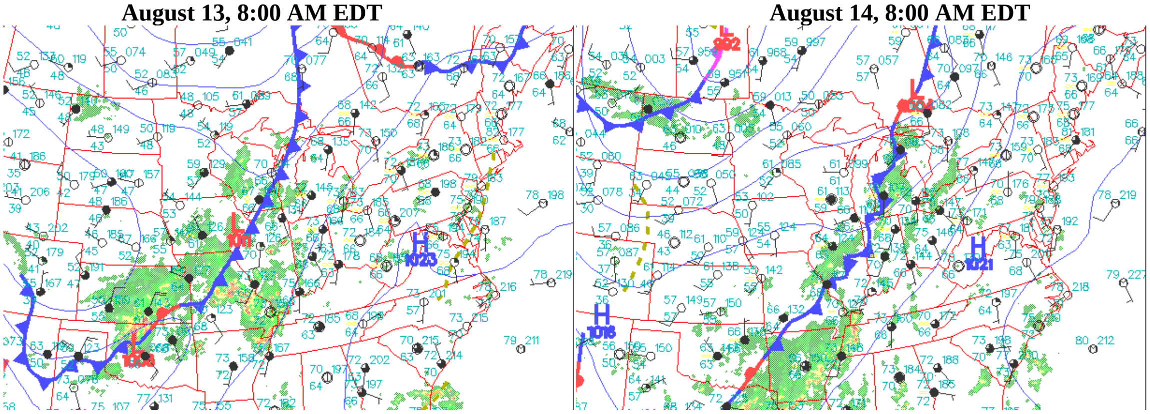
August 9, 8:00AM EDT **August 10, 8:00 AM EDT**



August 11, 8:00 AM EDT **August 12, 8:00 AM EDT**



August 13, 8:00 AM EDT **August 14, 8:00 AM EDT**



August 15, 8:00 AM EDT **August 16, 8:00 AM EDT**

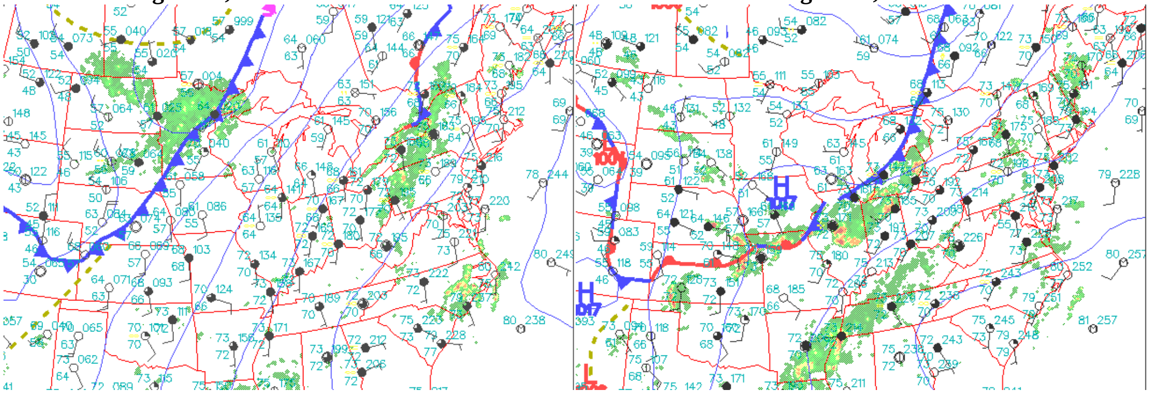
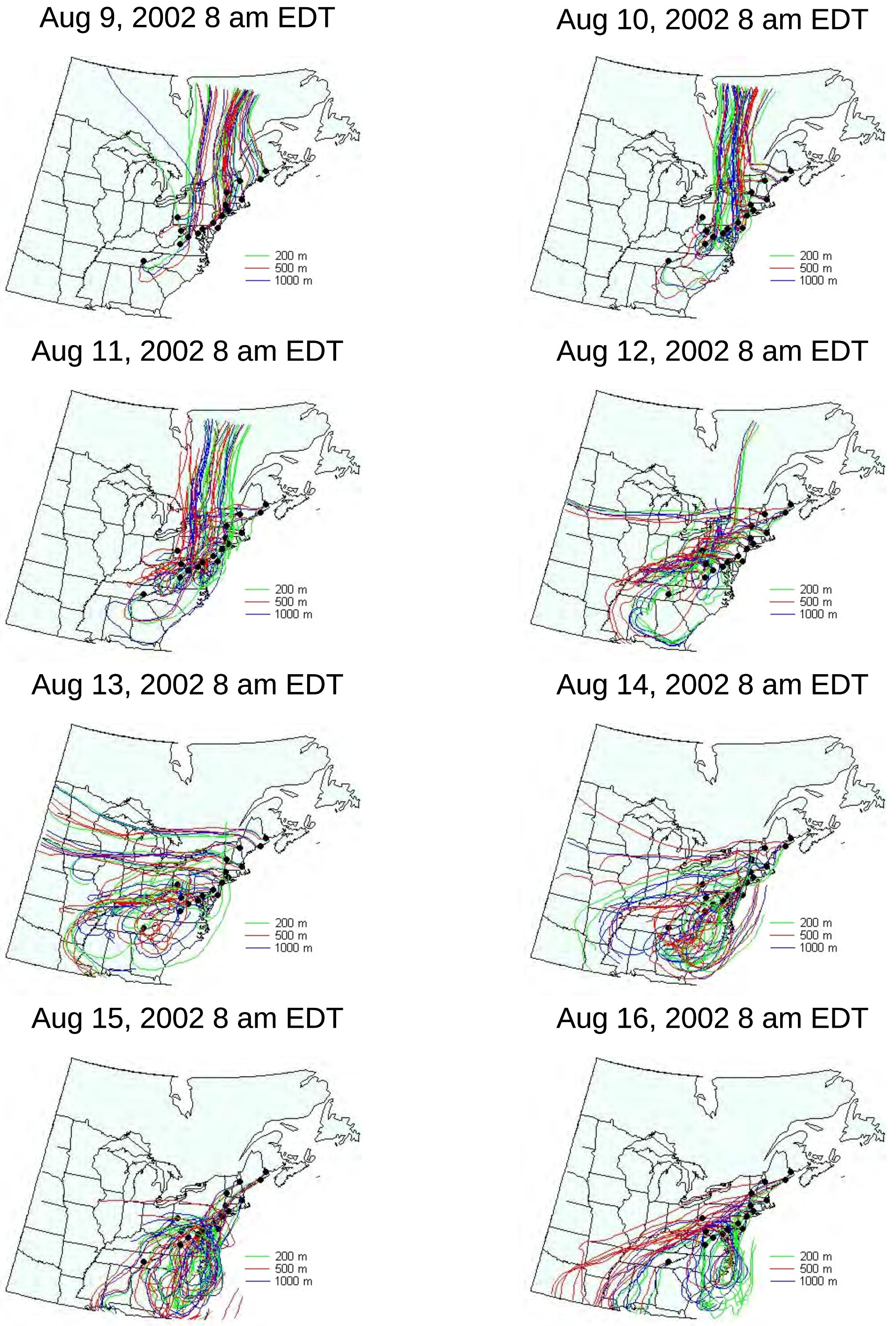


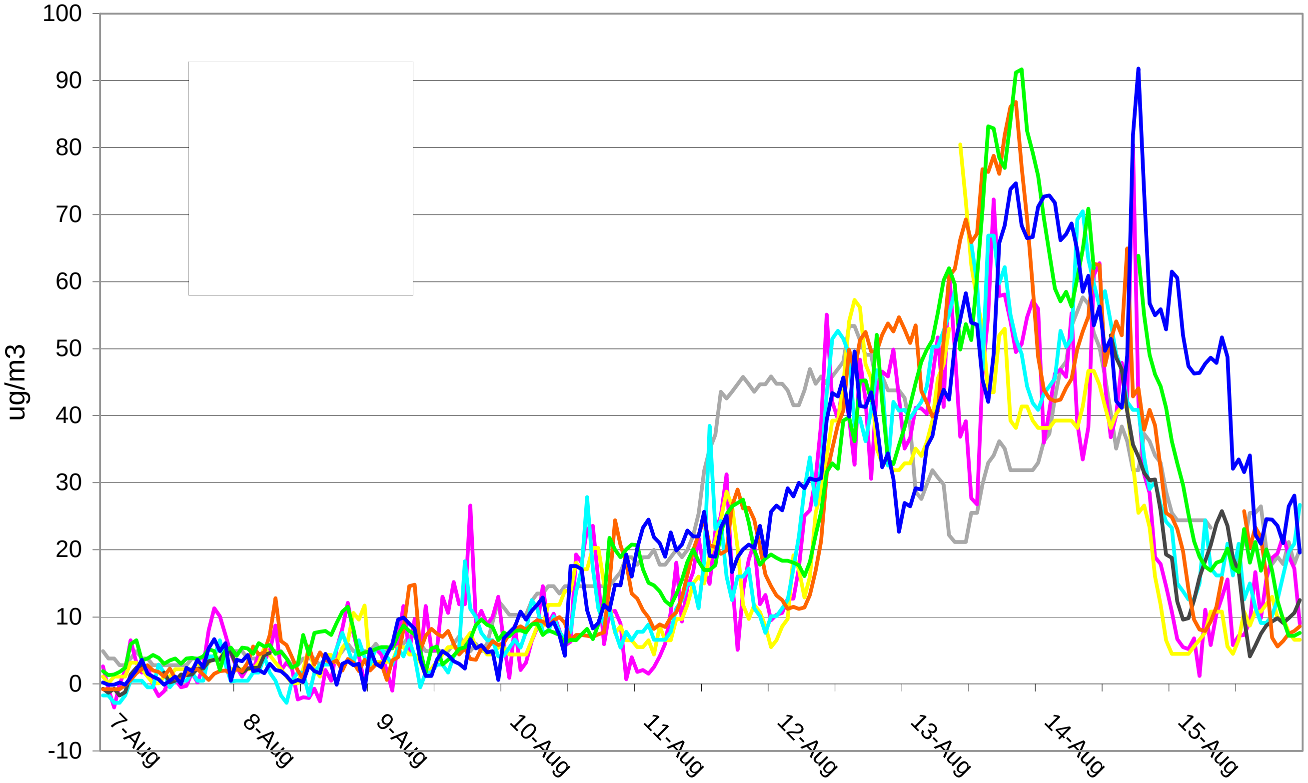
Figure 4-3. HYSPLIT 72-hour back trajectories for August 9-16, 2002



4.2. Temporally and spatially resolved $PM_{2.5}$ measurements

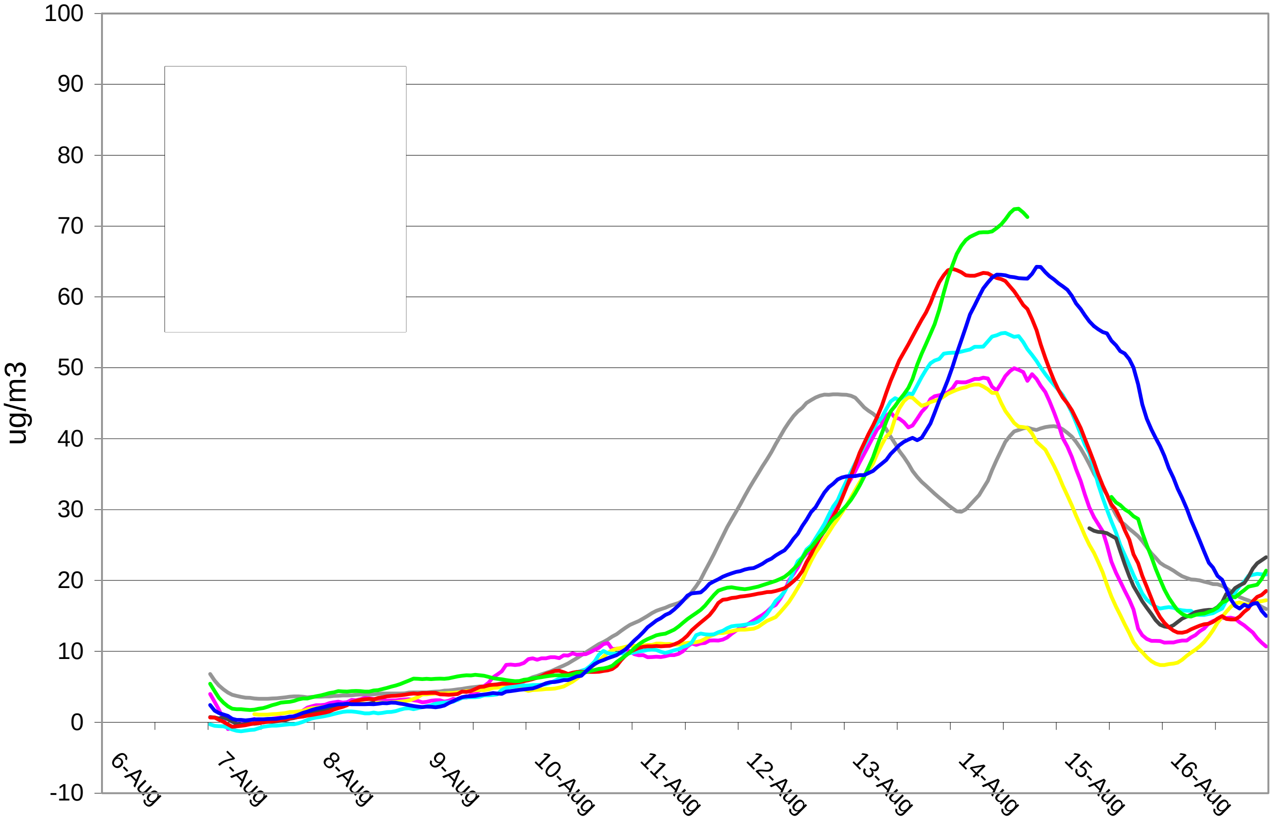
Higher temporal resolution data provide insight into how the events played out in much more detail than can be captured by eight frames on a page; however the most complete picture is obtained when these high *temporal* resolution data can be presented in the context of the relatively greater *spatial* detail provided by maps such as we have seen in Figure 4-1 through Figure 4-3. In Figure 4-4 and Figure 4-5, we present continuous $PM_{2.5}$ data (hourly average and 24-hour rolling average filtered, respectively) for the August 8-16, 2002 time period.

Figure 4-4. Hourly average fine aerosol at 8 sites during the August 2002 episode



Looking at Figure 4-4 in the context of the maps presented in the earlier figures, it is interesting to note the rapid increase, first, in Arendtsville, PA at noon on the 11th, followed by a rise in concentrations along the East Coast around noon on the 12th. This is consistent with Figure 4-1, which shows high $PM_{2.5}$ levels covering western Pennsylvania by 3 p.m. on the 11th and that high $PM_{2.5}$ area has moved over to cover the East Coast by 3 p.m. the next day. This also makes sense with respect to Figure 4-2 and Figure 4-3, which show the high pressure system established on the East Coast by the 11th with surface level back trajectories having shifted from northerly flow to slow southwesterly flow in the western portion of the domain by the morning of the 11th and the coastal sites having switched by the morning of the 12th.

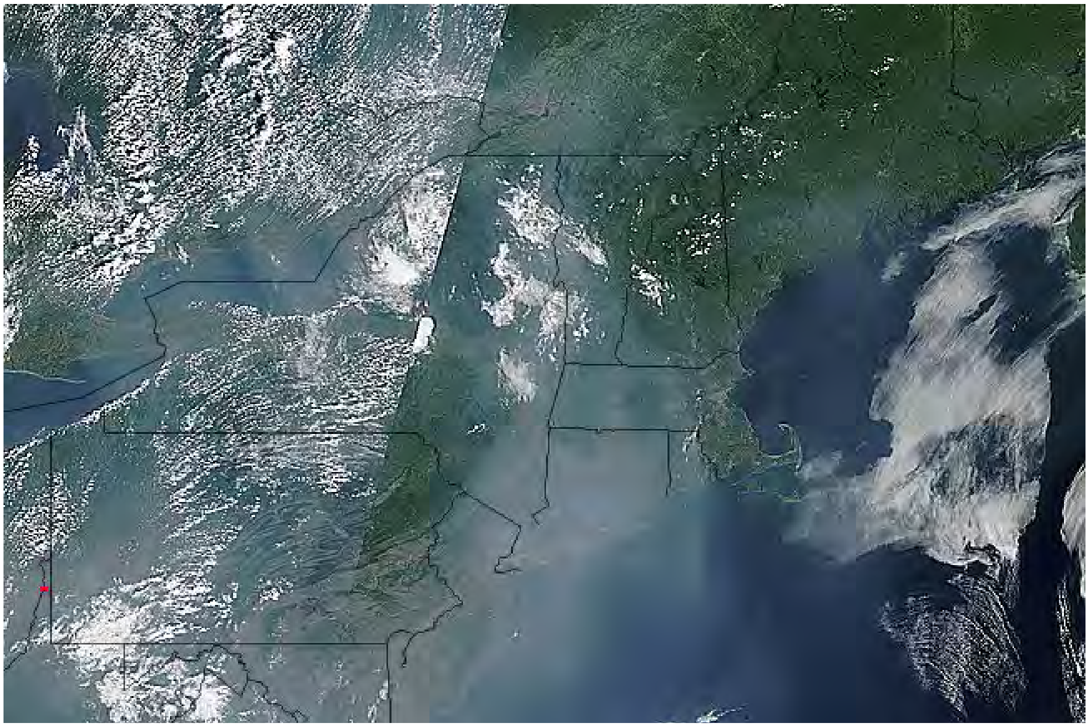
Figure 4-5. 24-hour rolling average fine aerosol at 8 MANE-VU sites during the August 2002 episode



Also note the very high levels observed close to mid-day on the 13th at sites between New York City and Portland, Maine. This is consistent with the strong gradients shown for 3 p.m. on the 13th in Figure 4-1. These rapid increases in concentration are easily explained by the back trajectories of Figure 4-3 that show the advancing front (at this point over Lake Michigan) beginning to push, at upper levels of the atmosphere, an air mass from the upper Midwest due east across the northern half of MANE-VU. At lower levels (see 200 meter trajectories), it can be seen that closer to the surface, this air mass had spent the previous three to four days winding around the Tennessee and Ohio River Valleys before it was driven into the northern reaches of MANE-VU at the peak of the pollution event.

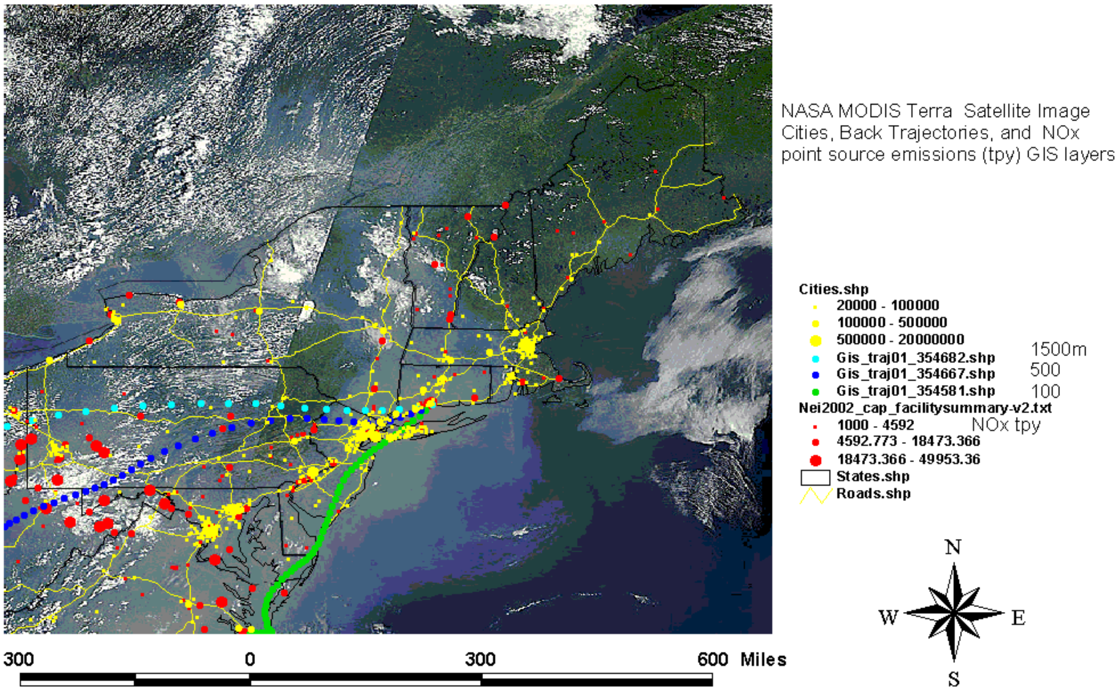
The following figures bring much of this information together in a single image. Figure 4-6 contains satellite photos from MODIS, a mosaic of two consecutive satellite passages on August 13, 2002 from NASA's TERRA satellite. Figure 4-7 shows the same image with geo-referenced activity data and inventory information layered on top to allow for simultaneous depiction of cities, roads, point source emissions, and back trajectories that play a role in the air pollution/haze that affected a large part of the Northeast during this episode.

Figure 4-6. Composite images from NASA's TERRA Satellite on August 13, 2002 showing fine particle pollution/haze.



Note the milky/gray haze due to particle pollution as distinct from the puffy white clouds over broad regions of southern New England and the eastern Mid-Atlantic region.

Figure 4-7. NASA MODIS Terra Satellite Image, Back Trajectories and NO_X Inventory



Geo-referenced activity and inventory data (on top of the satellite images presented above) demonstrating the relationship between observed pollution and upper level winds (driving weather patterns from West to East), mid-level winds (tracking back to major point sources), and lower level winds (tracking back to major population centers along the East Coast).

4.3. Implications for control strategies

A 2003 assessment of fine particulate matter by NARSTO[o] states, "[c]urrent air-quality management approaches focusing on reductions of emissions of SO_2, NO_X, and VOCs are anticipated to be effective first steps towards reducing $PM_{2.5}$ across North America, noting that in parts of California and some eastern urban areas VOC (volatile organic compounds) emissions could be important to nitrate formation."

This conclusion seems to be well supported by the historical record which documents a pronounced decline in particulate sulfate concentrations across the eastern United States during the 1990s. The timing of this observed decline suggests that this is linked to reductions in SO_2 emissions resulting from controls implemented under the federal Acid Rain program beginning in the early to mid-1990s. From 1989 to 1998, SO_2 emissions in the eastern half of the country — that is, including all states within a region defined by the western borders of Minnesota and Louisiana — declined by about 25 percent. This decline in SO_2 emissions correlated with a decline of about 40 percent in average SO_2 and sulfate concentrations, as measured at Clean Air States and Trend Networks (CASTNet) monitoring sites in the same region over the same time period. In fact, at prevailing levels of atmospheric SO_2 loading, the magnitudes of the emissions and concentration changes were not statistically different. This finding suggests that regional reductions in SO_2 emissions have produced near-proportional reductions of particulate sulfate in the eastern United States (NARSTO, 2003). Reductions since 1990 in precursor SO_2 emissions are likely also responsible for a continued decline in median sulfate concentrations in the northeastern United States. Nevertheless, episodes of high ambient sulfate concentrations (with peak levels well above the regional median or average) continue to occur, especially during the summertime when regional transport from the Ohio River Valley is also at its peak. This suggests that further reductions in regional and local SO_2 emissions would provide significant further air quality and visibility benefits (NARSTO, 2003).

For urban areas of the eastern United States, an effective emissions management approach may be to combine regional SO_2 control efforts aimed at reducing summertime $PM_{2.5}$ concentrations with local SO_2 and OC control efforts. Local SO_2 reductions would help reduce wintertime $PM_{2.5}$ concentrations, while OC reductions can help reduce overall $PM_{2.5}$ concentrations year-round. For areas with high wintertime $PM_{2.5}$ levels, strategies that involve NO_X reductions may also be effective (NARSTO, 2003).

Further support for this general approach may be found in a review of several studies by Watson (2002) which concluded that SO_2 emission reductions have in most cases been accompanied by statistically significant reductions in ambient sulfate concentrations. One study (Husar and Wilson, 1993) shows that regionally averaged light extinction closely tracks regionally averaged SO_2 emissions for the eastern United States from 1940 through the mid-1980s. Another study by Malm *et al.* (2002) shows that

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[o] NARSTO was formerly an acronym for the "North American Research Strategy for Tropospheric Ozone." More recently, the term NARSTO became simply a wordmark signifying a tri-national, public-private partnership for dealing with multiple features of tropospheric pollution, including ozone and suspended particulate matter. For more information on NARSTO see http://www.cgenv.com/Narsto/.

regionally averaged emissions and ambient concentrations decreased together from 1988 through 1999 over a broad region encompassing the states of Connecticut, Delaware, Illinois, Indiana, Kentucky, Maine, Massachusetts, Maryland, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Vermont, Virginia, Wisconsin, and West Virginia (Watson, 2002).

These studies and available data from the IMPROVE (Interagency Monitoring of Protected Visual Environment) monitoring network provide strong evidence that regional SO_2 reductions have yielded, and will continue to yield, reductions in ambient secondary sulfate levels with subsequent reductions in regional haze and associated light extinction. They indicate that reductions in anthropogenic primary particle emissions will also result in visibility improvements, but that these will not have a zone of influence as large as those of the secondary aerosols (Watson, 2002).

Watson (2002) notes that during the 65 years in which the regional haze program aims to reach its final visibility goals, several opportunities to revise this basic control approach will arise through the decadal SIP cycle. This enables new scientific results to continue to exert a positive influence as states implement new regulatory control programs for SO_2, NO_X and VOCs, and as ambient concentrations of these pollutants change relative to each other and relative to ambient ammonia levels. As these relationships between species change, atmospheric chemistry may dictate a revised control approach to those previously described. Further research on these issues should be a priority for supporting 2018 SIP submissions. They include the possibility that:

- Reduction of sulfate in a fully neutralized atmosphere (excess ammonia) could encourage ammonium nitrate formation.
- Ever-greater emissions reductions could be required to produce a given level of improvement in ambient pollutant concentrations because of non-linearities in the atmospheric formation of sulfate.
- Changes in ambient conditions favoring the aqueous oxidation of sulfate (this pathway largely accounts for the non-linearity noted above) may have implications for future emissions control programs. Causes of changing ambient conditions could include, for example, climate change.

West *et al.* (1999) examine a scenario for the eastern United States where $PM_{2.5}$ mass decreases linearly with ammonium sulfate until the latter is fully neutralized by ammonia. Further reductions would free ammonia for combination with gaseous nitric acid that, in turn, would slightly increase $PM_{2.5}$ until all of the nitric acid is neutralized and further sulfate reductions are reflected in lower $PM_{2.5}$ mass. This is an extreme case that is more relevant to source areas (e.g., Ohio) where nitric acid (HNO_3) is more abundant than in areas with lower emissions (e.g., Vermont) (Watson, 2002).

In most situations with non-neutralized sulfate (typical of the eastern United States), ammonia is a limiting agent for the formation of nitrate but will not make any difference until sulfate is reduced to the point where it is completely neutralized. At that point, identifying large sources of ammonia emissions will be important. This point is likely to be many years in the future, however (Watson, 2002).

Based on analyses using the Community Multi-Scale Air Quality (CMAQ) model, the aqueous phase production of sulfate in the Northeast appears to be very oxidant limited and hence non-linear. Thus, conditions that are conducive to a dominance of the gas-phase production pathway drive the summer peaks in ambient sulfate levels. Nonetheless, the expected reduction in ambient sulfate levels resulting from a given reduction in SO_2 emissions is less than proportional overall due to the non-linearity introduced by the aqueous pathway for sulfate formation (NARSTO, 2003). These non-linearity effects are more pronounced for haze than for sulfate deposition, especially at higher sulfate air concentrations (USNPS, 2003).

Finally, we note that because visibility in the clearest areas is sensitive to even minute increases in particle concentrations, strategies to preserve visibility on the clearest days may require stringent limits on emissions growth. In this context, even the dilute emissions from distant sources can be important (NARSTO, 2003)

4.4. Conclusion: Simplifying a complex problem

A conceptual understanding of fine particles from a regional perspective across MANE-VU and throughout the eastern U.S. is well understood, yet remains complex due to the multiplicity of source regions (both regional and local), pollutants (SO_2, NO_X, organic carbon, and primary $PM_{2.5}$), and seasons (summer and winter) that are involved in fine particle formation.

Regional approaches to the control of precursor SO_2 and NO_X emissions have been started through Title IV of the Clean Air Act, the NO_X SIP Call, the CAIR, and the establishment and support of Regional Planning Organizations to assist with Regional Haze Rule compliance. With the modeling foundation developed for the CAIR program, the USEPA has presented a compelling technical case on the need for additional regional SO_2 and NO_X reductions in the eastern U.S. to reduce particulate levels and protect public health. While states in the Northeast disagree with the extent of SO_2 and NO_X reductions and the timeline for those reductions to occur, the program is an excellent next step toward reducing fine particles in MANE-VU. It is tempting to suggest that the regional control of SO_2 and NO_X are the extent of the problem facing MANE-VU, but as the conceptual description contained in this report demonstrates, the reduction of fine particles in the eastern U.S. requires a careful balance of regional and local controls for SO_2, NO_X, sources of organic carbon and primary $PM_{2.5}$ during both summer and winter.

The (relatively) higher emissions of SO_2 and NO_X from regions upwind of MANE-VU as well as the long “reach” of sulfate pollution requires continued regional control of these fine particle precursors. However, local accumulation of SO_2-derived sulfate, NO_X-derived nitrate, and primary PM (mostly in the form of black carbon/diesel exhaust) can significantly boost urban $PM_{2.5}$ levels. Residential wood combustion in rural river valleys can significantly raise PM levels as well and affect rural visibility in areas near to Class I areas.

The balance between regional and local controls parallels the balance that needs to be achieved between pollutants. The regional contribution to fine particle pollution is driven by sulfates and organic carbon, whereas the local contribution to $PM_{2.5}$ is derived from SO_2, NO_X, organic carbon, and primary $PM_{2.5}$ (including black carbon/diesel exhaust).

Finally, control strategies which focus on regional SO_2 emissions reductions are needed throughout the summer and winter months, suggesting that a year-round approach to control is needed. Urban nonattainment counties with local emissions of NO_X and VOC will be driven to reduce these emissions during the summer for ozone benefits, but these same pollutants – as well as primary particulate emissions – contribute to high $PM_{2.5}$ levels in winter, suggesting that annual controls for all of these pollutants make sense in a multi-pollutant context. Finally, residential wood smoke near Class I areas is clearly a winter-only issue, and further controls may be desirable near specific Class I sites where organic carbon is a contributor on the 20 percent worst visibility days that occur in winter months.

To bring attainment to the current fine particle nonattainment counties and meet reasonable progress goals toward national visibility goals, there continues to be a need for more regional SO_2 and NO_X reductions coupled with appropriate local SO_2, NO_X, VOC, and primary $PM_{2.5}$ (including diesel exhaust) controls where local accumulation is shown to add to the regional burden of sulfate and nitrate $PM_{2.5}$ (primarily in winter). These local controls will vary by location and by season, but the regional control of SO_2 and NO_X should be maintained on an annual basis given the contribution of regional sulfate and nitrate to fine particle peaks during both summer and winter months.

Appendix A: Excerpts from EPA Guidance Document, Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze

APPENDIX A: EPA GUIDANCE DOCUMENT EXERPT

11.0 How Do I Get Started? - A "Conceptual Description"

A State/Tribe should start developing information to support a modeled attainment demonstration by assembling and reviewing available air quality, emissions and meteorological data. Baseline design values should be calculated at each monitoring site, as described in Section 3. For PM applications, speciated data should be reviewed to get a sense of what component(s) might be contributing most significantly to nonattainment or light extinction. If past modeling has been performed, the emission scenarios examined and air quality predictions may also be useful. Readily available information should be used by a State/Tribe to develop an initial conceptual description of the nonattainment or reasonable haze problem in the area which is the focus of a modeled demonstration. A conceptual description is instrumental for identifying potential stakeholders and for developing a modeling/analysis protocol. It may also influence a State's choice of air quality model, modeling domain, grid cell size, priorities for quality assuring and refining emissions estimates, and the choice of initial diagnostic tests to identify potentially effective control strategies. In general, a conceptual description is useful for helping a State/Tribe identify priorities and allocate resources in performing a modeled demonstration.

In this Section, we identify key parts of a conceptual description. We then present examples of analyses which could be used to describe each of these parts. We note that initial analyses may be complemented later by additional efforts performed by those implementing the protocol.

11.1 What Is A "Conceptual Description"?

A "conceptual description" is a qualitative way of characterizing the nature of an area's nonattainment or regional haze problem. It is best described by identifying key components of a description. Examples are listed below. There are 3 different examples. One each for ozone, annual $PM_{2 5}$, and regional haze. The examples are not necessarily comprehensive. There could be other features of an area's problem which are important in particular cases. For purposes of illustration later in the discussion, we have answered each of the questions posed below. Our responses appear in parentheses.

11.1.1 8-Hour Ozone NAAQS

1. Is the nonattainment problem primarily a local one, or are regional factors important?
(Surface measurements suggest transport of ozone close to 84 ppb is likely. There are some other nonattainment areas not too far distant.)

2. Are ozone and/or precursor concentrations aloft also high?
(There are no such measurements.)

3. Do violations of the NAAQS occur at several monitoring sites throughout the nonattainment area, or are they confined to one or a small number of sites in proximity to one another?
(Violations occur at a limited number of sites, located throughout the area.)

4. Do observed 8-hour daily maximum ozone concentrations exceed 84 ppb frequently or just on a few occasions?
(This varies among the monitors from 4 times up to 12 times per year.)

5. When 8-hour daily maxima in excess of 84 ppb occur, is there an accompanying characteristic spatial pattern, or is there a variety of spatial patterns?
(A variety of patterns is seen.)

6. Do monitored violations occur at locations subject to mesoscale wind patterns (e.g., at a coastline) which may differ from the general wind flow?
(No.)

7. Have there been any recent major changes in emissions of VOC or NO_X in or near the nonattainment area? If so, what changes have occurred?
(Yes, several local measures [include a list] believed to result in major reductions in VOC [quantify in tons per summer day] have been implemented in the last five years. Additionally, the area has seen large regional NO_X reductions from the NO_X SIP call.)

8. Are there discernible trends in design values or other air quality indicators which have accompanied a change in emissions?
(Yes, design values have decreased by about 10% at four sites over the past [x] years. Smaller or no reductions are seen at three other sites.)

9. Is there any apparent spatial pattern to the trends in design values?
(No.)

10. Have ambient precursor concentrations or measured VOC species profiles changed?
(There are no measurements.)

11. What past modeling has been performed and what do the results suggest?
(A regional modeling analysis has been performed. Two emission scenarios were modeled: current emissions and a substantial reduction in NO_X emissions throughout the regional domain. Reduced NO_X emissions led to substantial predicted reductions in 8-hour daily maximum ozone in most locations, but changes near the most populated area in the nonattainment area in question were small or nonexistent.)

12. Are there any distinctive meteorological measurements at the surface or aloft which appear to coincide with occasions with 8-hour daily maxima greater than 84 ppb?
(Other than routine soundings taken twice per day, there are no measurements aloft. There is no obvious correspondence with meteorological measurements other than daily maximum temperatures are always > 85 F on these days.)

Using responses to the preceding questions in this example, it is possible to construct an initial conceptual description of the nonattainment area's ozone problem. First, responses to questions 1 and 11 suggest there is a significant regional component to the area's nonattainment problem. Second, responses to questions 3, 4, 7, 8, and 11 indicate there is an important local component to the area's nonattainment problem. The responses to questions 4, 5 and 12 indicate that high ozone concentrations may be observed under several sets of meteorological conditions. The responses to questions 7, 8, and 11 suggest that ozone in and near the nonattainment area may be responsive to both VOC and NO_X controls and that the extent of this response may vary spatially. The response to question 6 suggests that it may be appropriate to develop a strategy using a model with 12 km grid cells.

The preceding conceptual description implies that the State/Tribe containing the nonattainment area in this example will need to involve stakeholders from other, nearby States/Tribes to develop and implement a modeling/analysis protocol. It also suggests that a nested regional modeling analysis will be needed to address the problem. Further, it may be necessary to model at least several distinctive types of episodes and additional analyses will be needed to select episodes. Finally, sensitivity (i.e., diagnostic) tests, or other modeling probing tools, will be needed to assess the effects of reducing VOC and NO_X emissions separately and at the same time.

11.1.2 Annual $PM_{2.5}$ NAAQS

1. Is the nonattainment problem primarily a local one, or are regional factors important?
(Surface measurements suggest that only design values in or immediately downwind of the city violate the NAAQS. However, other nearby design values come close to the concentration specified in the NAAQS)

2. What is the relative importance of measured primary and secondary components of $PM_{2.5}$ measured at sites violating the NAAQS?
(Secondary components (i.e., SO_4, NO_3, OC) constitute about 80% of the measured mass of $PM_{2.5}$. There are higher concentrations of primary $PM_{2.5}$ in the core urban area compared to the suburbs and more rural areas.)

3. What are the most prevalent components of measured $PM_{2.5}$?
(The most important components in ranked order are mass associated with SO_4, OC and inorganic primary particulate matter (IP)).

4. Does the measured mix of PM components appear to roughly agree with mix of emission categories surrounding the monitoring sites?
(No. Relative importance of measured crustal material (IP) appears less than what might be inferred from the inventory).

5. Do there appear to be any areas with large gradients of primary $PM_{2.5}$ in monitored or unmonitored areas?
(Cannot really tell for sources of crustal material until we resolve the preceding

inventory/monitoring discrepancy. There are no other obvious major sources of primary particulate matter).

6. Is there any indication of what precursor might be limiting formation of secondary particulate matter?
(No indicator species analyses have been performed. Past analyses performed for ozone-related SIP revisions suggest that ozone in this area may be limited by availability of VOC).

7. Do monitored violations occur at locations subject to mesoscale wind patterns (e.g., at a coastline) which may differ from the general wind flow?
(No.)

8. Have there been any recent major changes in emissions of PM or its precursors in or near the nonattainment area? What?
(Yes, measures believed to result in major reductions in VOC and NO_X have been implemented in the last 5 years. Reductions in power plant NO_X have resulted from the NO_X SIP call and SO_2 emissions reductions have resulted from the national program to reduce acid deposition.)

9. Are there discernible trends in design values or other air quality indicators which have accompanied a change in emissions?
(The trend appears to be downward, but the most recent air quality data has been higher. Overall, the period of record is insufficiently long to tell).

10. Is there any apparent spatial pattern to the trends in design values?
(No.)

11. What past modeling has been performed and what do the results suggest?
(A regional modeling analysis has been performed for ozone and $PM_{2.5}$. Two emission scenarios were modeled: current emissions and a substantial reduction in NO_X and SO_2 emissions throughout a regional domain. Reduced NO_X emissions led to substantial predicted reductions in 8-hour daily maximum ozone in most locations. Modeled SO_2 reductions from the CAIR rule had a strong impact on sulfate concentrations)

12. Are there any distinctive meteorological measurements at the surface or aloft which appear to coincide with occasions with $PM_{2.5}$ concentrations in excess of 15.0 :g/m^3?
(Other than routine soundings taken twice per day, there are no measurements aloft. There is no obvious correspondence with meteorological measurements other than daily maximum temperatures are often > 85F on days with the highest $PM_{2.5}$ observations.)

13. Do periods with high measured particulate matter or components of particulate matter appear to track each other or any other measured pollutant?
(There appears to be some correspondence between measured high concentrations of SO_4 and ozone).

Using responses to the preceding questions in this example, it is possible to construct an initial conceptual description of the nonattainment area's ozone problem. First, responses to questions 1, 2 and 3 suggest there is a significant regional component to the area's nonattainment problem. Second, responses to questions 1 and 3 indicate there is a local component to the problem. The responses to questions 11,12 and 13 suggest that there may be a link between reducing ozone and reducing particulate matter. Thus, it may be appropriate to assess effects of previously committed to strategies to reduce ozone and national PM control measures before simulating additional control measures. The responses to questions 4 and 5 suggest that it is premature to determine whether a "local area analysis" will be needed. The response to question 7 suggests that it may not be necessary to model with very small grid cells, at least for the secondary components of $PM_{2 5}$.

The preceding conceptual description implies that the State containing the nonattainment area in this example will need to involve stakeholders from other, nearby States to develop and implement a modeling/analysis protocol. It also suggests that a nested regional modeling analysis will be needed to address the problem.

11.1.3 Example reasonable progress application

1. What components of particulate matter appear to have high concentrations on days with poor visibility?
(Mass associated with SO_4 and coarse particulate matter (CM) seem to have the highest concentrations on most such days).

2. What are typical values for the humidity adjustment factor during the times of year when most of the days with poor visibility occur?
(Typical values appear to be about "4.0").

3. Does visibility appear to track well among nearby Class I areas?
(Yes, but not always).

4. Does poor visibility seem to occur under any specific meteorological conditions?
(This information is not readily available).

5. Does poor visibility seem to coincide with high observed concentrations of any particular other pollutant?
(There seems to be some correspondence with high regional ozone concentrations)

6. What components of particulate matter appear to have relatively high concentrations on days with good visibility?
(Coarse particulate matter and OC)

7. What are typical values for the humidity adjustment factor during times of year when most of the days with good visibility occur?
(About "2.3")

8. Does good visibility appear to occur under any specific meteorological conditions? (Don't know.)

Answers to the preceding questions suggest that strategies to reduce sulfate concentrations and, perhaps, regional ozone concentrations might be effective in reducing light extinction on days when visibility is currently poor. The responses suggest that a strategy which focuses on this alone should first be tried for the days with good visibility as well. Even though sulfate concentrations appear low on such days, the fact that sulfates scatter light efficiently (see Equation (6.1)) and relative humidity is still high enough to enhance this effect is worth considering. Responses suggest that further meteorological analyses would be worthwhile prior to selecting strategies to simulate with a resource intensive regional model.

It should be clear from the preceding examples that the initial conceptual description of an area's nonattainment problem draws on readily available information and need not be detailed. It is intended to help launch development and implementation of a modeling/analysis protocol in a productive direction. It will likely be supplemented by subsequent, more extensive modeling and ambient analyses performed by or for those implementing the modeling/analysis protocol discussed in Section 12.0.

Questions like those posed in Section 11.1 can be addressed using a variety of analyses ranging in complexity from an inspection of air quality data to sophisticated mathematical analyses. We anticipate the simpler analyses will often be used to develop the initial conceptual description. These will be followed by more complex approaches or by approaches requiring more extensive data bases as the need later becomes apparent. These analyses are intended to channel resources available to support modeled attainment demonstrations onto the most productive paths possible. They will also provide other pieces of information which can be used to reinforce conclusions reached with an air quality model, or cause a reassessment of assumptions made previously in applying the model. As noted in Section 7, corroboratory analyses should be used to help assess whether a simulated control strategy is sufficient to meet the NAAQS.

Appendix B: Monitoring Data from Class I sites in MANE-VU

Below are figures that were developed by Tom Downs of the Maine Department of Environmental Protection. These figures represent baseline monitoring data for the Class I sites (and Washington DC) based on IMPROVE monitoring network data using the EPA approved “default” algorithm for calculating reconstructed extinction and estimating natural background conditions. These statistics may need to be recreated using the alternative methodology approved by the IMPROVE steering committee and adopted by the MANE-VU states. Glide path graphs were created on the VIEWS website (http://vista.cira.colostate.edu/views/) using the Annual Summary Trends tool. Seasonal graphs were created from data downloaded from the VIEWS website using the Annual Summary Composition tool and should be updated to include 2004 data for a complete description of regional haze baseline data.

APPENDIX B: MONITORING DATA FROM CLASS I SITES IN MANE-VU

Figure B-1. Monitoring Data from Acadia NP, ME

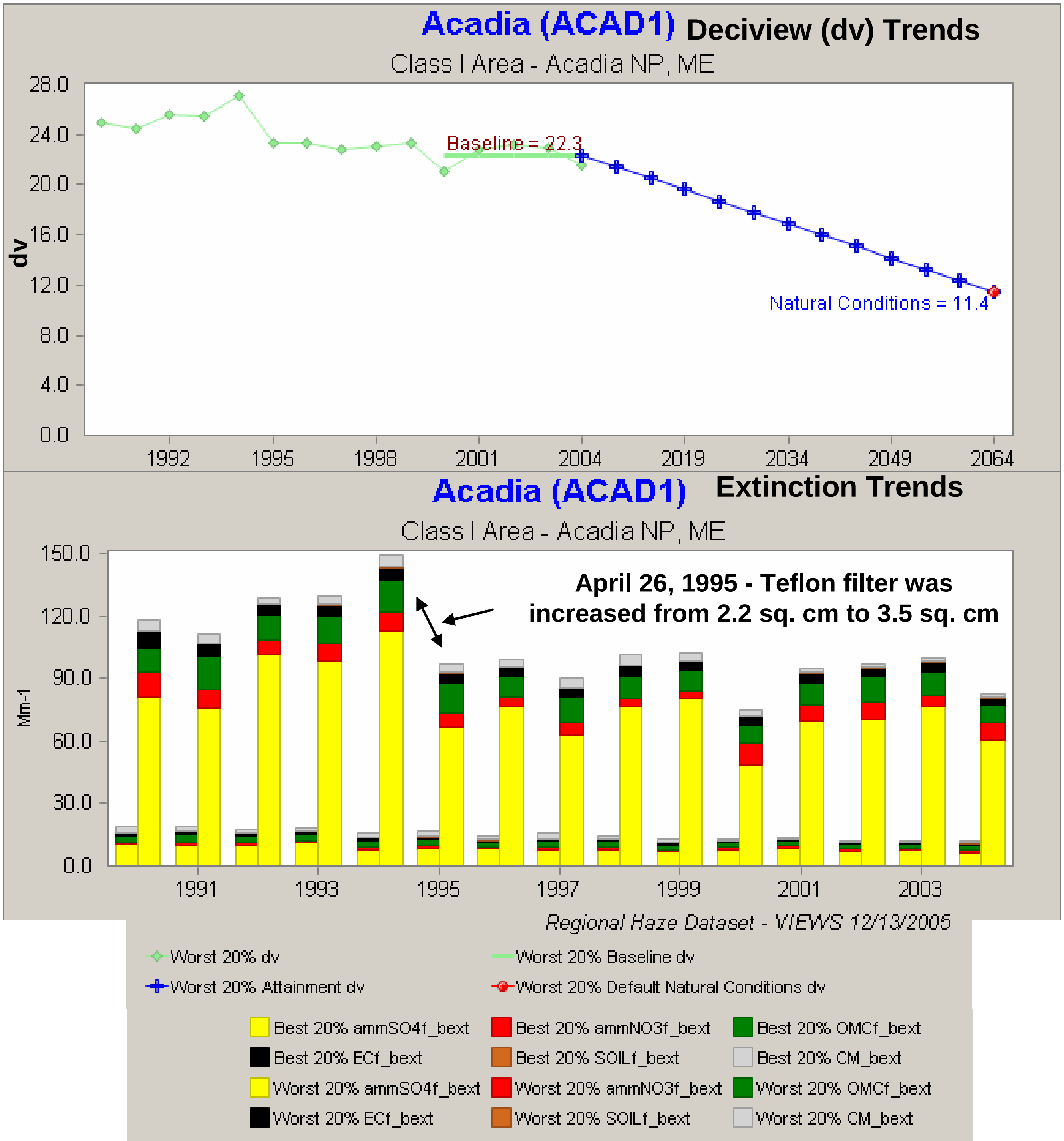


Figure B-2. Monitoring Data from Brigantine, ME

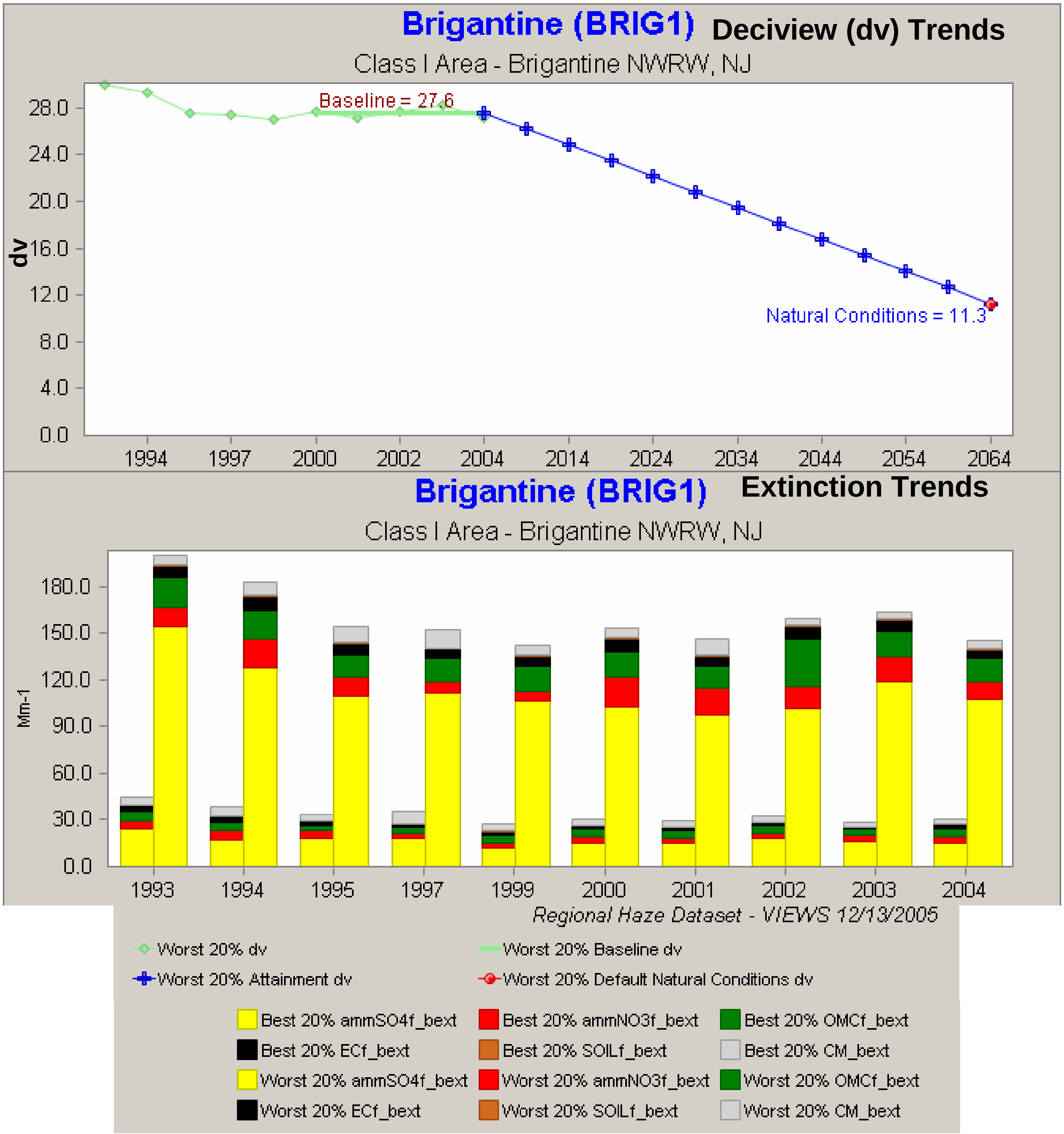


Figure B-3. Monitoring Data from Great Gulf, NH

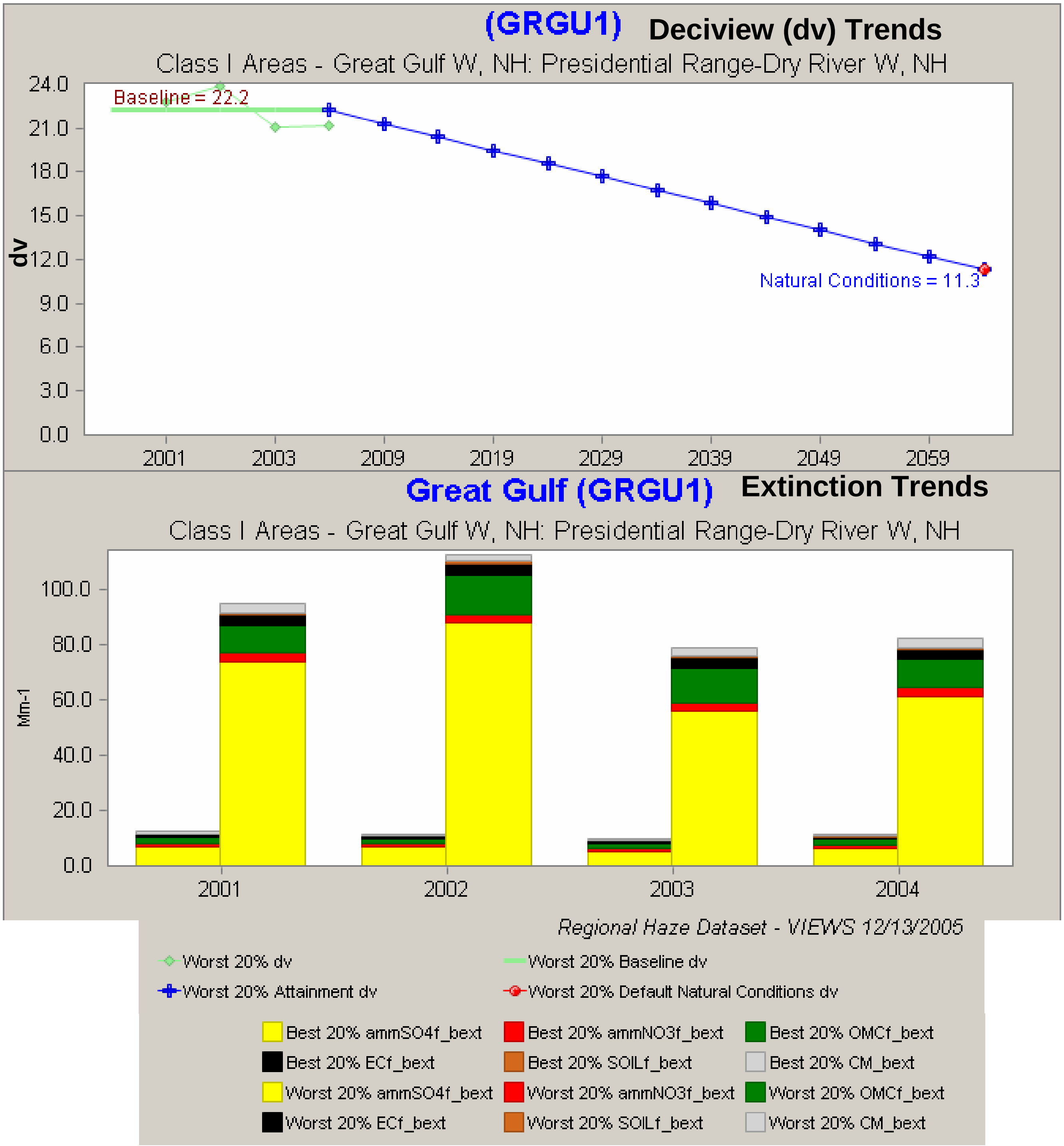


Figure B-4. Monitoring Data from Lye Brook, VT

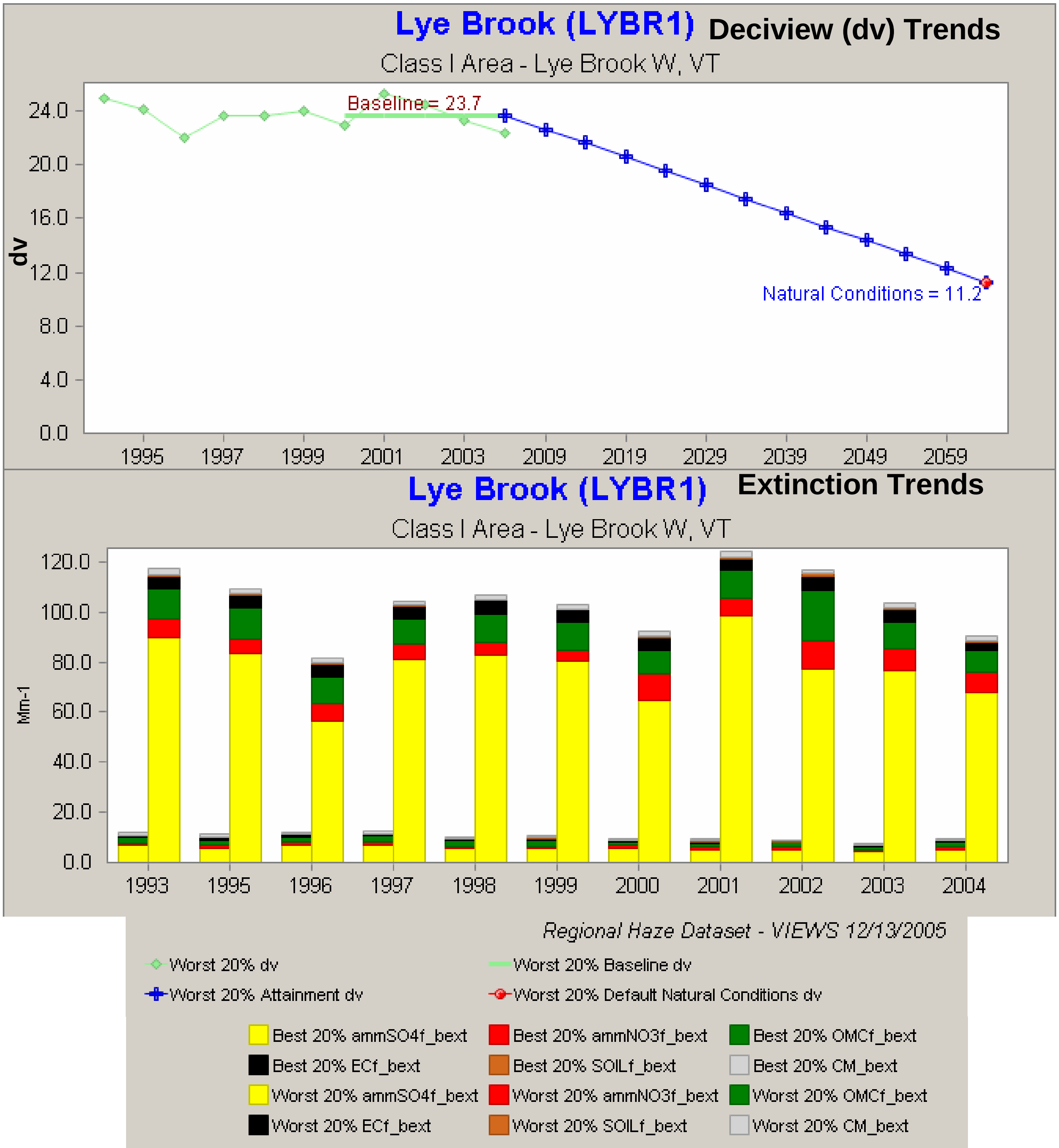


Figure B-5. Monitoring Data from Moosehorn, ME

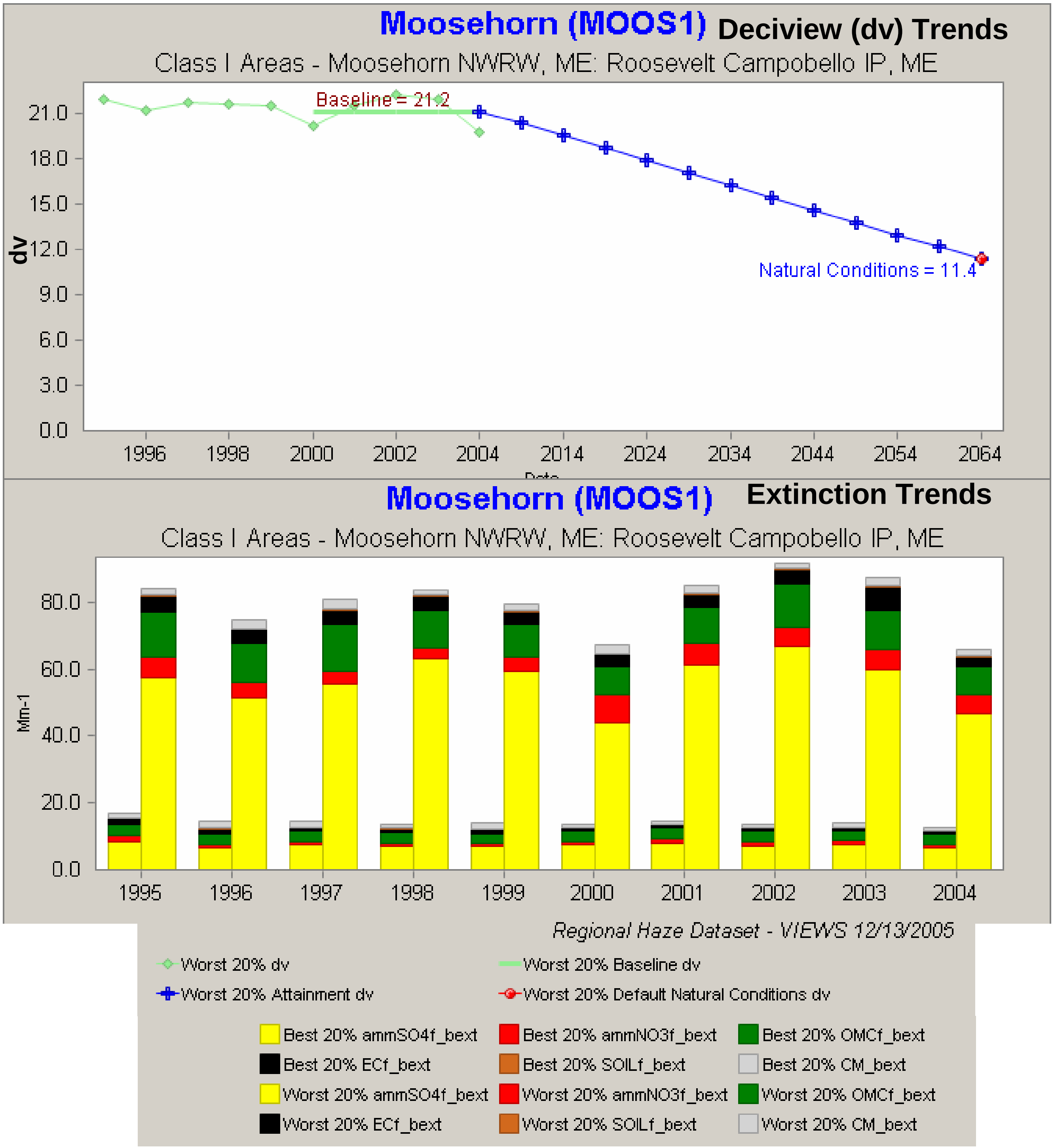


Figure B-6. Monitoring Data from Washington, DC

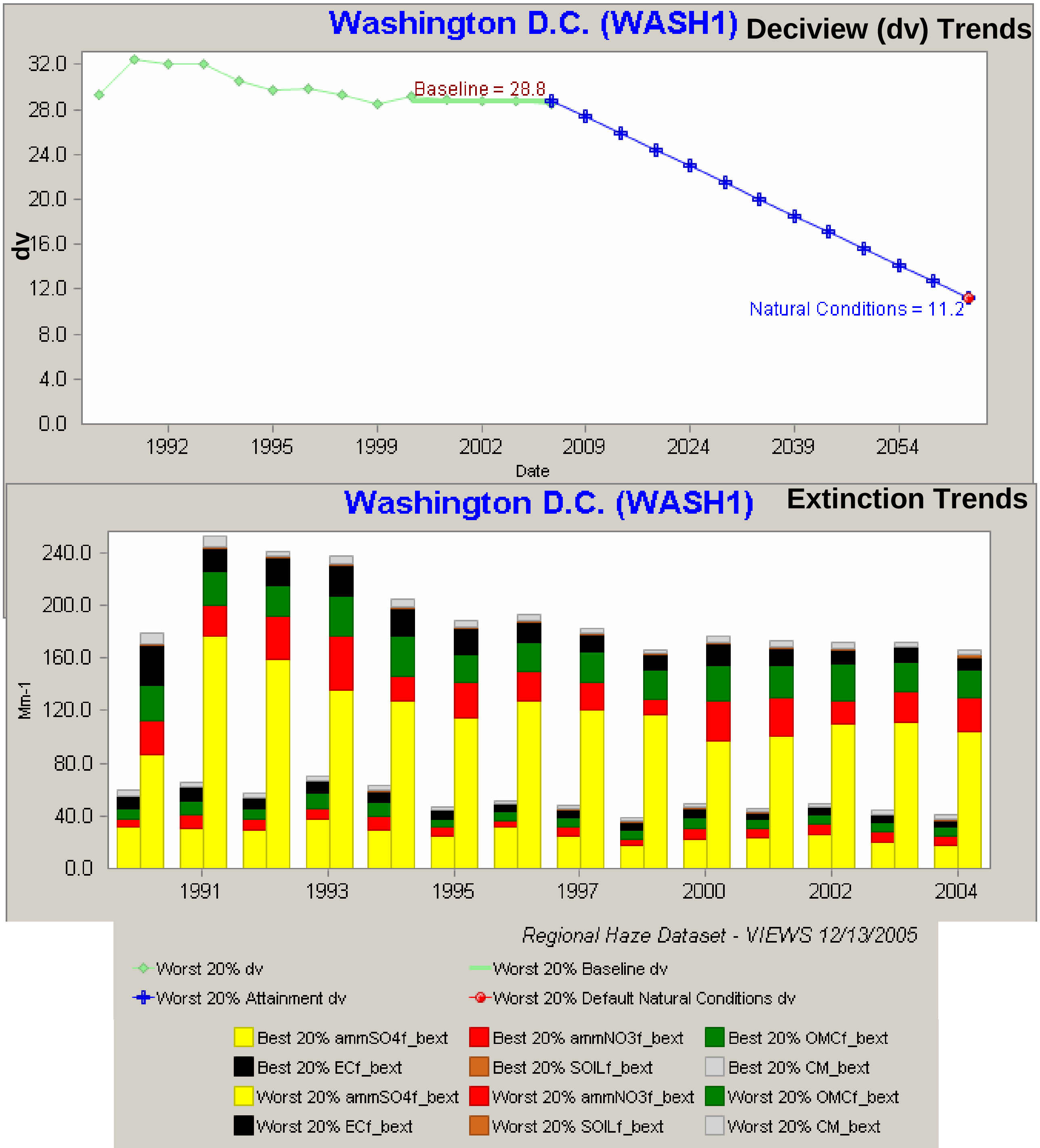
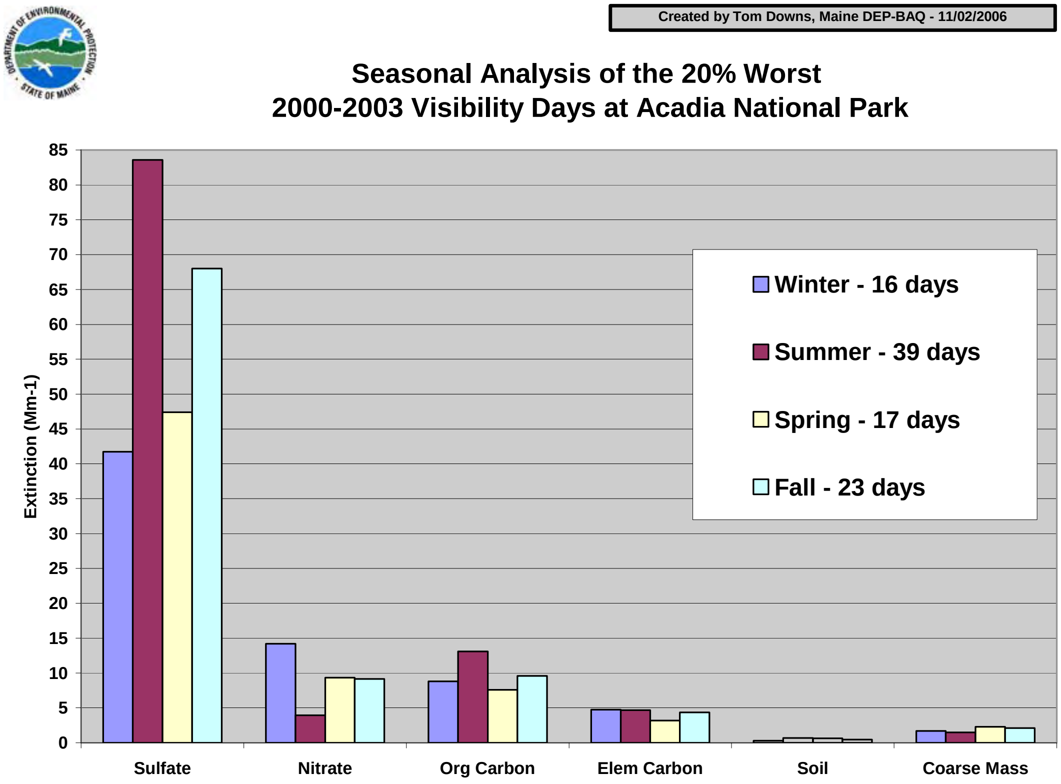
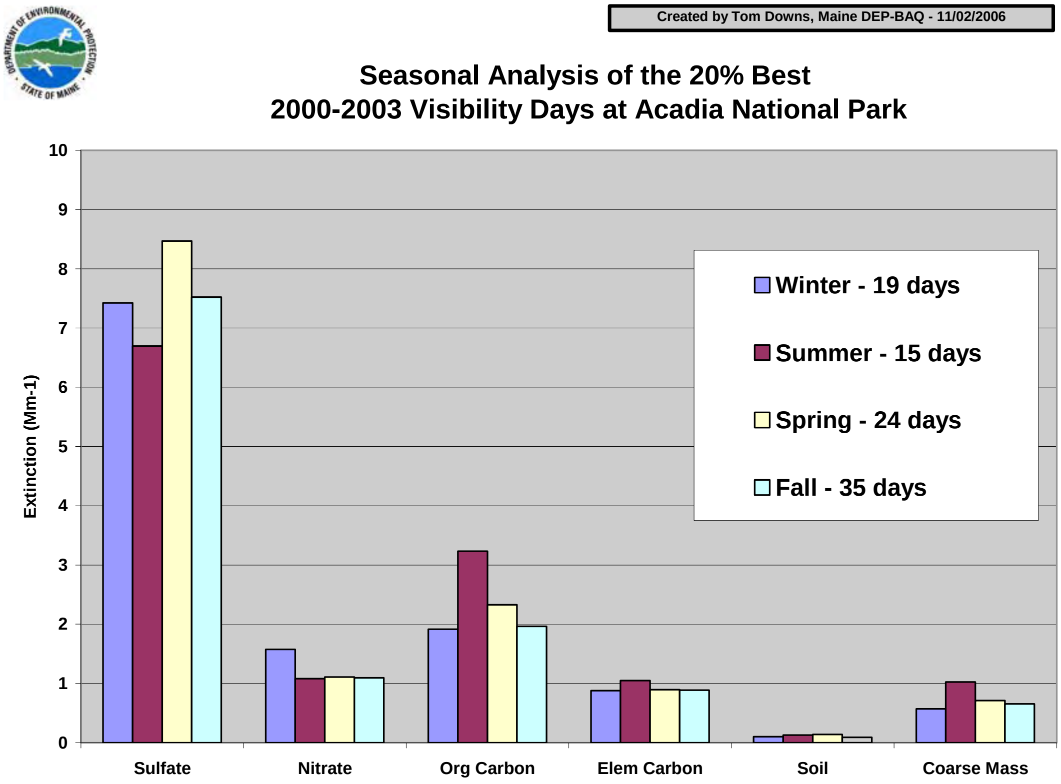


Figure B-7. 20% Worst and Best 2000-2003 Visibility Days at Acadia NP, ME



Created by Tom Downs, Maine DEP-BAQ - 11/02/2006

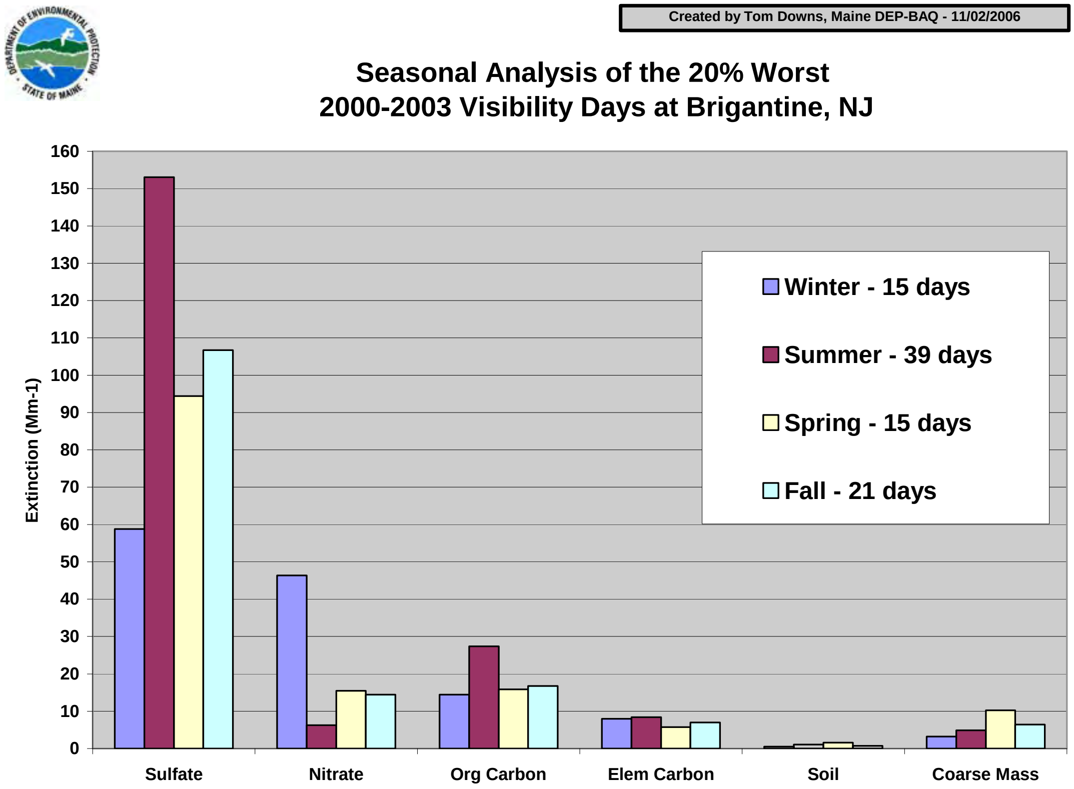
Seasonal Analysis of the 20% Worst 2000-2003 Visibility Days at Acadia National Park



Created by Tom Downs, Maine DEP-BAQ - 11/02/2006

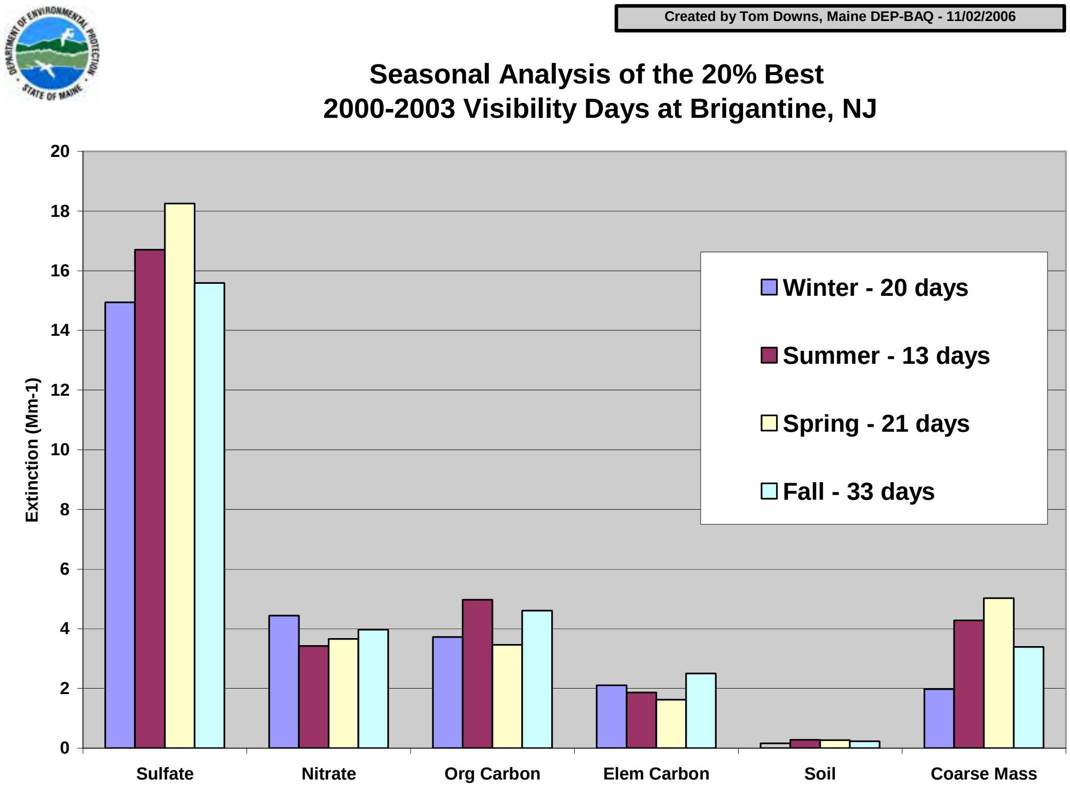
Seasonal Analysis of the 20% Best 2000-2003 Visibility Days at Acadia National Park

Figure B-8. 20% Worst and Best 2000-2003 Visibility Days at Brigantine, NJ



Created by Tom Downs, Maine DEP-BAQ - 11/02/2006

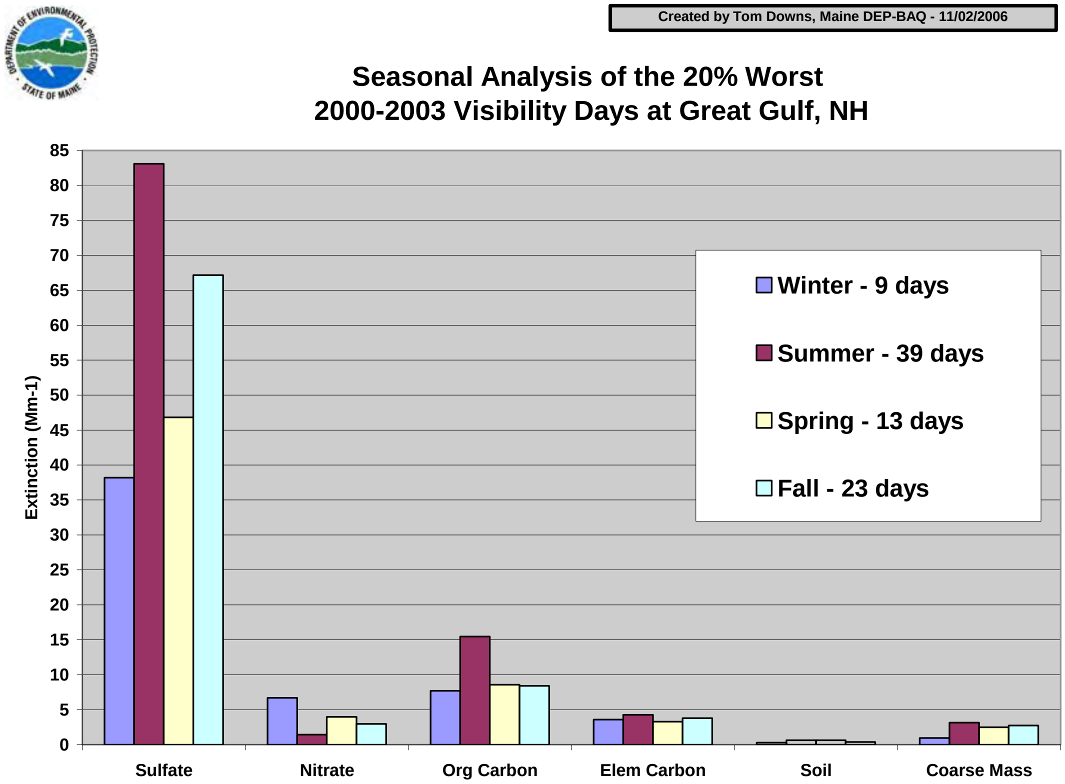
Seasonal Analysis of the 20% Worst 2000-2003 Visibility Days at Brigantine, NJ



Created by Tom Downs, Maine DEP-BAQ - 11/02/2006

Seasonal Analysis of the 20% Best 2000-2003 Visibility Days at Brigantine, NJ

Figure B-9. 20% Worst and Best 2000-2003 Visibility Days at Great Gulf, NH



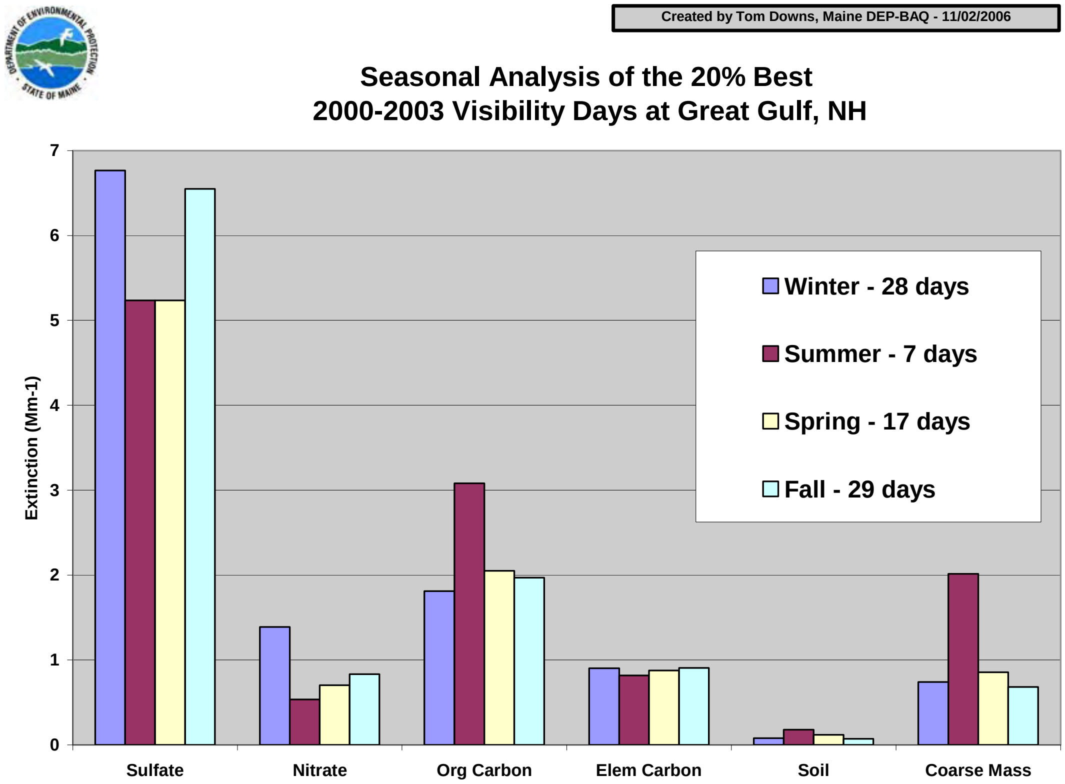
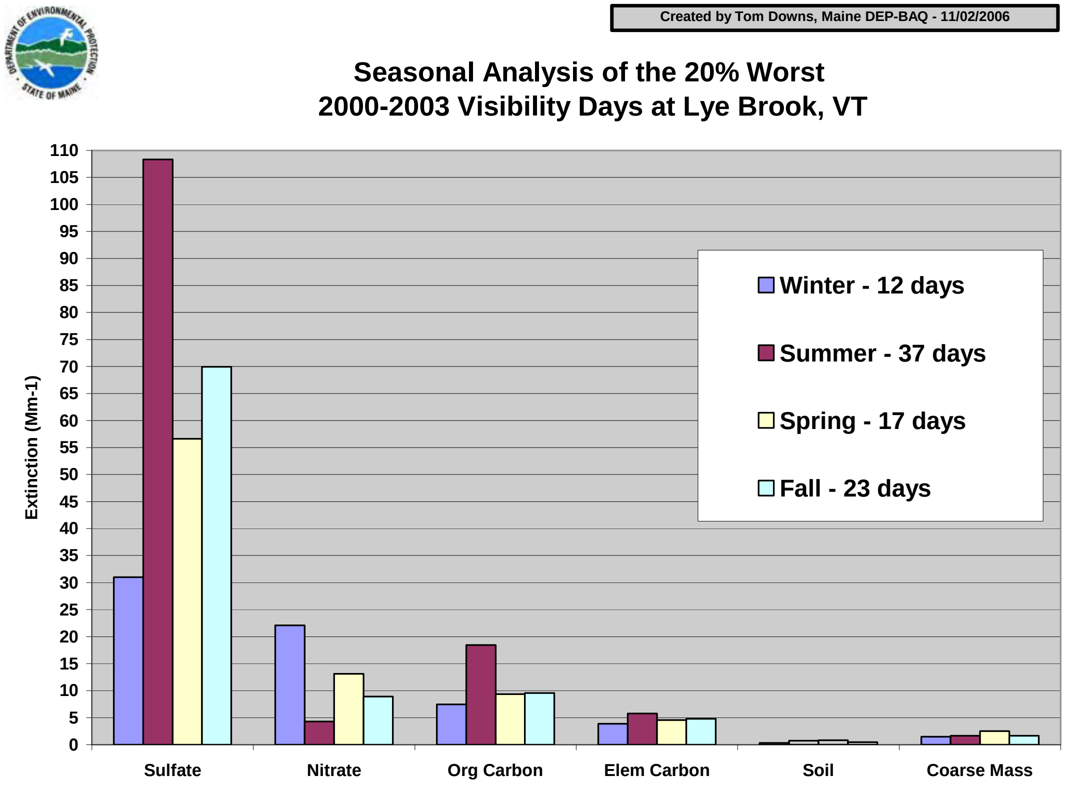


Figure B-10. 20% Worst and Best 2000-2003 Visibility Days at Lye Brook, VT



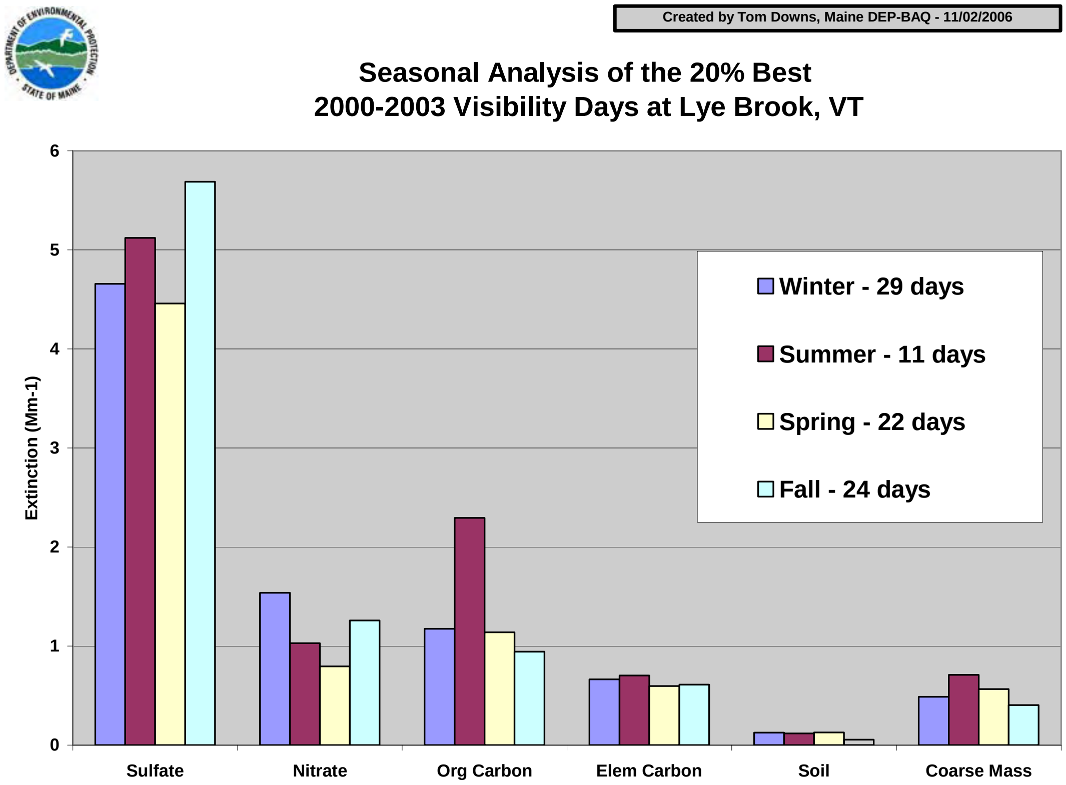
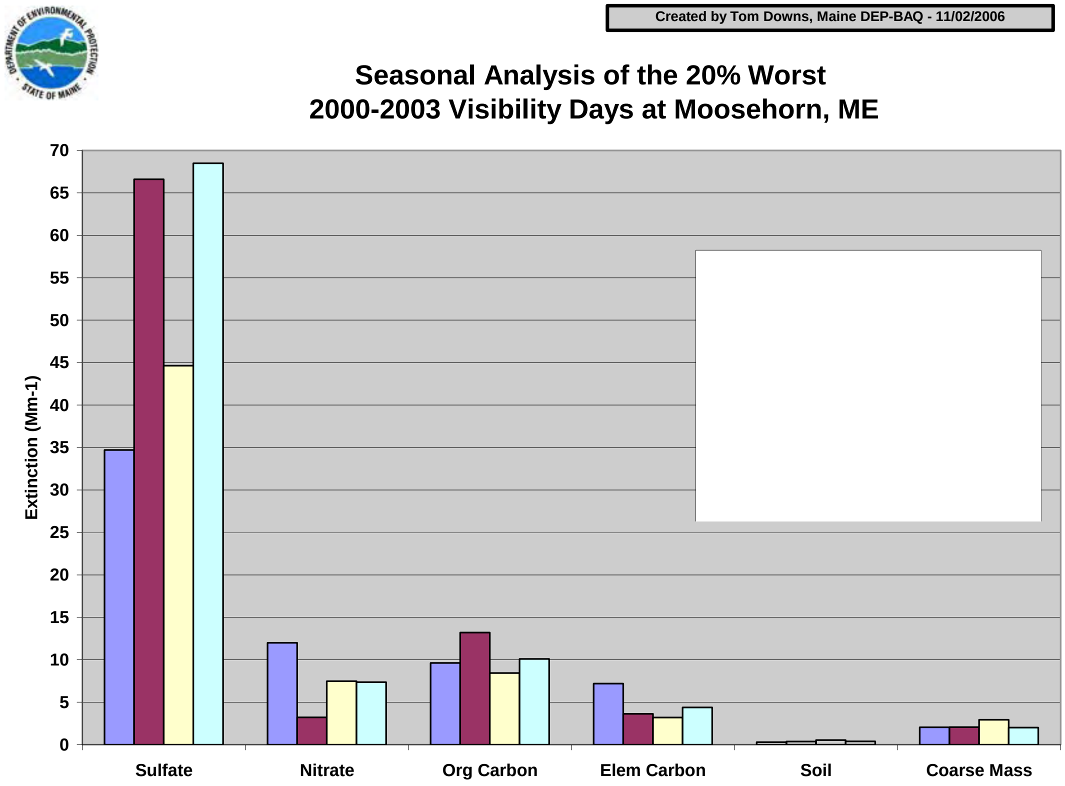


Figure B-11. 20% Worst and Best 2000-2003 Visibility Days at Moosehorn, ME



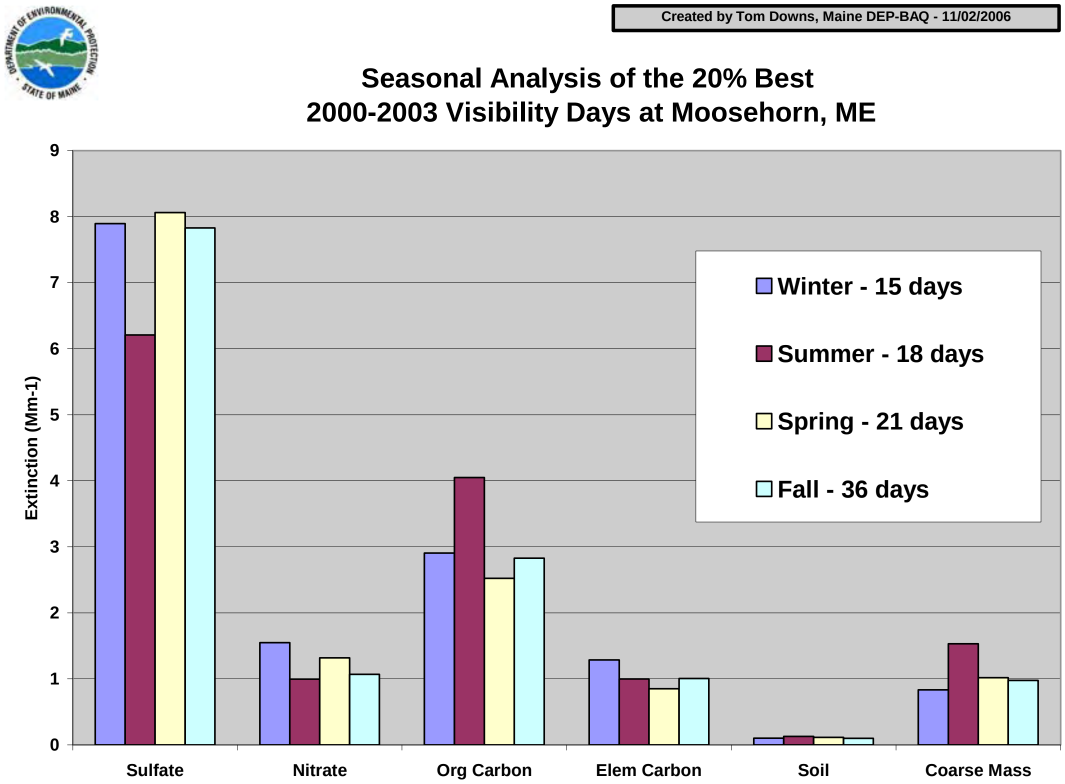


Figure B-12. 20% Worst and Best 2000-2003 Visibility Days at Washington, D.C.

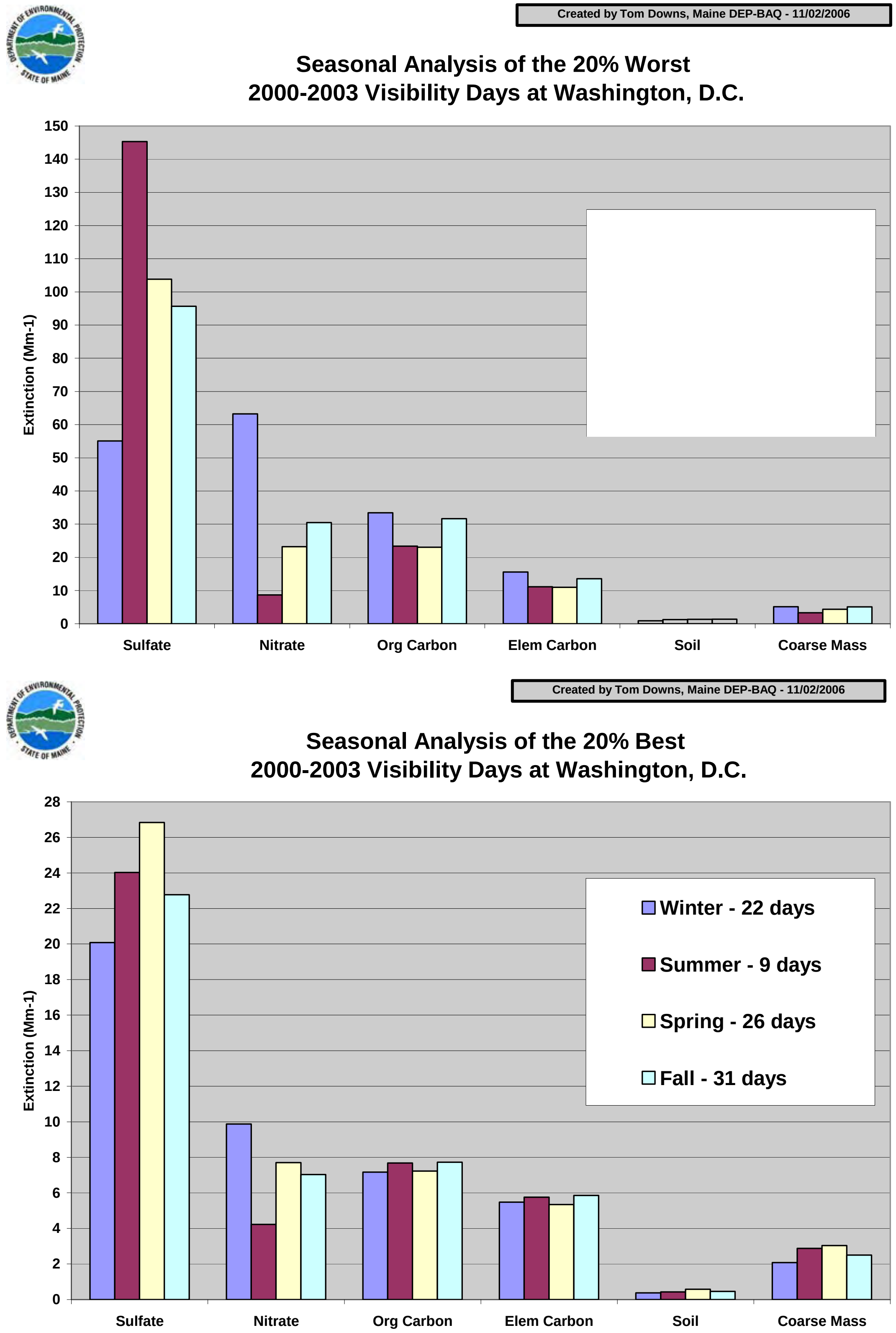
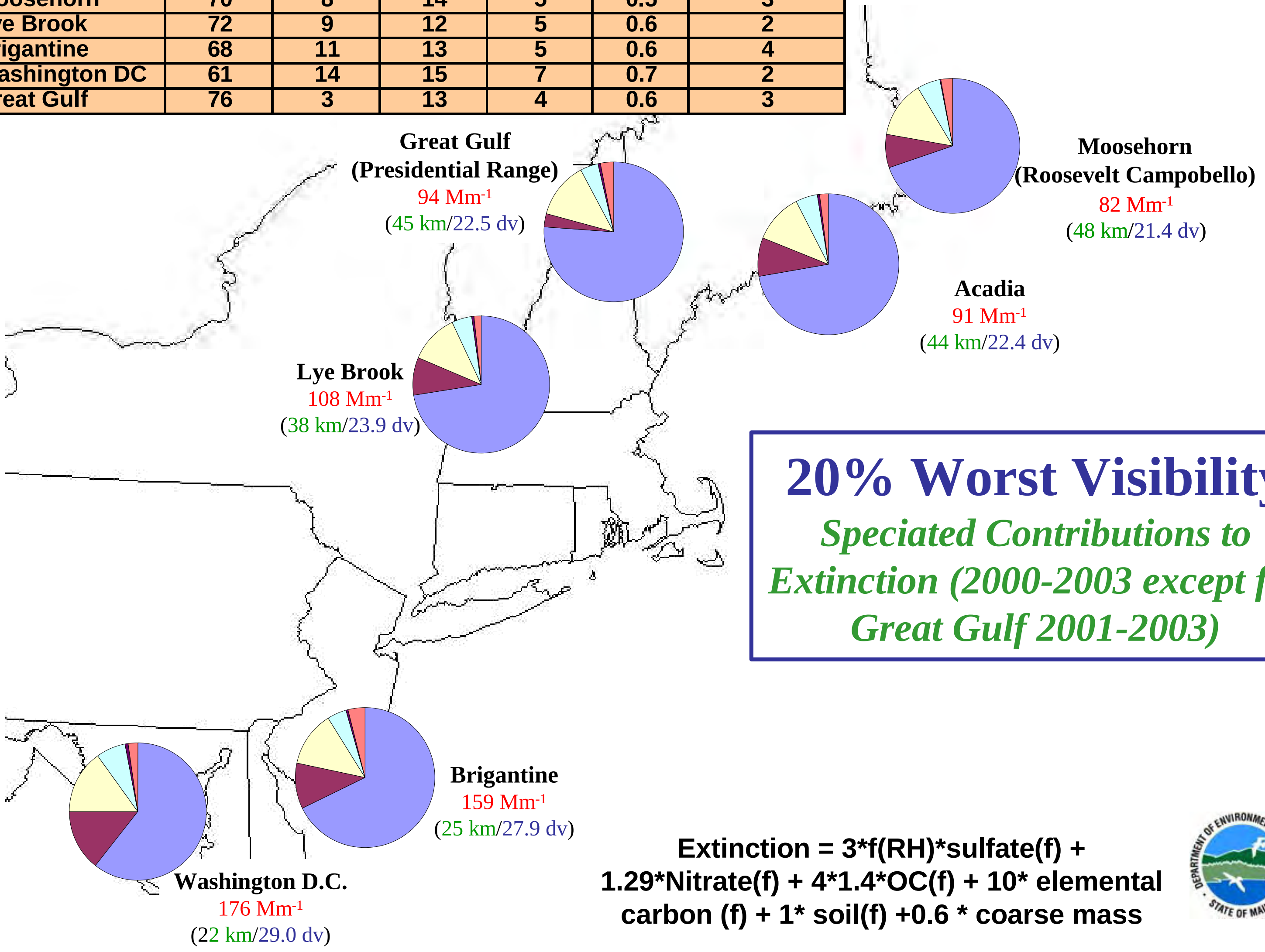


Figure B-13. 20% Best 2000-2003 Visibility Days Speciated Contributions to Extinction

	percent contributon to particle extinction					
Site	Sulfate	Nitrate	Org C	Elem C	Soil	Coarse Mass
Acadia	72	9	11	5	0.6	2
Moosehorn	70	8	14	5	0.5	3
Lye Brook	72	9	12	5	0.6	2
Brigantine	68	11	13	5	0.6	4
Washington DC	61	14	15	7	0.7	2
Great Gulf	76	3	13	4	0.6	3

Created by Tom Downs,
Maine DEP-BAQ 12/13/2005



20% Worst Visibility

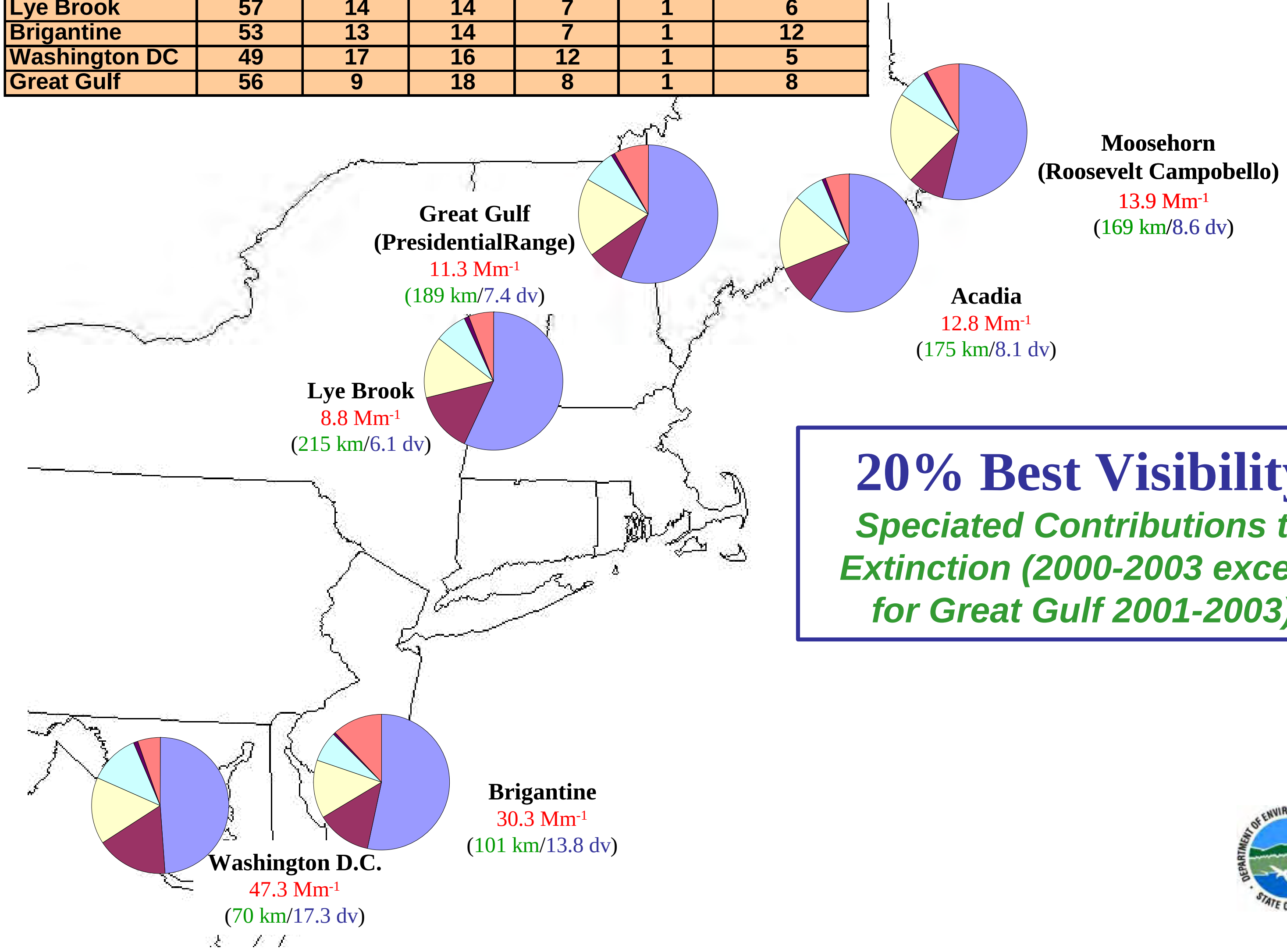
Speciated Contributions to Extinction (2000-2003 except for Great Gulf 2001-2003)

Extinction = 3*f(RH)*sulfate(f) + 1.29*Nitrate(f) + 4*1.4*OC(f) + 10* elemental carbon (f) + 1* soil(f) +0.6 * coarse mass

Figure B-14. 20% Best 2000-2003 Visibility Days Speciated Contributions to Extinction

	percent contributon to particle extinction					
Site	Sulfate	Nitrate	Org	Elem C	Soil	Coarse Mass
Acadia	60	9	18	7	1	6
Moosehorn	54	9	22	7	1	8
Lye Brook	57	14	14	7	1	6
Brigantine	53	13	14	7	1	12
Washington DC	49	17	16	12	1	5
Great Gulf	56	9	18	8	1	8

Created by Tom Downs,
Maine DEP-BAQ 12/13/2005



20% Best Visibility

Speciated Contributions to Extinction (2000-2003 except for Great Gulf 2001-2003)

Appendix C: Additional Considerations for $PM_{2.5}$ Air Quality Management

APPENDIX C: ADDITIONAL CONSIDERATIONS FOR $PM_{2.5}$ AIR QUALITY MANAGEMENT

C.1. Averaging times and data interpretation

In analyzing the chemical data available for interpreting the air quality event of August 2002, it is important to point out that the use of different averaging times can have a profound effect on our understanding of the progression of any specific episode. Many subtleties of synoptic-scale meteorology and atmospheric chemistry are “aliased out” of data sets with temporal resolution greater than 3-6 hours. These effects are demonstrated in Figure C-1 which show fine aerosol TEOM data from New Haven for the “episode” period August 10-16, 2002. In these figures, the hourly TEOM values have been aggregated into 3-, 6- and 24-hour mean values. Average concentrations are inversely proportional to the length of the averaging period and the ratio of peak hourly concentration within a daily average ranges from about 1.5 to 1.75 for this episode.

Figure C-1. Effects of averaging times (or temporal resolution) on time series information

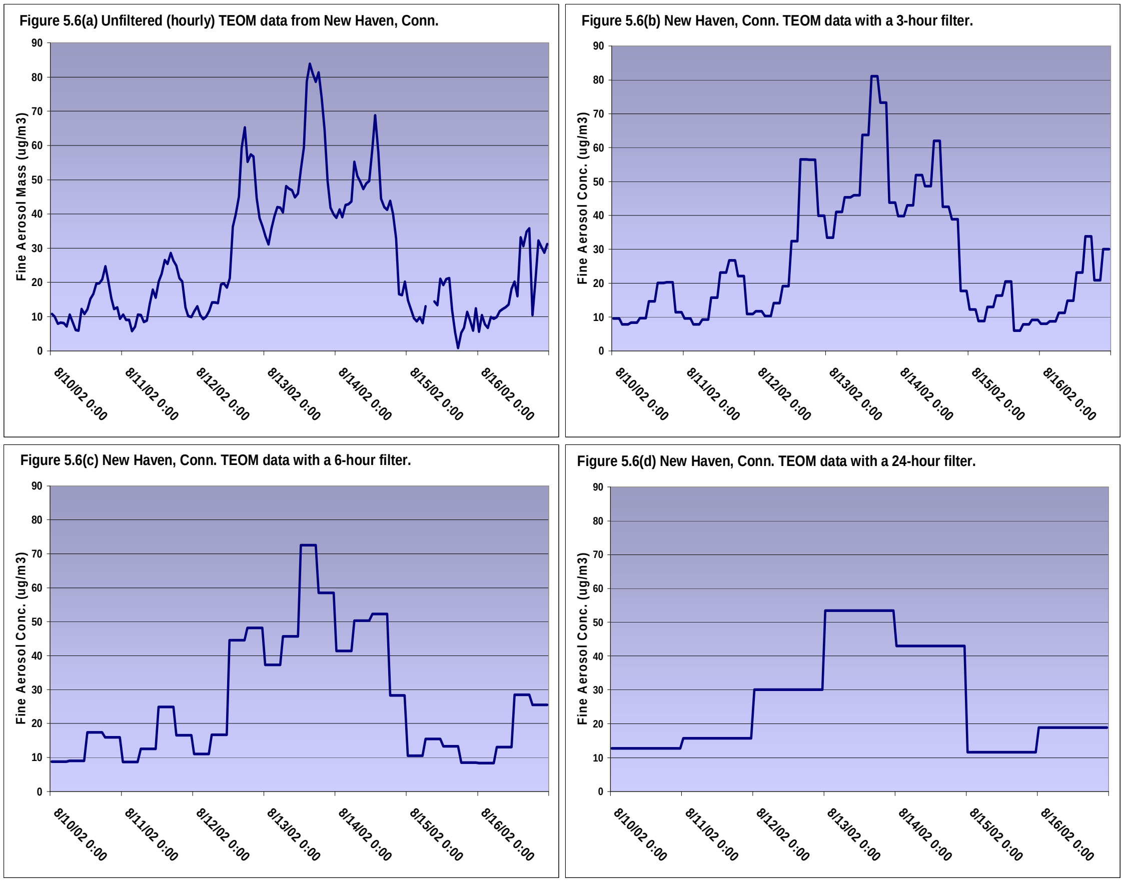


Figure 5.6(a) Unfiltered (hourly) TEOM data from New Haven, Conn.

Figure 5.6(b) New Haven, Conn. TEOM data with a 3-hour filter.

Figure 5.6(c) New Haven, Conn. TEOM data with a 6-hour filter.

Figure 5.6(d) New Haven, Conn. TEOM data with a 24-hour filter.

C.2. Rural versus urban $PM_{2.5}$ mass

Comparison of $PM_{2.5}$ concentrations from rural areas with those from urban/suburban areas can add significantly to our understanding of the impact on air quality of both urban sources and of medium to long-range fine aerosol transport. To assist with this approach, data from 10 pairs of rural and urban/suburban FRM sites throughout the MANE-VU region were selected and analyzed.

Table C-1 shows basic site description information including the approximate, straight-line distance between the site pairs.

Due to the difficulty in finding a significant number of urban-rural site pairs that operated on the same sampling schedule, sites with a mixture of schedules were used to insure samples representative of the entire MANE-VU region. As a result, three of the 20 sites employed an everyday schedule while two sites sampled every sixth day (the remainder sampled every third day). Data from the three everyday sites were edited so as to include data from the 1-in-3 schedule only. In all, a total of 1098 data points were possible from the 10 site pairs for 2002. Of the 1098 possible point-pairs, 951 (87%) were valid and were used in this analysis.

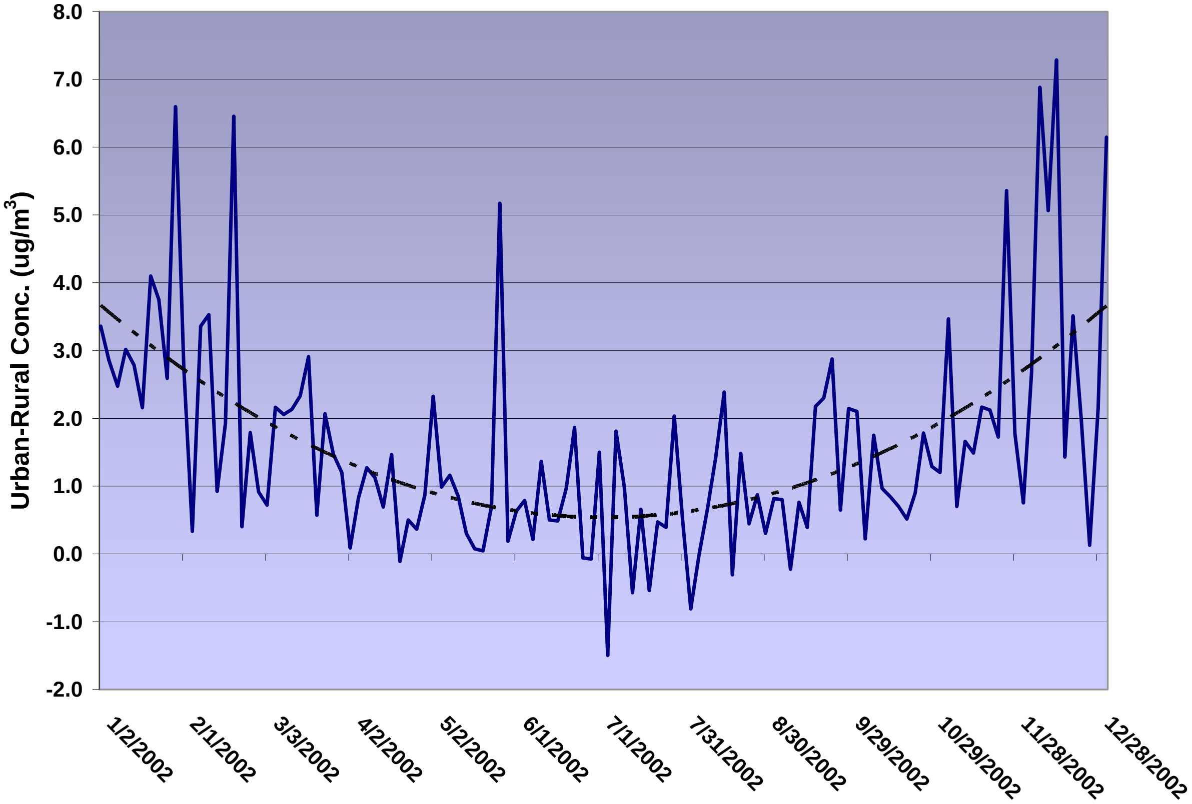
Table C-1. MANE-VU urban-rural site pair information

State	Site No	City	Land use	Location type	Longitude	Latitude	Inter-site Distance (mi)
DE	100051002		Agricultural	Rural	-75.55560	38.98470	
DE	100010002	Seaford	Residential	Suburban	-75.61310	38.64440	24.0
MA	250154002	Ware	Forest	Rural	-72.33472	42.29833	
MA	250130016	Springfield	Commercial	Urban & Center City	-72.59140	42.10890	17.6
MD	240030014		Agricultural	Rural	-76.65310	38.90250	
MD	245100049	Baltimore	Residential	Urban & Center City	-76.63750	39.26170	25.2
ME	230052003	Cape Elizabeth	Residential	Rural	-70.20778	43.56083	
ME	230010011	Lewiston	Commercial	Urban & Center City	-70.21500	44.08940	37.0
NJ	340218001		Agricultural	Rural	-74.85470	40.31500	
NJ	340210008	Trenton	Residential	Urban & Center City	-74.76360	40.22220	7.7
NY	360010012	Albany	Agricultural	Rural	-73.75690	42.68070	
NY	360930003	Schenectady	Residential	Suburban	-73.94020	42.79960	11.7
NY	361030001	Babylon	Commercial	Rural	-73.42030	40.74580	
NY	360590013	Bethpage	Residential	Suburban	-73.49060	40.76080	3.3
NY	360130011	Westfield	Agricultural	Rural	-79.60250	42.29080	
PA	420490003	Erie	Commercial	Suburban	-80.03860	42.14180	22.2
PA	420030093		Residential	Rural	-80.02080	40.60720	
PA	420030021	Pittsburgh	Residential	Suburban	-79.94140	40.41360	14.0
PA	420290100		Commercial	Rural	-75.76860	39.83440	
DE	100031012	Newark	Residential	Suburban	-75.76170	39.69190	10.0

As expected, urban/suburban areas, with their rich supply of emission sources, almost always reported higher concentrations than their nearby sister sites in rural areas. Of the 951 valid data pairs, 660 showed higher urban/suburban levels while 291 cases showed higher rural levels.

One interesting aspect of the 2002 urban-rural data concerns the pattern in seasonal differences between such site pairs. Figure C-2 shows the difference (urban-rural) between the 10 site pairs as a time series.

Figure C-2. Difference in FRM data between 10 urban-rural site pairs for 2002



Although some rural-to-urban seasonal differences are to be expected, the variation in the magnitude of this difference is surprising. In the warm/hot months, the mean rural/urban difference amounts to no more than ~0.7 μg/m^3 (based on a best-fit 2nd order polynomial curve), which is a relatively small differential. However, during the cool/cold months that difference climbs to almost 4 μg/m^3, demonstrating a total annual seasonal variation of at least 3 μg/m^3. Because the mean annual concentration of all sites is 12.6 μg/m^3, an annual variation of 3 μg/m^3 becomes significant.

One explanation for the observed seasonal variation concerns the temporal distribution of local and transported emissions. In the summertime, MANE-VU sites repeatedly experience sulfate events due to transport from regions to the south and west. During such events, rural and urban sites throughout MANE-VU record high (i.e., >15 μg/m^3) daily average PM$_{2.5}$ concentrations. During summer stagnation events, atmospheric ventilation is poor and local emissions are added to the transported burden with the result that concentrations throughout the region (rural and urban) are relatively uniform. There are enough of these events to drive the urban-rural difference down to less than 1 µg/m^3 during warm/hot months.

During the wintertime, strong local inversions frequently trap local emissions during the overnight and early morning periods, resulting in elevated urban concentrations. Rural areas experience those same inversions but have relatively fewer local sources so that wintertime concentrations in rural locations tend to be lower than those in nearby urban areas. Medium and long-range fine aerosol transport events do occur during the winter but at a much reduced rate compared to summertime. So, it is the interplay between local and distant sources as well as meteorological conditions that drive the observed seasonal urban-rural difference in FRM concentrations.

C.3. Seasonal relationship between $PM_{2.5}$ and NO_X

Because nitrogen oxides (NO_X) can be a good indicator of regional as well as local emissions, NO_X data for the MANE-VU region was downloaded from USEPA's AQS. Ultimately, data from six widely separated MANE-VU NO_X sites were selected (one site each in CT, DC, MA, NH, PA and VT). Sites were selected both for high data capture rates and geographic location. The NO_X data were then aggregated into regional averages on a daily basis and compared to $PM_{2.5}$ FRM data from 34 "everyday" sampling sites (which were also averaged on a regional basis).

During 2002, there were virtually no periods when regional mean $PM_{2.5}$ concentrations rose above 20 µg/m^3 and were not accompanied by rising (or already high) NO_X concentrations. However, as seen in Figure C-3, NO_X concentrations vary widely on an annual basis and tend to occur out-of-sync with fine particle concentrations.

Although the min/max extremes of these two pollutants are offset in time, they are highly correlated during some parts of the year. For example, Figure C-4 shows the regional $PM_{2.5}$ and NO_X data for the coldest (Jan., Feb., Nov., and Dec.) and hottest (May, June, July and Aug.) seasons of 2002. Wintertime NO_X and $PM_{2.5}$ concentrations are rather well correlated (r^2=0.67) while summertime concentrations are not at all linked. This dichotomy can be explained by several coincident effects including: 1) reduced UV radiation during cold months (which prevents photolysis of NO_2 to O_3); 2) the increase in space heating requirements from stationary sources (which preferentially increases morning NO_X emissions; increased NO_X emissions due to "cold-start" mobile source engines and 3) decreased mixing height depths due to reduced solar input (which allows morning concentrations to build quickly). Note that the Spring/Fall $PM_{2.5}$ vs. NO_X correlation (not shown) lies about mid-way between the winter/summer values shown in Figure C-4.

Figure C-3. Regional $PM_{2.5}$ and NO_X in 2002

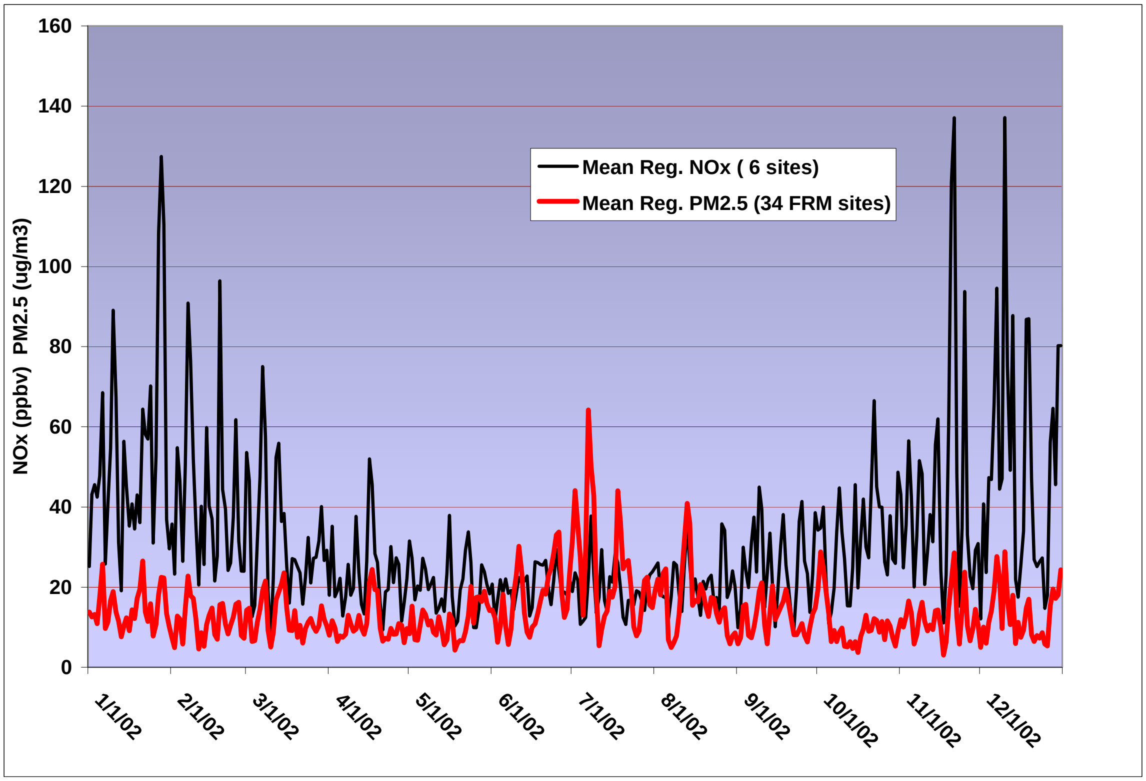
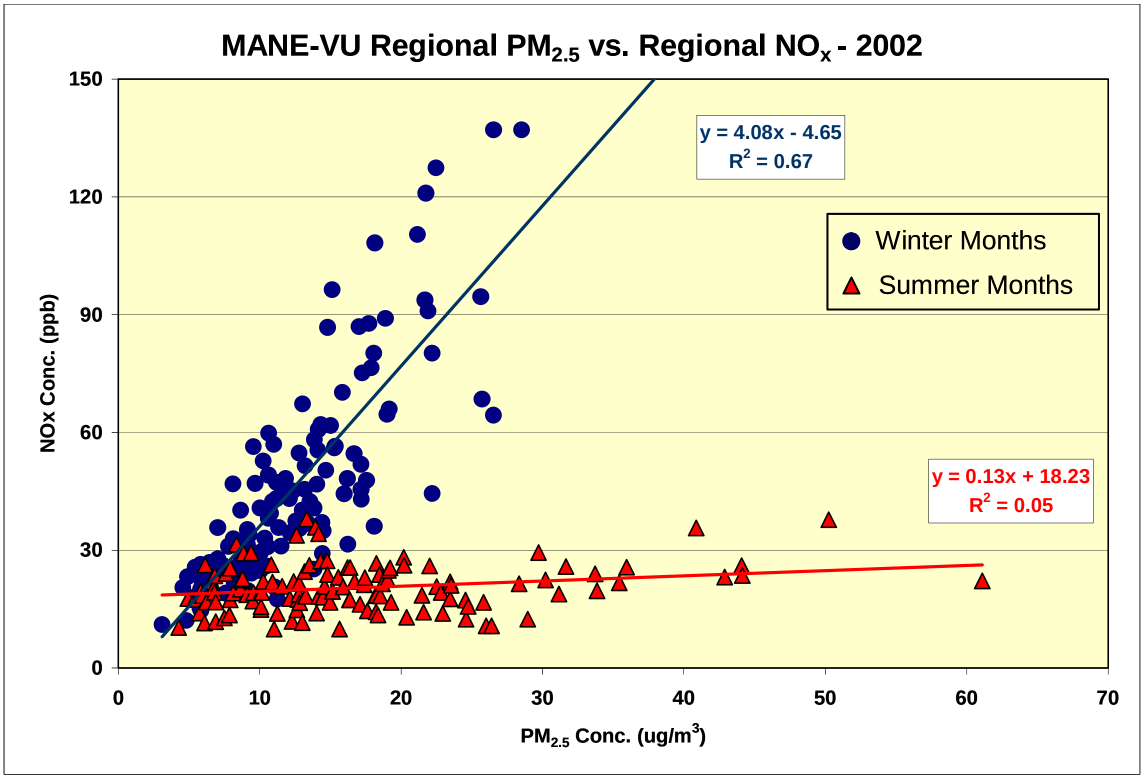


Figure C-4. $PM_{2.5}$ vs. NO_X correlation by season



Appendix N - MANE-VU Basis for Reasonable Controls

Class I States' Demonstration that the Goals are Based on Reasonable Controls

40 CFR Section (d)(1)(i)(A) of EPA's Clean Air Visibility 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, and the SIP must include a demonstration showing how these factors were taken into consideration in setting the goal. These factors are sometimes termed the "four statutory factors," since their consideration is required by the Clean Air Act.

Focus on SO_2

MANE-VU conducted a Contribution Assessment and developed a conceptual model that indicated that the dominant contributor to visibility impairment at all sites during all seasons in the base year was particulate sulfate formed from emissions of SO_2. (See the NESCAUM report entitled Contributions to Regional Haze in the Northeast and Mid-Atlantic United States, Appendix A). The report concludes that sulfates alone account for from one-half to two-thirds of total fine particle mass on the 20 percent haziest days at MANE-VU Class I sites. In view of the dominant role of sulfate in visibility impairment in Northeast and Mid-Atlantic class I areas, the report states that, "[T]hese findings suggest that an effective emissions management approach would rely heavily on broad-based regional SO2 control efforts in the eastern United States." 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 will yield the greatest near-term benefit. Therefore, it is reasonable that the additional measures considered in setting the reasonable progress goals described in this document required reductions of SO_2 emissions.

Contributing Sources

The MANE-VU Contributions Assessment indicates that emissions from within MANE-VU in 2002 were responsible for about 25 to 30 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, the MANE-VU strategies discussed in Section 9.4 and 9.5, above, include 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.

MANE-VU's Contribution Assessment documented the source categories most responsible for visibility degradation at MANE-VU Class I areas. As documented in the Long Term Strategy section of this SIP, there was a collaborative effort between the

Ozone Transport Commission and MANE-VU to evaluate a large number of potential control measures, and several measures that would reduce SO_2 emissions were identified for further study. This led MANE-VU to prepare the report entitled, “Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas” (MACTEC, July 9, 2007), which documented an analysis of the four statutory factors for five major source categories. This report is referred to below as the MANE-VU Reasonable Progress Report. Table 9.6 summarizes the results of MANE-VU’s Reasonable Progress Report, which are further discussed below as they pertain to the strategies adopted by MANE-VU.

MANE-VU states reviewed the four-factor analysis presented in the Reasonable Progress Report, consulted with each other about the measures, and concluded by adopting the statements referenced above in this SIP on June 20, 2007. These statements indicate which control measures would be further pursued for adoption.

MANE-VU Class I states shared these statements with states outside the region that they determined reasonably caused or contributed to visibility impairment in the MANE-VU Class I areas prior to consulting with those states.

The following discussion focuses on the control measures included in modeling used to set the reasonable progress goals: BART, emissions reductions from specific EGUs, low sulfur fuel oil requirements, and additional measures determined to be reasonable.

Summary of Results from the Four Factor Analysis

Source Category	Primary Regional Haze Pollutant	Potential 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)-Wet, Flue Gas Desulfurization (FGD)-Spray Dry, Flue Gas Desulfurization (FGD) -Dry.	MANE-VU application of IPM®* v.2.1.9 predicts $775 to $1,690. MACTEC reports $170 to $5,700 based on available literature depending on control method and size of source	2-3 years following SIP submittal	Fuel supply issues, potential permitting issues, reduction in 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 control, Flue Gas Desulfurization (FGD)-Wet, Flue Gas Desulfurization (FGD)-Spray Dry, Flue Gas Desulfurization (FGD) -Dry.	MACTEC reports $130 to $11,000 based on available literature. Depends on size of plant and control method.	2-3 years following SIP submittal	Fuel supply issues, potential permitting issues, control device energy requirements, wastewater issues	10-30 years

Source Category	Primary Regional Haze Pollutant	Potential 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
Cement and Lime Kilns	SO_2	Fuel switching, Dry Flue Gas Desulfurization-Spray Dryer Absorption (FGD), Wet Flue Gas Desulfurization (FGD), Advanced Flue Gas Desulfurization (FGD).	MACTEC reports $1,900 to $73,000 based on available literature. Depends on size of plant and control method.	2-3 years following SIP submittal	Control device energy requirements, wastewater issues	10-30 years
Heating Oil	SO_2	Lower the sulfur content in the fuel. Depends on the state.	MACTEC reports $550 to $750 based on available literature. There is a high uncertainty associated with this cost estimate.	Currently feasible. Capacity issues may influence timeframe for implementation of new fuel standards	Increases in furnace/boiler efficiency, Decreased 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, accelerated changeover inducement.	MACTEC reports $0 to $10,000 based on available literature	Several years - dependent on mechanism for emission reduction	Reduce greenhouse gas emissions, increase efficiency of combustion device	10-15 years

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

I. 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 controls and the cost and other factors associated with those controls. The reasonable progress goals set in this SIP assume that states whose emissions affect MANE-VU Class I areas will make reasonable determinations concerning BART controls for sources in their states.

II. Emissions Reductions from Specific EGUs are Reasonable

MANE-VU identified specific EGU stacks that were significant contributors to visibility degradation at MANE-VU Class I areas in 2002 based on CALPUFF modeling analyses documented in the Contribution Assessment. MANE-VU obtained information about existing and planned controls on emissions from those stacks. This analysis and the information on controls are documented in the MANE-VU Reasonable Progress Report, the Contribution Assessment, and the Emissions Inventory and Long Term Strategy section of this SIP.

Based on information gathered from the states and RPOs, MANE-VU anticipates that emissions from many of the specific EGU stacks will be controlled as a result of EPA's Clean Air Interstate Rule (CAIR). Since CAIR is a cap and trade program, it is not possible to predict with certainty which of the 167 stacks will in fact be controlled under CAIR in 2018.

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 and MANE-VU BART reports.

Costs of Compliance

Technologies to control the precursors of regional haze are commercially available.[1] Since 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 large number of small (say, 100MW) to very large boilers (over 1,000 MW) using different types of coal used. Over the last few years, a large amount of cost data have also become available that clearly indicated that many technologies

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[1] The information in this and the next paragraph comes from the "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities," March 2005, prepared by NESCAUM, in partnership with MANE-VU.

provide substantial and extremely cost effective reductions.

Both wet and dry scrubbers are in wide commercial use in the U.S. for controlling SO_2 emissions. The capital costs for new or retrofit wet or dry scrubbers are higher than the capital costs for NO_x and PM controls. Capital costs ranged from $180/kW for large units (larger than 600 MW) to as high as $350/kW for small units (200 to 300 MW), (page 2-22). However, the last few years have seen a general trend of declining capital costs due to vendor competition and technology maturation. The cost effectiveness (in dollars per ton) is very attractive, since these devices remove a very large amount of SO_2(driven by high sulfur content of coal burned). The typical cost effectiveness is in the range of 200 to 500 dollars per ton of SO_2 removed though higher values are obtained for small units operating at low capacity factors and burning low-sulfur coals. The cost effectiveness is determined mostly by the baseline pre-controlled SO_2 emission rate (or sulfur content of fuel), size and capacity factor of the unit, as well as the capital cost of FGDs (that generally ranges from $150 to $200/Kw).

To predict future emissions from EGUs and to further study the costs of emissions controls for EGUs, the Mid-Atlantic/Northeast Visibility Union (MANE-VU) and other Regional Planning Organizations have also followed the example of the US Environmental Protection Agency (EPA) in using the Integrated Planning Model (IPM®), an integrated economic and emissions model. IPM projects electricity supply based on various assumptions and develops a least-cost solution to generating needed electricity within specified emissions targets. IPM also provides estimates of the costs of complying with various policy requirements.

EPA developed Base Case version 2.1.9 using IPM to evaluate the impacts of CAIR and the Clean Air Mercury Rule (CAMR). (Recently, EPA updated their input data and developed Base Case v.3.0. Due to timing, all MANE-VU runs were based on EPA Base Case v.2.1.9 with some updates and corrections.)[2]

The Regional Planning Organizations collaborated with each other to update EPA Base Case v.2.1.9 using more current data about EGUs with more realistic fuel prices, creating an IPM run called VISTAS PC_1f. This VISTAS IPM implementation is the one that has been used in regional air

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[2] Although the IPM model runs anticipated the implementation of EPA's Clean Air Mercury Rule (CAMR), that rule has since been vacated by the courts. However, it is anticipated the adjustments to the predicted SO_2 emissions from electric generating units (EGUs) used in the air quality modeling, based on state-specific comments on the amount of SO_2 controls that will actually be installed due to state specific regulations and the EPA's CAIR rule, will have more of an impact on the air quality modeling analysis conducted for this SIP than the vacature of the CAMR rule. MANE-VU believes the adjustments based on state-specific comments improved the reliability of the inventory and made the modeling results more dependable.

quality modeling for ozone and haze state implementation plans.

MANE-VU, through MARAMA, contracted with ICF to prepare two new IPM runs.[3] The MARAMA CAIR Base Case run was based on the VISTAS PC_1f run and underlying EPA Base Case v.2.1.9, with some of the information updated, (e.g., fuel prices, control constraints, etc.) to better reflect current information. The MARAMA CAIR Base Case run is also sometimes called MARAMA_5c. The MARAMA CAIR Plus run was also based on VISTAS PC_1f run and the underlying EPA Base Case v.2.1.9, but using lower NOx emission caps and higher SO2 retirement ratios. Consistent with the MARAMA CAIR Base Case Run, the CAIR Plus Run also updated some of the information used in the VISTAS run (e.g., fuel prices, control constraints, etc.) to better reflect current information. The MARAMA CAIR Plus run is also sometimes referred to as MARAMA_4c.

Using IPM, EPA estimates average costs for compliance with CAIR to be \$500 to \$700 per ton of SO_2 emissions, with marginal costs of \$700 to \$1,000 per ton of SO2 emissions. On the other hand, the above referenced analysis conducted for MANE-VU by ICF, Inc., which used updated cost estimates for natural gas, indicated that the cost of compliance with CAIR would rise from \$806 in 2008 to \$1,392 per ton in 2018 (marginal costs of allowances in 2006 dollars).[4]

The MANE-VU Reasonable Progress Report 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 (though not necessarily appropriate for all installations) is FGD, which can achieve up to 95 percent reduction in SO_2 emissions. The cost varies considerably among units and was estimated to range from as low as \$170/ton to as high as \$5,700/ton. (Converted from 2001 to 2006 dollars using a conversion factor of 1.1383 www.inflationdata.com). The 2005 MANE-VU Report "Assessment of Control Technology Options for BART-Eligible Sources estimated that wet/dry scrubbers would cost \$200 to \$500 (2006 dollars) per ton of SO_2 removed at BART-Eligible EGUs, which tend to be large, older units.

MANE-VU's strategy calls for a 90 percent reduction in SO_2 emissions from the identified 167 key stacks, but it provides that alternative measures may be pursued if it is infeasible to achieve that level of

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[3] See the report, *Comparison of CAIR and CAIR+ Proposal using the Integrated Planning Model (IPM®),* ICF Resources LLC, May 2007, which is posted on the MARAMA web site.

[4] See Table 6, "Allowance Prices (Marginal Costs) of Emissions Reductions…" p. 9, ICF, May 2007. Marginal cost is defined as the cost of reducing one additional ton of emissions.

reduction. These stacks are located both inside and outside the MANE-VU region. Costs for specific individual plants to reduce emissions by 90 percent as recommended by the MANE-VU strategy will vary. The MANE-VU strategy provides the flexibility for states to control emissions from alternative sources if necessary in order to reduce costs and asks states to pursue controls on specific sources as appropriate and necessary. Given the importance of SO_2 emissions from specific EGUs in impairing visibility in MANE-VU Class I areas, the availability of technology to reduce emissions, the estimated cost, the costs of alternative measures, and the flexibility to achieve alternative reductions if necessary, MANE-VU Commissioners concluded that the costs of reducing emissions from the identified key stacks was reasonable.

Time Necessary for Compliance

MANE-VU's Reasonable Progress Report indicates that generally, sources are given a two to four year phase-in period to comply with new rules. Under Phase I of the NOx SIP call, EPA provided a compliance date of about 3.5 years from the SIP submittal date. Most MACT standards allow a 3-year compliance period.

MANE-VU has concluded 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.

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. These included potential impacts on fuel supplies if there were large-scale fuel switching, triggering NSR requirements, and the generation of wastewater and sludge from flue gas desulfurization systems. Mercury emissions may be reduced by the addition of controls for other pollutants. Furthermore, SO_2, NOx, and ammonia controls would have beneficial environmental impacts by reducing acid deposition and nitrogen deposition to water bodies and natural landscapes. Reductions would also result in decreases in ambient levels of $PM_{2.5}$ with corresponding health benefits. MANE-VU concluded that the energy and non-air quality impacts of additional EGU controls are reasonable.

Remaining Useful Life of Any Potentially Affected Sources

It is highly unlikely that additional EGU controls required under this SIP would have any impact on the remaining useful life of a particular EGU. 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 the size of the unit, capacity factor, and level of maintenance performed. Typical life expectancies range to 50 years or more. Additionally, implementation of regulations over the years has resulted in retrofitting that has ultimately increased the expected life span 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. This may be particularly likely if the unit serves an area which has limited transmission capacity available to bring in other power. The remaining useful life of a unit should not be confused with the economic decision of whether or not to continue operating a unit or to re-power or replace it. The cost of environmental compliance is only one of many factors involved in such a decision.

III. Low Sulfur Fuel Oil Requirements are Reasonable within MANE-VU

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 a minimum of 75 percent and maximum of 99.25 percent less sulfur in #2 fuel oil (also known as home heating oil, distillate, or diesel fuel) at an acceptably small increase in price to the consumer.

The MANE-VU Reasonable Progress Report discussed the four factors as they apply to low sulfur fuel use in chapters assessing controls for industrial, commercial, and institutional boilers and heating oil controls.

MANE-VU's Reasonable Progress Report identified switching to a lower sulfur 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.

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 and ultra-low sulfur diesel. 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 www.inflationdata.com). (See Chapter 8 of the Reasonable Progress Report.) In some seasons and some locations, low sulfur diesel is actually cheaper than regular diesel fuel.

While costs for these emissions reductions are somewhat uncertain, they are quite reasonable in comparison to 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 agreed that a low-sulfur oil strategy is both reasonable and achievable by 2018. MANE-VU has concluded that the cost of requiring lower sulfur fuel is reasonable.

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 technology 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 nationally, more ULSD is produced than both LSD and high sulfur fuel. The report concludes that the US has the infrastructure to produce adequate stocks of LSD and ULSD. The NESCAUM Low Sulfur Heating Oil Report[5] also notes 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 the likelihood of a fuel shortage in the short term due to use of ULSD for heating oil is reduced. 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 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 and look to increase imports from offshore refiners producing low sulfur product. Blending domestically produced biodiesel into heating oil offers opportunity to reduce imports, stabilize supplies and minimize supply-related price spikes. Air quality regulators are also considering permitting seasonal averaging of sulfur content which would allow higher sulfur imports to be brought to the Northeast market during periods of peak demand. Over the course of the year, the higher sulfur fuel would

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[5] "Low Sulfur Heating Oil in the Northeast States: An Overview of Benefits, Costs and Implementation Issues", December 31, 2005 by NESCAUM.

have to be offset by heating oil with a sulfur content below the standard.

The strategy adopted by MANE-VU phases in the requirement for lower sulfur fuel over the next 10 years, providing adequate time for this strategy to be implemented.

Energy and Non-Air Quality Environmental Impacts of Compliance

Reducing the sulfur content of fuel oil would have a variety of beneficial consequences for boilers and furnaces using the fuel, according to MANE-VU's Reasonable Progress Report. 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. 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 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. Furthermore, SO_2 controls would also have beneficial environmental impacts by reducing acid deposition and helping to decrease concentrations of $PM_{2.5}$. Reductions in $PM_{2.5}$ would potentially help nonattainment areas meet health-based National Ambient Air Quality Standards.

Remaining Useful Life of Any Potentially Affected Sources

Switching to low sulfur fuel would not adversely affect the remaining useful lifetime of any affected source. In fact, the use of low sulfur oil could extend the useful life of a source by reducing the maintenance required since low sulfur oil is less damaging to the combustion equipment.

IV. Additional Emission Reduction Measures Outside MANE-VU are Reasonable

The MANE-VU Statement concerning controls outside MANE-VU explained in Section 9.4.3, above, requested states to reduce non-EGU SO_2 emissions by 28 percent relative to on-the-books, on-the-way 2018 emissions projections[6]. MANE-VU asked neighboring RPOs to consider non-EGU emissions reductions comparable to MANE-VU's low sulfur fuel

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[6] The MANE-VU Statement concerning controls outside of MANE-VU titled, 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" dated June 20, 2007.

strategies, which are expected to achieve a greater than 28 percent reduction in non-EGU SO_2 emissions in 2018. This request was reflected in the modeling used to determine the reasonable progress goals by reducing emissions from the following source categories in both the Midwest RPO and the VISTAS regions:

- Coal-fired industrial/commercial/institutional boilers (60 percent reduction)
- Oil-fired industrial/commercial/institutional boilers (75 percent reduction)
- Other industrial/commercial/institutional boilers (50 percent reduction)

In addition, emissions from the following source categories were reduced in the VISTAS region:

- Other oil combustion sources in the area source inventory (75 percent reduction) (same SCC codes as used in MANE-VU). These strategies are similar to those being pursued in the MANE-VU region.

Low Sulfur Oil Strategy The strategies reducing emissions from oil-fired installations are considered reasonable in other regions for the reasons noted above with regard to the low sulfur fuel oil requirements being pursued within MANE-VU. MANE-VU realizes that the use of fuel oil is more prevalent in the Northeastern US than in the Midwest or Southeast. Switching to lower sulfur fuel in the Midwest or Southeast may achieve a smaller reduction in emissions than will be achieved in the Northeast. However, use of the lower sulfur fuel will have beneficial impacts on regional haze, fine particulate air pollution, acid rain, and equipment operation, as described above, and MANE-VU has concluded that the costs of requiring lower sulfur fuel would be reasonable in light of these benefits. Furthermore, MANE-VU's reasonable progress goals would allow Midwestern and Southeastern states the flexibility to achieve needed emissions reductions in the manner they determine to be most practical for their states; a low sulfur oil strategy is not mandated.

Coal-Fired ICI Boiler Strategy The reduction of emissions from coal-fired ICI boilers in the Midwest RPO and VISTAS is considered a reasonable strategy given the importance of those sources in the Midwest and Southeastern US and the costs and benefits described in several reasonable progress analyses. Further discussion of the reasonableness of controlling ICI boilers is provided below.

Emissions from ICI boilers are currently governed by multiple State and federal regulations under the Titles I, III, and IV of the Clean Air Act. The regulation of ICI boilers by various Clean Air Act programs has resulted in a variety of unit level emission limits resulting from SIP, New Source Performance Standards, New Source Review, or Maximum Achievable Control Technology requirements. Overlaid on these unit level requirements are system-wide allowances of the NO_X SIP call and the Acid Rain SO_2 opt-in program. Thus, the specific emission limits and control requirements for a given ICI boiler vary and depend on boiler age, size, and geographic location.

Air pollution reduction and control technologies for ICI boilers have advanced substantially over the past 25 years. In addition, advances in power generation technologies, renewable energy, and energy efficiency have the potential to further reduce emissions from these facilities. The focus of the evaluation in the MANE-VU Reasonable Progress Report was on the first category mentioned above - emission control technologies. The timing and magnitude of reductions from the other strategies – improved technologies, demand reduction/energy efficiency, and clean power may be part of a longer-term solution.

Descriptions of available SO_2 control technology options are available in Chapter 4 of the MANE-VU Reasonable Progress Report.

Analysis of controls for the Midwest Regional Planning Organization also identified SO2 control at ICI boilers as an important control strategy.[7] The EC/R report documented the importance of controlling emissions from ICI boilers in the Northern Midwest because “Source apportionment analyses identify SO_2 and NOx emissions from non-EGU point sources as the second largest contributor to visibility impairment in Isle Royale in 2018. ICI boilers account for a large portion of SO_2 and NOx emission from non-EGU point sources.” The report indicated analyzed means to achieve two market-based control strategies that would reduce ICI boiler SO_2 emissions between 40 percent and 77 percent. The EC/R analysis indicated that either strategy could be achieved by controlling coal fired boilers with spray dryer absorber (SDA) technology and by switching oil fired boilers to a lower sulfur fuel.

In addition to the MANE-VU Reasonable Progress Report, the analysis of the ICI boiler strategy relied on the 2005 MANE-VU report, “Assessment of Control Technology Options for BART-Eligible Sources.” (The following paragraphs are from the 2005 NESCAUM BART Document)

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[7] The report entitled “Reasonable Progress for Class I Areas in the Northern Midwest – Factor Analysis (July 18, 2007, EC/R Inc. for LADCO and Minnesota Pollution Control Agency) evaluated the four statutory factors for controls on ICI boilers. The report covered a region that included the states of North and South Dakota, Minnesota, Wisconsin, Michigan, Iowa, Missouri, Illinois, and Indiana. This will be called the EC/R report.

According to the 1998 survey of industrial boilers by EPA (2004), only 2 percent of gas-fired boilers and 3 percent of oil-fired boilers had any kind of air pollution control device. More coal-fired boilers had air pollution control devices: 47 percent had some control device and these were largely PM controls.

Post-combustion SO2 control was used by less than one percent of industrial boilers in 1998, with the exception of boilers firing petroleum coke: 2 percent of boilers firing petroleum coke had acid scrubbers. A small percentage of industrial boilers had combustion controls in place in 1998, although since 1998, additional low-NOX firing systems may have been installed.

Almost all SO2 emission control technologies fall in the category of reducing SO2 after its formation, as opposed to minimizing its formation during combustion. The exception to the nearly universal use of post-combustion controls is found in fluidized bed boilers, in which limestone is added to the fluidized bed combustion. Typically 90 percent of the sulfur can be captured in a coal-fired fluidized bed using limestone with Ca/S molar ratios of 2 to 2.5, depending on the sulfur content of the fuel, the reactivity of the limestone and the operation of the combustor. Post-combustion SO2 control is accomplished by reacting the SO2 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 technology used. SO2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) and/or "Scrubbers" 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). Within each technology category, multiple variations are possible and typically involve the type and preparation of the reagent, the temperature of the reaction (for dry processes), the use of enhancing additives, etc. Because these variations mostly involve complex process chemistry, but are fundamentally similar, this summary focuses on the major categories of SO2 control technologies, their applicability, performance and cost.

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typically involve the type and preparation of the reagent, the temperature of the reaction (for dry processes), the use of enhancing additives, etc. Because these variations mostly involve complex process chemistry, but are fundamentally similar, this summary focuses on the major categories of SO2 control technologies, their applicability, performance and cost.

A coal with sufficiently low sulfur content that when burned in the boiler meets the applicable SO2 emission standards without the use of additional controls is sometimes referred to as “compliance coal.” Coals naturally low in sulfur content may be mined directly from the ground. Alternatively, the sulfur content of coal fired in the boiler may be lowered first by cleaning the coal or blending coals obtained from several sources.

However, burning low-sulfur coal may not be a technically feasible or economically practical SO2 control alternative for all boilers. In some cases, a coal with the required sulfur content to meet the applicable standard may not be available or cannot be fired satisfactorily in a given boiler unit design. Even if such a coal is available, use of the low-sulfur coal that must be transported long distances from the mine may not be cost competitive with burning higher sulfur coal supplied by closer mines and using a post-combustion control device.

Various coal cleaning processes may be used to reduce the sulfur content of the coal. A significant portion of the pyritic sulfur minerals mixed with the mined coal can usually be removed by physical gravity separation or surface property (flotation) methods. However, physical coal cleaning methods are not effective for removing the organic sulfur bound in coal. Another method of reducing the overall sulfur content of the coal burned in a given boiler unit is to blend coals with different sulfur contents to meet a desired or target sulfur level.

Fluidized bed boilers generally operate at lower temperatures than other combustion systems, 800 to 870oC (1500 to 1600^{o}F). The lower temperatures allow the use of limestone or dolomite to be added to the bed to capture sulfur. Limestone (CaCO3) is converted to CaO at approximately 800oC (1500oF). SO2 released from the fuel reacts with CaO to form CaSO4, which is thermodynamically stable at bed temperatures. By recycling some of the solids leaving the bed, which contain unsulfated calcium, 90 percent removal of SO2 can be achieved with Ca/S molar ratios of 2 to 2.5 in circulating fluidized beds. Higher Ca/S ratios are required in bubbling beds. In either case, the sorbent is removed with the ash from the bed and sent to disposal.

Wet FGD “scrubbers” date back to the 1960s with commercial applications in Japan and the U.S. in the early 1970s. They represent the predominant SO2 control technology in use today with over 80 percent of the controlled capacity in the world and the U.S.

In a wet scrubber, the SO2-containing flue gas passes through a vessel or tower where it contacts an alkaline slurry, usually in a counterflow arrangement. The intensive contact between the gas and the liquid droplets ensures rapid and effective reactions that can yield greater than 90 percent SO2 capture. Currently, advanced scrubber designs have eliminated many of the early problems, primarily related to reliability, but have also demonstrated very high SO2 reduction capabilities with some units providing over 95 percent control.

Variations of the basic technology, in addition to equipment improvements made over the years, include reagent and byproduct differences. Limestone, lime, sodium carbonate and even seawater-based processes are commercial. Limestone is by far the most widely used with commercial-grade gypsum (wallboard quality) being produced in the so-called Limestone Forced Oxidation (LSFO) process. The use of other reagents, as mentioned, is driven by site-specific criteria, such as local reagent availability, economics, efficiency targets, etc.

Dry processes include spray dryer absorbers (SDA) and Dry Sorbent Injection (DSI) technologies. SDA refers to a configuration where the reaction between SO2 and the sorbent takes place in a dedicated reactor or scrubber hence the common reference to “dry scrubber”; conversely, DSI uses the existing boiler/duct system as the "reactor" and several configurations are possible based on the temperature window desired. This can occur at furnace (~2200ºF), economizer (800-900ºF) or duct temperatures (~250ºF). Dry processes are more compatible with low to medium sulfur coals due to limitations in reaction rates and sorbent handling (e.g., atomization). Therefore, high-sulfur applications are not likely. In addition, another common feature among them is the need for particulate control downstream of the sorbent injection. Usually this is accomplished through the use of fabric filters (baghouses) which are, not only efficient collectors of particulates, but also provide additional SO2 removal as the flue gas passes through unreacted sorbent collected on the filters.

Dry SO2 controls vary significantly in performance, with SDAs being able to achieve about 80 percent removal rates, whereas the various forms of DSI are capable of 40 to 75 percent efficiencies.

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 individual boilers will depend on the capacity of the boiler and typical operating conditions.

The MANE-VU "Ask" provides the flexibility for states to control sources where costs are in the lower end of the projected range rather than applying a blanket reduction across all sources. The modeling assumptions are applied across entire categories in order to estimate impacts on visibility but this does not preclude another approach that achieves similar emissions reductions at lower costs.

MANE-VU's Reasonable Progress Report provides cost estimates for controlling emissions from ICI boilers that range from $130 per ton to $11,000 per ton, a very wide range due to the variability of sources in this category.[8]

The 1995 Assessment of Control Technology Options for BART-Eligible Sources noted that both wet and dry scrubbers are in wide commercial use to control SO2 emissions from industrial boilers in the U.S. Dry sorbent injection (DSI) has lower capital costs than a spray dryer absorber (SDA), although DSI can only achieve about 40 percent SO2 reduction. SDA systems can achieve 90 percent reduction. Capital costs for DSI are in the range of $8,600 to $26,000 per MMBtu/hr, depending on the size of the system and on the sulfur content of the fuel. Capital costs for SDA systems are about double that for DSI systems, but the cost per ton of SO2 removed is similar: $400 to $4000 per ton of SO2 removed. These costs are higher than the costs for scrubbers on EGUs, which are only $100 to $200 per ton of SO2 removed.

Wet FGD systems also remove 90 percent and higher of the SO_2, but the capital cost is a bout 50 percent higher than the cost for an SDA system. The costs per ton of SO_2 removed are similar to the cots for SDA for coal-fired boilers. Costs per ton of SO_2 are estimated to be about twice as high for oil-fired boilers as compared to coal-fired boilers.

In the BART Five-Factor Analysis[9] NESCAUM compiled cost estimates for controls on BART units from state staff, the 2005 BART Control Technology Report by NESCAUM report, and other RPO analyses. Cost estimates from NESCAUM as well as the low, medium, and high cost designations are summarized below in the table below.

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[8] MANE-VU's Reasonable Progress Report is entitled "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas" prepared by MACTEC for MARAMA, dated July 9, 2007.

[9] BART Five Factor Analysis titled, "Five-Factor Analysis of BART-Eligible Sources: Survey of Options for Conduction BART Determinations" prepared by NESCAUM for MANE-VU dated June 1, 2007.

Cost of Technologies for Industrial Boilers[10]

Pollutant	Industrial Boilers		Cost Effectiveness	
	Control	Cost	Units	Cost Bin
NOx	Low NOx Burners	200-3000	$/Ton NOx	Mid
NOx	SNCR	1300-10000	$/Ton NOx	Mid to High
NOx	SCR	4000-15000	$/mmBtu/hr	High
SO2	Wet/Dry Scrubbers	400-4000	$/Ton SO2 (coal)	Mid
SO2	Wet/Dry Scrubbers	800-8000	$/Ton SO2 (oil)	Mid to High
PM	ESP	15-40	$/Actual cubic feet/minute	--
PM	Reverse Air Fabric Filter	15-40	$/Actual cubic feet/minute	--
PM	Pulse Jet Fabric Filter	17-40	$/Actual cubic feet/minute	--
PM	Venturi Scrubber	12-40	$/Actual cubic feet/minute	--
PM	Cyclone	1-5	$/Actual cubic feet/minute	--

Time Necessary for Compliance

MANE-VU has concluded that there is sufficient time between 2008 and 2018 for affected states to adopt requirements and for affected sources to install necessary controls.

For combustion based and post-combustion based engineering and construction leads 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 2-4 year phase-in period to comply with new rules. Under the previous 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

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[10] Table from Appendix B in “Five-Factor Analysis of BART-Eligible Sources: Survey of Options for Conduction BART Determinations” prepared by NESCAUM for MANE-VU dated June 1, 2007

NO_X SIP Call, EPA provided a 2-year period after the SIP submittal date for compliance. States generally provided a 2-year period for compliance with RACT rules. MANE-VU's Reasonable Progress report assumed that a 2-year period after SIP submittal is adequate for pre-combustion controls (fuel switching or cleaning) and a three year period for the installation of post combustion controls.

For BART control measures, the proposed BART guidelines require States to establish enforceable limits and require compliance with the BART emission limitations no later than 5 years after EPA approves the regional haze SIP.

Energy and Non-Air Quality Environmental Impacts of Compliance

Switching to lower sulfur fuel or installing post-combustion controls may reduce boiler heat rate and energy output. Scrubbers and spray dryers will require additional safeguards for fuel handling and waste handling systems to avoid additional non-air environmental impacts such as increased effluents in waste water discharges and storm water runoff. These factors will need to be considered specific to individual sources. Carbon dioxide is emitted as a by-product of flue gas desulfurization, therefore impacts of increased carbon emissions will need to be considered, particularly if carbon emissions are limited in the future under climate change mitigation strategies.

The MANE-VU reasonable progress report notes, "Reducing the sulfur content of 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." (p.4-14)

The EC/R report for the Northern Midwest region concludes, "The energy and other environmental impacts of the potential control measures for ICI boilers are believed to be manageable." (p.102). The report indicates, "the electricity and steam required by controls installed to meet SO_2 and NOx emission caps would be less than 1 percent of the total electricity and steam production in the region. Solid waste disposal and wastewater treatment costs are expected to be less than 5 percent of the total operating costs of pollution control equipment." (p.48)

SO_2 controls would have beneficial environmental impacts by reducing acid deposition and helping to decrease concentrations of $PM_{2.5}$. Reductions in $PM_{2.5}$ would potentially help nonattainment areas meet health-based National Ambient Air Quality Standards.

The MANE-VU reasonable progress report notes, "Reducing the sulfur

> content of 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." (p. 4-14)

Remaining Useful Life of Any Potentially Affected Sources

It is unlikely that additional controls required to meet the goals established under this SIP would have any impact on the remaining useful life of a particular source. The strategy provides for flexibility in determining which sources to control so that the most cost-effective controls can be adopted and implemented over the next 10 years.

Available information for remaining useful life estimates of ICI boilers indicates a wide range of operating time, depending on size of the unit, capacity factor, and level of maintenance performed. Typical life expectancies range from about 10 years up to over 30 years. However, the remaining useful life of a source is very unit specific.

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 February 25, 2004).

Supplemental Air Quality Modeling Technical Support Document (TSD) for the Clean Air Interstate Rule (CAIR), May, 2004.

I. Introduction

This document provides additional background and analyses supporting EPA's proposed determination that compliance with the proposed CAIR, if achieved by power plants under the model cap-and-trade programs, would satisfy the best available retrofit technology (BART) requirements for those sources as a "better than BART" alternative. Section III.E of the supplemental proposal (SNPR) of the Clean Air Interstate Rule (CAIR) discusses this proposed determination. The EPA's supporting assessment is consistent with the requirements established under the regional haze rule (64 FR 3714, July 1, 1999), and under the proposed Guidelines for Best Available Retrofit Technology (BART) Determinations (66 FR 38108, July 20, 2001, and 69 FR 25184, May 5, 2004). Section II of this document discusses and compares the emissions projections for reductions expected under the proposed CAIR and under the BART requirements. Section III of this document explains the projections of visibility impacts at Class I areas used to support the "better than BART" determination in the CAIR proposed rule.

II. Emissions Projections Used for CAIR Analysis

A. Overview of Emission Projections

As discussed in the SNPR preamble, in performing the "Better-than-BART" analysis we would ideally use air quality modeling based on emissions projections for the scenario where the proposed CAIR is in effect only in the proposed CAIR region and source-specific BART is in effect in the rest of the country.[1] We would compare the visibility impacts of this scenario to existing visibility conditions to determine whether the proposed CAIR resulted in a degradation of visibility at any Class I area. We would also compare these visibility impacts with the visibility impacts of nationwide BART implementation, to assess whether the proposed CAIR would result in greater average visibility improvement than nationwide BART. These comparisons should be made for the year in which source-specific BART would be fully implemented (2014).

As noted in the SNPR preamble, currently available modeling runs approximated, but did not exactly match the scenarios described above. Specifically, emissions projections for BART are currently available only on a nationwide basis, and only for EGUs larger than 250 MW. The available emissions projections reflecting implementation of the proposed CAIR are based on nationwide SO2[2] and 32[3] state NOx emissions reduction requirements for all EGUs, without

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[1] As discussed in the SNPR preamble, we applied the two-pronged visibility test, rather than the simpler overall emissions reductions test, because our modeling showed a potential for a different geographic distribution of emissions reductions under the proposed CAIR cap and trade program than under source-specific BART.

[2] SO2 emissions for this modeling were based on a 2.86:1 retirement ratio of Title IV allowances.

[3] 31 entire states and a portion of one state (eastern Texas).

BART being in effect outside the proposed CAIR region.

We believe that, despite the differences in the geographic scope of the proposed CAIR emission reductions requirements as modeled and as proposed, our CAIR modeling reasonably approximates the expected emissions under the proposed CAIR. Similarly, we believe that the emissions projections we used to represent BART implementation reasonably approximate emissions under BART as ideally modeled. The rest of this section summarizes the emissions projections that EPA used in this analysis; explains why EPA believes that they represent reasonable approximations of the ideal scenarios; and explains qualitatively what EPA believes would be the impact of further refining the emissions projections.

B. CAIR EGU Emissions Projections

EGU emissions were projected using the Integrated Planning Model. A full description of the Integrated Planning Model as well as the assumptions for the Base Case can be found at: http://www.epa.gov/airmarkets/epa-ipm/ . The emissions projections for the proposed CAIR were described in the January 2004 CAIR analysis. In that analysis, EPA analysts simulated nationwide cap on SO2 emissions and a 32 State regionwide cap on NOx emissions.By contrast, the CAIR as proposed would achieve SO2 emission reductions in an eastern region of 28 States and the District of Columbia, rather than nationwide. Similarly, while the proposed CAIR would achieve NOx reductions in 29 States and the District of Columbia, the modeling scenarios EPA analyzed also included NOx reductions in Vermont, New Hampshire, Maine and Rhode Island, which were not required under the proposed CAIR. Conversely, NOx reductions in Kansas and the western half of Texas are required by the CAIR proposal but were not included in the CAIRscenario as modeled.

However, as noted in the January 30, 2004 notice of proposed rulemaking (NPRM), and illustrated further in the tables below, the SO_2 and NOx reduction requirements simulated in this analysis provide a very close estimate to the reductions that would be expected under the CAIR as proposed.

The State-by-State emissions under the base case and the proposed CAIR as analyzed are presented in Table 1 below. Table 2 summarizes total emissions in proposed CAIR and Non-CAIR States under the base case and under the proposed CAIR, and shows the resulting emission reductions expected under the proposed CAIR in each region.

Table II-1: Projected 2015 EGU Emissions under Base Case and CAIR (as analyzed)[4] (1000 tons)

CAIR-region State	Base Case		"CAIR"	
	SO_2	NOx	SO_2	NOx
Alabama	416	129	334	59
Arkansas	123	53	78	9
Connecticut†	6	5	5	5
Delaware	48	11	35	9
District Of Columbia	0	0	0	0
Florida	230	171	174	54
Georgia	600	153	197	52
Illinois	534	179	258	95
Indiana	523	242	327	74
Iowa	160	87	146	35
Kansas*	65	102	60	101
Kentucky	357	199	282	53
Louisiana	113	50	80	15
Maryland	230	62	40	25
Massachusetts	16	12	10	11
Michigan	384	126	379	94
Minnesota	87	105	73	42
Mississippi	74	45	43	15
Missouri	307	141	279	69
New Jersey	38	30	20	14
New York	197	66	101	53
North Carolina	141	62	141	54
Ohio	1,025	256	290	97
Pennsylvania	806	213	170	77
South Carolina	196	66	145	31
Tennessee	310	103	192	32
Texas*	487	200	365	159
Virginia	185	57	116	33
West Virginia	485	148	139	36
Wisconsin	176	97	168	56
Total	8,319	3,169	4,646	1,457

Non-CAIR region State	Base Case		"CAIR"	
	SO_2	NOx	SO_2	NOx
Arizona	47.8	86.0	47.8	85.8
California	10.7	17.8	10.7	17.8
Colorado	70.4	81.0	70.4	81.0
Idaho	-	1.2	-	1.2
Maine††	2.6	1.9	2.6	1.9
Montana	17.7	38.5	17.0	38.5
Nebraska	96.3	56.6	96.3	56.8
Nevada	17.3	40.7	17.5	41.1
New Hampshire††	7.3	3.8	5.6	3.1
New Mexico	48.2	76.1	48.2	76.3
North Dakota**	171.2	80.2	67.2	84.5
Oklahoma	133.0	86.6	131.9	87.2
Oregon	15.2	13.5	15.2	13.5
Rhode Island††	-	2.0	-	2.0
South Dakota**	41.5	12.3	2.2	16.4
Utah	31.4	69.2	31.4	69.2
Vermont††	-	-	-	-
Washington	5.4	25.5	5.4	25.4
Wyoming	46.0	89.0	44.5	89.0
Total	762.0	781.9	613.9	790.7

* modeling of the NOx cap did not include Kansas and the Western half of Texas

**Modeling the CAIR rule as actually proposed would not likely show significant SO_2 reductions in North Dakota and South Dakota, because they would not be within the CAIR region.

†Connecticut is required under the proposed CAIR to control NOx in the summertime

†† Our CAIR modeling included NOx emission reduction requirements for ME, NH, RI, and VT which are not required by the CAIR proposal.

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[4] The scenario we used to represent the CAIR differed slightly from the actual CAIR proposal, as explained in the text and noted in the Table notes above.

Table II-2. Summary of Projected 2015 SO_2 and NOx Emissions Totals in proposed CAIR and non-CAIR States under the CAIR as analyzed [5] (1000 tons).

	Base Case		CAIR as analyzed		Emission Reductions (Base Case – CAIR)	
	SO_2	NOx	SO_2	NOx	SO_2	NOx
Total in CAIR States	8,319	3,169	4,646	1,457	3,673	1,712
Total in non-CAIR states	762	782	614	791	148	– 9
			Total Reductions		3,821	1,704

When we compare the total emissions after proposed CAIR implementation to the baseline, both in the non-CAIR States and in the CAIR states, we note that of the 3,822,000 tons of SO_2 reductions, only 149,000 tons of reductions, or less than 4%, occurred in non-CAIR states. For NOx, all of the reductions occurred in the CAIR States, with a 9,000 ton increase in non-CAIR states (about 1% over base case). Because these differences are small relative to the overall reductions, they do not affect the validity of the Better-than-BART analysis.

C. BART EGU Emissions Projections

BART is applicable to all fossil-fuel fired steam electric plants that have the potential to emit more than 250 tons of any pollutant contributing to regional haze, that were not in operation by August 7, 1962, and for which construction began by August 7, 1977. (BART also applies to 25 other source categories, but our analysis considered only EGUs, because only EGUs are eligible for participation in the proposed base CAIR model cap and trade program).

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[5] As explained in text and noted in Table 1, the assumptions in the CAIR as analyzed differed slightly from CAIR as proposed.

Table II-3: State-by-state EGU Emissions Projections under BART (as analyzed)[6] in 2015 (1000 tons).

CAIR-Region State	2015EGU Emissions Under "BART"		Non-CAIR Region State	2015 EGU Emissions Under "BART"	
	SO_2	NOx		SO_2	NOx
Alabama	371	89	Arizona	47.8	86.2
Arkansas	31	36	California	17.3	19.6
Connecticut	3	5	Colorado	49.0	64.3
Delaware	52	10	Idaho	-	1.2
District Of Columbia	-	0	Maine	3.2	2.1
Florida	194	144	Montana	21.8	38.5
Georgia	224	41	Nebraska	69.0	44.4
Illinois	317	112	Nevada	17.1	30.2
Indiana	579	148	New Hampshire	8.8	3.9
Iowa	185	81	New Mexico	48.6	76.5
			North Dakota	118.4	49.7
Kansas	70	56	Oklahoma	42.2	57.9
Kentucky	346	99	Oregon	15.2	13.5
Louisiana	72	43	Rhode Island	-	2.0
Maryland	144	27	South Dakota	5.6	4.7
Massachusetts	17	12	Utah	31.5	69.4
Michigan	182	103	Vermont	-	0.0
Minnesota	91	77	Washington	6.0	16.1
Mississippi	94	36	Wyoming	50.0	90.5
Missouri	158	110	Total	551.5	670.7
New Jersey	61	14			
New York	227	63			
North Carolina	146	64			
Ohio	948	138			
Pennsylvania	396	110			
South Carolina	167	37			
Tennessee	418	53			
Texas	343	204			
Virginia	141	40			
West Virginia	323	65			
Wisconsin	162	95			
Total	6,460	2,110			

*Connecticut is a CAIR region state for purposes of summertime NOx only

The BART emissions projections used in the "better than BART" analysis were developed for EPA's April, 15, 2004 BART proposal. The modeling of EGUs for that rule included controls on BART-eligible EGUs larger than 250 MW. There are 302 BART-eligible units of greater than 250 MW, as listed in Table A-1 in the Appendix, that emit about 85% of both the SO_2 and the NOx emitted by all BART eligible EGUs. The EPA's modeling of the BART proposal projects emissions reductions of approximately 3.2 million tons of SO_2 and 1.2 million tons of NOx in 2015 from these larger EGUs. However, States would also be required

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[6] BART control assumptions were applied only to BART-eligible EGUs larger than 250MW, as explained in text.

to make BART determinations for BART eligible units smaller than 250 MW. Therefore, it is likely that the BART rule would actually achieve greater reductions than currently modeled, although it is uncertain as to the extent of reductions achievable from these smaller EGUs.

We can gain an idea of the upper bound of potential reductions if all of the smaller EGUs install BART. Nationwide there are between 130 and 166 units that are of a size between 25 MW and 250 MW in size that would otherwise meet the BART criteria[7]. In 2001 these units emitted between 742,000 and 806,000 tons of SO2 and between 287,000 and 341,000 tons of NOx. These emissions provide an upper bound to the amount of emissions reductions possible from these units under BART, if one assumed that all of the units were reduced to zero.

For this analysis, we used a modeling scenario for CAIR that does not reflect the effect of BART requirements in the western States. As a result, we believe the results suggesting a small difference in visibility improvements between the BART and CAIR scenarios in visibility improvement in a few Class I areas is an artifact of the available emissions scenarios used for modeling and does not accurately reflect the effect of the combination of CAIR coupled with the BART requirements in western States. We will develop this more accurate modeling scenario when we redo the air quality modeling in developing a final rule.

Table 4 shows how these emissions are distributed between CAIR and non-CAIR States. As can be seen, the large portion of these emissions are from units located in the CAIR region.

Table II-4: SO_2 and NOx emissions from BART eligible EGUs between 25 MW and 250 MW (1,000 tons)

Area	NOx	SO_2
CAIR Region	228 to 265	647 to 694
non-CAIR Region	59 to 76	96 to 112
Total	287 to 341	742 to 807

Source: Acid Rain Database

As discussed in the SNPR preamble, for SO_2 the proposed CAIR would achieve 1.6 million tons more reductions than BART in 2015, and 2.6 million tons more by 2020. For NOx, the proposed CAIR would result in about 500,000 tons more emissions reductions than BART in both 2015 and 2020. These differences are about twice the level of total emissions from the BART-eligible EGUs of 25-250 MW. Therefore, even if all SO_2 and NOx emissions from BART-eligible EGUs between 25 and 250 MW were to be reduced to zero, the proposed CAIR would still result in about 800,000 to 1.6 million tons more SO_2 reductions, and about 250,000

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[7] The range reflects different assumptions regarding the BART eligibility of units with on-line dates after 1977. The higher number of units reflects the inclusion of all coal units that went on line through 1985. The lower number reflects only units that came on-line through 1977. BART only applies to those units that began actual construction before August 7, 1977. We utilized a range because without an extensive review of permitting and construction history, it is not apparent when many potentially BART-eligible sources commenced construction. States are currently engaged in such a review.

tons more NOx reductions, than source-specific BART.

D. Comparing BART and CAIR Projections

1. Year of CAIR-to-BART Comparison

The better-than-BART analysis is based on emissions projections for the year 2015, because that is the year for which the air quality modeling was performed indeveloping the CAIR proposal. This year occurs when the projected difference between the proposed CAIR emissions and the BART emissions are near their minimum. Emissions reductions from the proposed CAIR are projected to be greater than for a national BART strategy in all other years, except for 2014. Since BART does not require or provide incentives for reductions before 2014, or 2013 at the earliest[8], the proposed CAIR is expected to show greater emissions reductions than the BART requirements in the years leading up to full implementation of the BART requiements. Similarly, emissions in the BART case will grow after 2015 with the growth of the EGU sector (and lack of cap), while they would be expected to decline after 2015 in the CAIR case, and continue to be constrained by the cap in future years under proposed CAIR. In 2014, the likely first year of the BART program, emissions for the two programs should be similar to the emissions EPA is projecting for 2015.

2. Effect of not including BART (outside the CAIR region) in the CAIR emissions projections

Because SO_2 reductions under BART in the non-CAIR states were greater (by about 65,000 tons) than the modeled reductions for the proposed CAIR in those same states,[9] we note that EPA's proposed policy approach – CAIR combined with BART in the non-CAIR region – would lead to greater reductions than was modeled for the proposed CAIR by itself.

With respect to NOx, our modeling of emissions reductios from the proposed CAIR included reductions in areas not actually covered by the CAIR proposal (VT, NH, ME, RH). However, as can be seen in Table II-1, total NOx emissions for these four states are very small (7,700 tons total or 1% of base case NOx emissions for all non-CAIR states) and our CAIR modeling projected only 700 tons of emissions reductions from this level (all from NH). Our modeling of CAIR emissions reductions also excluded some areas that are covered by the CAIR proposal (KS, west TX). When we include the proposed CAIR NOx emission reduction requirements for KS and west TX, we anticipate that the additional NOx reductions from these states will be greater than the reductions from the four New England states, which were

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[8] States that develop a trading program or other measures in lieu of BART have until 2018 to fully implement the program. However, our better-than-BART analysis compares CAIR to source-specific BART, not to yet-to-be developed trading or other alternatives. If in fact some states opt for cap and trade programs or other alternatives in lieu of BART, on a 2018 schedule, BART reductions would be even further into the future than CAIR reductions.

[9] Total SO_2 emissions for non-CAIR states are 571,100 tons under the proposed CAIR (see Table II-1) and 506,200 tons under BART (see Table II-3). The difference is 64,800 tons.

incorrectly attributed to the CAIR in our modeling.

Aside from these differences in the region where NOx emissions were modeled, the CAIR modeling understated expected NOx reductions on a national basis since it did not reflect any NOx reductions outside of the 32 state region. In fact, eligible units in those states would be required to reduce emissions under BART. Therefore, as with SO_2, we note that implementation of the proposed CAIR, in conjunction with BART in the non-CAIR region, will lead to greater nationwide emissions reductions than implementation of BART nationally.

As explained in section III below, the visibility projections based on CAIR alone – without BART implementation in the non-CAIR region – satisfy the better-than-BART test. Inclusion of BART reductions in the non-CAIR region would only increase emissions reductions and result in greater visibility improvement. Therefore, the lack of western (non-CAIR region) BART emissions reductions in our CAIR-scenario projections does not affect the better-than-BART conclusions.

III. Air Quality Analysis

A. Air quality modeling to determine future visibility

Introduction

In this section we describe the photochemical air quality modeling performed to support the proposed finding in the CAIR supplemental proposal that compliance with the proposed CAIR model trading rule by BART-eligible sources would result in greater visibility improvement that source-specific BART..

This section also includes technical information on the air quality model applied in support of the supplemental proposed rule, and the procedures for projecting regional haze for future year scenarios. The IAQR Air Quality Modeling Technical Support Document (NPR-AQMTSD)[10] contains more detailed information on the air quality modeling aspects of this rule. This technical support document provides additional information, including further details on the postprocessing of model results and calculation of visibility and visibility metrics.

1. Overview of the Modeling Process

We completed numerous modeling runs and postprocessing calculations to determine the impacts of emissions and emissions control strategies on visibility in Class I areas. Determining such visibility impacts allows comparison of the effects of compliance with BART compared with compliance with the proposed CAIR model rule. We detail these calculations and the modeling process in subsequent sections, following a brief description of the overall process.

The cornerstone of our modeling process was the development of the 2015 base case,

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[10] U.S. EPA, Technical Support Document for the Interstate Air Quality Rule - Air Quality Modeling Analyses. January 2004. Docket number OAR-2003-0053-0162.

which contains emissions for 2015 based on predicted growth and existing emissions controls. We used modeled PM concentrations to estimate visibility impairment at Class I areas. We then used the model-predicted changes in visibility impairment along with the observed current visibility values to estimate future visibility impairment at each Class I area. We applied the relative predicted changes in visibility (expressed as a percent) from the model, due to emissions changes, to the current visibility values to estimate future visibility. The projected visibility values were based on emissions changes between the 2001 "proxy" inventory and the 2015 inventory.

After we established the future year base case visibility values, we calculated estimated visibility improvements at each Class I area by modeling the CAIR control strategy as well as the BART strategy in 2015.

2. Methodology

In general, we estimated base and future year visibility impairment using the same modeling approach that was used in the January 2004 proposal to develop base and future year predictions of $PM_{2.5}$ values. As in the January 2004 proposal, we used the REMSAD model to predict base and future $PM_{2.5}$ levels. We used the REMSAD predicted $PM_{2.5}$ components to estimate future year changes in visibility at Class I areas. Details of the application of REMSAD, including model performance, can be found in the NPR-AQMTSD. That modeling approach is described in detail in the January 2004 proposal preamble, 64 FR 4593-4596, 4607-4609, 4635-4639 (January 30, 2004) and the NPR-AQMTSD (pp. 10-22, 37-42, and 57-63) and familiarity with that detailed description is assumed for present purposes.

As described in the NPR-AQMTSD, we performed a 1996 Base Year simulation to examine the ability of the modeling system to replicate observed concentrations of PM and its precursors. We then performed simulations using a 2001 "proxy" emissions inventory. The 2001 "proxy" inventory was created for the purpose of modeling 2001, which represents the most recent year for which modeling is practicable. We followed the 2001 modeling with a simulation for a future-year base case scenario for 2015. The future-year base case scenario included emissions resulting from growth and emissions controls required under Federal and State law. We then quantified the impacts of the CAIR and BART controls on visibility impairment by comparing the results of the current base case and future-year base case model runs with the results of the CAIR and BART control strategy model runs.

We quantified visibility impacts in this manner at the 44 Class I areas for which ambient $PM_{2.5}$ data for 1996 exists. Since the base year meteorology used in the REMSAD modeling is from 1996, ambient data from 1996 is needed to be able to apply the model results. It is necessary to know which days make up the 20 percent best and worst days so that the model outputs can be calculated on the same days. For a Class I area without ambient data in 1996, there is no way to match up the model predicted changes in visibility with the ambient data from the 20 percent best and worst days. There are currently 110 IMPROVE monitoring sites collecting ambient PM2.5 data at Class I areas, but only 44 of these sites have complete data for 1996.

These 44 sites are scattered throughout the country and represent all of the IMPROVE defined regional visibility areas[11] except the Boundary Waters (Northern Great Lakes) region. Of the 44 sites, 15 are in the East[12] and 29 are in the West, where the bulk of the Class I areas are located.

3. Calculation of Base Year (Current) Visibility Levels

Base year (current) visibility values at Class I areas were needed to determine the starting point for calculating future year visibility improvements. For the purpose of evaluating visibility for the "better than BART" analysis, visibility impairment was calculated for the 20% worst days and the 20% best days at each Class I area. For this proposal, the calculation of baseline visibility values for each Class I area generally followed the procedures detailed in the Guidance for Tracking Progress.[13] The baseline visibility on the 20% worst days at each Class I area was calculated using the default IMPROVE visibility equation[14]. The daily deciview values were ranked for each Class I area for 1996. The 20% highest deciview values were identified as the 20% worst days for the year. A similar procedure was followed to get the 20% best days in each Class I area.

Table III-1 shows the current (1998-2002[15]) estimated visibility impairment (in deciviews) at the 44 Class I areas on the 20% worst days and 20% best days at each area[16]. Each IMPROVE site had 1-5 years of complete data available for the analysis. The number of years of complete data for each site is listed in the table.

Table III-1. Current visibility (1998-2002) on the 20% best days and 20% worst days, at 44 IMPROVE sites

Class I Area (IMPROVE Site)	IMPROVE Site Identifier	State	Number of Years of Complete Data	1998-2002 Baseline Visibility (in dv) 20% Worst Days	1998-2002 Baseline Visibility (in dv) 20% Best Days
Acadia National Park	ACAD	Maine	5	22.7	8.4

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[11] IMPROVE: Spatial and Seasonal Patterns and Temporal Variability of Haze and its Constituents in the United States: Report III (May 2000).

[12] The East is defined as the part of the country that is east of 100 degrees longitude.

[13] U.S. EPA, Guidance for Tracking Progress Under the Regional Haze Rule (Tracking Progress Guidance) (September 2003).

[14] Tracking Progress Guidance, page 3-10.

[15] Analyses under the Regional Haze rule(including BART analyses) will use a five-year visibility base period of 2000-2004. For this analysis, we used visibility data from the most recently available five year period (1998-2002).

[16] The best and worst day calculations for the current visibility used the ambient data from 1998-2002. The best and worst modeling days for each Class I area were identified based on the 1996 ambient data.

Class I Area (IMPROVE Site)	IMPROVE Site Identifier	State	Number of Years of Complete Data	1998-2002 Baseline Visibility (in dv) 20% Worst Days	1998-2002 Baseline Visibility (in dv) 20% Best Days
Badlands National Park	BADL	South Dakota	5	17.3	7.1
Bandelier National Monument	BAND	New Mexico	5	13.2	6.3
Big Bend National Park	BIBE	Texas	4	18.4	7.7
Bliss State Park (Desolation)	BLIS	California	3	12.9	3.5
Bryce Canyon National Park	BRCA	Utah	5	12.0	4.1
Bridger Wilderness	BRID	Wyoming	5	11.5	3.8
Brigantine National Wildlife Refuge	BRIG	New Jersey	4	27.6	13.6
Canyonlands National Park	CANY	Utah	5	12.0	5.3
Chassahowitzka National Wildlife	CHAS	Florida	4	25.7	16.4
Chiricahua National Monument	CHIR	Arizona	5	13.9	5.9
Crater Lake National Park	CRLA	Oregon	3	14.1	3.2
Dolly Sods /Otter Creek Wildernes	DOSO	West Virginia	5	27.6	13.0
Gila Wilderness	GICL	New Mexico	4	13.5	5.1
Glacier National Park	GLAC	Montana	4	19.5	7.3
Grand Canyon- Hopi Point	GRCA	Arizona	3	12.0	4.1
Great Sand Dunes National Monument	GRSA	Colorado	5	13.1	5.7
Great Smoky Mountains National Park	GRSM	Tennessee	5	29.5	14.2
Guadalupe Mountains National Park	GUMO	Texas	5	17.6	7.2
Jarbidge Wilderness	JARB	Nevada	3	12.6	3.0
Jefferson/James River Face Wilderness	JEFF	Virginia	1	28.3	15.8
Lassen Volcanic National Park	LAVO	California	5	14.8	3.3
Lye Brook Wilderness	LYBR	Vermont	4	23.9	6.6
Mammoth Cave National Park	MACA	Kentucky	4	30.2	16.5
Mesa Verde National Park	MEVE	Colorado	5	12.8	5.5
Moosehorn NWR	MOOS	Maine	5	21.4	8.6
Mount Rainier National Park	MORA	Washington	5	18.9	4.9
Mount Zirkel Wilderness	MOZI	Colorado	4	11.7	4.4
Okefenokee National Wildlife Refuge	OKEF	Georgia	5	26.4	15.5

Class I Area (IMPROVE Site)	IMPROVE Site Identifier	State	Number of Years of Complete Data	1998-2002 Baseline Visibility (in dv) 20% Worst Days	1998-2002 Baseline Visibility (in dv) 20% Best Days
Petrified Forest National Park	PEFO	Arizona	5	13.5	6.3
Pinnacles National Monument	PINN	California	3	19.1	8.8
Point Reyes National Seashore	PORE	California	2	20.2	8.6
Redwood National Park	REDW	California	5	16.5	5.0
Cape Romain National Wildlife Refuge	ROMA	South Carolina	4	25.9	13.8
San Gorgonio Wilderness	SAGO	California	4	21.5	6.8
Sequoia National Park	SEQU	California	3	23.5	8.8
Shenandoah National Park	SHEN	Virginia	4	27.6	12.2
Shining Rock Wilderness	SHRO	North Carolina	1	29.7	7.8
Sipsy Wilderness	SIPS	Alabama	4	28.7	16.3
Three Sisters Wilderness	THIS	Idaho	5	15.7	2.8
Tonto National Monument	TONT	Arizona	3	14.7	7.4
Upper Buffalo Wilderness	UPBU	Arkansas	5	25.5	12.2
Weminuche Wilderness	WEMI	Colorado	4	11.6	4.4
Yosemite National Park	YOSE	California	5	17.6	4.0

4. Projection of Future Year Visibility Levels

Future year levels of visibility impairment were estimated by applying relative changes in model predicted visibility to current measurements of ambient data. As with forecasting future year design values for $PM_{2.5}$, the approach for forecasting future visibility impairment used the model predictions in a relative way to project current visibility levels to 2015. The modeling portion of this approach uses the annual simulations for 2001 emissions and the 2015 Base Case emissions scenario. As described below, the predictions from these runs were used to calculate relative reduction factors (RRFs) which were then applied to current visibility values[17]. The approach we followed is consistent with the procedures in the draft regional haze air quality modeling guidance[18].

The modeling guidance recommends that model predictions be used in a relative sense to estimate changes expected to occur in each major PM species that are used to estimate visibility impairment on the 20% best and worst days. These species are ammonium sulfate, ammonium

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[17] An example calculation is included in Appendix M of the NPR-AQMTSD.

[18] U.S. EPA, Draft Guidance for Demonstrating Attainment of Air Quality Goals for PM2.5 and Regional Haze. January 2001.

nitrate, organic carbon mass, elemental carbon, crustal mass and coarse mass. Consistent with the IMPROVE procedures, sulfate is assumed to be in the form of ammonium sulfate. Nitrate is assumed to in the form of ammonium nitrate. Measured organic carbon concentrations are multiplied by 1.4 to derive total organic mass. Crustal $PM_{2.5}$ mass is calculated using the IMPROVE crustal formula. Coarse mass is defined as the difference between PM_{10} and $PM_{2.5}$.

The procedure for calculating future year regional haze values is similar to the "Speciated Modeled Attainment Test" (SMAT) that was used to calculate future year $PM_{2.5}$ design values in the January 2004 proposal. The following is a brief summary of those steps. Additional details on the SMAT procedure are provided in the NPR-AQMTSD (Appendix E).

Step 1. Calculate mean light extinction[19] on the 20% worst and best days for each of the six components of regional haze. This is done by using the default IMPROVE equation applied to IMPROVE ambient measurements.

Step 2. For each of the 20% worst and best days[20], calculate the ratio of future (e.g., 2015) to current (i.e., 2001) predictions for each component specie. The result is a component-specific RRF (e.g., assume that 2001 predicted sulfate extinction for a particular location is 50 Mm^{-1} and the 2015 Base extinction is 40 Mm^{-1}, then the RRF for sulfate is 0.8).

Step 3. For each component specie, multiply the current daily component light extinction (step 1) by the component-specific daily RRF obtained in step 2. This produces an estimated future mean light extinction value for each component, for each of the 20% worst(best) days (e.g., sulfate extinction of 50 Mm^{-1} x 0.8 = future sulfate extinction of 40 Mm^{-1}).

Step 4. Sum the daily component extinction values to get total daily light extinction[21] and convert extinction to daily average deciviews.

Step 5. Compute the future mean deciview values for the 20% best and worst days by averaging the daily deciview values.

The results of this analysis are discussed in the next section below.

B. Air Quality Modeling of Proposed Emissions Reductions

Introduction

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[19] Light extinction is measured in units of inverse megameters (Mm^{-1}).

[20] The model predicted RRFs are calculated on the 20% best and worst days from 1996 based on the 1996 ambient IMPROVE data.

[21] A value of 10 Mm^{-1} is added to each daily value of bext to account for Rayleigh scattering.

In this section we describe the air quality modeling performed to determine the projected impacts on visibility impairment of the CAIR regional SO_2 and NOx emissions reductions, as well as air quality modeling of the BART program. The visibility improvements from the proposed CAIR strategy were compared to the BART visibility improvements as part of the "better-than-BART" test.

The better-than-BART test is a two pronged test. Under the first prong, visibility must not decline at any Class I area, as determined by comparing the predicted visibility impacts at each affected Class I area under the (CAIR) trading program with existing visibility conditions. Under the second prong, overall visibility, as measured by the average improvement at all affected Class I areas, must be better under the trading program than under source-specific BART. The future year air quality modeling results were used to make this demonstration.

1. Modeling of the CAIR and BART strategies for 2015

The PM and visibility modeling platform described above was used by EPA to model the impacts of the proposed EGU SO_2 and NOx controls on visibility impairment. Modeling for visibility was performed for 2015 to assess the expected effects of the CAIR and BART controls on projected visibility impairment (compared to the 2001 base year).

The modeled effects of the emissions reductions on visibility are expressed in terms of expected future visibility impairment on the 20% best and worst days (in deciviews). Smaller numbers represent better visibility.

Table III-2 shows the projected visibility on the 20% best days at each Class I area in the 2015 baseline and from the CAIR and BART control strategies. Visibility impairment is shown for the 20% best days for the current (1998-2002) baseline, the 2015 baseline, and the CAIR and BART strategies in 2015. Also shown is the average visibility (on the 20% best days) for the 44 Class I areas and the 15 Eastern Class I areas.

Table III-2. **Projected visibility for the 2015 baseline and the 2015 CAIR and BART (as analyzed)[22] strategies on the 20% best days, at 44 IMPROVE sites.**

Class I Areas (IMPROVE Site)	**State**	**1998-2002 Baseline Visibility (dv)**	**2015 Baseline Visibility (dv)**	**2015 "CAIR" Control Case Visibility (dv)**	**2015 "BART" Control Case Visibility (dv)**
Acadia National Park	Maine	8.4	8.1	7.8	8.0
Brigantine National Wildlife Refuge	New Jersey	13.6	13.4	12.8	13.1
Chassahowitzka National Wildlife	Florida	16.4	15.2	14.0	13.9
Dolly Sods /Otter Creek Wilderness	West Virginia	13.0	12.4	11.1	11.8
Great Smoky Mountains National Park	Tennessee	14.2	13.7	12.6	13.0
Jefferson/James River Face Wilderness	Virginia	15.8	15.3	14.3	14.8
Lye Brook Wilderness	Vermont	6.6	6.2	6.0	6.1
Mammoth Cave National Park	Kentucky	16.5	15.5	14.8	15.2
Moosehorn NWR	Maine	8.6	8.3	8.2	8.2
Okefenokee National Wildlife Refuge	Georgia	15.5	14.9	14.1	14.4
Cape Romain National Wildlife Refuge	South Carolina	13.8	13.4	12.7	13.0
Shenandoah National Park	Virginia	12.2	11.7	10.6	11.3
Shining Rock Wilderness	North Carolina	7.8	7.5	6.9	7.2
Sipsy Wilderness	Alabama	16.3	15.6	15.1	15.2
Upper Buffalo Wilderness	Arkansas	12.2	11.5	11.2	11.1
	areas)	**12.7**	**12.2**	**11.5**	**11.8**
Badlands National Park	South Dakota	7.1	6.7	6.7	6.7
Bandelier National Monument	New Mexico	6.3	5.9	5.9	5.9
Big Bend National Park	Texas	7.7	7.4	7.3	7.3
Bliss State Park (Desolation)	California	3.5	3.0	3.0	3.0
Bryce Canyon National Park	Utah	4.1	3.7	3.7	3.7
Bridger Wilderness	Wyoming	3.8	3.5	3.5	3.5
Canyonlands National Park	Utah	5.3	5.1	5.1	5.1
Chiricahua National Monument	Arizona	5.9	5.7	5.7	5.7
Crater Lake National Park	Oregon	3.2	2.8	2.8	2.8
Gila Wilderness	New Mexico	5.1	4.9	4.9	4.9
Glacier National Park	Montana	7.3	6.7	6.7	6.7
Grand Canyon- Hopi Point	Arizona	4.1	3.9	3.8	3.8

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[22] See section II.B above for discussion of differences between the CAIR as analyzed and as proposed, and see section II.C. above for discussion of differences between BART as analyzed and the maximum potential reductions available from BART as proposed.

Class I Areas (IMPROVE Site)	**State**	**1998-2002 Baseline Visibility (dv)**	**2015 Baseline Visibility (dv)**	**2015 "CAIR" Control Case Visibility (dv)**	**2015 "BART" Control Case Visibility (dv)**
Great Sand Dunes National Monument	Colorado	5.7	5.4	5.4	5.4
Guadalupe Mountains National Park	Texas	7.2	6.8	6.7	6.7
Jarbidge Wilderness	Nevada	3.0	2.8	2.8	2.8
Lassen Volcanic National Park	California	3.3	2.9	2.9	2.9
Mesa Verde National Park	Colorado	5.5	5.1	5.1	5.1
Mount Rainier National Park	Washington	4.9	4.3	4.3	4.3
Mount Zirkel Wilderness	Colorado	4.4	4.2	4.2	4.2
Petrified Forest National Park	Arizona	6.3	6.0	6.0	6.0
Pinnacles National Monument	California	8.8	7.9	7.9	7.9
Point Reyes National Seashore	California	8.6	7.7	7.7	7.7
Redwood National Park	California	5.0	4.8	4.8	4.8
San Gorgonio Wilderness	California	6.8	6.4	6.4	6.4
Sequoia National Park	California	8.8	8.1	8.1	8.1
Three Sisters Wilderness	Idaho	2.8	2.5	2.5	2.5
Tonto National Monument	Arizona	7.4	7.2	7.2	7.2
Weminuche Wilderness	Colorado	4.4	4.0	4.0	4.0
Yosemite National Park	California	4.0	3.7	3.7	3.7
Average Visibility (all 44 Class I areas)		**8.0**	**7.5**	**7.3**	**7.4**

The modeling results show that the proposed CAIR cap-and-trade programs will not result in degradation of visibility on the 20% best days, compared to existing visibility conditions (or the 2015 baseline), at any of the 44 Class I areas considered. In each of the 44 areas – the 13 within the proposed CAIR region and the 31 outside of it – visibility is expected to improve (compared to current visibility) or at worst remain unchanged (compared to 2015 baseline visibility).

For Class I areas in the proposed CAIR region, our analysis indicates that proposed CAIR emissions reductions in the East produce greater visibility improvements than source-specific BART. Specifically, for the 15 Eastern Class I areas analyzed, the average visibility improvement (on the 20 percent best days) expected solely as a result of the CAIR is 0.7 deciviews (dv), and the average degree of improvement predicted for source-specific BART is 0.4 dv.

Similarly, on a national basis, the visibility modeling shows that for the 44 class I areas evaluated, the average visibility improvement, on the 20 percent best days, in 2015 was 0.2 dv under the proposed CAIR cap-and-trade programs, and 0.1 dv under the source-specific BART approach

We note that for western Class I areas the projection of greater visibility improvement under BART than under CAIR is an artifact of the available emissions scenarios used for the modeling. Because our CAIR scenario did not include BART reductions in the non-CAIR region, the modeling naturally shows western Class I areas seeing more improvement under a nationwide BART scenario than they do under the CAIR scenario used, with emissions reductions only in the east. This will be resolved when we re-do the air quality modeling using a CAIR scenario which includes BART in the non-CAIR region.

Table III-3 shows the projected visibility on the 20% worst days at each Class I area in the 2015 baseline and from the CAIR and BART control strategies. Visibility impairment is shown for the 20% worst days for the current (1998-2002) baseline, the 2015 baseline, and the CAIR and BART strategies in 2015. Also shown is the average visibility (on the 20% worst days) for the 44 Class I areas and the 15 Eastern Class I areas.

Table III-3- Projected visibility for the 2015 baseline and the 2015 CAIR and BART (as analyzed)[23] strategies on the 20% worst days, at 44 IMPROVE sites.

Class I Area (IMPROVE Site)	State	1998-2002 Baseline Visibility (dv)	2015 Baseline Visibility (dv)	2015 "CAIR" Control Case Visibility (dv)	2015 "BART" Control Case Visibility (dv)
Acadia National Park	Maine	22.7	21.5	20.3	21.0
Brigantine National Wildlife Refuge	New Jersey	27.6	26.5	24.8	25.8
Chassahowitzka National Wildlife	Florida	25.7	24.0	22.0	22.0
Dolly Sods /Otter Creek Wilderness	West Virginia	27.6	25.6	23.0	24.6
Great Smoky Mountains National Park	Tennessee	29.5	27.6	25.0	26.5
Jefferson/James River Face Wilderness	Virginia	28.3	26.6	24.5	25.6
Lye Brook Wilderness	Vermont	23.9	22.9	21.9	22.4
Mammoth Cave National Park	Kentucky	30.2	27.7	25.1	26.9
Moosehorn NWR	Maine	21.4	20.4	19.3	19.9
Okefenokee National Wildlife Refuge	Georgia	26.4	25.1	23.5	24.2
Cape Romain National Wildlife Refuge	South Carolina	25.9	25.2	23.5	24.3
Shenandoah National Park	Virginia	27.6	26.0	23.4	24.9
Shining Rock Wilderness	North Carolina	29.7	27.5	25.1	26.3
Sipsy Wilderness	Alabama	28.7	26.9	24.4	25.8
Upper Buffalo Wilderness	Arkansas	25.5	24.5	22.4	23.1
Average Visibility (15 Eastern Class I areas)		**26.7**	**25.2**	**23.2**	**24.2**

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[23] See section II.B above for discussion of differences between CAIR as analyzed and as proposed, and see section II.C. above for discussion of differences between BART as analyzed and the maximum potential reductions available from BART as proposed.

Class I Area (IMPROVE Site)	State	1998-2002 Baseline Visibility (dv)	2015 Baseline Visibility (dv)	2015 “CAIR” Control Case Visibility (dv)	2015 “BART” Control Case Visibility (dv)
Badlands National Park	South Dakota	17.3	16.6	16.2	16.1
Bandelier National Monument	New Mexico	13.2	12.5	12.4	12.3
Big Bend National Park	Texas	18.4	18.0	18.0	18.0
Bliss State Park (Desolation)	California	12.9	11.4	11.4	11.4
Bryce Canyon National Park	Utah	12.0	11.1	11.1	11.0
Bridger Wilderness	Wyoming	11.5	10.4	10.4	10.4
Canyonlands National Park	Utah	12.0	11.3	11.3	11.3
Chiricahua National Monument	Arizona	13.9	13.6	13.6	13.6
Crater Lake National Park	Oregon	14.1	12.4	12.4	12.4
Gila Wilderness	New Mexico	13.5	12.8	12.8	12.8
Glacier National Park	Montana	19.5	18.6	18.6	18.6
Grand Canyon- Hopi Point	Arizona	12.0	11.3	11.3	11.3
Great Sand Dunes National Monument	Colorado	13.1	12.4	12.3	12.2
Guadalupe Mountains National Park	Texas	17.6	17.1	17.0	16.9
Jarbidge Wilderness	Nevada	12.6	11.4	11.4	11.4
Lassen Volcanic National Park	California	14.8	13.5	13.5	13.5
Mesa Verde National Park	Colorado	12.8	12.0	12.0	11.9
Mount Rainier National Park	Washington	18.9	17.0	17.0	16.9
Mount Zirkel Wilderness	Colorado	11.7	10.9	10.9	10.8
Petrified Forest National Park	Arizona	13.5	12.9	12.9	12.9
Pinnacles National Monument	California	19.1	17.5	17.5	17.5
Point Reyes National Seashore	California	20.2	18.4	18.3	18.4
Redwood National Park	California	16.5	14.5	14.5	14.5
San Gorgonio Wilderness	California	21.5	18.6	18.6	18.6
Sequoia National Park	California	23.5	21.3	21.3	21.3
Three Sisters Wilderness	Idaho	15.7	13.8	13.8	13.8
Tonto National Monument	Arizona	14.7	14.0	13.9	13.9
Weminuche Wilderness	Colorado	11.6	10.7	10.7	10.7
Yosemite National Park	California	17.6	16.0	16.0	16.0
Average Visibility (all 44 Class I areas)		**19.2**	**18.0**	**17.3**	**17.6**

The modeling results show that the CAIR cap-and- trade program will not result in degradation of visibility on the 20% worst days, compared to existing visibility conditions (or the 2015 baseline), at any of the 44 Class I areas considered. In each of the 44 areas – the 13 within the proposed CAIR region and the 31 outside of it – visibility is expected to improve (compared to current visibility) or at worst remain unchanged (compared to 2015 baseline visibility). Based on these results, we believe the CAIR impact on emissions passes the first prong of the two-pronged "better-than-BART" test by not causing degradation of visibility at any Class I area on the 20% best or worst visibility days.

For Class I areas in the proposed CAIR region, our analysis indicates that proposed CAIR emissions reductions in the East produce significantly greater visibility improvements than source-specific BART. For the 15 Eastern Class I areas analyzed, the average visibility improvement (on the 20 percent worst days) expected solely as a result of the CAIR is 2.0 deciviews (dv), and the average degree of improvement predicted for source-specific BART is 1.0 dv. Therefore, the proposed CAIR is substantially better than BART – indeed, the proposed CAIR provides more than twice the visibility improvement benefits – for Eastern Class I areas.

Similarly, on a national basis, the visibility modeling shows that for the 44 class I areas evaluated, the average visibility improvement, on the 20 percent worst days, in 2015 was 0.7 dv under the proposed CAIR cap-and-trade programs, but only 0.4 dv under the source-specific BART approach. Based on these results, the proposed CAIR passes the second prong of the better-than-BART test based on the fact that, on average, in both the Eastern Class I areas and nationally, visibility improvement is greater under the proposed CAIR compared to BART on the 20% best and 20% worst visibility days.

2. Better-than-BART Test

We believe the impact of the proposed CAIR on emissions passes the first prong of the two-pronged "better-than-BART" test by not causing degradation of visibility at any Class I area on either the 20% best or 20% worst visibility days. The CAIR also passes the second prong of the better-than-BART visibility test based on the expectation that, on average, in both the Eastern Class I areas and nationally, visibility improvement is greater under the proposed CAIR compared to BART on the 20% best and 20% worst days. We therefore believe that these results, in combination with the emissions analysis in Section II, demonstrate that the both prongs of the better-than-BART test are met.

Appendix

The list of units below reflects the 302 BART-eligible coal-fired generating units larger than 250 MW and for which controls were presumed in the IPM modeling. EPA has estimated that these units had gone online after August 7, 1962, but began construction before August 7, 1977

Table A-1:
Units that were Presumed to be BART-eligible, Requiring Controls, for purposes of Modeling Emissions.

STATE	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity [1]
MN	Allen S King	1	1968	598
OH	Avon Lake Power Plant	12	1970	680
IN	Bailly	8	1968	422
IL	Baldwin	1	1970	623
IL	Baldwin	2	1973	635
IL	Baldwin	3	1975	635
AL	Barry	4	1969	404
AL	Barry	5	1971	789
NC	Belews Creek	1	1974	1080
NC	Belews Creek	2	1975	1080
MI	Belle River	1	1984	698
MI	Belle River	2	1985	698
FL	Big Bend	BB01	1970	446
FL	Big Bend	BB02	1973	446
FL	Big Bend	BB03	1976	446
TX	Big Brown	1	1971	593
TX	Big Brown	2	1972	593
LA	Big Cajun 2	2B1	1980	559
LA	Big Cajun 2	2B2	1981	559
KY	Big Sandy	BSU1	1963	281
KY	Big Sandy	BSU2	1969	816
SD	Big Stone	1	1975	456
GA	Bowen	1BLR	1971	700
GA	Bowen	2BLR	1972	700
GA	Bowen	3BLR	1974	880
GA	Bowen	4BLR	1975	880
MA	Brayton Point	3	1969	643
CT	Bridgeport Harbor Station	BHB3	1968	400
PA	Bruce Mansfield	1	1976	914
PA	Bruce Mansfield	2	1977	914
PA	Bruce Mansfield	3	1980	914

STATE	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity [1]
PA	Brunner Island	2	1965	405
PA	Brunner Island	3	1969	790
TN	Bull Run	1	1967	950
KY	Cane Run	6	1969	272
OH	Cardinal	1	1967	615
OH	Cardinal	2	1967	615
OH	Cardinal	3	1977	650
IN	Cayuga	1	1970	531
IN	Cayuga	2	1972	531
WA	Centralia	BW21	1972	730
WA	Centralia	BW22	1973	730
MD	Chalk Point	1	1964	364
MD	Chalk Point	2	1965	364
VA	Chesterfield	5	1964	359
VA	Chesterfield	6	1969	694
PA	Cheswick	1	1970	565
AZ	Cholla	3	1980	289
AZ	Cholla	2	1978	289
AZ	Cholla	4	1981	414
MN	Clay Boswell	3	1973	365
NC	Cliffside	5	1972	571
ND	Coal Creek	1	1979	506
ND	Coal Creek	2	1981	506
IL	Coffeen	01	1965	389
IL	Coffeen	02	1972	617
AL	Colbert	5	1965	550
WI	Columbia	1	1975	512
WI	Columbia	2	1978	512
CO	Comanche (470)	1	1973	350
CO	Comanche (470)	2	1975	350
PA	Conemaugh	1	1970	936
PA	Conemaugh	2	1971	936
OH	Conesville	4	1973	842
OH	Conesville	5	1976	444
OH	Conesville	6	1978	444
AZ	Coronado Generating Station	U1B	1979	411
AZ	Coronado Generating Station	U2B	1980	411
IA	Council Bluffs	3	1978	726
CO	Craig	C1	1980	446
CO	Craig	C2	1979	446
FL	Crist Electric Generating Plant	6	1970	370
FL	Crist Electric Generating Plant	7	1973	578

STATE	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity [1]
FL	Crystal River	1	1966	441
FL	Crystal River	2	1969	524
FL	Crystal River	4	1982	739
FL	Crystal River	5	1984	739
TN	Cumberland	1	1973	1300
TN	Cumberland	2	1973	1300
MS	Daniel Electric Generating Plant	1	1977	500
MS	Daniel Electric Generating Plant	2	1981	500
WY	Dave Johnston	BW44	1972	360
IL	Duck Creek	1	1976	441
AL	E C Gaston	5	1974	952
IL	E D Edwards	2	1968	281
IL	E D Edwards	3	1972	364
KY	E W Brown	3	1971	446
OH	Eastlake	5	1972	680
KY	Elmer Smith	2	1974	265
IN	F B Culley Generating Station	3	1973	265
FL	F J Gannon	GB06	1967	414
AR	Flint Creek	1	1978	558
WV	Fort Martin	1	1967	576
WV	Fort Martin	2	1968	576
NM	Four Corners	3	1964	253
NM	Four Corners	4	1969	818
NM	Four Corners	5	1970	818
OH	Gen J M Gavin	1	1974	1300
OH	Gen J M Gavin	2	1975	1300
WI	Genoa	1	1969	346
IA	George Neal North	2	1972	349
IA	George Neal North	3	1975	550
NE	Gerald Gentleman Station	1	1979	681
NE	Gerald Gentleman Station	2	1982	681
KY	Ghent	2	1977	556
KY	Ghent	1	1974	557
IN	Gibson	1	1976	668
IN	Gibson	2	1975	668
IN	Gibson	3	1978	668
IN	Gibson	4	1979	668
AL	Gorgas	10	1972	789
AL	Greene County	2	1966	269
AL	Greene County	1	1965	299

STATE	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity [1]
KY	H L Spurlock	1	1977	305
KY	H L Spurlock	2	1981	508
GA	Hammond	4	1970	500
IN	Harding Street Station (EW Stout)	70	1973	471
GA	Harllee Branch	1	1965	250
GA	Harllee Branch	2	1967	319
GA	Harllee Branch	3	1968	481
GA	Harllee Branch	4	1969	490
TX	Harrington Station	061B	1976	360
WV	Harrison	1	1972	684
WV	Harrison	2	1973	684
WV	Harrison	3	1974	684
PA	Hatfields Ferry	1	1969	576
PA	Hatfields Ferry	2	1970	576
PA	Hatfields Ferry	3	1971	576
IL	Havana	9	1978	488
CO	Hayden	H2	1976	275
MD	Herbert a Wagner	3	1966	359
PA	Homer City	1	1969	660
PA	Homer City	2	1969	660
PA	Homer City	3	1977	692
NJ	Hudson	2	1968	660
UT	Huntington	2	1974	446
UT	Huntington	1	1977	446
AR	Independence	1	1983	850
MI	J H Campbell	1	1962	265
MI	J H Campbell	2	1967	385
MI	J H Campbell	3	1980	871
OH	J M Stuart	1	1971	610
OH	J M Stuart	2	1970	610
OH	J M Stuart	3	1972	610
OH	J M Stuart	4	1974	610
TX	J T Deely	1	1977	446
TX	J T Deely	2	1978	446
AL	James H Miller Jr	1	1978	706
AL	James H Miller Jr	2	1985	706
KS	Jeffrey Energy Center	1	1978	720
KS	Jeffrey Energy Center	2	1980	720
WY	Jim Bridger	BW71	1974	561
WY	Jim Bridger	BW72	1975	561
WY	Jim Bridger	BW73	1976	561

STATE	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity [1]
WY	Jim Bridger	BW74	1979	561
WV	John E Amos	1	1971	816
WV	John E Amos	2	1972	816
WV	John E Amos	3	1973	1300
IL	Joliet 29	71	1965	660
IL	Joliet 29	72	1965	660
IL	Joliet 29	81	1965	660
IL	Joliet 29	82	1965	660
PA	Keystone	1	1967	936
PA	Keystone	2	1968	936
IL	Kincaid	1	1967	660
IL	Kincaid	2	1968	660
NC	L V Sutton	3	1972	447
KS	La Cygne	2	1977	685
KS	La Cygne	1	1973	893
MO	Labadie	1	1970	574
MO	Labadie	2	1971	574
MO	Labadie	3	1972	621
MO	Labadie	4	1973	621
OH	Lake Shore	18	1962	256
IA	Lansing	4	1977	275
WY	Laramie River	3	1982	570
WY	Laramie River	1	1980	570
WY	Laramie River	2	1981	570
KS	Lawrence Energy Center	5	1971	458
NC	Lee	3	1962	252
ND	Leland Olds	2	1975	440
NC	Marshall	1	1965	350
NC	Marshall	2	1966	350
NC	Marshall	3	1969	648
NC	Marshall	4	1970	648
TX	Martin Lake	1	1977	793
TX	Martin Lake	2	1978	793
IN	Merom	1SG1	1983	540
IN	Merom	2SG1	1982	540
NH	Merrimack	2	1968	346
OH	Miami Fort	7	1975	557
OH	Miami Fort	8	1978	558
IN	Michigan City	12	1974	540
KY	Mill Creek	1	1972	356
KY	Mill Creek	2	1974	356
KY	Mill Creek	3	1978	463

STATE	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity [1]
KY	Mill Creek	4	1982	544
ND	Milton R Young	B1	1970	257
ND	Milton R Young	B2	1977	477
WV	Mitchell	1	1971	816
WV	Mitchell	2	1971	816
PA	Mitchell	33	1963	299
NV	Mohave	1	1971	818
NV	Mohave	2	1971	818
MI	Monroe	1	1971	817
MI	Monroe	4	1974	817
MI	Monroe	2	1973	823
MI	Monroe	3	1973	823
TX	Monticello	1	1974	593
TX	Monticello	2	1975	593
TX	Monticello	3	1978	793
PA	Montour	2	1973	819
PA	Montour	1	1972	823
MD	Morgantown	1	1970	626
MD	Morgantown	2	1971	626
WV	Mount Storm Power Station	3	1973	522
WV	Mount Storm Power Station	1	1965	570
WV	Mount Storm Power Station	2	1966	570
WV	Mountaineer (1301)	1	1980	1300
OH	Muskingum River	5	1968	615
OK	Muskogee	4	1977	572
OK	Muskogee	5	1978	572
WY	Naughton	3	1971	326
AZ	Navajo Generating Station	1	1974	803
AZ	Navajo Generating Station	2	1975	803
AZ	Navajo Generating Station	3	1976	803
MO	New Madrid	1	1972	600
MO	New Madrid	2	1977	600
IL	Newton	1	1977	617
IL	Newton	2	1982	617
OK	Northeastern	3313	1979	473
OK	Northeastern	3314	1980	473
KY	Paradise	3	1970	1150
KY	Paradise	1	1963	704
KY	Paradise	2	1963	704
IN	Petersburg	1	1967	253
IN	Petersburg	2	1969	471
IN	Petersburg	3	1977	574

STATE	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity [1]
WV	Pleasants	1	1979	684
WV	Pleasants	2	1980	684
PA	Portland	2	1962	255
IL	Powerton	51	1972	893
IL	Powerton	52	1972	893
IL	Powerton	61	1975	893
IL	Powerton	62	1975	893
IN	R M Schahfer	14	1976	540
IN	R M Schahfer	15	1979	556
NC	Roxboro	1	1966	411
NC	Roxboro	2	1968	657
NC	Roxboro	3A	1973	745
NC	Roxboro	3B	1973	745
NC	Roxboro	4A	1980	745
NC	Roxboro	4B	1980	745
MO	Rush Island	1	1976	621
MO	Rush Island	2	1977	621
TX	Sam Seymour	1	1979	615
TX	Sam Seymour	2	1980	615
NM	San Juan	2	1973	350
NM	San Juan	1	1976	361
NM	San Juan	3	1979	534
NM	San Juan	4	1982	534
GA	Scherer	1	1982	818
GA	Scherer	2	1984	818
MN	Sherburne County	1	1976	660
MN	Sherburne County	2	1977	660
MO	Sibley	3	1969	419
MO	Sioux	1	1967	550
MO	Sioux	2	1968	550
OK	Sooner	1	1979	569
OK	Sooner	2	1980	569
WI	South Oak Creek	7	1965	318
WI	South Oak Creek	8	1967	324
MI	St. Clair	7	1969	545
IN	State Line Generating Station (IN)	4	1962	389
IN	Tanners Creek	U4	1964	580
MO	Thomas Hill	MB2	1969	285
MI	Trenton Channel	9A	1968	536
TX	W A Parish	WAP5	1977	734
TX	W A Parish	WAP6	1978	734

STATE	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity [1]
OH	W H Sammis	5	1967	318
OH	W H Sammis	6	1969	623
OH	W H Sammis	7	1971	623
IN	Wabash River	6	1968	387
OH	Walter C Beckjord	6	1969	461
GA	Wansley (6052)	1	1976	865
GA	Wansley (6052)	2	1978	865
IN	Warrick	4	1970	323
SC	Wateree	WAT1	1970	386
SC	Wateree	WAT2	1971	386
IL	Waukegan	8	1962	355
TX	Welsh	1	1977	558
TX	Welsh	2	1980	558
TX	Welsh	3	1982	558
AR	White Bluff	1	1980	850
AR	White Bluff	2	1981	850
AL	Widows Creek	8	1965	550
IL	Will County	4	1963	598
SC	Williams	WIL1	1973	633
SC	Winyah	1	1975	315
SC	Winyah	2	1977	315
IL	Wood River	5	1964	388
WY	Wyodak	BW91	1978	362

[1] Nameplate capacity of generator connected to boiler

TOP ELECTRIC GENERATING EMISSION POINTS CONTRIBUTING TO VISIBILITY IMPAIRMENT IN MANE-VU - MODELED BY BOTH VTDEC AND MM5

Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code		
1	D005935	593			90	54			2,138	2,136	1	EDGE MOOR	O/G Steam	Delaware	10		
2	D005941	594				95				3,742	2	INDIAN RIVER	Coal Steam	Delaware	10		
3	D005942	594				74				3,760	2	INDIAN RIVER	Coal Steam	Delaware	10		
4	D005943	594			84	44			4,686	4,682	2	INDIAN RIVER	Coal Steam	Delaware	10		
5	D005944	594			69	21			7,390	7,384	2	INDIAN RIVER	Coal Steam	Delaware	10		
6	D007031LR	703	79			86		75	38,520	38,486	3	BOWEN	Coal Steam	Georgia	13		
7	D007032LR	703	72		89		61	68	37,289	37,256	3	BOWEN	Coal Steam	Georgia	13		
8	D007033LR	703	71	99	74	64	63	94	43,067	43,029	3	BOWEN	Coal Steam	Georgia	13		
9	D007034LR	703	69	95	86	58	60	89	41,010	40,974	3	BOWEN	Coal Steam	Georgia	13		
10	D00709C02	709		84		75	89	71	47,591	47,549	4	HARLLEE BRANCH	Coal Steam	Georgia	13		
11	D00861C01	861	28	96		65	46	62	42,355	42,318	5	COFFEEN	Coal Steam	Illinois	17		
12	D010011	1001			53				28,876	28,851	6	CAYUGA	Coal Steam	Indiana	18		
13	D010012	1001	95		46	68			26,016	25,992	6	CAYUGA	Coal Steam	Indiana	18		
14	D00983C01	983					52		19,922		7	CLIFTY CREEK	Coal Steam	Indiana	18		
15	D00983C02	983					54		18,131		7	CLIFTY CREEK	Coal Steam	Indiana	18		
16	D0099070	990		55	100	70		37	29,801	29,774	8	ELMER W STOUT	O/G Steam	Indiana	18		
17	D06113C03	6113	30	48	14	43	22	41	71,182	71,119	9	GIBSON	Coal Steam	Indiana	18		
18	D06113C04	6113	44	70	97	83	73	83	27,848	27,823	9	GIBSON	Coal Steam	Indiana	18		
19	D01008C01	1008			73		100	47	24,109	24,087	10	R GALLAGHER	Coal Steam	Indiana	18		
20	D01008C02	1008			98			55	23,849	23,828	10	R GALLAGHER	Coal Steam	Indiana	18		
21	D06166C02	6166	62	44	30	81	33	57	51,708	51,663	11	ROCKPORT	Coal Steam	Indiana	18		
22	D00988C03	988						77		15,946	12	TANNERS CREEK	Coal Steam	Indiana	18		
23	D00988U4	988	14	29	52	34	7	19	45,062	45,022	12	TANNERS CREEK	Coal Steam	Indiana	18		
24	D01010C05	1010	43	32	12	28	31	17	60,747	60,693	13	WABASH RIVER	Coal Steam	Indiana	18		
25	D067054	6705	34	60	34		44	73	40,118	40,082	14	WARRICK	Coal Steam	Indiana	18		
26	D06705C02	6705	92		75		96		27,895		14	WARRICK	Coal Steam	Indiana	18		
27	D01353C02	1353	38	30	15	26	85	29	41,545	41,508	15	BIG SANDY	Coal Steam	Kentucky	21		
28	D01384CS1	1384	22				58		21,837	21,817	16	COOPER	Coal Steam	Kentucky	21		
29	D01355C03	1355	21		51	99	68	52	38,104	38,070	17	E W BROWN	Coal Steam	Kentucky	21		
30	D060182	6018	83				39		12,083		18	EAST BEND	Coal Steam	Kentucky	21		
31	D01356C02	1356	93	71		88	50	59	25,646	25,623	19	GHENT	Coal Steam	Kentucky	21		
32	D060411	6041	61						18,375		20	H L SPURLOCK	Coal Steam	Kentucky	21		
33	D060412	6041	53		91			98	20,491	20,473	20	H L SPURLOCK	Coal Steam	Kentucky	21		
34	D013644	1364			81				7,185		21	MILL CREEK	Coal Steam	Kentucky	21		
35	D013782	1378					87		20,245		22	PARADISE	Coal Steam	Kentucky	21		

Notes:
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MM5 by ERM for Maryland

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Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code		
36	D013783	1378	76	100	11	84	55	42	46,701	46,660	22	PARADISE	Coal Steam	Kentucky	21		
37	D015074	1507	78						1,170		23	WILLIAM F WYMAN	O/G Steam	Maine	23		
38	D006021	602	90		38			100	20,014	19,996	24	BRANDON SHORES	Coal Steam	Maryland	24		
39	D006022	602	99		29			99	19,280	19,263	24	BRANDON SHORES	Coal Steam	Maryland	24		
40	D015521	1552			63				17,782	17,767	25	C P CRANE	Coal Steam	Maryland	24		
41	D015522	1552			68				14,274	14,262	25	C P CRANE	Coal Steam	Maryland	24		
42	D01571CE2	1571	42	47	1	4	20	28	48,566	48,522	26	CHALK POINT	Coal Steam	Maryland	24		
43	D01572C23	1572	73	79	47	45	69	32	32,188	32,159	27	DICKERSON	Coal Steam	Maryland	24		
44	D015543	1554			77				10,084	10,075	28	HERBERT A WAGNER	O/G Steam	Maryland	24		
45	D015731	1573	67	50	16	12	56	38	36,823	36,790	29	MORGANTOWN	Coal Steam	Maryland	24		
46	D015732	1573	59	53	10	13	51	39	30,788	30,761	29	MORGANTOWN	Coal Steam	Maryland	24		
47	D016191	1619	37	80					9,252	9,244	30	BRAYTON POINT	Coal Steam	Massachusetts	25		
48	D016192	1619	35	66					8,889	8,881	30	BRAYTON POINT	Coal Steam	Massachusetts	25		
49	D016193	1619	4	14	65	56	79		19,325	19,308	30	BRAYTON POINT	Coal Steam	Massachusetts	25		
50	D015991	1599	5	36			65		13,014	13,002	31	CANAL	O/G Steam	Massachusetts	25		
51	D015992	1599	7	27			74		8,980	8,971	31	CANAL	O/G Steam	Massachusetts	25		
52	D016061	1606						48		5,249	32	MOUNT TOM	Coal Steam	Massachusetts	25		
53	D016261	1626	85						3,430		33	SALEM HARBOR	Coal Steam	Massachusetts	25		
54	D016263	1626	91	78					4,971	4,966	33	SALEM HARBOR	Coal Steam	Massachusetts	25		
55	D016264	1626	32	25					2,880	2,878	33	SALEM HARBOR	O/G Steam	Massachusetts	25		
56	D016138	1613	94						4,376		34	SOMERSET	Coal Steam	Massachusetts	25		
57	D01702C09	1702						96		4,565	35	DAN E KARN	Coal Steam	Michigan	26		
58	D01733C12	1733	49	24	80	80	45	22	46,081	46,040	36	MONROE	Coal Steam	Michigan	26		
59	D01733C34	1733	27	26		76	26	27	39,362	39,327	36	MONROE	Coal Steam	Michigan	26		
60	D017437	1743		91						15,805	37	ST CLAIR	Coal Steam	Michigan	26		
61	D017459A	1745					76	61	18,341	18,324	38	TRENTON CHANNEL	Coal Steam	Michigan	26		
62	D023641	2364	2	57					9,356	9,348	39	MERRIMACK	Coal Steam	New Hampshire	33		
63	D023642	2364	1	17	99		28	87	19,453	19,435	39	MERRIMACK	Coal Steam	New Hampshire	33		
64	D080021	8002	45	74					5,033	5,028	40	NEWINGTON	O/G Steam	New Hampshire	33		
65	D023781	2378		81	2	15			9,747	9,738	41	B L ENGLAND	Coal Steam	New Jersey	34		
66	D024032	2403	63	97	25	50	40	44	18,785	18,768	42	HUDSON	O/G Steam	New Jersey	34		
67	D024081	2408			95				8,076		43	MERCER	Coal Steam	New Jersey	34		
68	D024082	2408			60				5,675		43	MERCER	Coal Steam	New Jersey	34		
69	D02549C01	2549		64	41		42	72	25,343	25,320	44	C R HUNTLEY	Coal Steam	New York	36		
70	D02549C02	2549					99		12,317		44	C R HUNTLEY	Coal Steam	New York	36		
71	D024804	2480					71		7,720		45	DANSKAMMER	O/G Steam	New York	36		

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Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
72	D02554C03	2554	33	51	62		27	51	30,151	30,125	46	DUNKIRK	Coal Steam	New York	36
73	D02526C03	2526					78		14,929		47	WESTOVER	Coal Steam	New York	36
74	D025276	2527					80		12,650		48	GREENIDGE	Coal Steam	New York	36
75	D025163	2516			96				7,359		49	NORTHPORT	O/G Steam	New York	36
76	D025945	2594		76						1,747	50	OSWEGO	O/G Steam	New York	36
77	D02642CS2	2642					91		14,086		51	ROCHESTER 7	Coal Steam	New York	36
78	D080061	8006						93		3,817	52	ROSETON	O/G Steam	New York	36
79	D080062	8006						88		2,840	52	ROSETON	O/G Steam	New York	36
80	D080421	8042	13	12	18	5	10	34	57,820	57,769	53	BELEWS CREEK	Coal Steam	North Carolina	37
81	D080422	8042	23	15	32	10	15	49	45,296	45,256	53	BELEWS CREEK	Coal Steam	North Carolina	37
82	D027215	2721	98	45	87	39	97	85	19,145	19,128	54	CLIFFSIDE	Coal Steam	North Carolina	37
83	D027133	2713		61						14,460	55	L V SUTTON	Coal Steam	North Carolina	37
84	D027093	2709				97				9,390	56	LEE	Coal Steam	North Carolina	37
85	D027273	2727	100	40		48	75	84	26,329	26,305	57	MARSHALL	Coal Steam	North Carolina	37
86	D027274	2727	89	39	83	51	66	82	27,308	27,284	57	MARSHALL	Coal Steam	North Carolina	37
87	D06250C05	6250	60	59		35	37		27,395	27,371	58	MAYO	Coal Steam	North Carolina	37
88	D027121	2712				59			12,031	12,020	59	ROXBORO	Coal Steam	North Carolina	37
89	D027122	2712	82	41	54	23	94		29,337	29,310	59	ROXBORO	Coal Steam	North Carolina	37
90	D02712C03	2712	56	37	57	24	21	78	30,776	30,749	59	ROXBORO	Coal Steam	North Carolina	37
91	D02712C04	2712	88	72		47	47		22,962	22,941	59	ROXBORO	Coal Steam	North Carolina	37
92	D0283612	2836	55	20	48	89	29	35	41,432	41,395	60	AVON LAKE	Coal Steam	Ohio	39
93	D028281	2828	29	9	31	30	24	8	37,307	37,274	61	CARDINAL	Coal Steam	Ohio	39
94	D028282	2828						56	20,598	20,580	61	CARDINAL	Coal Steam	Ohio	39
95	D028283	2828						80		15,372	61	CARDINAL	Coal Steam	Ohio	39
96	D028404	2840	3	1	6	2	2	3	87,801	87,724	62	CONESVILLE	Coal Steam	Ohio	39
97	D02840C02	2840	84	73			81	63	22,791	22,771	62	CONESVILLE	Coal Steam	Ohio	39
98	D028375	2837		86	56		35	70	35,970	35,938	63	EASTLAKE	Coal Steam	Ohio	39
99	D081021	8102			23	71	59	95	18,207	18,191	64	GEN J M GAVIN	Coal Steam	Ohio	39
100	D081022	8102				78			12,333	12,322	64	GEN J M GAVIN	Coal Steam	Ohio	39
101	D028501	2850	36	67	39	53		45	30,798	30,771	65	J M STUART	Coal Steam	Ohio	39
102	D028502	2850	24	65	40	49	98	46	28,698	28,673	65	J M STUART	Coal Steam	Ohio	39
103	D028503	2850	26		72	62			27,968	27,944	65	J M STUART	Coal Steam	Ohio	39
104	D028504	2850	20	77	45	52	88	54	27,343	27,319	65	J M STUART	Coal Steam	Ohio	39
105	D060312	6031			67	77		90	19,517	19,500	66	KILLEN STATION	Coal Steam	Ohio	39
106	D02876C01	2876	40	7	3	9	30	10	72,593	72,529	67	KYGER CREEK	Coal Steam	Ohio	39
107	D028327	2832	65	28	59	22	48	20	46,991	46,950	68	MIAMI FORT	Coal Steam	Ohio	39

Notes:
Plants in Red are added as a result of MM5 met modeling.
List does not include sources in states that do not contribute 2% of visibility impact to MANE VU Class I areas.
MM5 by ERM for Maryland

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Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code		
108	D02832C06	2832				60	43	64	23,694	23,673	68	MIAMI FORT	Coal Steam	Ohio	39		
109	D028725	2872	74	92	78		90	36	30,079	30,052	69	MUSKINGUM RIVER	Coal Steam	Ohio	39		
110	D02872C04	2872	6	19	13	6	19	15	83,134	83,060	69	MUSKINGUM RIVER	Coal Steam	Ohio	39		
111	D02864C01	2864	70	56	61	63	49	24	35,193	35,162	70	R E BURGER	Coal Steam	Ohio	39		
112	D07253C01	7253		89	58	57		33	30,977	30,949	71	RICHARD GORSUCH		Ohio	39		
113	D028665	2866		82				53	19,796	19,779	72	W H SAMMIS	Coal Steam	Ohio	39		
114	D028667	2866	57	16	42	41	41	16	33,601	33,572	72	W H SAMMIS	Coal Steam	Ohio	39		
115	D02866C01	2866	97	54	93	96	92	30	24,649	24,627	72	W H SAMMIS	Coal Steam	Ohio	39		
116	D02866C02	2866		69	92			50	26,022	25,999	72	W H SAMMIS	Coal Steam	Ohio	39		
117	D02866M6A	2866		85				58	19,564	19,546	72	W H SAMMIS	Coal Steam	Ohio	39		
118	D060191	6019		93		72		60		21,496	73	W H ZIMMER	Coal Steam	Ohio	39		
119	D028306	2830	46	38	70	40	12	69	30,466	30,439	74	WALTER C BECKJORD	Coal Steam	Ohio	39		
120	D031782	3178	77	63				81	16,484	16,469	75	ARMSTRONG	Coal Steam	Pennsylvania	42		
121	D031403	3140	31	34	9	46	18	18	38,801	38,767	76	BRUNNER ISLAND	Coal Steam	Pennsylvania	42		
122	D03140C12	3140	52	46	49	69	25	23	29,736	29,709	76	BRUNNER ISLAND	Coal Steam	Pennsylvania	42		
123	D082261	8226	25	21	33	42	36	9	40,268	40,232	77	CHESWICK	Coal Steam	Pennsylvania	42		
124	D03179C01	3179	16	10	5	8	5	4	79,635	79,565	78	HATFIELD'S FERRY	Coal Steam	Pennsylvania	42		
125	D031221	3122	11	6	26	38	17	14	45,754	45,714	79	HOMER CITY	Coal Steam	Pennsylvania	42		
126	D031222	3122	9	4	37	92	13	11	55,216	55,167	79	HOMER CITY	Coal Steam	Pennsylvania	42		
127	D031361	3136	8	2	4	14	6	1	87,434	87,357	80	KEYSTONE	Coal Steam	Pennsylvania	42		
128	D031362	3136	18	3	8	19	8	2	62,847	62,791	80	KEYSTONE	Coal Steam	Pennsylvania	42		
129	D03148C12	3148			71		84		17,214		81	MARTINS CREEK	Coal Steam	Pennsylvania	42		
130	D031491	3149	19	8	35	7	1	6	60,242	60,188	82	MONTOUR	Coal Steam	Pennsylvania	42		
131	D031492	3149	15	5	21	20	3	5	50,276	50,232	82	MONTOUR	Coal Steam	Pennsylvania	42		
132	D031131	3113			82				9,674		83	PORTLAND	Coal Steam	Pennsylvania	42		
133	D031132	3113			36		93		14,294		83	PORTLAND	Coal Steam	Pennsylvania	42		
134	D03131CS1	3131	54	31	79		32	65	22,344	22,324	84	SHAWVILLE	Coal Steam	Pennsylvania	42		
135	D033193	3319				100				11,045	85	JEFFERIES	O/G Steam	South Carolina	45		
136	D033194	3319		90		87				11,838	85	JEFFERIES	O/G Steam	South Carolina	45		
137	D03297WT1	3297		68		61				17,671	86	WATEREE	Coal Steam	South Carolina	45		
138	D03297WT2	3297		83		73				17,199	86	WATEREE	Coal Steam	South Carolina	45		
139	D03298WL1	3298		35	94	37			25,170	25,148	87	WILLIAMS	Coal Steam	South Carolina	45		
140	D062491	6249		58		82				17,920	88	WINYAH	Coal Steam	South Carolina	45		
141	D03403C34	3403			85				20,314		89	GALLATIN	Coal Steam	Tennessee	47		
142	D03405C34	3405	39						19,368		90	JOHN SEVIER	Coal Steam	Tennessee	47		
143	D03406C10	3406	10	11	27	33	4	43	104,523	104,431	91	JOHNSONVILLE	Coal Steam	Tennessee	47		

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MM5 by ERM for Maryland

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Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
144	D03407C15	3407	64	87		66	67	76	37,308	37,274	92	KINGSTON	Coal Steam	Tennessee	47
145	D03407C69	3407	48	98		91	82	91	38,645	38,611	92	KINGSTON	Coal Steam	Tennessee	47
146	D038033	3803				55				9,493	93	CHESAPEAKE	Coal Steam	Virginia	51
147	D038034	3803		94		16				10,806	93	CHESAPEAKE	Coal Steam	Virginia	51
148	D037974	3797				90				9,293	94	CHESTERFIELD	Coal Steam	Virginia	51
149	D037975	3797		88	44	27	86		19,620	19,602	94	CHESTERFIELD	Coal Steam	Virginia	51
150	D037976	3797	66	18	7	3	34	66	40,570	40,534	94	CHESTERFIELD	Coal Steam	Virginia	51
151	D03775C02	3775	47						16,674		95	CLINCH RIVER	Coal Steam	Virginia	51
152	D038093	3809		52	64	29			10,477	10,468	96	YORKTOWN	Coal Steam	Virginia	51
153	D03809CS0	3809	96	43	19	17	62		21,219	21,201	96	YORKTOWN	Coal Steam	Virginia	51
154	D039423	3942						79		10,126	97	ALBRIGHT	Coal Steam	West Virginia	54
155	D039431	3943	51	23	20	32	16	13	42,385	42,348	97	FORT MARTIN	Coal Steam	West Virginia	54
156	D039432	3943	50	22	22	31	14	12	45,850	45,809	97	FORT MARTIN	Coal Steam	West Virginia	54
157	D039353	3935	41	33	28	11	64	26	42,212	42,174	98	JOHN E AMOS	Coal Steam	West Virginia	54
158	D03935C02	3935	17	42	43	1	11	21	63,066	63,010	98	JOHN E AMOS	Coal Steam	West Virginia	54
159	D03947C03	3947	86	62	55		57	25	38,575	38,541	99	KAMMER	Coal Steam	West Virginia	54
160	D03936C02	3936				98			15,480	15,467	100	KANAWHA RIVER	Coal Steam	West Virginia	54
161	D03948C02	3948	58	13	17	36	9	7	55,405	55,356	101	MITCHELL	Coal Steam	West Virginia	54
162	D062641	6264	75	49	50	18	77	40	42,757	42,719	102	MOUNTAINEER	Coal Steam	West Virginia	54
163	D03954CS0	3954	68		24	25	23	67	20,130	20,112	103	MT STORM	Coal Steam	West Virginia	54
164	D0393851	3938				79		97	12,948	12,936	104	PHILIP SPORN	Coal Steam	West Virginia	54
165	D03938C04	3938				94			26,451	26,427	104	PHILIP SPORN	Coal Steam	West Virginia	54
166	D060041	6004			66		83	31	21,581	21,562	105	PLEASANTS	Coal Steam	West Virginia	54
167	D060042	6004			88			92	20,550	20,532	105	PLEASANTS	Coal Steam	West Virginia	54

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List does not include sources in states that do not contribute 2% of visibility impact to MANE VU Class I areas.
MM5 by ERM for Maryland

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Five-Factor Analysis of BART-Eligible Sources

Survey of Options for Conducting BART Determinations

Prepared by
NESCAUM
for the
Mid-Atlantic/Northeast Visibility Union (MANE-VU) Regional Planning Organization

June 1, 2007

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FIVE-FACTOR ANALYISIS OF BART-ELIGIBLE SOURCES

Survey of Options for Conducting BART Determinations

Project Manager

Gary Kleiman, NESCAUM

Principal Contributors

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Acknowledgements

NESCAUM acknowledges the support of its member agencies and the staff time that they dedicated in providing survey information on the types and level of control available for various source categories subject to the BART requirements of the Regional Haze Rule. Their insight has allowed NESCAUM to create what it hopes will be a valuable guide for all members of MANE-VU as they proceed to conduct source-specific BART determinations. NESCAUM also acknowledges the funding for this work through U.S. EPA agreement number XA-97318101-0 to the Ozone Transport Commission in support of the MANE-VU Regional Planning Organization. NESCAUM is solely responsible for the content of this report and any errors it may contain.

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The 1999 U.S. Environmental Protection Agency (USEPA) “Regional Haze Rule” [64 Fed. Reg. 35714 (July 1, 1999)] requires certain emission sources that “may reasonably be anticipated to cause or contribute” to visibility impairment in downwind Class I areas to install Best Available Retrofit Technology (BART). These requirements are intended to reduce emissions specifically from large sources that, due to age, were exempted from other control requirements of the Clean Air Act.

States are required to undertake three key steps to comply with the BART requirements of the Regional Haze Rule. These steps include:

- Determining if a source is BART-eligible;
- Determining if a source reasonably causes or contributes to visibility impairment in any Class I area (subject to BART);
- Determining if additional controls or emission limits are necessary (BART determination).

This report is intended to summarize one approach to satisfy the BART requirements of the Regional Haze Rule that member states may consider. We also review BART-eligible sources in the MANE-VU region and provide – on a regional basis – an analysis of the general applicability of the five statutory factors that states must consider in determining BART controls for various source categories subject to BART. This analysis will allow MANE-VU states to place their source-specific BART determinations into the regional context of similar sources within MANE-VU. This review includes an examination of individual units’ impacts on visibility at Class I areas based on CALPUFF modeling and an evaluation of existing or potential controls and feasibility of these controls relative to the statutory factors identified in the BART rule.

Ultimately, the strength of the MANE-VU BART program, as determined by individual state control decisions and informed by this analysis, will demonstrate MANE-VU’s resolve to tackle visibility and related air quality problems in its region. As MANE-VU enters into consultations with other regional planning organizations (RPOs), its willingness to seek reasonable emission reductions within its own region will help set expectations for the other RPOs, and the BART program represents a cornerstone of this process.

1. INTRODUCTION

The 1999 U.S. Environmental Protection Agency (USEPA) "Regional Haze Rule" [64 Fed. Reg. 35714 (July 1, 1999)] requires certain emission sources that "may reasonably be anticipated to cause or contribute" to visibility impairment in downwind Class I areas to install Best Available Retrofit Technology (BART).[1] These requirements are intended to reduce emissions specifically from large sources that, due to age, were exempted from new source performance standards (NSPS) requirements of the Clean Air Act.

BART requirements pertain to 26 specified major point source categories, including power plants, industrial boilers, paper and pulp plants, cement kilns, and other large stationary sources. To be considered BART-eligible, sources from these specified categories must have the potential to emit at least 250 tons per year of any haze forming pollutant and must have commenced operation or come into existence in the 15 year period prior to August 7, 1977 (the date of passage of the 1977 Clean Air Act Amendments, which first required new source performance standards).

Because of the regional focus of the 1999 haze rule, it is likely that BART requirements will be applied to a much larger number of sources across a broader geographic region than has been the case historically (i.e., through reasonably attributable visibility impairment requirements in the 1980 haze regulations). In addition, USEPA has for the first time introduced the possibility that source-by-source, command and control type BART implementation may be replaced by more flexible state initiatives (e.g. market-based approaches), provided such alternatives can be shown to achieve greater progress toward visibility objectives than the source by source BART approach.

1.1. The BART Rule

In June 2001, EPA released proposed guidelines on BART. This guidance outlined the method for determining if a facility has a BART-elgible source, if a source is subject to BART provisions, and methods for conducting a BART control review for such sources.

In 2002, industry groups challenged the method EPA outlined in the Regional Haze Rule to determine the degree of visibility improvement resulting from application of BART controls. Under EPA's interpretation of the statute, a state would deem sources subject to BART if they emitted into a geographic area or region from which pollutants are likely transported downwind into a protected area. In May 2002, the D.C. Circuit Court of Appeals agreed with industry petitioners that this interpretation impermissibly constrained the authority of any state that wanted to provide an exemption mechanism from BART requirements. The Court vacated those portions of the Regional Haze Rule dealing with BART.

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[1] There are seven designated Class I areas in the Northeast and Mid-Atlantic States. They include Acadia National Park and Moosehorn Wilderness Area in Maine; Roosevelt Campobello International Park in New Brunswick and Maine; the Lye Brook Wilderness Area in Vermont; the Great Gulf and Presidential Range-Dry River Wilderness Areas in New Hampshire; and the Brigantine Wilderness Area in New Jersey.

In June 2005, EPA released the final BART guidelines that also addressed the remanded portions of the Regional Haze Rule dealing with BART. Under the final rule, the BART program requires states to develop an inventory of sources within each state or tribal jurisdiction that could be subject to control. Specifically, the rule:

- Outlined methods to determine if a source is "reasonably anticipated to cause or contribute to haze;"
- Defined the methodology for conducting a BART control analysis;
- Provided presumptive control limits for electricity generating units (EGUs) larger than 750 Megawatts;
- Provided a justification for the use of the Clean Air Interstate Rule (CAIR) as BART for CAIR state EGUs.

Beyond the specific elements listed above, EPA provided the states with a great degree of flexibility in how they choose to implement the BART program. The following section summarizes the core requirements for state compliance with BART regulations.

1.2. Overview of State BART Requirements

As finally promulgated, States are required to undertake three key steps to comply with the BART requirements of the Regional Haze Rule. These steps include:

- Determining if a source is BART-eligible;
- Determining if a source reasonably causes or contributes to visibility impairment in any Class I area (subject to BART);
- Determining if additional controls or emission limits are necessary (BART determination).

As stated earlier, eligibility is limited to sources in one of 26 source categories that have units installed and operating between 1962 and 1977 with the potential to emit more than 250 tons per year of a visibility impairing pollutant. Once a source is found to be "eligible" for the BART program, states must determine if that source is "subject to BART," that is, if it causes haze or contributes to the formation of haze at any Class I area. EPA's 2005 rule outlines three options to determine if a source is subject to BART. These options include:

- ***Individual source assessment (Exemption Modeling)*** – This assessment uses CALPUFF or other EPA approved modeling methods. Results of modeling would be compared to natural background conditions. EPA defined "cause" as an impact of 1.0 deciview or more and "contribute" as an impact of 0.5 deciview or more.[2] The rule, however, gave states discretion to set lower thresholds for contribution.

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[2] Impacts are based on the difference in deciviews (delta deciview) calculated between the best twenty percent natural visibility conditions (states have the option to use annual average conditions as an alternative) at a Class I site with and without individual source contributions included.

- ***Cumulative assessment of all BART "eligible sources"*** **–** Under this method, a state can choose to find that all eligible sources within a geographic area or region are subject to BART. This method could also be used to analyze an area's contribution to visibility impairment and demonstrate that *no* sources are subject, based on cumulative modeling.
- ***Assessment based on model plants*** – This method provides a mechanism to exempt sources with common characteristics that are found not to impair visibility at Class I areas.

Once a source has been identified as BART-eligible and "subject" to BART, it must conduct an engineering review to determine if the installation of new control requirements is appropriate.[3] This review takes into consideration five factors:

- Cost of controls
- Energy and non-air quality environmental impacts
- Existing controls at source
- Remaining useful life of source
- Visibility improvement reasonably expected from application of the controls.

1.3. Overview of Report

This report is intended to summarize an approach to satisfy the BART requirements of the Regional Haze Rule based on the "cumulative assessment of contribution" option for determining if eligible sources are subject to BART. We also review BART-eligible sources in the MANE-VU region and provide – on a regional basis – an analysis of the general applicability of the five factors for various source categories subject to BART. This analysis should not be viewed as preventing states from exercising their flexibility in structuring their own approach to BART or in applying the five factors to that approach. Rather, this analysis will allow MANE-VU states to place their source-specific BART determinations into the regional context of similar sources within MANE-VU. This review includes an examination of individual units' impacts on visibility at Class I areas, based on CALPUFF modeling and an evaluation of existing or potential controls and feasibility of these controls relative to the statutory factors identified in the BART rule[4].

To that end, Section 2 of this report first develops a list of all BART-eligible sources in the MANE-VU region. Section 3 provides an overview of the region's approach to determining BART eligibility. Finally, Section 4 presents observations on the regional and sectoral differences among control options and the applicability of the five-factor analysis.

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[3] A possible exception to this requirement would exist in the case where a state has adopted a "better than BART" alternative program that would take the place of a source-specific BART determination. The RPO is not aware of any MANE-VU states that are adopting such programs at this time.

[4] Throughout this report we refer to the collection of sources at a stationary facility potentially subject to BART as a "BART-eligible source." Individual emitting units at these BART-eligible sources will be referred to as "units" when emissions are modeled and descriptions of possible control strategies are offered.

2. DETERMINING BART-ELIGIBLE SOURCES

To assist MANE-VU states and tribes with BART implementation efforts, MANE-VU developed a list of BART-eligible sources in the region (NESCAUM, 2001; NESCAUM, 2003). Since then, the preliminary list developed in these documents was refined through consultation with state permitting staff to verify completeness and accuracy of the list. Emissions of SO_2, NO_X, and PM_{10} as well as stack information were compiled through either consultation with state permitting staff or the 2002 MANE-VU emissions inventory. The final list of sources (as well as associated 2002 emissions and stack parameters) was developed in consultation with state staffs (see Appendix A for a complete list of BART-eligible sources and units in the MANE-VU region).

3. MANE-VU APPROACH TO "SUBJECT TO BART"

Based on the MANE-VU contribution assessment (NESCAUM, 2006b), every MANE-VU state with BART-eligible sources contributes to visibility impairment at a Class I area to a significant degree. Therefore, MANE-VU staff continues to support the policy decision made by the MANE-VU Board in June 2004, that ***if a source is eligible for BART, it is subject to BART***. (i.e., no exemption test will be used). The reasons why MANE-VU has chosen to pursue this option for demonstrating its sources are reasonably anticipated to cause or contribute to visibility impairment at Class I areas are threefold: (1) the BART sources represent an opportunity to achieve greater reasonable progress, (2) additional public health and welfare benefits will accrue from resulting decreases in fine particulate matter, and (3) to demonstrate its commitment to federal land managers (FLMs) and other RPOs as it seeks emissions reductions wherever it is reasonable to do so.

This recommendation is not equivalent, however, to the statement that every BART-eligible source must install controls. The approach presented for MANE-VU state consideration – starting with this document and continuing with their own source specific analyses – requires the consideration of each of the five factors required by statute before determining whether or not controls are warranted.

4. REGIONAL FIVE FACTOR ANALYSIS

4.1. The Degree of Visibility Improvement That May Reasonably be Anticipated from the Use of BART

BART emission limits must be determined subject to an evaluation of the five statutory factors. These factors include:

(a) the costs of compliance,
(b) the energy and non-air quality environmental impacts of compliance,
(c) any existing pollution control technology in use at the source,
(d) the remaining useful life of the source, and

(e) the degree of visibility improvement which may reasonably be anticipated from the use of BART.

To begin its regional analysis of these factors, MANE-VU staff first considered the degree of visibility improvement that could result from the installation of BART controls. This is slightly different than the statutory language and is meant to reflect our first-order approach to estimating the maximum visibility benefit that could be achieved by eliminating all emissions from the source. While this is not a realistic approach to fully satisfying the intent of factor (e) above, it does provide the states a useful metric for determining which sources are unlikely to warrant BART controls based on consideration of this factor.

This analysis was achieved by first modeling 2002 emissions of SO_2, NO_X, and PM_{10} from all BART-eligible units in the region.[5] A total of 136 BART-eligible sources were identified in the MANE-VU region and modeled on the two CALPUFF platforms. Table 4-1 displays the types and numbers of sources modeled in the region.

Table 4-1. Types of BART-eligible sources modeled in the region

Source Type	Number of Sources	Number of Units/MM5*	Number of Units/NWS
Chemical Manufacturer	12	48	107
Chemical Plant	1	4	18
Coal Cleaning	1	1	1
EGU	59	139	296
Glass Fiber	3	14	33
Incinerator	1	2	2
Industrial Boilers	2	6	8
Lime Plant	2	4	14
Metal Production	13	64	140
Mineral Products	1	4	13
Paper and Pulp	14	39	63
Petroleum Storage	4	6	10
Portland Cement	13	49	228
Refinery	9	70	497
Total	**136**	**455**	**1449**

* Units with very small emissions were grouped together and modeled as one stack for the MM5-based CALPUFF runs.

The two CALPUFF modeling platforms are described in greater detail elsewhere (NESCAUM, 2006b) and are driven by two respective meteorological datasets: 1) a wind field based on National Weather Service (NWS) observations and 2) a wind field based on output from the MM5 meteorological model (MM5, 2006). Environmental Resources Management (ERM) developed CALMET-processed meteorology on a large domain (extending from Oklahoma City, OK up to Prince Edward Island, Canada). The CALMET meteorology was processed directly from the MM5 model output developed

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[5] Emissions information was gathered from the MANE-VU 2002 Version 2 (Base A) emissions inventory. Since then, the MANE-VU 2002 Version 3 (Base B) emissions inventory has been developed which includes several changes made by the OTC modeling committee.

on a 12-km horizontal grid by the University of Maryland for the OTC modeling committee and MANE-VU. The Vermont Department of Environmental Conservation (VT DEC) developed CALMET meteorology (for the identical domain) driven by the NWS's surface observation network, rawinsonde network, and supplemented by the Airport Surface Observation System (ASOS) network. This observation-based dataset provides an alternative to the gridded wind fields generated by the diagnostic model MM5.

Modeling results from both NWS and MM5 platforms have been made available to the states involved in this process. Results include each BART-eligible unit's maximum 24-hr, 8th highest 24-hr, and annual average impact at the Class I area most heavily impacted, as well as the total impact from all BART sources on each Class I area. These visibility impacts were modeled relative to 20 percent best, 20 percent worst, and annual average natural background conditions. For the purposes of this analysis, we examined the 24-hr maximum visibility impact relative to the 20 percent best days. On July 19, 2006, EPA provided clarification to guidance that states may use either estimates of 20 percent best or annual average natural background visibility conditions as the basis for calculating the deciview difference that individual sources would contribute for BART exemption modeling purposes. MANE-VU has opted to use the best conditions estimates for their consideration of the "degree of visibility improvement" modeling because it is more protective to the region.

Given that no modeling of 2018 "post-BART" emission levels has been conducted yet, the 2002 modeling, in essence, provides MANE-VU with an estimate of the maximum improvement in visibility that could result from installation of BART controls at Class I areas in the region (i.e., if the source was zeroed out). In virtually all instances, the installation of BART controls would result in less visibility improvement than what is represented by a source's 2002 impact, but this does provide a consistent means of identifying those sources whose emissions represent a more significant contribution to visibility impairment than others.

In July of 2004, MANE-VU submitted comments to EPA that included visibility impact analysis of a representative sample of EGUs across the country. Based on that representative sample, MANE-VU determined that the value of the maximum 24-hour impact relative to natural conditions that would include 98 percent of the cumulative visibility impact on MANE-VU sites was likely between 0.1 and 0.2 dv. However, this dataset was limited in that it only explored the relationship of EGUs and did not provide an indication of how the total frequency impact might change with numerous smaller, non-EGU, BART-eligible sources. With this new CALPUFF modeling data, we were able to repeat this analysis for the dataset that included all BART-eligible units in the region. This analysis remains limited that in that it includes only MANE-VU sources. It is likely that the additional sources from VISTAS and MWRPO would add to the total visibility impairment experienced at MANE-VU class I areas and, to some extent, to the top 98 percent of the visibility impacts. Without knowing the exact contribution of extra-regional BART sources to impairment at our Class I sites, it is impossible to determine the cumulative 98th percentile frequency precisely.

Notwithstanding this limitation, the results of this new analysis showed that 98 percent of the cumulative frequency visibility impact from all MANE-VU BART-eligible sources corresponds to a maximum 24-hr impact of 0.22 dv from the NWS-driven data and 0.29 dv from the MM5 data. We therefore concluded that a range of 0.2 to 0.3 dv would represent a "significant" impact at MANE-VU Class I areas on an average basis. Given the analysis and the limitation due to exclusion of sources outside of MANE-VU, we decided to place increased weight on sources with an individual visibility impact greater than 0.1 dv for this 1st order regional 5-factor analysis. This threshold is overly inclusive relative to exemption processes being conducted by other RPOs, but still provides MANE-VU states flexibility in choosing the weight to be given to the first of the five factors considered (i.e., the degree of visibility improvement that could result from BART).

As an additional demonstration that sources whose impact were below the 0.1 dv level were too small to warrant BART controls, the entire MANE-VU population of these units was modeled together to examine their cumulative impacts on each Class I site. The result of this simulation showed that the maximum 24-hr impact at any Class I area of *all* modeled sources with individual impacts below 0.1 dv was only a 0.35 dv change relative to the estimated best days natural conditions at Acadia National Park. This value is below the 0.5 dv impact recommended by EPA for exemption modeling and we can be fairly certain that sources below the 0.1 dv level have very small individual impacts on visibility at Class I areas.

Among the sources with a greater than 0.1 dv total impact at any Class I area were 29 EGUs with 95 BART-eligible units that are located in states subject to CAIR. These CAIR-eligible EGU units may use the CAIR program to satisfy BART for SO_2 and in most cases NO_X BART. We did not consider these sources further with the exception of the three EGU sources (eight units) that had greater than 0.1 dv contribution for PM alone. These three EGU sources, along with 14 additional EGU sources in states that are not subject to CAIR (17 EGUs total), and 36 additional non-EGU sources with visibility impacts that may warrant BART controls are listed in Table 4-2 by type.

Table 4-2. Types of sources in MANE-VU region with greater than 0.1 dv impact at any Class I area (non year-round CAIR states).

Source Type	Number of Sources	Number of Units/MM5*
Chemical Manufacturer	1	3
Coal Cleaning	1	1
EGU	17	30
Glass Fiber	1	6
Incinerator	1	2
Metal Production	2	7
Paper and Pulp	12	30
Portland Cement	12	25
Refinery	5	37
Total	53	142

*Only MM5 Data were used for this analysis.

4.2. Cost and Availability of Controls and Controls Already in Place

The second and third steps of the MANE-VU five-factor analysis involved evaluating current controls at sources and costs of additional controls at these sources – factors (a) and (c) above. To address these factors, the list of these 53 highest impacting sources, including all the BART-eligible units at these sources (142 units), was sent out to state permitting staff for feedback on possible controls recommendations for these types of units and cost information for typical installation of these controls. Several states informed us that some of the eligible sources are subject to future controls under existing state regulations that will achieve "BART-like" levels of control. In these cases, we have listed the control level where applicable, or designated the control as "Currently Controlled" if the controls are already in place. Other states are considering a cost threshold to determine whether controls are feasible. If potential additional controls are above any known cost thresholds, then it is likely that a state would not feel that additional controls beyond those currently in place are warranted and we have therefore designated such units as "No Further Controls Warranted." In situations where we did not have sufficient information to assess current or potential future controls, the unit has been designated as "No Known Further Controls." In cases where other control programs such will satisfy BART, the control program is listed. Finally, we have listed the control technology as "No Known Further Controls" for BART-eligible sources where no information was available on possible control options.

NESCAUM compiled the available survey results provided by state staffs on expected or potential controls on these units and projected 2018 emissions from these units. Summaries of these results are found in Table 4-3 to Table 4-5. Cost information for various control options was obtained from a variety of sources including individual states, previous NESCAUM reports (NESCAUM, 2005), and other RPO analyses. Cost estimates from NESCAUM (2005) as well as the low, medium, and high cost designations described in the Tables 4.3-4.5 are summarized in Appendix B. Obviously, more detailed analysis of the cost of various control options will have to be conducted at the source-specific level by the states as they conduct source-specific BART determinations.

Table 4-3. Possible range of SO_2 controls and costs based on survey of state staff

Type of Source	*Number of Sources*	*Control Strategies*	*Number of Emission Units Control Strategy May Apply*	*Total 2002 SO_2 Emissions*	*Total Estimated Decrease in SO_2 (tons/yr)*	*Estimated Cost ($/Ton SO2)*	*Notes*
Chemical Manufacturer	3	SO2 Scrubber	1	24000	9600	400-8000	Mid Range (1)
		Currently Controlled	2	80	NA	0	
Glass Fiber	6	Currently Controlled	6	17	0	0	
Coal Cleaning	1	No Known Further Controls	1	68	0	0	
EGU/Coal	5	Dry Scrubber	4	58000	52600	200-500	Mid Range, assume 90% scrubber efficiency
		0.33 lb/MMBtu	1	4000	1200	NA	
EGU/Oil (Resid and Dist)	17	0.3% fuel sulfur limit	3	1400	340	0	Switch to 0.3% has already occurred for 3 boilers.
		0.56 lb/MMBtu	1	85	NA	NA	
		2.0 % Fuel Sulfur Limit	1	600	300	NA	
		1.5% Fuel Sulfur Limit	1	5200	3900	NA	
		0.33 lb/MMBtu	1	4000	3100	NA	
		3.0 lb/MWh	5	31000	NA	NA	
		1.1-1.2 lb/MMBtu	2	480	NA	NA	
		Currently Controlled	3	1200	0	0	
Incinerator	2	Currently Controlled	2	84	0	0	
Metal Production	7	No Further Controls Warranted	5	2200	0	0	
		Increased efficiency of the facility's wet scrubber	2	3000	300	Limited Cost	Low Range
Paper and Pulp	30	FGD (SO_2 Scrubber)	3	13000	11000	400-8000	Mid Range (1)
		1.8% Fuel Oil	2	6050	3000	NA	
		2.0% Fuel Oil	1	2800	1400	NA	
		No Known further controls	3	10000	0	0	
		Currently Controlled	21	4000	0	0	
Portland Cement	25	Fuel switching: CE of SOx 10%	3	2300	230	NA	
		No Further Controls Warranted	5	3700	0	0	
		No Known Further Controls	7	300	0	0	
		SO_2 Scrubber	10	26000	19000	400-8000	Mid Range (1)
Refinery	37	Refinery RACT	9	5400	NA	0	
		SO2 Scrubber	3	NA	NA	400-8000	Mid Range (1)
		No Known Further Controls	25	NA	NA	0	

(1) Cost estimate from NESCAUM 2005 for Industrial Boilers
NA- No information currently available.

Table 4-4. Possible range of NO_X controls and costs based on survey of state staff

Type of Source	Number of Sources	Control Strategies	Number of Emission Units Control Strategy May Apply	Total 2002 NO_x Emissions	Total Estimated Decrease in NO_x (tons/yr)	Estimated Cost ($/Ton NO_x)	Notes
Chemical Manufacturer	3	SCR	1	4900	3400	1300-10000	(2)
		Currently Controlled	2	5000	0	0	
Glass Fiber	6	Currently Controlled	6	180	0	0	
Coal Cleaning	1	Low NOx burners, CE of 15%	1	160	25	1-2 Million (capital cost)	Low Range
EGU/Coal	5	Currently Controlled	2	2900	820	0	
		SCR and 1.5 lb/MWh	2	9800	NA	1000-1500	Mid Range (1)
		NOx Budget & 1.5 #/MWh	1	2300	NA	NA	
EGU/Oil	17	Currently Controlled	6	3200	0	0	
		No Known Controls	3	390	0	0	
		NOx Budget	3	700	NA	NA	
		NOx Budget and 1.5 lb/MWh	4	5300	NA	NA	
		SNCR, 1.5 lb/MWh	1	2400	NA	500-700	Mid Range (1)
Incinerator	1	Currently Controlled	2	720	0	NA	
Metal Production	2	Currently Controlled	2	0	0	0	
	5	No Further Controls Warranted	5	110	0	0	
Paper and Pulp	30	SCR or SNCR	2	710	430	1300-10000	Mid to High Range (2)
		No Known Further Controls	13	4500	0	0	
		Currently Controlled	15	4600	0	0	
Portland Cement	25	Low NOx burners	3	2800	430	200-3000	Mid Range (3)
		Low NO_x Burners and Mid Kiln Firing, 40% Reduction	2	8500	3400	1200-10000	Mid Range (2)
		SCR, 65% Red.	1	740	480	1300-10000	(2)
		No Known Further Controls	9	2000	0	0	
		Currently Controlled	1	1700	0	0	
		SNCR	9	7100	2900	900-1200	Mid Range (3)
Refinery	37	Refinery RACT	9	2300	NA	NA	
		No Known Further Controls	25	0	0	0	
		SCR	2	460	40	1300-10000	(2)
		SNCR	1	1000	560	1300-10000	(2)

(1) Cost estimate from NESCAUM 2005, EGU controls
(2) Cost estimate from NESCAUM 2005, Industrial Boiler controls
(3) Cost estimate from NESCAUM 2005, Portland Cement Kilns
NA-No information currently available.

Table 4-5. Possible range of PM_{10} controls and costs based on survey of state staff

Type of Source	*Number of Sources*	*Control Strategies*	*Number of Emission Units Control Strategy May Apply*	*Total 2002 PM_{10} Emissions*	*Total Estimated Decrease in PM_{10} (tons/yr)*	*Estimated Cost (\$/Ton PM_{10})*	*Notes*
Chemical Manufacturer	3	Currently Controlled	3	200	0	0	
Coal Cleaning	1	No Known Further Controls	1	46	0	0	
EGU/Coal	10	Currently Controlled ESP	7	2000	0	0	
		PM co-benefit reductions expected due to FGD-25-50% reduction	2	1500	370	0	
		Baghouse	1	1500	NA	$50 M	Capital Cost
EGU/Natural Gas	2	Controls information included with oil/coal boilers	2	13	NA	NA	
EGU/Oil	18	Currently Controlled	13	410	42	0	
		No Known Further Controls	5	50	0	0	
Incinerator	2	Currently Controlled Fabric Filter	2	0	0	0	
Glass Fiber	6	Currently Controlled	6	190	0	0	
Metal Production	7	Currently Controlled	7	41	0	0	
Paper and Pulp	30	Upgrade from ESP to baghouse, CE of 4% estimate	2	180	7	$15 M	Capital Cost
		No Known Further Controls	7	280	0	0	
		Currently Controlled (ESP, Venturi Scrubbers, Demister, or MultiCyclones)	9	690	0	0	
		Current Controls	7	670	0	NA	
Portland Cement	25	Upgrade on current ESP, CE of 5%	3	210	11	Limited Cost	
		No Known Further Controls	15	300	0	0	
		Currently Controlled	6	370	0	0	
		Baghouse or electric precipitator	1	4	NA	NA	
Refinery	37	No Known Further Controls	28	NA	0	0	
		Refinery RACT	9	270	NA	NA	

NA-No information currently available.

Table 4-3 through Table 4-5 display general summary information from state surveys on possible BART control efforts as well as cost information gathered from several sources. The sections below will describe the contents of these tables in further detail.

4.2.1. Chemical Manufacturers

In the MANE-VU region, one chemical manufacturing source showed visibility impacts greater than 0.1 dv at a Class I area. At this source the state is considering SO_2 scrubber installation at one boiler unit (emission unit containing three oil and coal fired boilers) that could result in a decrease of 9600 tons of SO_2 emitted from this source annually. The State is also considering an installation of an SCR (Selective Catalytic Reduction) at this unit that could result in a decrease of 3400 tons of NO_x emissions annually from the three boilers. This unit currently has an ESP installed for PM control which is expected to satisfy BART.

4.2.2. Glass Fiber

There is one glass fiber source in the region with a significant visibility impact on a Class I area in MANE-VU. Recent conversion from air/natural gas firing to oxygen/natural firing in 2000 has led to to an 85% reduction from the previous configuration which adequately satisfies BART.

4.2.3. Coal Cleaning

One coal cleaning source in the region showed a significant visibility impact at Class I areas. Low NO_X burners for NO_X control are considered a low-cost option for the thermal coal dryer unit at this source (Appendix B).. Additional control options for SO_2 and PM may not be warranted based on a survey of state staff. Low NO_X burners could result in approximately 24 tons of NO_X reduced annually.

4.2.4. Electric Generation Units

Of the 58 EGUs modeled in the region, 40 sources are located in states implementing a year-round CAIR program, while 15 sources are located in states implementing an ozone season CAIR program. Units covered in a year-round CAIR program were removed from further SO_2 and NO_X analysis because BART would likely be satisfied through CAIR requirements. Visibility modeling was conducted for all EGUs in the region and of the 18 EGU sources in MANE-VU states without a year-round CAIR program under development, 13 showed a significant impact at Class I areas in the region. In addition, three sources in states with a year-round CAIR program showed a significant PM impact, and were included in the PM control and cost analysis.

Coal-Fired Units

States with coal-fired EGU units are considering two options for SO_2 control; dry scrubber installation (a mid level cost option) and a 0.33 lb/mmBTU capacity limit. A dry scrubber could result in over 90 percent SO_2 decrease while a capacity limit of 0.33

lb/mmBTU could result in a decrease of 1200 tons SO_2 at one unit considering this option.

In terms of NO_X control, two boilers in the region have current controls of Low-NOx concentric firing systems and SCR that are being considered sufficient for BART. Two units are looking at SCR controls to achieve a 1.5 lb/MWh emission rate, a mid level cost option for this source. One unit's control level under the NO_X Budget Program will simultaneously control for BART.

The majority of coal-fired units at EGUs in the region are currently fit with ESPs and further PM control recommendations are not warranted. For the units without ESPs, one state was looking at baghouse installation as a possible option and another expects sufficient reductions due to a PM co-benefit from the installation of an FGD (Fluid Gas Desulfurization) scrubber for SO_2 control.

Oil-Fired Units

The majority of BART-eligible oil-fired EGU boilers in the region were found in one state. For these units, input- and output-based capacity limits established under other programs for which the BART-eligible units were covered may satisfy SO_2 BART control requirements. The levels of those programs are 0.56 and 1.1 lb/MMBtu for two different EGUs respectively, and 3.0 lb/MWh output-based limit for several other EGUs.

Another control option being considered by other states is a fuel sulfur limit (0.3 percent) or an equivalent 0.33 lb/MMBtu emissions rate. Four BART-eligible units in the region have been controlled at this level since 2002 and would consider this level of control appropriate for BART. This BART control option has reduced total SO_2 emissions by 3100 tons annually at the one controlled sources, but is not anticipated to achieve as great a reduction at the other three BART-eligible sources, which are smaller. One unit is considering a 1.5 percent fuel sulfur limit that could result in approximately 3900 tons (or approximately 75 percent reduction) of SO_2 emissions from the one candidate for this option. We have no information on potential controls for two other BART-eligible units in the region.

Regarding NO_X controls on oil-fired boilers, possible technologies being considered for BART include SNCR (Selective Non-Catalytic Reduction) installation. Several units in the region are either currently controlled, with further controls considered unwarranted, or are under a NO_X budget program that would serve as BART. Current controls on oil-fired boilers at EGUs include SNCR, boiler excess air control, and Low-NO_x burners. For several of these units, information on BART recommendations was unavailable.

As with the coal-fired units, the majority of oil-fired boilers in the region have existing PM control technologies like ESPs, multicyclones, and mechanical collectors.

4.2.5. Incinerators

The lone BART-eligible incinerator source in the region has already achieved an approximately 75 percent reduction in SO_2 emissions through the installation of a dry scrubber. This source already has SNCR NO_X controls and reverse air fabric filters for PM controls and therefore further controls are not warranted. The air pollution controls on this source are the same controls required by new municipal waste combustion facilities MACT requirements.

4.2.6. Metal Production

Two metal production sources consisting of seven BART eligible units showed significant visibility impact on the region For one source, the state was looking at low cost, better efficiency measures for the SO_2 scrubber that would result in an increase of SO_2 control efficiency by 10 percent at two aluminum ore reduction units. A preliminary cost analysis conducted by the state at another source showed that SO_2 controls were not warranted at the sources BART eligible units (baking furnaces and potlines). The survey of state staff indicated that current controls for PM would likely satisfy BART for all metal production units in the region. Two units in the region are currently controlled for NOx while a cost analysis for NO_x controls at 5 units indicated that no further controls were warranted.

4.2.7. Paper and Pulp

There are 30 eligible units at paper and pulp sources with significant visibility impact in the region. While the majority of these units are industrial boilers, this category also contains lime kilns, smelt tanks, and other process units. States are contemplating FGD scrubber installations for SO_2 control for at least three industrial boiler units as possible BART control options. This is a mid-range cost technology for typical installations that could result in an estimated 20,000 fewer tons of SO_2 for these three units alone. At three industrial boiler units, a fuel switching option is being considered by the state. Two boilers switching to 1.8% Sulfur fuel oil could result in 3000 tons of SO_2 being reduced while one boiler switching to 2.0% sulfur fuel oil could result in 1400 tons of SO_2 reduced. Twenty-one units are currently controlled at a level such that existing controls are likely to satisfy BART, while no known further controls are expected for three units in this category. Current controls on these boiler units are generally wet scrubbers.

For the majority of paper and pulp units, either the existing Low NO_X burner controls or current capacity limits may satisfy BART or we did not have information about possible controls for units. Possible control options being considered for uncontrolled sources include SCR or SNCR technologies on boilers that could achieve 60 to 80 percent NO_X control. This is a mid to high cost control option, depending on the source. Installation of these technologies is estimated to result in a decrease of 430 tons of NO_X emissions at two units considering this option.

Most of the units at paper and pulp sources with significant visibility impacts in the region have existing PM controls including ESPs, baghouses, multicyclones, and venturi scrubbers and were therefore not viewed as candidates for further controls. One state is considering upgrading ESPs on two coal fired industrial boilers to baghouses that would result in a decrease of 7 tons of PM emitted per year.

4.2.8. Portland Cement Plants

Twenty-five Portland cement units in MANE-VU are located at BART-eligible sources with significant visibility impacts on Class I areas in the region. At these sources, states are considering installation of SO_2 scrubbers at 10 cement kilns at these sources, which would significantly reduce the amount of SO_2 emitted from this sector. If installed, scrubbers at these kilns would result in a decrease in emissions of 19,000 tons of SO_2 annually.

Another BART control option being considered for cement kilns in the region is fuel switching. Units considering this option for kilns could decrease annual SO_2 emissions by 230 tons. Twelve units in this sector either have existing controls that will likely satisfy BART, or control information for SO_2 is currently unknown.

Control technologies under consideration for NO_X at cement plants were varied according to our survey information. Low NO_X burners are a possible control option for uncontrolled cement kilns. This is a mid range cost option that could result in an annual decrease of 430 tons of NO_X emitted from three units. Another possible control option is Low NO_X burners with mid-kiln firing. At a mid level cost, this technology could result in a decrease of 3400 annual tons of NO_X emissions at units where this option is applicable. SCR installation is being considered at one unit, also a mid level cost option that could decrease emissions from unit by 480 tons annually. SNCR control technology is a mid level cost option, which if in place at units considering this option, could result in a decrease of 2900 tons of NO_X emissions. Ten of the 25 units in this category either have existing controls that will likely satisfy BART or controls for NO_X are currently unknown.

Most of the units at these Portland cement plants either have existing PM controls or potential control information is unknown. Where no controls exist, possible control options include installation of a baghouse or an ESP. One state is considering a recommendation of upgrading ESPs at three units, a low cost option that would reduce annual emissions of PM by 11 tons.

4.2.9. Refineries

At this time, for the majority of the units in this category, control information is unknown. One possible control option for SO_2 is installation of a scrubber on fluid catalytic cracking units, a mid range cost option being considered for three units in the region. Nine of these units are currently subject to refinery RACT (Reasonably Available Control Technology) controls for 8-hour ozone and these control levels for SO_2, NO_X, and PM are likely to satisfy BART requirements. States are also considering SCR or SNCR controls for three fluid catalytic cracking units in the region for possible NO_X control, also a mid level cost option.

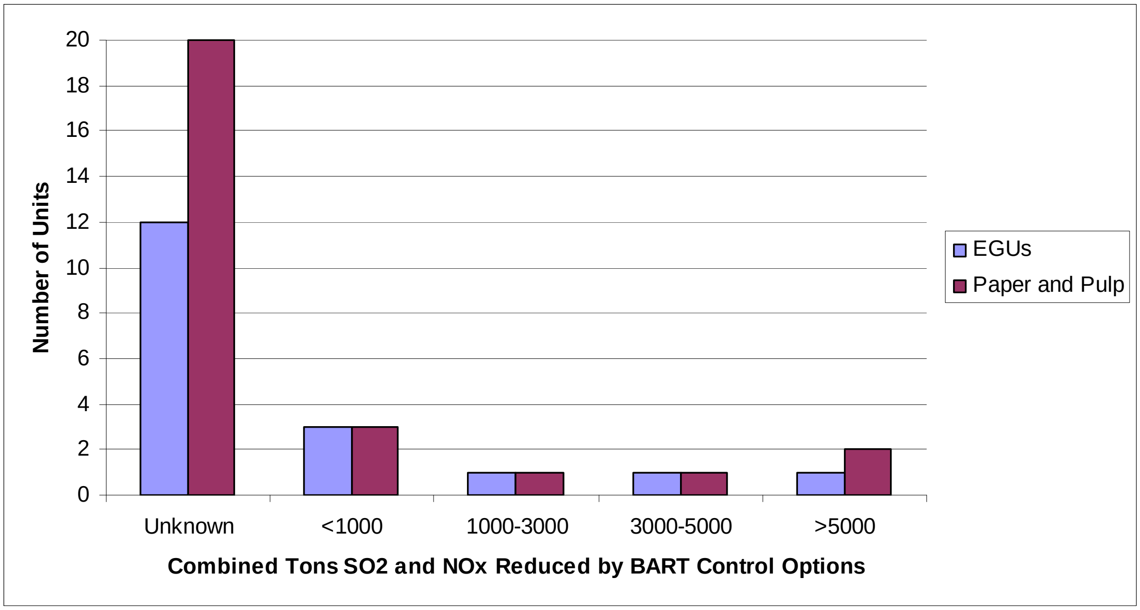
4.3. Energy and Non-Air Quality Environmental Impacts

While there are certain to be several issues that arise on a source-specific basis with respect to individual control technologies (e.g., water quality impacts or solid waste disposal issues), we are unable to address these issues in a regional analysis. One environmental benefit that should be considered in weighing control options for BART is the regional impact on acid deposition in MANE-VU.

An analysis of combined SO_2 and NO_X reduction potential of BART control options by sector showed similar results for EGUs and paper and pulp sources. Figure

4-1 shows the amount of SO_2 and NO_X that could be reduced if BART control options were implemented at the units for which likely control options are known. Figure 4-1 shows that generally, when emission reduction options are known, the emissions reduction potential is evenly distributed across the range of sources in the region. This is important as states are weighing whether controls are warranted or not for EGUs or paper and pulp boilers. However, for the majority of units with significant visibility impact in these sectors, the amount of SO_2 and NO_X reduction potential is currently unknown, limiting the power of this analysis.

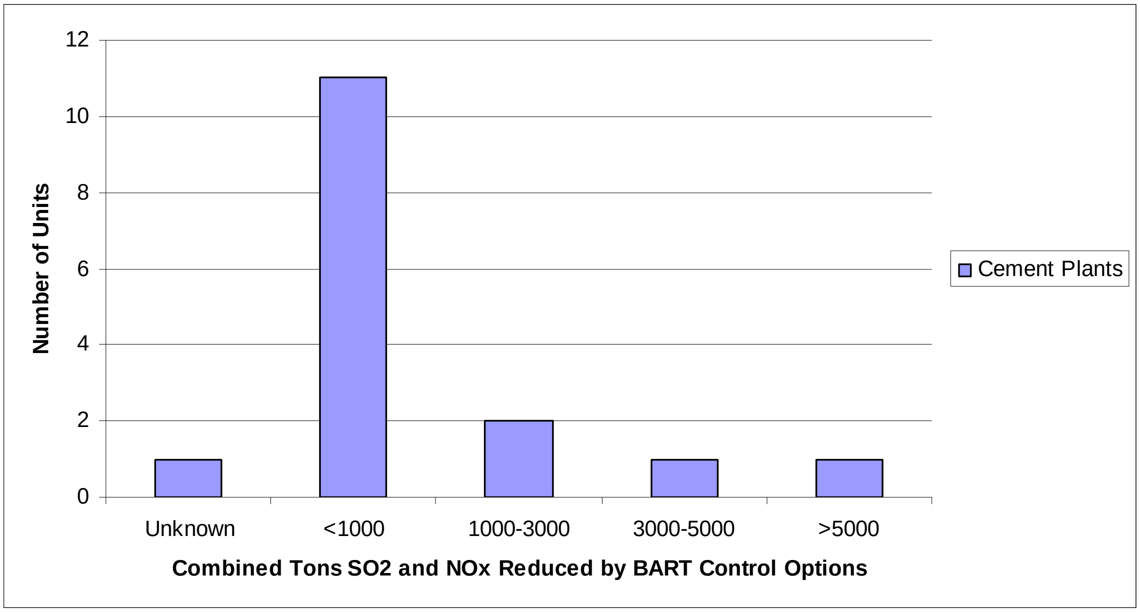
Figure 4-1. Reduction potential of BART control options at EGUs and Paper and Pulp Sources



For Portland cement plants, possible emissions reduction data were more complete and allowed for a clearer analysis of SO_2 and NO_X control. Figure 4-2 shows the emissions reduction potential that would be achieved by BART if the survey control options were implemented for units in this sector. While several units would benefit from BART control options with emissions being reduced by greater than 3,000 tons of combined SO_2 and NO_X, the majority of the cement plant units would reduce emissions by less than 1,000 tons. As states weigh whether additional controls are warranted for cement plants, this non air-quality environmental factor may play less of a role for these sources.

For other source categories, the statistics are generally too small to make an analysis meaningful, but as a general rule, the remaining source categories tend to have lower overall emissions and lower overall reduction potential, which may factor into control decisions accordingly.

Figure 4-2. Reduction potential of BART control options at Cement Plants



4.4. Remaining Useful Life

The MANE-VU BART Workgroup has considered what weight to give to this factor in conducting BART determinations and has recommended that remaining useful life of a source will be addressed in the following way. A BART-eligible source that is found to have reasonable control options available to it should either control emissions from that BART-eligible source prior to 2013 or accept a federally enforceable permit limitation or retirement date prior to each state's public notice and hearing processes and FLM review of BART SIP elements.

5. CONCLUSIONS

As MANE-VU states prepare to conduct source-specific BART determinations for the eligible units in their jurisdictions, this report provides a regional assessment of the five factors that must be considered in determining whether additional controls are warranted for an individual BART source. This information is intended to lay out a regional approach and provide regional context for individual control decisions that will be made by the MANE-VU member states. This information may also serve as an important regional basis for dialogue and internal MANE-VU consultations as states consider what level of stringency is justified and reasonable based on consideration of the five factors.

Important findings of this analysis include the identification of BART-eligible sources in the region, the numbers of units in various categories subject to BART consideration, BART control technology options being considered in the region, and estimates of the total emissions and reduction potential from units contributing to potentially significant visibility impacts at Class I areas.

Table 4-1 and Table 4-2 indicate that 136 BART-eligible sources exist in the region with 53 contributing to potentially significant visibility impairment at a Class I area. The majority of BART-eligible sources in the region are EGUs, however, most of these sources fall under a year-round CAIR program that will satisfy BART.

Of the BART-eligible source categories with potentially significant visibility impacts, the non-CAIR EGU sector was the largest emitter of SO_2, NO_X, and PM_{10} in 2002. BART-eligible EGUs with significant visibility impacts included 17 sources with 30 units emitting 110,000 tons SO_2, 28,000 tons NO_X, and 7,000 tons PM_{10} in 2002. The majority of these units are anticipating controls for SO_2 and NO_X to satisfy BART requirements. Although the amount of expected reductions is currently unknown, we can expect significant reductions in emissions from this sector given widely available control technologies for SO_2 and NO_X with proven cost-effectiveness. Most of these units are currently controlled for particulate matter and further controls are not expected.

Portland cement plants and paper and pulp sources are sectors with many BART-eligible units that made significant contributions to visibility impairment and total pollutant emissions in the region. Paper and pulp sources with significant visibility impacts emitted 36,000 tons SO_2, 10,000 tons NO_X, and 2,000 ton PM_{10} at 30 units in 2002. Although information on controls is currently unknown for many of these units, information from units considering controls indicates that significant reductions can be achieved from this sector (19,000 tons SO_2 reduced if scrubbers are installed at 13 units and 400 tons NO_X reduced if SCR controls are introduced to two units). Portland cement sources with significant visibility impacts emitted 32,000 tons SO_2, 23,000 tons NO_X, and 850 tons PM_{10} at 25 units in the region. With more complete information for cement plants, we estimated a reduction of 19,000 tons SO_2 at 13 units and 7,000 tons NO_X at 15 units when considering controls that would satisfy BART.

Ultimately, the strength of the MANE-VU BART program, as determined by individual state control decisions and informed by this analysis, will demonstrate MANE-VU's resolve to tackle visibility and related air quality problems in its region. As MANE-VU enters into inter-RPO consultations, its willingness to seek reasonable emission reductions within its own region will help set expectations for the other RPOs, and the BART program represents a cornerstone of this process.

6. REFERENCES

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Appendix A: List of BART-Eligible Sources in the MANE-VU Region

State	Plant	Type	Number of Units
CT	Middletown Power LLC (NRG)	EGU	2
CT	Montville Power LLC (NRG)	EGU	1
CT	Norwalk Power LLC (NRG)	EGU	1
CT	PSEG Power CT Bridgeport Harbor Station	EGU	1
CT	PSEG Power CT New Haven Harbor Station	EGU	1
CT	Sprague Paperboard Caraustar	Fossil Fuel Boiler (>250 MMBtu	1
DC	Benning (PEPCO -15)	EGU	1
DC	Benning (PEPCO -16)	EGU	1
DE	City of Dover - Mckee Run	EGU	1
DE	Connectiv Edgemore	EGU	2
DE	NRG- Indian River	EGU	1
MA	Exxon Mobil Everett	Petroleum Storage	1
MA	Global Petroleum Revere	Petroleum Storage	1
MA	Gulf Oil Chelsea	Petroleum Storage	1
MA	Solutia	Chemical Process Plant	3
MA	Braintree Electric	EGU	1
MA	Brayton Point	EGU	4
MA	Eastman Gelatin (boilers only)	Chemical Process Plant/Industrial Boilers	4
MA	General Electric Lynn	EGU	1
MA	Harvard U (Blackstone)	EGU	2
MA	Mirant Kendall LLC	EGU	3
MA	Mirant-Canal Electric	EGU	2
MA	Mystic	EGU	1
MA	New Boston	EGU	1
MA	Salem Harbor	EGU	1
MA	TMLP - Cleary Flood	EGU	3
MA	Trigen - Kneeland St	EGU	1
MA	Wheelabrator -Saugus	Municipal Incinerator	2
MD	CONSTELLATION POWER SOURCE GENERATION CP CRANE	EGU	7
MD	CONSTELLATION POWER SOURCE GENERATION HERBERT WAGNER	EGU	2
MD	EASTALCO ALUMINUM	Primary Aluminum Ore Reduction Plant	2
MD	INDEPENDENT CEMENT ST LAWERENCE	Portland Cement	1
MD	LEHIGH PORTLAND CEMENT	Portland Cement	3

MD	METTIKI COAL CORPORATION	Coal Cleaning	1
MD	MILLENIUM INORGANIC CHEMICALS	Chemical Process Plants	5
MD	MIRANT MID ATLANTIC LLC MORGANTOWN	EGU	2
MD	MIRANT MID ATLANTIC DICKERSON	EGU	1
MD	PEPCO CHALK POINT	EGU	3
MD	TRIGEN LEADENHALL STREET	Fossil Fuel Boiler (>250 MMBtu	4
MD	VIENNA GENERATING STATION	EGU	1
MD	WESTVACO FINE PAPERS	Kraft Pulp Mill/Fossil Fuel Boiler (>250 MMBtu	3
ME	Domtar Ind	Industrial Boiler/Kraft Pulp Mill	2
ME	Dragon Products	Portland Cement	1
ME	Georgia Pacific Old Town	Industrial Boiler/Kraft Pulp Mill	2
ME	IP Bucksport	Fossil Fuel Boiler (>250 MMBtu	1
ME	IP Jay	Industrial Boiler/ Kraft Pulp Mill	9
ME	Katahdin Paper Millinocket	Fossil Fuel Boiler (>250 MMBtu	1
ME	Lincoln Paper and Tissue	Industrial Boiler/Kraft Pulp Mill	2
ME	Rumford Paper	Industrial Boiler	1
ME	SAPPI Somerset	Industrial Boiler/Kraft Pulp Mill	4
ME	Wyman Station	EGU	2
NH	PSNH Merrimack Station	EGU	1
NH	PSNH Newington Station	EGU	1
NJ	Amerada Hess Corporation-Port Reading Re	Petroleum Refinery	13
NJ	Bayway Refinery	Petroleum Refinery	257
NJ	Chevron Products Company	Petroleum Refinery	22
NJ	COASTAL EAGLE POINT OIL COMPANY	Petroleum Refinery	145
NJ	Hudson Generation Station	EGU	4
NY	3M TONAWANDA	Chemical Process Plants/Industrial Boilers	4
NY	ALCAN ALUMINUM CORPORATION	Primary and Secondary Aluminum Production	9
NY	ALCOA MASSENA OPERATIONS (WEST PLANT)	Primary and Secondary Aluminum Production	25
NY	ARTHUR KILL GENERATING STATION	EGU	2
NY	ASTORIA GENERATING STATION	EGU	2
NY	BOWLINE POINT GENERATING STATION	EGU	5

NY	BUFFALO COLOR CORP - LEE ST PLANT	Chemical Process Plants/Industrial Boilers	5
NY	CON ED-59TH ST STA	EGU	4
NY	DANSKAMMER GENERATING STATION	EGU	2
NY	EF BARRETT POWER STATION	EGU	44
NY	ERWIN MANUFACTURING COMPLEX	Glass Fiber Processing Plants	3
NY	GENERAL ELECTRIC SELKIRK PLASTICS PLT	Chemical Process Plants/Industrial Boilers	16
NY	GLENS FALLS LEHIGH CEMENT COMPANY	Portland Cement	46
NY	INTERFACE SOLUTIONS INC	Kraft Pulp Mill/Industrial Boilers	9
NY	INTERNATIONAL PAPER TICONDEROGA MILL	Kraft Pulp Mill/Industrial Boilers	11
NY	KODAK PARK DIVISION	Chemical Process Plants/Industrial Boilers	20
NY	LACKAWANNA PLANT- REPUBLIC ENG PROD INC	Primary Metal Production/Industrial Boilers	3
NY	LAFARGE BUILDING MATERIALS INC	Portland Cement	31
NY	LOVETT GENERATING STATION	EGU	4
NY	NORTHPORT POWER STATION	EGU	17
NY	OSWEGO HARBOR POWER	EGU	3
NY	OWENS-CORNING DELMAR PLANT	Glass Fiber Processing Plants	27
NY	RAVENSWOOD GENERATING STATION	EGU	60
NY	REVERE SMELTING & REFINING CORP	Primary Metal Production/Industrial Boilers	8
NY	RIVERBAY CORP-CO-OP CITY	Industrial Boilers	4
NY	RIVERHEAD TERMINAL-CONOCOPHILLIPS	Petroleum Storage/Industrial Boilers	7
NY	ROSETON GENERATING STATION	EGU	4
NY	SAMUEL A CARLSON GENERATING STATION	EGU	2
NY	SCHENECTADY INTERNATIONAL ROTT JCT FAC	Chemical Plant/Industrial Boilers	18
NY	ST LAWRENCE CEMENT CORP-CATSKILL QUARRY	Portland Cement	37
NY	WASHINGTON MILLS ELECTRO MINERALS	Glass Fiber Processing Plants	3
PA	ALLEGHENY_LUDLUM_CORP_BRACKENRIDGE	EGU	8
PA	EASTMAN_CHEMICAL_RESINS_INC	Chemical Process Plants/Industrial Boilers	2
PA	ESSROC/BESSEMER	Portland Cement	14

PA	NEVILLE_CHEMICAL_COMPANY	Chemical Process Plants	5
PA	ORION_POWER_MIDWEST_CHESWICK_STATION	EGU	2
PA	USS_CLAIRTON_WORKS	Metal Production/Industrial Boilers	4
PA	AK STEEL CORP BUTLER WORKS	Iron and Steel Mill Plants	16
PA	ALLEGHENY ENERGY SUPPLY CO HATFIELDS FER	EGU	5
PA	ALLEGHENY ENERGY SUPPLY CO MITCHELL POWE	EGU	19
PA	AMER REF GROUP BRADFORD	Petroleum Refinery	4
PA	APPLETON PAPERS SPRING MILL	Kraft Pulp Mill/Industrial Boilers	9
PA	CARMEUSE LIME INC MILLARD LIME PLT	Lime Plant	8
PA	CEMEX INC WAMPUM CEMENT PLT	Portland Cement	9
PA	CONOCOPHILLIPS CO TRAINER REF	Petroleum Refinery	10
PA	DUFERCO FARRELL CORP FARRELL PLT	Iron and Steel Mill Plants	1
PA	DYNO NOBEL INC DONORA	Chemical Process Plants	9
PA	ESSROC NAZARETH LOWER CEMENT PLT 1	Portland Cement	1
PA	EXELON GENERATION CO EDDYSTONE	EGU	6
PA	EXIDE TECH READING SMELTER	Secondary Metal Production	9
PA	HOMER CITY OL HOMER CITY GEN STA	EGU	6
PA	HORSEHEAD CORP MONACA SMELTER	Primary Zinc Smelter	25
PA	INDSPEC CHEM CORP PETROLIA	Chemical Process Plants	17
PA	INMETCO ELLWOOD CITY	Iron and Steel Mill Plants	6
PA	ISG PLATE LLC COATESVILLE	Iron and Steel Mill Plants	20
PA	KEYSTONE PORTLAND CEMENT EAST ALLEN	Portland Cement	4
PA	LAFARGE CORP WHITEHALL PLT	Portland Cement	28
PA	LEHIGH CEMENT CO EVANSVILLE CEMENT PLT	Portland Cement	42
PA	LEHIGH CEMENT CO YORK OPERATIONS	Portland Cement	11
PA	LWB REFRACTORIES CO W MANCHESTER	Mineral Products	13
PA	MERCER LIME & STONE BRANCHTON	Lime Plant	6
PA	NEW CASTLE POWER PLT	EGU	2
PA	PA POWER CO BRUCE MANSFIELD PLT	EGU	18
PA	PH GLATFELTER CO SPRING GROVE	Paper and Pulp/Industrial Boilers	8
PA	PPL BRUNNER ISLAND L BRUNNER ISLAND	EGU	4
PA	PPL MARTINS CREEK LLC MARTINS CREEK	EGU	2
PA	PPL MONTOUR LLC MONTOUR SES	EGU	4
PA	RELIANT ENERGY NORTHEAST CONEMAUGH PLT	EGU	6
PA	RELIANT ENERGY NORTHEAST MGMT KEYSTONE POWER PLT	EGU	2
PA	RELIANT ENERGY PORTLAND GENERATING STATION	EGU	2
PA	SUNOCO CHEMICALS (FORMER ALLIED SIGNAL)	Chemical Process	17

		Plants	
PA	SUNOCO INC (R&M) MARCUS HOOK REFINERY	Refinery	10
PA	SUNOCO INC (R&M)	Refinery	26
PA	TRIGEN - EDISON	EGU	4
PA	TRIGEN - SCHUYLKILL	EGU	1
PA	UNITED REFINING CO WARREN PLT	Refinery	10
PA	VICTAULIC CO AMER FORKS FACILITY	Secondary Metal Production	12

Appendix B: Costs of Technologies

From NESCAUM, 2005.

EGU **Cost Effectiveness**

Pollutant	*Control*	*Cost*	*Units*	*Cost Bin*
SO2	Wet/Dry Scrubbers (FGD)	200-500	Dollars per ton SO2	Low
NOx	Gas Reburn	500-2000	Dollars per ton NOx	Mid
NOx	Low-NOx Burners	200-500	Dollars per ton NOx	Low
NOx	Overfire Air	250-600	Dollars per ton NOx	Low
NOx	SCR	1000-1500	Dollars per ton NOx	Mid
NOx	SNCR	500-700	Dollars per ton NOx	Mid
PM	ESP	15-40	Dollars per Actual Cubic Feet per Minute	
PM	Fabric Filters	12-40	Dollars per Actual Cubic Feet per Minute	

Industrial Boilers **Cost Effectiveness**

Pollutant	*Control*	*Cost*	*Units*	*Cost Bin*
NOx	Low NOx-Burners	200-3000	Dollars per ton NOx	Mid
NOx	SNCR	1300-10000	Dollars per ton NOx	Mid to High
NOx	SCR	4000-15000	dollars per MMBtu/hr	High
SO2	Wet/Dry Scrubbers	400-4000	Dollars per ton SO2 (coal)	Mid
SO2	Wet/Dry Scrubbers	800-8000	Dollars per ton SO2 (oil)	Mid to High
PM	ESP	15-40	Dollars per Actual Cubic Feet per Minute	
PM	Reverse Air Fabric Filter	15-40	Dollars per Actual Cubic Feet per Minute	
PM	Pule Jet Fabric Filter	17-40	Dollars per Actual Cubic Feet per Minute	
PM	Venturi Scrubber	12-40	Dollars per Actual Cubic Feet per Minute	
PM	Cyclone	1-5	Dollars per Actual Cubic Feet per Minute	

Portland Cement Kilns **Cost Effectiveness**

Pollutant	*Control*	*Cost*	*Units*	*Cost Bin*
SO2	Spray Dryer	10.96-54.67	dollars/ton Clinker	
SO2	Wet Scrubber	10.83-47.00	dollars/ton Clinker	
NOx	Process Modifications	3100-8800	Dollars per ton NOx	Mid to High
NOx	Low NOx Burners w/Indirect Firing	5800-8100	Dollars per ton NOx	High
NOx	Low NOx Burners w/Indirect Firing and Mid-Kiln Tire Injection	1-1800	Dollars per ton NOx	Low to Mid
NOx	Mid-Kiln Injection of Fuel	5100-11500	Dollars per ton NOx	Mid to High
NOx	CemStar	0-600	Dollars per ton NOx	Low
NOx	Low NOx Precalciner	2700-3600	Dollars per ton NOx	Mid
NOx	SNCR	900-1200	Dollars per ton NOx	Mid
NOx	Biosolids Injection	100-1800	Dollars per ton NOx	Low to Mid
PM	ESP	3.33-41.00	dollars/ton clinker	
PM	Baghouse	4.00-16.67	dollars/ton clinker	

Paper and Pulp

Cost Effectiveness Not Available

Cost levels	*SO2*	*NOx*
Low	<800	<500
Mid	800-2000	500-10000
High	>2000	>10000

Appendix C: BART Workgroup Draft Recommendations

Draft BART Recommendations
to MANE-VU Air Directors
September 7, 2006

Under the U.S. Environmental Protection Agency's (USEPA) 1999 "regional haze rule" [64 Fed. Reg. 35714 (July 1, 1999)], certain emission sources that "may reasonably be anticipated to cause or contribute" to visibility impairment in downwind Class I areas are required to install Best Available Retrofit Technology (BART).[6] These requirements are intended to reduce emissions specifically from large sources that, due to age, were exempted from other control requirements of the Clean Air Act (CAA).

BART requirements pertain to 26 specified major point source categories, including power plants, industrial boilers, paper and pulp plants, cement kilns and other large stationary sources. To be considered BART-eligible, sources from these specified categories must have the potential to emit at least 250 tons per year of any haze forming pollutant and must have commenced operation in the fifteen year period prior to August 7, 1977 (the date of passage of the 1977 Clean Air Act Amendments (CAAA), which first required new source performance standards).

MANE-VU formed the BART workgroup as part of an effort to assist states and tribes as they prepare to comply with the Best Available Retrofit Technology Requirements (BART) of the Regional Haze Rule. To date states have made substantial progress in identifying sources that are BART-eligible, however that is only the first step in the process. Once a source is identified as "BART eligible", an analysis must be conducted to determine what will constitute BART control levels. The Haze Rule requires states to determine the most stringent technologically feasible system of controls that can reasonably be installed at each source eligible for BART. The BART workgroup has developed a list of draft recommendations for the BART control process that will be submitted to the MANE-VU Directors. Feedback on these recommendations will be useful to assist the Air Directors in their review. The recommendations include overall BART policies and specific "presumptive" levels and types of control. These recommendations will serve as a regional foundation for conducting BART engineering reviews on a state-by-state basis. The workgroup recommendations are presented below:

1. ***Any BART-eligible facility may "cap-out" of BART via a permit emission limit, however all permit modifications must be finalized prior to December 16, 2006* in order to eliminate BART-eligibility.*** Caps must limit emissions from BART eligible units below 250 tons per year of any visibility impairing pollutant

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[6] There are seven designated Class I areas in the Northeast and Mid-Atlantic States. They include Acadia National Park and Moosehorn Wilderness Area in Maine; Roosevelt-Campobello International Park in New Brunswick and Maine; the Lye Brook Wilderness Area in Vermont; the Great Gulf and Presidential Range-Dry River Wilderness Areas in New Hampshire; and the Brigantine Wilderness Area in New Jersey.

* It is not clear from the final rule when a federally enforceable permit limitation would need to be in place in order to avoid BART-eligibility. We are recommending to EPA that they allow permit limits which go into place prior to December 16, 2006. This will enable states to take action to get permit limitations in place and achieve emission limits (though probably not reductions) prior to SIP submission avoiding the need for formal BART determinations. The 2006 date will give states one full year prior to the submission deadline for public notice and hearing processes on a final SIP package.

2. MANE-VU staff continues to support the policy decision made by the MANE-VU Board in June 2004, that ***if a source is eligible for BART, it is subject to BART***. (i.e. no exemptions will be given).

3. ***Regional performance standards or cost thresholds are appropriate*** for many individual categories of BART eligible sources. The attachment contains an initial round of recommended presumptive levels of control for EGUs, industrial boilers and cement kilns. The workgroup may develop additional presumptive levels in the future.

4. ***Remaining useful life*** of a source will be considered in the following way: Sources have the option to ***either control a BART-eligible facility prior to 2013 or accept federally enforceable permit limitation or retirement date prior to December 16, 2006.***

5. ***Control technology in place*** (other than for source categories covered by the attached list of presumptive control levels) ***will likely have to be dealt with on a source by source basis***. (i.e. no regional recommendation)

6. ***Energy and non-air quality environmental impacts will likely have to be dealt with on a source by source basis***. (i.e. no regional recommendation) however the workgroup is still considering regional recommendations for non-air quality environmental impacts.

7. ***If data does not exist*** to accurately determine the installation date for emission unit(s)within a facility ***then the unit will be treated as though it IS within the BART date range unless the facility can provide proof otherwise (i.e., proof that the unit was in operation prior to 1962)***. Many states are having difficulty identifying installation dates for pre-1977 units. All states felt they could easily identify post-1977 units. Therefore, the workgroup supported a policy position that when the state could not accurately determine the "in existence" date, the burden of proof lay with the facility in proving that the unit was installed prior to 1962.

MANE-VU BART Workgroup Recommendations
DRAFT Presumptive Control Levels
Updated September 7, 2006

Non-CAIR EGUs:

- SO_2 – Coal - 95% control or 0.15 lb/MMBtu*
  Oil - 95% control or 0.33 lb/MMBtu (0.3% sulfur content)*
- NO_X
    - in NO_X SIP call area, extend use of controls to year-round
    - 0.1 – 0.25 lb/MMBtu, depending on boiler and fuel type
- PM – 0.02 – 0.04 lb/MMBtu**

CAIR EGUs:

- SO_2 – CAIR requirements
- NO_X – CAIR requirements
- PM – 0.02- 0.04 lb/MMBtu**

If an EGU is only enrolled in CAIR for one or two pollutants, it still must complete an analysis for the remaining visibility impairing pollutants such as particulate matter.

Industrial Boilers

- SO_2 – 90% control, MACT acid gas control level, ICI-RACT, or 0.55 lb/MMBtu (0.5% fuel sulfur limit)
- NO_X
    - 0.1 – 0.4 lb/MMBtu, depending on boiler and fuel type***
- PM – 0.02 - 0.07 lb/MMBtu

Cement Kilns

No common emission threshold has been identified. The following lists, however, recommend control technologies to evaluate.

- SO_2
    - in process removal
    - wet or dry scrubbers
    - conversion from wet kiln to dry kiln
- NO_X
    - Combustion optimization
    - Low NO_X burners
    - Secondary combustion control (SNCR/SCR)
    - Mid-Kiln firing
    - Flame shape adjustment
- PM
    - baghouse
    - electrostatic precipitator
    - baghouse/ESP upgrades of existing controls

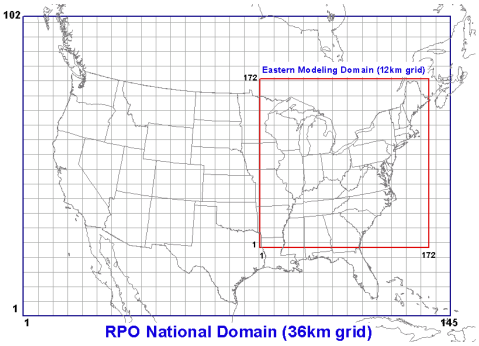
*Consistent with EPA presumptive BART for EGUs and OTC Control Strategy

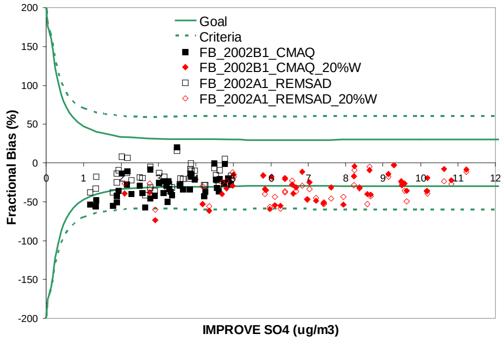
** PM measures are based on front-half (Method 5) particulate matter measures

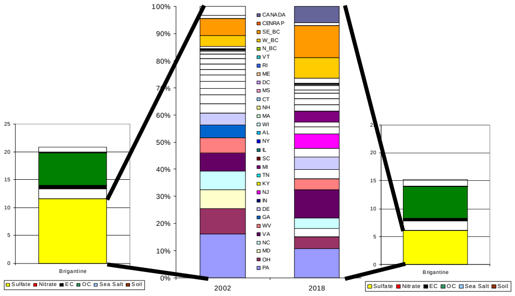
*** Consistent with OTC Control Strategies and NO_X SIP call emission limits

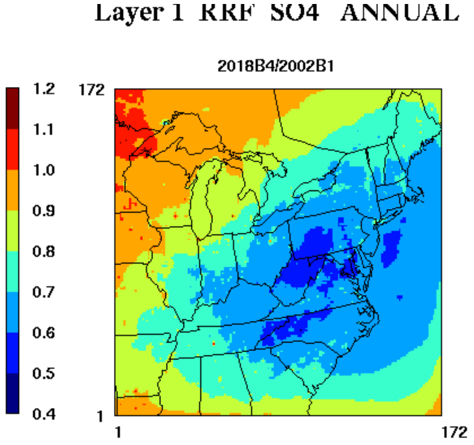
MANE-VU Modeling for Reasonable Progress Goals

Model performance evaluation, pollution apportionment, and control measure benefits









Prepared by
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Mid-Atlantic/Northeast Visibility Union Regional Planning Organization

February 7, 2008

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MANE-VU Modeling for Reasonable Progress Goals

Model performance evaluation, pollution apportionment, and control measure benefits

Prepared by
NESCAUM
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February 7, 2008

MANE-VU MODELING FOR REASONABLE PROGRESS GOALS

MODEL PERFORMANCE EVALUATION, POLLUTION APPORTIONMENT, AND CONTROL MEASURE BENEFITS

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Executive Summary

The main purpose of this report is to assist states in developing effective solutions to regional visibility and fine particle problems and comply with requirements under the Regional Haze Rule. NESCAUM has utilized in-house air quality modeling capabilities that include emission processing, meteorological input analysis, and chemical transport modeling to conduct regional air quality simulations for calendar year 2002 and several future periods. This work has been directed at satisfying a number of compliance goals under the Haze State Implementation Plan (SIP), including a contribution assessment, a pollution apportionment for 2018, and the evaluation of visibility benefits of control measures being considered for achieving reasonable progress goals and establishing a long-term emissions management strategy for MANE-VU Class I areas.

The modeling tools utilized for these analyses include MM5, SMOKE, CMAQ and REMSAD, and incorporate tagging features that allow for the tracking of individual source regions or measures. These tools have been evaluated and found to perform adequately relative to USEPA modeling guidance.

Results show that sulfate aerosol – the dominant contributor to visibility impairment in the Northeast’s Class I areas on the 20 percent worst visibility days – has significant contributions from states throughout the eastern U.S. that are projected to continue in future years from all three of the eastern regional planning organizations (RPOs).

An assessment of potential control measures that would address this future contribution has identified a number of promising strategies that would yield significant visibility benefits beyond the uniform rate of progress and, in fact, significantly beyond the projected visibility conditions that would result from “on the books/on the way” air quality protection programs. These “beyond on the way” measures include the adoption of low sulfur heating oil, implementation of Best Available Retrofit Technology (BART) requirements, and additional electric generating unit (EGU) controls on select sources. The combined benefits of adopting all of these programs could lead to an additional benefit of between 0.38 and 1.1 deciviews at MANE-VU Class I areas on the 20 percent worst visibility days by 2018.

1. INTRODUCTION

1.1. Background

This report presents information intended to assist states in developing effective solutions to regional visibility and fine particle problems and comply with requirements under the 1999 U.S. Environmental Protection Agency (USEPA) "Regional Haze Rule" [64 Fed. Reg. 35714 (July 1, 1999)]. NESCAUM has utilized in-house air quality modeling capabilities that include emission processing, meteorological input analysis, and chemical transport modeling to conduct regional air quality simulations for calendar year 2002 and several future periods.

This work has been directed at satisfying a number of compliance goals under the Haze State Implementation Plans (SIPs), including a contribution assessment (*see* NESCAUM, 2006a), a pollution apportionment for 2018, and the evaluation of benefits of control measures being considered for achieving reasonable progress establishing a long-term emissions management strategy for MANE-VU Class I areas.[1] NESCAUM has employed several tools to achieve all of these goals, but the primary tool described and detailed here consists of a regional air quality modeling platform using meteorological fields developed by the University of Maryland using the MM5 platform (Penn State, 2007), emission inventories developed by MANE-VU (MARAMA, 2007a) and processed through the SMOKE emissions processing tool (SMOKE, 2007), and air quality simulations conducted jointly by multiple modeling centers utilizing USEPA's Community Multi-scale Air Quality (CMAQ) model (Byun and Ching, 1999). Sulfate apportionment was also carried out using the REMSAD model (SAI, 2005) with SO_2 tagging capabilities and control strategy evaluation was conducted utilizing a beta version of CMAQ-PPTM (ICF, 2006).

This report describes these efforts that form the foundation upon which MANE-VU states will base their haze SIP submissions. After the MANE-VU RPO considers the results provided here and consults with neighboring states and federal land managers, we anticipate that a final model simulation will be conducted to serve as a basis for calculating final reasonable progress goals.

This introduction provides a basic description of the modeling platform and the input data that we used for regional air quality simulations. Chapter 2 provides a model performance evaluation for both the meteorological input data as well as the chemical transport model for the base year 2002. Chapters 3 through 5 present results from 2018 simulations with respect to the projected "beyond on the way" scenario that we take as a starting point for the haze program, pollution apportionment for 2018, and haze control strategy evaluation.

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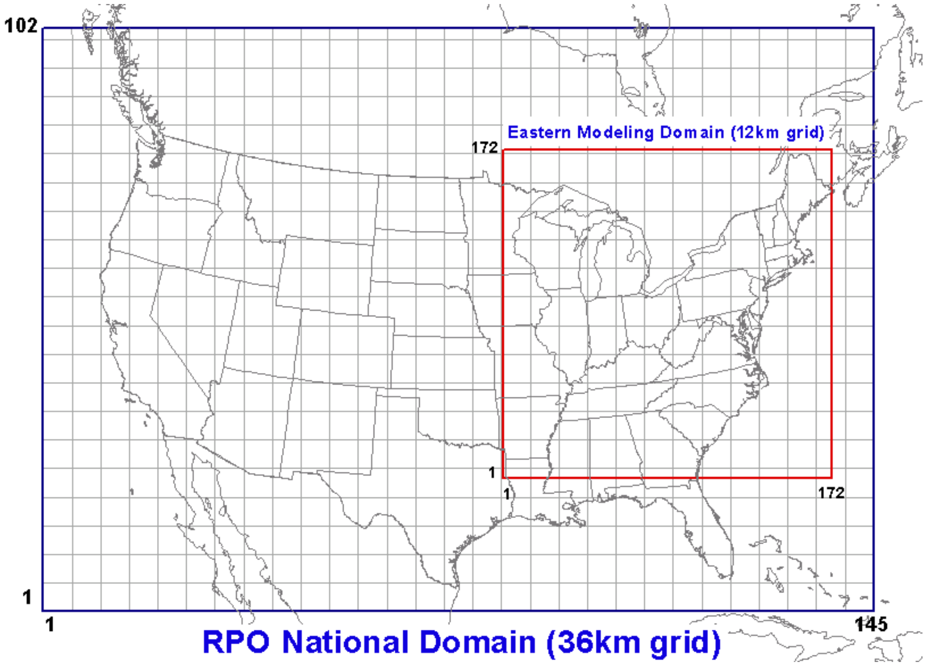
[1] There are seven designated Class I areas in the Northeast and Mid-Atlantic States. They include Acadia National Park and Moosehorn Wilderness Area in Maine; Roosevelt Campobello International Park in New Brunswick and Maine; the Lye Brook Wilderness Area in Vermont; the Great Gulf and Presidential Range-Dry River Wilderness Areas in New Hampshire; and the Brigantine Wilderness Area in New Jersey.

1.2. Meteorology

Professor Dalin Zhang's group from University of Maryland (UMD) provided the 2002 annual meteorological field for air quality modeling. Meteorological inputs for CMAQ are derived from the Fifth-Generation Pennsylvania State University/National Center for Atmospheric Research (NCAR) Mesoscale Model (MM5)[2] system meteorological fields. MM5 is a model with limited-area primitive equations of momentum, thermodynamics, and moisture with the option of hydrostatic and non-hydrostatic physics. It is designed to simulate mesoscale atmospheric circulation. Domains are uniform rectangular grids representing three-dimensional regions of the atmosphere.

MANE-VU has adopted the Inter-RPO domain description for its modeling runs.[3] This 36-km domain covers the continental United States, southern Canada and northern Mexico. The dimensions of this domain are 145 and 102 cells in the east-west and north-south directions, respectively. A 12-km inner domain was selected to better characterize air quality in MANE-VU and surrounding RPO regions. This domain covers the eastern region, which includes the northeastern, central, and southeastern U.S., as well as southeastern Canada. It extends from 66°W~94°W in longitude and 29°N~50°N in latitude with 172 × 172 grid cells (Figure 1-1).

Figure 1-1. Modeling domains used in MANE-VU air quality modeling studies with CMAQ. Outer (blue) domain grid is 36 km and inner (red) domain is 12 km grid. The gridlines are shown at 180 km intervals (5 × 5 36 km cells/15 × 15 12 km cells).



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[2] http://www.mmm.ucar.edu/mm5/

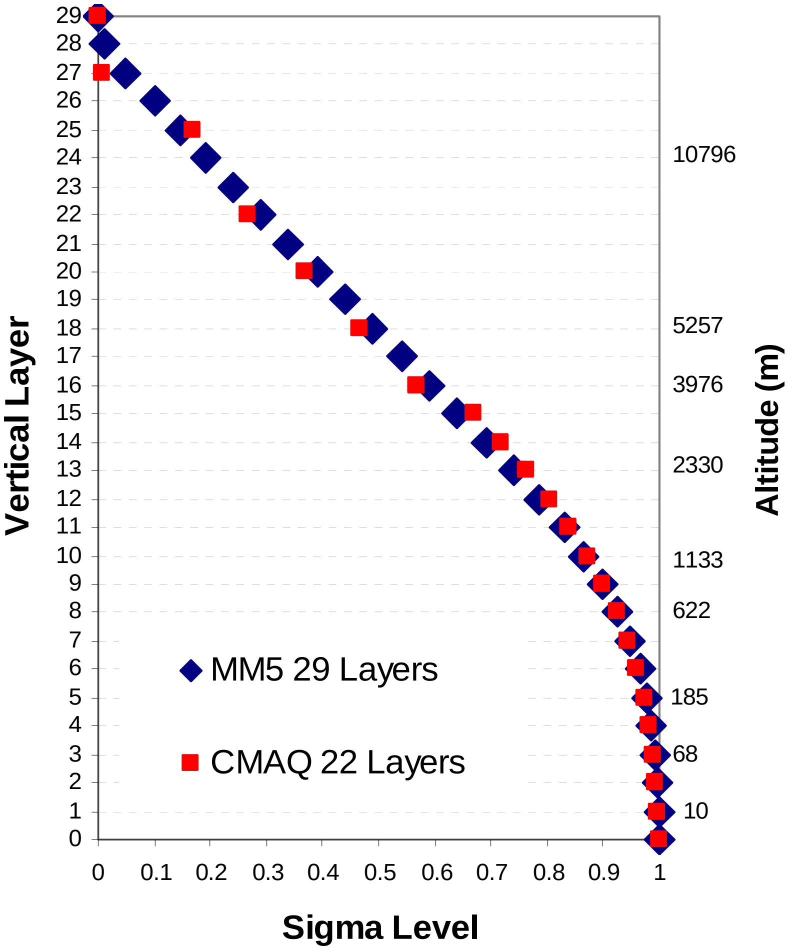
[3] The modeling system for 2002 annual simulation is applied with a Lambert Conformal Conic projection with parallels at 33N and 45N. A spherical earth radius of 6370km is used for all elements of the system (MM5/SMOKE/CMAQ).

The UMD MM5 model runs are made on these two nested domains with the inner (12 km) domain using finer resolution terrain data. Initially, we conducted a set of test runs for the period of August 6 to 16, 2002.

The horizontal coordinated system is equally spaced geographically and uses the Arakawa-B gridding scheme. The resolution can be as high as 1 km. Sigma (σ) is a terrain-following vertical coordinate that is a function of pressure at the point (for hydrostatic) or reference (non-hydrostatic) state pressure (P), the surface pressure (P_{s0}), and the pressure at the top (P_{top}) of the model; $\sigma = (P-P_{top}) / (P_{s0}-P_{top})$. The model utilizes a terrain-following sigma coordinate with 29 layers. The first level is at 10 m and a radiative upper-boundary condition is at 50 hPa (Figure 1-2).

Based on test run results, the boundary layer processes were determined using the Blackadar high-resolution planetary boundary layer parameterization. Physics options also included explicit representations of cloud physics with simple ice microphysics (no mixed-phase processes) and the Kain-Fritsch cumulus parameterization. UMD ran the non-hydrostatic MM5 v3.5.3 with three planetary boundary layer (PBL) schemes; (1) modified Blackadar [BL], (2) the Pleim-Xiu scheme with the soil module [P-X], and (3) modified Blackadar with soil module [SSIB].The model was initialized with the analyses of the National Center for Environmental Prediction (Eta Model). TDL data are used for MM5 nudging. A modeled wind field map (Figure 1-3) shows typical prevailing mesoscale flows from the midwest U.S. to the East Coast.

Figure 1-2. Vertical Structure of Meteorological and Air Quality Modeling Domains



The simulated meteorological fields were compared to the measurements from Techniques Development Laboratory of National Weather Service (TDL NWS) and Clean Air Status and Trends Network (CASTNET). The TDL data are reflective of urban/suburban settings, while the CASTNET sites are more representative of rural areas. There are 48 CASTNET sites and about 800 TDL sites within Domain 2 (as shown in Figure 1-4). Overall, the BL scheme shows a better correspondence to the measured data than the other two schemes, although it poorly captures the diurnal pattern of humidity. While the P-X scheme shows a better correspondence with the observed diurnal pattern for humidity, it fails to perform well for wind speed and temperature (Hao et al., 2004).

Figure 1-3. MM5 modeled wind field map at 12:00 UTC on August 8, 2002

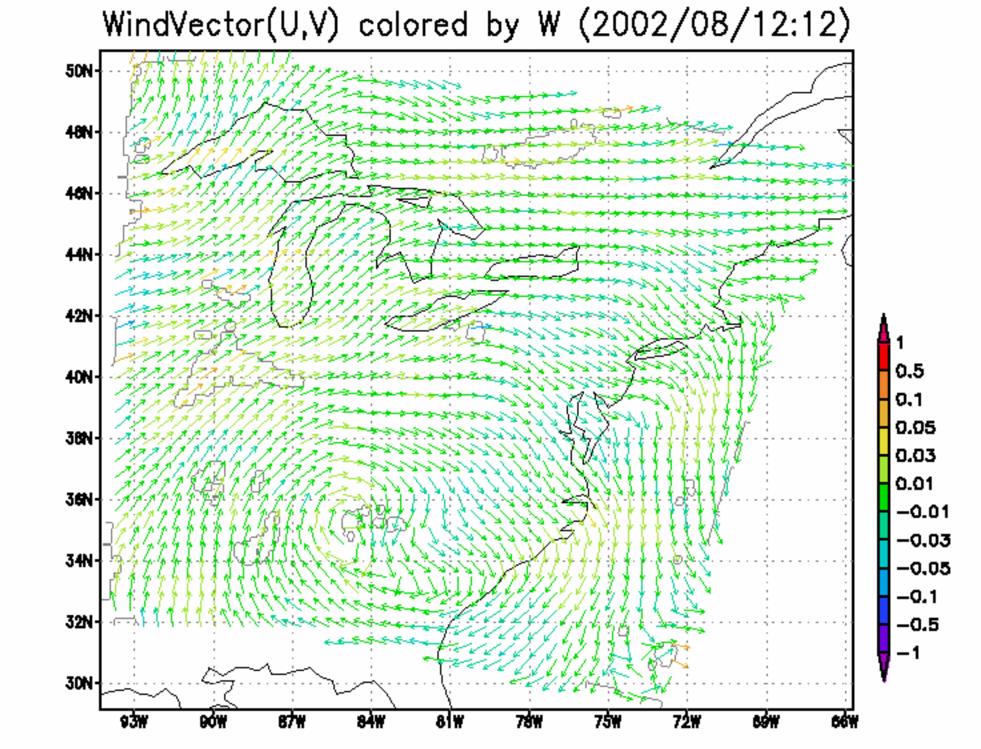
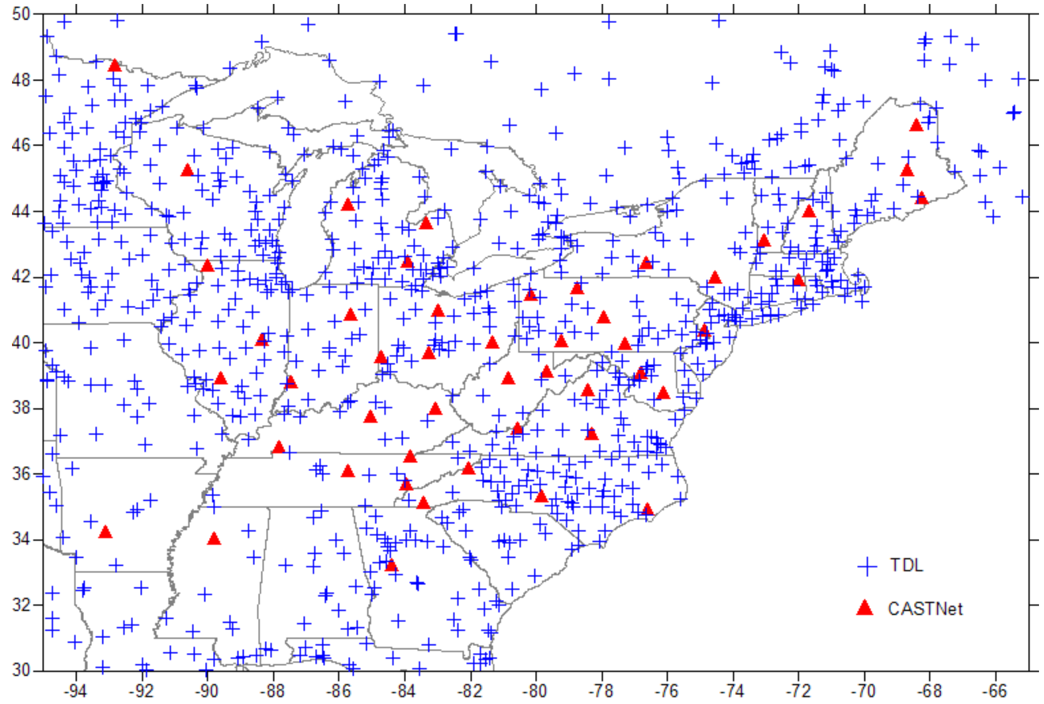


Figure 1-4. Observation Network sites within 12km resolution domain



1.3. Emissions Preparations

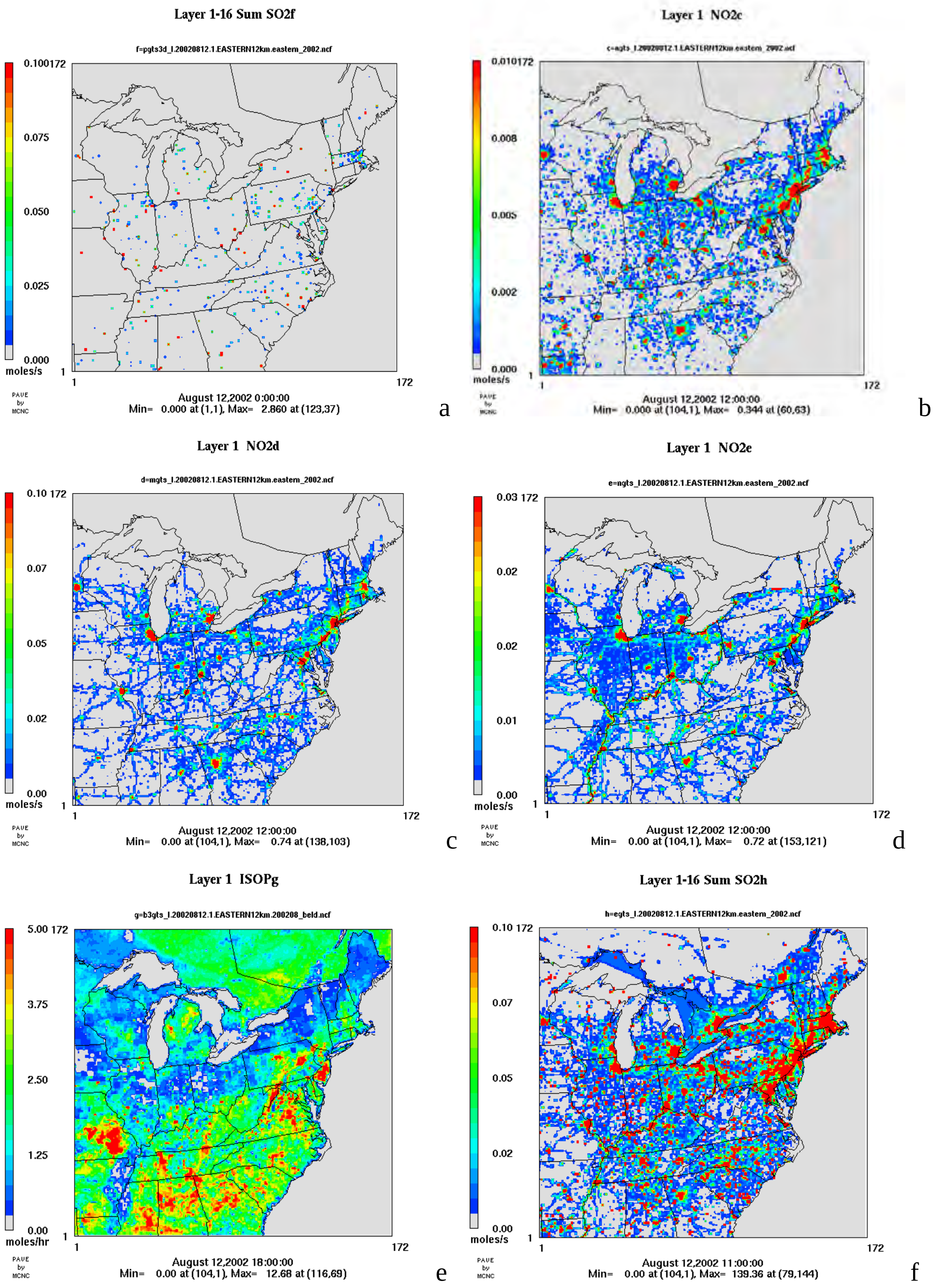
We simulated emission scenarios using the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System. SMOKE is primarily an emissions processing system designed to create gridded, speciated, hourly emissions for input into a variety of air quality models, such as CMAQ and REMSAD. SMOKE supports area, biogenic, mobile (both onroad and nonroad), and point source emissions processing for criteria, particulate, and toxic pollutants. For biogenic emissions modeling, SMOKE uses the Biogenic Emission Inventory System, version 2.3 (BEIS2) and version 3.09 and 3.12 (BEIS3). SMOKE is also integrated with the onroad emissions model MOBILE6.

The sparse matrix approach used throughout SMOKE permits rapid and flexible processing of emissions data. Flexible processing comes from splitting the processing steps of inventory growth, controls, chemical speciation, temporal allocation, and spatial allocation into independent steps whenever possible. The results from these steps are merged together in the final stage of processing using vector-matrix multiplication. It allows individual steps (such as adding a new control strategy, or processing for a different grid) to be performed and merged without having to redo all of the other processing steps (http://cf.unc.edu/cep/empd/products/smoke/version2.1/html/).

The emission processing for CMAQ for the 36 km national domain and 12 km eastern domain (Domain 2) has been performed by the New York State Department of Environmental Conservation (NYS DEC) (for base year 2002 and future year 2009) and by NESCAUM (for future year 2018) using SMOKE v2.1 compiled on a Red Hat 9.0 Linux operating system with the Portland Group Fortran compiler version 5.1. They use the 2002 static emission inventory, CEM data, and surrogates data based on the 2002 RPO data. Biogenic emissions are calculated using BEIS3 with BELD3 data. Mobile source emissions are processed using MOBILE6. An updated 2000 inventory for Canada and a 1999 inventory for Mexico inventory were used for processing.

The emissions processing was performed on a month-by-month and RPO-by-RPO basis, i.e., SMOKE processing was performed for each of the RPOs (MANE-VU, VISTAS, CENRAP, MRPO, WRAP) individually as well as for Canada and Mexico. Note the processing of WRAP and Mexican emissions was necessary for use with the 36 km grid modeling only. For each month/RPO combination, a separate SMOKE ASSIGNS file was created, and the length of the episode in each of these ASSIGNS files was set to the entire month. Specific data sources for individual source categories are listed below and the examples of processed emissions outputs are shown in Figure 1-5.

Figure 1-5. Examples of processed model-ready emissions: (a) SO_2 from Point; (b) NO_2 from Area; (c) NO_2 from Onroad; (d) NO_2 from Nonroad; (e) ISOP from Biogenic; (f) SO_2 from all source categories



1.3.1. Emissions Processing Files

The profile and cross reference files listed below are held constant for all modeling years unless stated otherwise.

Temporal Allocation

MANE-VU:

Area and Nonroad sources:
amptpro.m3.us+can.manevu.030205.txt and amptref.m3.manevu.012405.txt
Mobile source: MANEVU_2002_mtpro_02022006_addCT.txt
MANEVU_2002_mtref_02022006_addCT.txt
Point sources: Based on the same files as for the MANE-VU area and nonroad temporal files listed above, but added the VISTAS-generated CEM-based 2002 state-specific temporal profiles and cross-references for EGU sources for the MANE-VU states. No CEM, hour-specific, EGU emissions were used.

CENRAP:

The following temporal profiles and cross-reference files were used for all source categories: amptpro.m3.us_can.cenrap.010605.txt, amptref.m3.cenrap.010605.txt
These files were downloaded from the CENRAP website www.cenrap.org/emission_document.asp
For point sources, the CEM-based hour-specific EGU emissions described in Section 2.2.4 were utilized to override the annual-total based emissions whenever a match could be established by SMOKE

VISTAS, WRAP and MRPO:

The following month-specific temporal profiles and cross-reference files were used for all source categories:
amptpro_typ_us_can_{MMM}_vistas_27nov04.txt where {MMM} is jan, feb, mar, etc., amptref_2002_us_can_vistas_17dec04.txt
These files were obtained from Greg Stella (Alpine Geophysics)
For point sources (EGU and fires), the hour-specific emission files described in Sections 2.3.4 and 2.5.4 were utilized for the VISTAS and WRAP states to override the annual-total based emissions whenever a match could be established by SMOKE

Canada and Mexico:

The SMOKE2.1 default temporal profiles and cross-reference files (amptpro.m3.us+can.txt and amptref.m3.us+can.txt) were utilized.

Chemical speciation

The same speciation profiles (gspro.cmaq.cb4p25.txt) and cross-references (gsref.cmaq.cb4p25.txt) were utilized for all regions and all source categories. Different versions of these files were obtained (SMOKE2.1 default, USEPA-CAIR modeling, VISTAS, CENRAP and MANE-VU) and compared. After comparing the creation dates and header lines of these files, it was determined that the USEPA-CAIR and MANE-VU files had the most recent updates, and consequently the final speciation profile and cross-reference files used for all regions and source categories was based on the USEPA-CAIR files with the addition of MANE-VU specific updates.

Spatial Allocation

U.S.

The spatial surrogates for the 12 km and 36 km domains were extracted from the national grid 12 km and 36 km U.S. gridding surrogates posted at USEPA’s website at www.epa.gov/ttn/chief/emch/spatial/newsurrogate.html. The gridding cross-references were also obtained from this website, but for the processing of MANE-VU area source emissions, MANE-VU specific cross-reference entries posted on the MARAMA ftp site were added.

Canada

The spatial surrogates for Canadian emissions for the 12 km and 36 km domains were extracted from the national grid 12 km and 36 km Canadian gridding surrogates posted at USEPA’s website at www.epa.gov/ttn/chief/emch/spatial/newsurrogate.html.
The gridding cross-references were also obtained from this website.

Mexico

The spatial surrogates for Mexican emissions the 36 km domain were extracted from the national 36 km gridding surrogates used by USEPA in the CAIR modeling. These files were obtained from USEPA’s CAIR NODA ftp site www.airmodelingftp.com. The gridding cross-references were also obtained from this ftp site.

1.3.2. 2002 Emission Inventory

A 2002 base year emission inventory was developed to assess model performance and to serve as a point of comparison for future year projections in terms of emissions reductions and air quality improvement. In order to assess model performance, actual 2002 emissions (to the extent possible) are incorporated into the inventory and simulated in CMAQ in order to compare with observations. In addition, 2002 simulated values are compared to 2009 or 2018 projections with various emission reductions incorporated to see what degree of air quality improvement can be expected as a result of those reductions.

CANADA:

All source categories except that of point sources where were obtained from USEPA's ftp site ftp.epa.gov/EmisInventory/canada_2000inventory.

No county/province-specific correction factors were available for Canada. Hence, a "divide-by-four" correction for Source Classification Codes (SCCs) listed at www.epa.gov/ttn/chief/emch/invent/index.html#dust were adjusted with FORTRAN prior to running SMOKE.

Area
AS2000_SMOKEready.txt
Nonroad
NONROAD2000_SMOKEready.txt
Onroad
MOBILE2000_SMOKEready.txt
Point

There has long been difficulty in obtaining an up-to-date Canadian criteria emissions inventory for point sources. This is due largely to confidentiality rights afforded to Canadian facilities. Thus far, the most recent inventory of Canadian point sources is rooted in the 1985 NAPAP data. Toward this end, an effort was made to obtain more recent Canadian point source data and incorporate it into an inventory database.

Perhaps the most accurate and publicly accessible source of Canadian pollutant data is now available from the National Pollutant Release Inventory (NPRI) database. The NPRI data are available at Environment Canada's website, www.ec.gc.ca/pdb/npri/npri_home_e.cfm. The page hosts a database available for download as an MS Access or Excel file. The database contains a rather comprehensive list of information. Detailed information is available about each facility, including location, activity and annual emissions. In addition, facilities having stacks with a height of 50 meters or more are required to report stack parameters.

Unfortunately, one of the limitations of the NPRI database for modeling purposes is that the data are only available at the facility level, so in order to use this data, a few generalizations had to be made. Each facility has a Standard Industrial Classification (SIC) code associated with it; however, emissions models require SCCs. While no direct relationship exists between these two codes, a general albeit subjective association can be made, since SCCs are needed for SMOKE. In most cases, only a SCC3 level code was assigned with confidence.

CENRAP:

All CENRAP BaseB files were downloaded from its ftp site ftp.cenrap.org.

County-specific correction factors were applied to take into account fugitive dust for SCCs listed at: www.epa.gov/ttn/chief/emch/invent/index.html#dust; the correction factor file gcntl.xportfrac.txt was obtained from USEPA's CAIR NODA ftp site http://www.airmodelingftp.com (password protected); this adjustment was performed using the SMOKE programs cntlmat and grwinven to generate an adjusted IDA inventory file used for subsequent SMOKE processing for "other area" and point sources.

Where data sets are month dependant, {MMM} represents JAN, FEB, MAR, etc. Note that for both area and nonroad sources, the annual and monthly inventories were processed in one step. Processed with SMK_AVEDAY_YN set to N such that seasonal profiles were used to apportion the inventories into monthly values.

Area

CENRAP_AREA_MISC_SMOKE_INPUT_ANN_STATE_071905.txt
CENRAP_AREA_BURNING_SMOKE_INPUT_ANN_TX_NELI_071905.txt
CENRAP_AREA_MISC_SMOKE_INPUT_NH3_MONTH_{MMM}_072805.txt
CENRAP_AREA_SMOKE_INPUT_NH3_MONTH_{MMM}_071905.txt
CENRAP_AREA_SMOKE_INPUT_ANN_STATE_081705_xfact.txt
- "_xfact" is the adjusted version for fugitive dust as described above

Nonroad

CENRAP_NONROAD_SMOKE_INPUT_ANN_071305.txt
CENRAP_NONROAD_SMOKE_INPUT_MONTH_{MMM}_071305.txt

Onroad

M6-Input files + VMT - MOBILSMOKE_Inputs.zip (Mar06)
VMT/Speed files: mbinv02_vmt_cenrap_ce.ida, mbinv02_vmt_cenrap_no.ida, mbinv02_vmt_cenrap_so.ida, and mbinv02_vmt_cenrap_we.ida

Point

CENRAP_POINT_SMOKE_INPUT_ANNUAL_DAILY_072505_xfact.txt
- "_xfact" is the adjusted version for fugitive dust as described above

MANE-VU:

PECHAN prepared all of the MANE-VUv3.0 inventories for SMOKEv2.1 located at ftp://ftp.marama.org/2002 Version 3/ (username: mane-vu, password: exchange).

County-specific correction factors were applied to take into account fugitive dust for SCCs listed at: www.epa.gov/ttn/chief/emch/invent/index.html#dust; the correction factor file gcntl.xportfrac.txt was obtained from USEPA's CAIR NODA ftp site http://www.airmodelingftp.com (password protected); this adjustment was performed using the SMOKE programs cntlmat and grwinven to generate an adjusted IDA inventory file used for subsequent SMOKE processing for area and point sources.

Area
MANEVU_AREA_SMOKE_INPUT_ANNUAL_SUMMERDAY_040606.txt
MANEVU_AREA_SMOKE_INPUT_ANNUAL_WINTERDAY_040606.txt
Nonroad
MANEVU_NRD2002_SMOKE_030306.ida
Onroad
VMT/Speed: MANEVU_2002_mbinv_02022006_addCT.txt was prepared by PECHAN and NESCAUM; MANEVU_V3_update.tar can be downloaded from http://bronze.nescaum.org/Private/junghun/MANE-VU/onroad_ver3_update/
Point
MANEVU_Point_SMOKE_INPUT_ANNUAL_SUMMERDAY_041006.txt
MANEVU_Point_SMOKE_INPUT_ANNUAL_WINTERDAY_041006.txt

MRPO:

MARAMA contracted Alpine Geophysics to convert MRPO BaseK NIF formatted inventory to IDA, a SMOKE ready inventory format. Files can be found at ftp.alpinegeophysics.com – username: marama or on MARAMA's ftp site ftp.marama.org – username: mane-vu, password: exchange. Obtained by NESCAUM between April and June 2006.

County-specific correction factors were applied to take into account fugitive dust for SCCs listed at: www.epa.gov/ttn/chief/emch/invent/index.html#dust; the correction factor file gcntl.xportfrac.txt was obtained from USEPA's CAIR NODA ftp site http://www.airmodelingftp.com (password protected); this adjustment was performed using the SMOKE programs cntlmat and grwinven to generate an adjusted IDA inventory file used for subsequent SMOKE processing for "other area" and point sources.

Where data sets are month dependant, {MMM} represents jan, feb, mar, etc. and {MM} is 01, 02, 03, etc.

Area
Agricultural Ammonia - arinv_nh3_2002_mrpok_{MMM}_3may2006.txt
Wind Erosion Fug-Dust - dustinv_2002_mrpok_{MMM}_23may2006.txt
- The month-specific files were processed separately from the annual runs and SMK_AVEDAY_YN was set to Y so that no seasonal profiles would be applied and the inventory numbers in the 'average day' column would be used.

Other Area Sources - arinv_other_mrpok_2002_20jun2006_xfact.txt

- Adjusted for fugitive dust as described above
- SMK_AVEDAY_YN was set to N, so seasonal profiles were used to apportion the annual inventory numbers by month.
- To save SMOKE processing, the annual “marine” inventory was processed together with other area sources.

Nonroad

NMIM Generated Sources - nrinv_2002_mrpok_{MMM}_3may2006.txt
MAR (Marine/Air/Rail) - arinv_mar_mrpok_2002_27apr2006.txt

- MAR inventory was SMOKE processed with annual other area sources.

Onroad

M6-Input files & VMT – mobile_inventory_mrpobasek.tar.gz
M6-Ancillary – mobile_m6files_mrpobasek.tar.gz
VMT/Speed file: mbinv_mrpo_02f_vmt_02may06.txt

- VMT is based on VISTAS Phase II modeling which was verified and updated for MRPOs BaseK May 2006 provided by Greg Stella (Alpine Geophysics)

Point

EGU - ptinv_egu_2002_mrpok_1may2006.txt
Non-EGU - ptinv_negu_2002_mrpok_1may2006.txt

- Christian Hogrefe (NYSDEC) merged the two inventories and adjusted for fugitive dust, ptinv_egu_negu_2002_mrpok_1may2006_xfact.txt

VISTAS:

All VISTAS emission files were obtained from Greg Stella (Alpine Geophysics) via ftp.alpinegeophysics.com – username: vistasei They reflect version BaseG of the VISTAS inventory with the exception of fire emissions, which reflect BaseF for Lo-Fires and BaseD for Hi-Fires. Files were obtained between February and August, 2006.

The header lines of these files indicate that the fugitive dust correction was already applied, so no further correction was performed. Where data sets are month dependant, {MMM} represents jan, feb, mar, etc. and {MM} is 01, 02, 03, etc.

Area

arinv_vistas_2002g_2453922_w_pmfac.txt – Base G
ida_ar_fire_2002_vistaonly_basef.ida – Base F low fires

Nonroad

NMIM Generated Sources - nrinv_vistas_2002g_2453908.txt
MAR (Marine/Air/Rail) - marinv_vistas_2002g_2453908.txt

Onroad

M6-Input files – vistas_baseg02_m6_inputs_20Jul06.tar
VMT/Speed – mbinv_vistas_02g_vmt_12jun06.txt Base G generated by C. Loomis (Alpine Geophysics) July 2006 for VISTAS states

Point

Annual EGU - egu_ptinv_vistas_2002typ_baseg_2453909.txt

Annual Non-EGU - negu_ptinv_vistas_2002typ_baseg_2453909.txt
Hour-specific - pthour_2002typ_baseg_{MMM}_28jun2006.ems
Month Dependant Hi-Fire - ptinv_fires_{MM}_typ.vistas.ida (vr.BaseD)
Hour-specific plume-rise - pthour_fires_{MM}_typ.vistas.ida (vr.Jan05)

1.3.3. 2018 "On the Books/On the Way" (OTB/OTW) Emission Inventory

The emissions processing was conducted in a very similar manner for future projection years relative to the 2002 base year, but with the projected inventories. The future years "on the books/on the way" (OTB/OTW) emissions inventories account for emission control regulations already in place as well as emission control regulations that are final but have not yet been fully implemented and are likely to achieve additional reductions by 2009. Processing occurred during January of 2007.

CANADA:

All source categories except that of point sources were obtained from USEPA's ftp site ftp.epa.gov/EmisInventory/canada_2000inventory.

No county/province-specific correction factors were available for Canada. Hence, for Area, Onroad, and Nonroad, a "divide-by-four" correction for SCCs listed at www.epa.gov/ttn/chief/emch/invent/index.html#dust were adjusted with FORTRAN prior to running SMOKE.

Area
AS2020_SMOKEready.txt
Nonroad
NONROAD2020_SMOKEready.txt
Onroad
MOBILE2020_SMOKEready.txt
Point
Non-EGUs -- ptinv_canada_2002_negu.ida same as 2002 BaseB4
EGUs -- egu062idasum_cp.txt and egu062idawin_cp.txt
- U.S.-Canada 2020 Canadian Base Case -- Scenario #062
- Original IPM parsed file (based on NEEDS 2.1.6)
- Annualized emissions were calculated by combining summer and winter with FORTRAN to create and use ptinv_canada_2020_egu.ida

CENRAP

County-specific correction factors were applied to take into account fugitive dust for SCCs listed at: www.epa.gov/ttn/chief/emch/invent/index.html#dust; the correction factor file gcntl.xportfrac.txt was obtained from USEPA's CAIR NODA ftp site http://www.airmodelingftp.com (password protected); this adjustment was performed using the SMOKE programs cntlmat and grwinven to generate an adjusted IDA inventory file used for subsequent SMOKE processing.

Area

arinv_nodust_ref_cenrap2002-2018_081705.ida
fdinv.cnrap2002_2018_wfac.ida
nh3inv.annual.cenrap2002_2018.ida
nh3inv.cenrap2002_2018.ann.ida
nh3inv.misc_annual.cenrap2002_2018.ida
nh3inv.misc.cenrap2002_2018.ann.ida
rdinv.cnrap2002_2018.wfac.ida

- To save SMOKE processing, all area source inventories were processed with area sources from the MWRPO and VISTAS.

Nonroad

cenrap_2018_fnl_nrd_emissions091506.txt
nrinv_cenrap_2018_mod_w_mrpok_15sep2006.txt
nrinv_cenrap_2018_mod_w_mrpok_14sep2006.txt

- To save SMOKE processing, all nonroad source inventories were processed with nonroad sources from the MWRPO and VISTAS.
- "mod_w_mrpok" files include both MRPO and CENRAP sources

Onroad

M6List – BaseG_2018_mobile_m6.tar.gz or in the sub-directory input
VMT – cenrap2018_vmt_072005.ida

- bronze.nescaum.org/Private/junghun/CMV_mobile/
- To save SMOKE processing all mobile source inventories where processed with mobile sources from the MWRPO and VISTAS.

Point

EGU – ptinv_egu_2018_cenrap_11sep2006.txt
Non-EGU – ptinv_negu_cenrap2018_25aug2006_xfact.ida

- "_xfact" version is the adjusted version for fugitive dust as described
- Obtained from Alpine Geophysics contracted by MARAMA ftp.alpinegeophysics.com/Work_Order_1/Task_2_BaseK_2018\ (12-Sep06) – username: marama, password: emisdata
- Used IPM2.1.9 without adjustments

MANE-VU:

MARAMA developed the future year OTB/OTW emissions inventories for non-EGU point, area, and nonroad sources accounting for the OTB/OTW inventories, based on the MANE-VU 2002 Version 3 inventory. (MARAMA, 2007b).

County-specific correction factors were applied to take into account fugitive dust for SCCs listed at: www.epa.gov/ttn/chief/emch/invent/index.html#dust; the factors were obtained from www.epa.gov/ttn/chief/emch/invent/transportfractions.xls; this adjustment was performed outside of SMOKE with FORTRAN for area and point sources.

Area

MANEVU_OTB2018_Area_IDA3V_2.txt (Nov 2006)
ftp.marama.org/2009,12,18 OTB Version 3.1/AREA/Area IDA files/
Inventory Development Notes:

- After the release of version 3, Massachusetts revised their inventory for heating oil emissions due to two changes: (1) SO_2 emission factors were adjusted for the sulfur content from 1.0 to 0.03; (2) use of the latest DOE-EIA 2002 fuel use data instead of the previous version from 2001. These two changes significantly altered the 2002 SO_2 emissions for area source heating oil combustion. The revised version was used to do the projections.
- The District of Columbia discovered a gross error in the 2002 residential, non-residential, and roadway construction sources. It requested that for PM10-PRIM and PM25-PRIM for SCCs 23110X0000, different values be used for the 2002 base year and as the basis for the 2009/2012/2018 projections

Nonroad

MANEVU_OTB2018_NR_IDAV3_1.txt (Oct 2006)
ftp.marama.org/2009,12,18 OTB Version 3.1/NONROAD/NONROAD_IDA_Files_v3.1/

- MACTEC utilized the NMIM2005 model to develop projections for nonroad engines included in the NONROAD2005 model. Projected emission estimates were calculated using NMIM default data. Prior to starting the NMIM2005 runs, MACTEC confirmed with USEPA's Office of Transportation and Air Quality (OTAQ) that the database used for fuel sulfur content, gas Reid Vapor Pressure (RVP) values, and reformulated fuel programs was current and up to date for the MANE-VU region.
- Emission calculations were made at the monthly level and consolidated to provide annual values. This enabled monthly temperatures and changes in reformulated gas to be captured by the program.

Onroad

ManevuFutureM6_v2_20051103_wjh.tar.gz

- bronze.nescaum.org/Private/junghun/CMV_mobile/

Point

Non-EGU: MANEVU2018NonEGUV3_0_Point_IDA.txt (Jun 2006)
ftp.marama.org/2009,12,18 OTB Version 3.1/non-EGU Point/nonEGU IDA Files/

MRPO:

Alpine Geophysics was contracted by MARAMA to convert MRPO BaseK NIF formatted inventory to IDA a SMOKE ready inventory format. Files can be found at ftp.alpinegeophysics.com/Work_Order_1/Task_2_BaseK_2018/ – username: marama or on MARAMA's ftp site ftp.marama.org – username: mane-vu, password: exchange. Obtained between April and June 2006.

Where data sets are month dependant, {MMM} represents jan, feb, mar, etc. and {MM} is 01, 02, 03, etc.

Area

Other Area Sources – arinv_other_mrpok_2018_22aug2006.txt
Agricultural Ammonia – arinv_nh3_2018_mrpok_{MMM}_22aug2006.txt
Wind Erosion Fug-Dust Base F – dustinv_mrpo_basef_2018_29jul05.ida
- In order to save time, all area source categories were processed simultaneously for CENRAP, MRPO and VISTAS.

Nonroad

arinv_mar_mrpok_2018_22aug2006.txt
nrinv_2018_mrpok_apr_22aug2006.txt
- To save SMOKE processing all nonroad source inventories where processed with nonroad sources from the MWRPO and VISTAS.

On-road

M6LIST – .in files can be found in the sub-directory input
VMT - mbinv_vistas+mrpo_18g_vmt_12jun06.ida
- bronze.nescaum.org/Private/junghun/CMV_mobile/
- To save SMOKE processing all mobile source inventories where processed with mobile sources from the CENRAP and VISTAS.

Point

EGU: ptinv_egu_2018_mrpok_11sep006.txt
Non-EGU: ptinv_negu_2018_mrpok_23aug2006_xfact.txt
- “_xfact” version is the adjusted version for fugitive dust as described
- Used IPM2.1.9 includes post-IPM adjustments

VISTAS:

The header lines of these files indicate that the fugitive dust correction was already applied, so no further correction was performed. Where data sets are month dependant {MMM} is jan, feb, mar, etc. and {MM} is 1, 2, 3, etc.

Area

arinv_vistas_2018g_2453922_w_pmfac.txt
- To save SMOKE processing, area source inventories where processed with area sources from the MWRPO and CENRAP.

Lo-Fire: area_level_fires_vistas2018_baseg.ida

Nonroad

marinv_vistas_2018g_2453972.txt
nrinv_vistas_2018g_2453908.txt
- To save SMOKE processing, all nonroad source inventories were processed with nonroad sources from the MWRPO and VISTAS.

Onroad

M6LIST – .in files can be found in the sub-directory input
VMT - mbinv_vistas+mrpo_18g_vmt_12jun06.ida
- bronze.nescaum.org/Private/junghun/CMV_mobile/
- Based off Base G inventory BaseG_2018_mobile_m6.tar and Baseg_2018_mv_vmt.tar

- To save SMOKE processing all mobile source inventories where processed with mobile sources from the MWRPO and CENRAP.

Point

EGU: egu_18_vistas_g_2453993.txt
Non-EGU: negu_ptinv_vistas_2018_baseg_2453957_xfact.txt
Hourly: pthour_2018_baseg_{MMM}_2453993.ems
Hi-Fire: ptinv.plume.vistasbaseg18.{MM}.ida
ptday.plume.vistasbaseg18.{MM}.ida
Hi-Fire hourly plume-rise: pthour.plume.vistasbaseg18.{MM}.ida

- Used IPM2.1.9 includes post-IPM adjustments

1.3.4. 2018 “Beyond on the Way” (BOTW) Emission Inventory

The emissions processing for a “beyond on the way” (BOTW) inventory was conducted in a very similar manner to other future projection scenarios relative to the 2002 base year, but with different inventories. These inventories were based on additional control measures that the MANE-VU states are considering for attaining various regional haze, ozone, and $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS) goals. The resulting CMAQ simulation (BOTW) is the same run that has been used by the OTC Modeling Committee for projecting the long-term benefits of regional ozone control programs and was conducted on the Integrated SIP Modeling Platform by the five regional modeling centers.

CANADA:

Same as 2018OTB/OTW

CENRAP:

Same as 2018OTB/OTW

MANE-VU:

MARAMA produced the Nonroad, Area and Non-EGU projections for 2018 under different scenarios (MARAMA, 2007b).

The EGU inventories were developed by ICF Consulting for the RPOS using the Integrated Planning Model (IPM version 2.1.9). Alpine Geophysics processed the results into IDA inventory format for MANE-VU.

Fugitive dust correction was applied as county-specific correction factors for SCCs listed at http://www.epa.gov/ttn/chief/emch/invent/index.html#dust; the correction factors were obtained from http://www.epa.gov/ttn/chief/emch/invent/transportfractions.xls; this adjustment was performed outside of SMOKE with FORTRAN.

Area

manevu_botw2018_area_IDAV3_2_xfact.txt

- “_xfact” version is the adjusted version for fugitive dust as described

Nonroad

nrinv_manevu_18_19oct05.txt

Onroad

Same as 2018 OTB/OTW

Point

EGU: ptinv_egu_2018_manevu_11sep2006.txt
- bronze.nescaum.org/Private/junghun/POINT_2018BOTW_B4

Non-Fossil 2009: manevu_nonfossil_2009_19sept2006.txt
- Alpines ftp – marama -- Work_Order_1/Task_4_2009_Nonfossil/

Non-EGU: MANEVU_BOTW2018_nonegu_IDAV3_1_xfact.txt
- “_xfact” version is the adjusted version for fugitive dust as described

MRPO:

Same as 2018OTB/OTW

VISTAS:

Same as 2018OTB/OTW

1.3.5. 2018 Sulfate Tagging (BOTW) Emission Inventory

An additional BOTW inventory was prepared specifically to allow for a state-by-state tagging run with REMSAD and a sensitivity run with the CMAQ Particle and Precursor Tagging Methodology (CMAQ-PPTM) system. The inventory used for these runs was essentially the same inventory described for the regular BOTW scenario; however, in order to process this inventory for use with the tagging methodology, various components of the inventory were processed separately and identified as a specific “type” of sulfur dioxide so that it could be tracked through the system.

The state-by-state tagging used the identical inventory to the 2018 BOTW inventory described in the previous section. It was processed such that each state’s SO_2 emissions were separately tagged requiring three separate REMSAD simulations to accommodate 29 eastern states, Canada, and the boundaries.

A separate CMAQ-PPTM simulation was conducted using the same inventory, but modified to reflect additional controls due to a number of strategies to be tested. The specific scenarios that were tracked by this run include:

1. OTB/OTW
2. S-1 fuel oil strategy (500 ppm distillate; 0.5% fuel-sulfur content by weight for No. 6 residual oil; 0.25% fuel-sulfur content by weight for No. 4 residual oil.)
3. S-2 fuel oil strategy (15 ppm distillate; 0.5% fuel-sulfur content by weight for No. 6 residual oil; 0.25% fuel-sulfur content by weight for No. 4 residual oil.)
4. BART (approximately 35,000 tons of SO_2 reductions at specific facilities identified by state survey of permitting staff)

5. "167 Stack" Strategy; (90% control on all EGUs in the 167 stacks identified as having the most significant impact on MANE-VU Class I areas)

Two additional tags were required to account for corrections to the assumed baseline fuel sulfur content of distillate and to add EGU emissions reductions back into the system as a result of potential permit trading in response to the 167 stack strategy. These strategies are described in more detail in Chapter 4.

1.4. Model Platforms

Currently two regional-scale air quality models have been evaluated and used by NESCAUM to perform air quality simulations. These are the Community Multi-scale Air Quality modeling system (CMAQ; Byun and Ching, 1999) and the Regional Modeling System for Aerosols and Deposition (REMSAD; SAI, 2002). CMAQ was developed by USEPA, while REMSAD was developed by ICF Consulting/Systems Applications International (ICF/SAI) with USEPA support. CMAQ has undergone extensive community development and peer review (Amar et al., 2005) and has been successfully used in a number of regional air quality studies (Bell and Ellis, 2003; Hogrefe et al., 2004; Jimenez and Baldasano, 2004; Mao and Talbot, 2003; Mebust et al., 2003). REMSAD has also has been peer reviewed (Seigneur et al., 1999) and used by USEPA for regulatory applications (www.epa.gov/otaq/regs/hd2007/frm/r00028.pdf and www.epa.gov/clearskies/air_quality_tech.html) to study ambient concentrations and deposition of sulfate and other PM species.

1.4.1. CMAQ

The CMAQ modeling system is a three-dimensional Eulerian model that incorporates output fields from emissions and meteorological modeling systems and several other data sources through special interface processors into the CMAQ Chemical Transport Model (CCTM). The CCTM then performs chemical transport modeling for multiple pollutants on multiple scales. With this structure, CMAQ retains the flexibility to substitute other emissions processing systems and meteorological models. CMAQ is designed to provide an air quality modeling system with a "one atmosphere" capability containing state-of-science parameterizations of atmospheric processes affecting transport, transformation, and deposition of such pollutants as ozone, particulate matter, airborne toxics, and acidic and nutrient pollutant species (Byun and Ching, 1999).

To date, MANE-VU SIP modeling on both 36 km and 12 km domains used CMAQv4.5.1, IOAPI V2.2 and NETCDF V3.5 libraries. The CMAQ model is configured with the Carbon Bond IV mechanism (Gery et al., 1989) using the EBI solver for gas phase chemistry rather than the SAPRC-99 mechanism due to better computing efficiency with no significant model performance differences for ozone and PM as compared to observations.

NY DEC has completed annual 2002 CMAQ modeling on the 36 km domain to provide dynamic boundary conditions for all simulations performed on the 12 km domain. Three-hourly boundary conditions for the outer domain were derived from an annual model run performed by researchers at Harvard University using the GEOS-

CHEM global chemistry transport model (Park et al., 2004). Model resolution was species dependent at either 4° latitude by 5° longitude or 2° by 2.5°.

Five modeling centers are working collectively to maximize efficiency of computing resources in MANE-VU for SIP modeling. These centers include NY DEC, NJ DEP/Rutgers, VA DEQ, UMD, and NESCAUM. Annual CMAQ modeling on the 12 km domain is divided into five periods. UMD is responsible for the period from January 1 to February 28; NJ DEP/Rutgers are responsible for the period from March 1 to May 14; NY DEC is responsible for the period from May 15 to September 30; VA DEQ is responsible for the period from October 1 to October 31; and NESCAUM is responsible for the period from November 1 to December 31. Each period uses a 15 day spin up run to minimize the impact of the default initial concentration fields. Each group performs CMAQ simulations on its period for a series of scenarios including 2002 Base Case, 2009 Base Case, 2018 Base Case, 2009 Control Case, and 2018 Control Case. All scenarios adopt the same meteorological field (2002) and boundary conditions, varying only emission inputs. To ensure consistency, a benchmark test was conducted by each modeling group.

In addition to the annual simulations conducted with CMAQ by the five modeling centers, NESCAUM has conducted limited sensitivity analysis of several control measures using the beta version of CMAQ with the particle and precursor tagging methodology (CMAQ-PPTM) (ICF, 2006). These runs and their results are described separately in Chapter 5.

1.4.2. REMSAD

The Regional Modeling System for Aerosols and Deposition (REMSAD) is a three-dimensional Eulerian model designed to support a better understanding of the distributions, sources, and removal processes relevant to fine particles and other airborne pollutants. It calculates the concentrations of both inert and chemically reactive pollutants by simulating the physical and chemical processes in the atmosphere that affect pollutant concentrations. The basis for the model is the atmospheric diffusion equation representing a mass balance in which all of the relevant emissions, transport, diffusion, chemical reactions, and removal processes are expressed in mathematical terms. The REMSAD model performs a four-step solution procedure: emissions, horizontal advection/diffusion, vertical advection/diffusion and deposition, and chemical transformations during one half of each advective time step, and then reverses the order for the following half time step. The maximum advective time step for stability is a function of the grid size and the maximum wind velocity or horizontal diffusion coefficient. Vertical diffusion is solved on fractions of the advective time step to keep their individual numerical schemes stable.

REMSAD uses a flexible horizontal and vertical coordinate system with nested-grid capabilities and user-defined vertical layers. It accepts a geodetic (latitude/longitude) horizontal coordinate system or a Cartesian horizontal coordinate system measured in kilometers. REMSAD uses a simplified version of CB-IV chemistry mechanism that is based on a reduction in the number of different organic compound species and also includes radical-radical termination reactions. The organic portion of the chemistry is based on three primary organic compound species and one carbonyl species.

The model parameterizes aerosol chemistry and dynamics for PM and calculates secondary organic aerosol (SOA) yields from emitted hydrocarbons. REMSAD V7.12 and newer versions have capabilities that allow model tags of sulfur species (up to 11 tags), nitrogen (4 tags), mercury (up to 24 tags), and cadmium (up to 10 tags) to identify the impact of specific tagged species.

Unlike CMAQ, REMSAD provides no choice of chemical and physical mechanisms. The modeling configuration for future work with REMSAD will be similar to the CMAQ modeling setup. The initial concentrations and boundary conditions will be generated using the same concentration profile used by CMAQ. The approach is to use similar model inputs to allow comparison of REMSAD with CMAQ to better understand differences between the two models. Due to the simplified chemistry mechanism, REMSAD may not simulate atmospheric processes as well as CMAQ. However, advantages such as the tagging feature for sulfur, more efficient modeling, and reasonable correspondence with measurements for many species, make REMSAD an important source apportionment tool for MANE-VU.

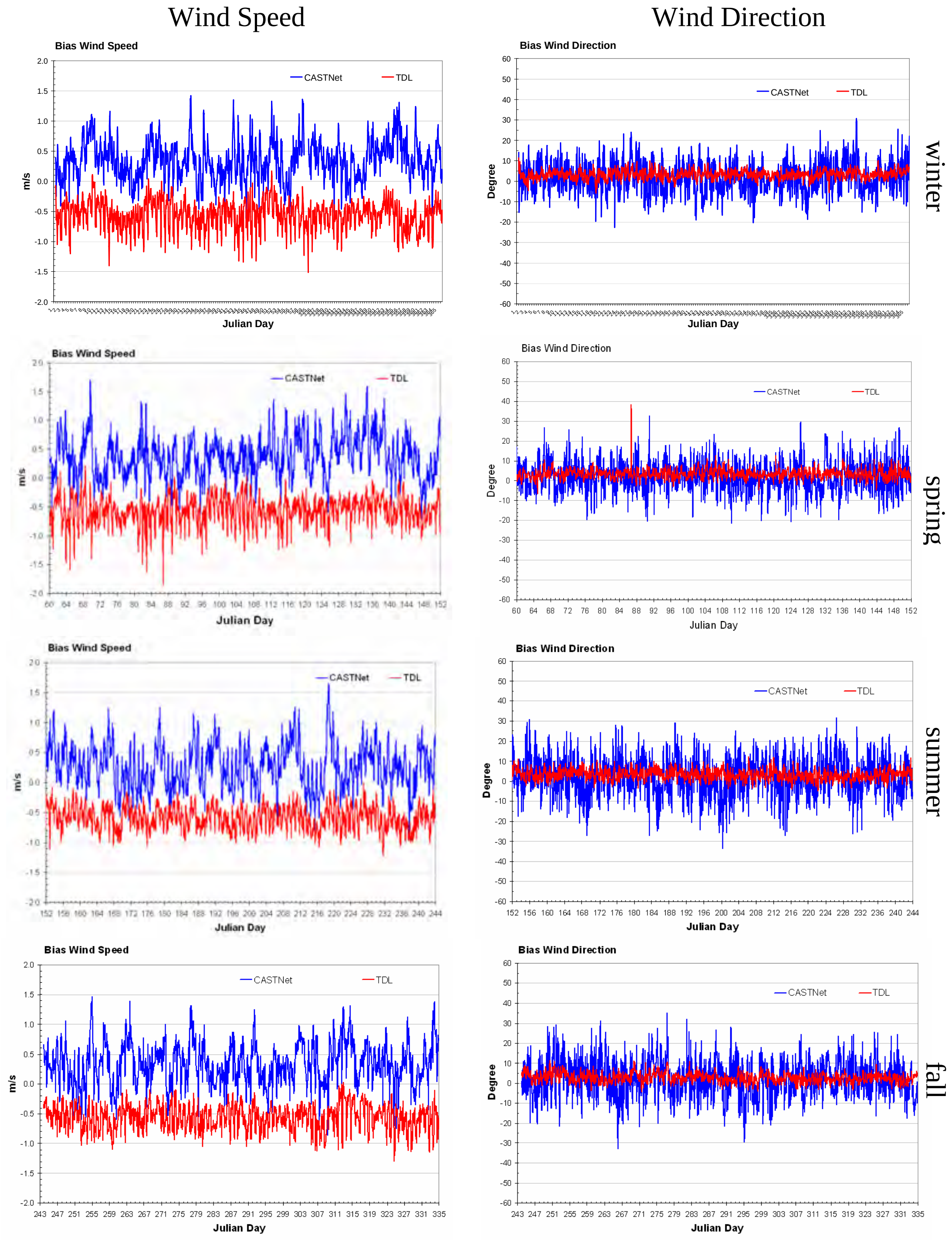
In our present REMSAD modeling, we use the same 12 km domain (i.e., domain2) presented in the previous section for three full annual runs for the base year (2002). Multiple runs are necessary to permit tagging of sulfur emissions for all of the states in the domain, Canada, and the boundary conditions.

2. PERFORMANCE EVALUATION

2.1. Meteorological Evaluation

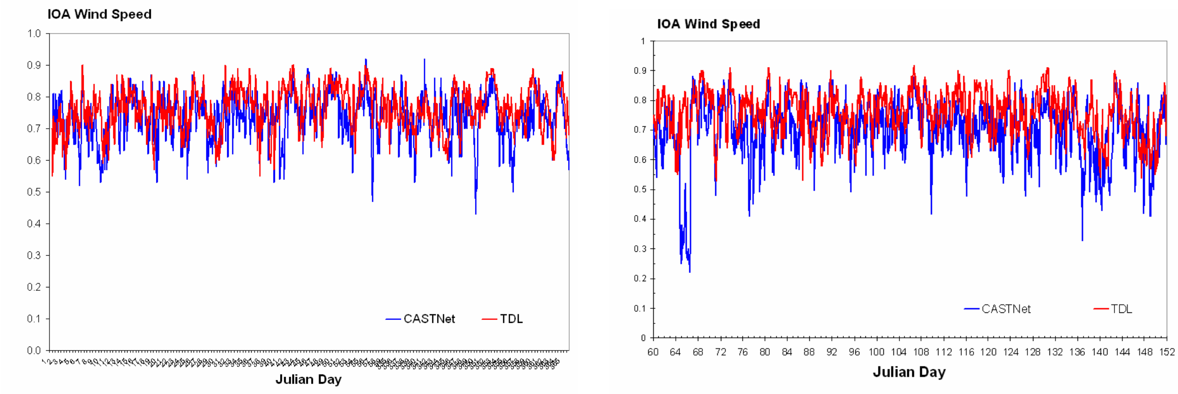
The 2002 annual 12 km resolution meteorological fields generated by MM5 have been evaluated by NESCAUM using ENVIRON's METSTAT program. Model results of surface wind speed, wind direction, temperature, and humidity are paired with measurements from EPA's Clean Air Status and Trends Network (CASTNET) and National Center for Atmospheric Research's Techniques Data Laboratory (TDL) network by hour and by location and then statistically compared. Figure 2-1 presents domain-wide average hourly bias of wind speed (left panel) and wind direction (right panel) between the MM5 results and two sets of measurement for every season in 2002 (winter includes Jan., Feb., and Dec.; spring includes Mar., Apr., and May; summer includes Jun., Jul., and Aug.; fall includes Sep., Oct., and Nov.). It shows that MM5 capably predicts wind speed with reasonably small bias and equal consistency. Within the domain, MM5 tends to overestimate wind speed (hourly bias up to 1.7 m/s) at CASTNET sites, and underestimate wind speed (hourly bias up to -1.85 m/s) at TDL sites. Seasonal mean bias of MM5 wind speed to CASTNET wind speed is ~0.3 to 0.4 m/s, while seasonal mean bias of MM5 wind speed to TDL wind speed is about ~-0.5 to -0.6 m/s. No significant seasonal variation on this wind speed bias is observed. MM5 prediction of wind direction shows a larger variation with CASTNET wind direction (hourly bias from ~-30 degree to ~30 degree) than with TDL wind direction (hourly bias from ~-5 degree to ~10 degree). However, seasonal mean bias of MM5 wind direction to CASTNET wind direction (~2 degree) is smaller than seasonal mean bias of MM5 wind direction to TDL wind direction (~3 degree) because the large variation of positive and negative bias offset each other.

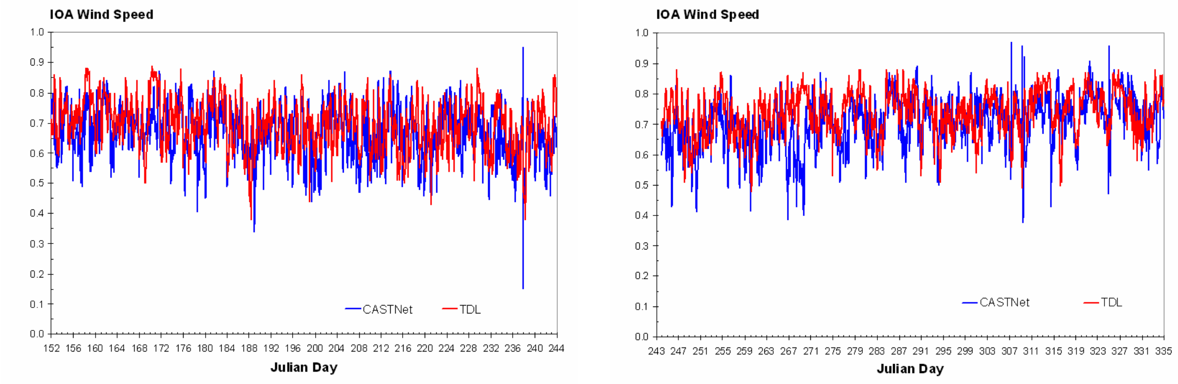
Figure 2-1. 2002 seasonal average hourly bias of wind speed and direction



Index of Agreement (IOA) is a statistical measure of difference between prediction and measurement, calculated as a ratio of Root Mean Square Error to the sum of the difference between prediction and mean observation and difference between observation and mean observation. IOA varies from 0 to 1, with a value of 1 indicating the perfect agreement between model prediction and observation, and a value larger than 0.5 IOA indicating acceptable model performance. Domain-wide average hourly IOAs of wind speed are presented in Figure 2-2. MM5 predictions of wind speed values are in good agreement (IOA from ~0.5 to ~0.9) to both CASTNET data and TDL data with similar IOA variation. Seasonal mean values of IOA are ~ 0.7. No particular season of the year stands out in terms of its agreement with measurement.

Figure 2-2. 2002 seasonal hourly average index of agreement for wind speed


a) winter b) spring


c) summer d) fall

Quarterly correlation coefficients in Figure 2-3 show good MM5 performance on hourly wind speed for each observation site. MM5 predictions exhibit similar spatial patterns of correlation with CASTNET (left panel) and TDL (right panel) measurements – stronger correlation in north than in south. Over the year, the model has stronger correlation in the 1st quarter (Jan., Feb., Mar., top 1st row), 2nd quarter (Apr., May, Jun., 2nd row) and 4th quarter (Oct., Nov., Dec., bottom row) than it does in the 3rd quarter (Jun., Jul., Aug., 3rd row), with an average of 0.1 correlation coefficient difference. Generally, MM5 predictions and measurements have strongest correlation (0.8~0.9) within the midwestern U.S., strong correlation (0.7~0.8) within the northeastern U.S. and along the coastline, and acceptable correlation (0.5~0.7) within the southern U.S. and interior portions of the U.S. East Coast. MM5 predictions consistently show very similar spatial patterns and temporal variations for wind direction (as shown in Figure 2-4) and wind speed. There is strong correlation (>0.7) between prediction and measurement for wind direction at most of sites.

Figure 2-3. Quarterly correlation coefficient (r) of hourly wind speed between modeling and measurement for each observation site in 2002

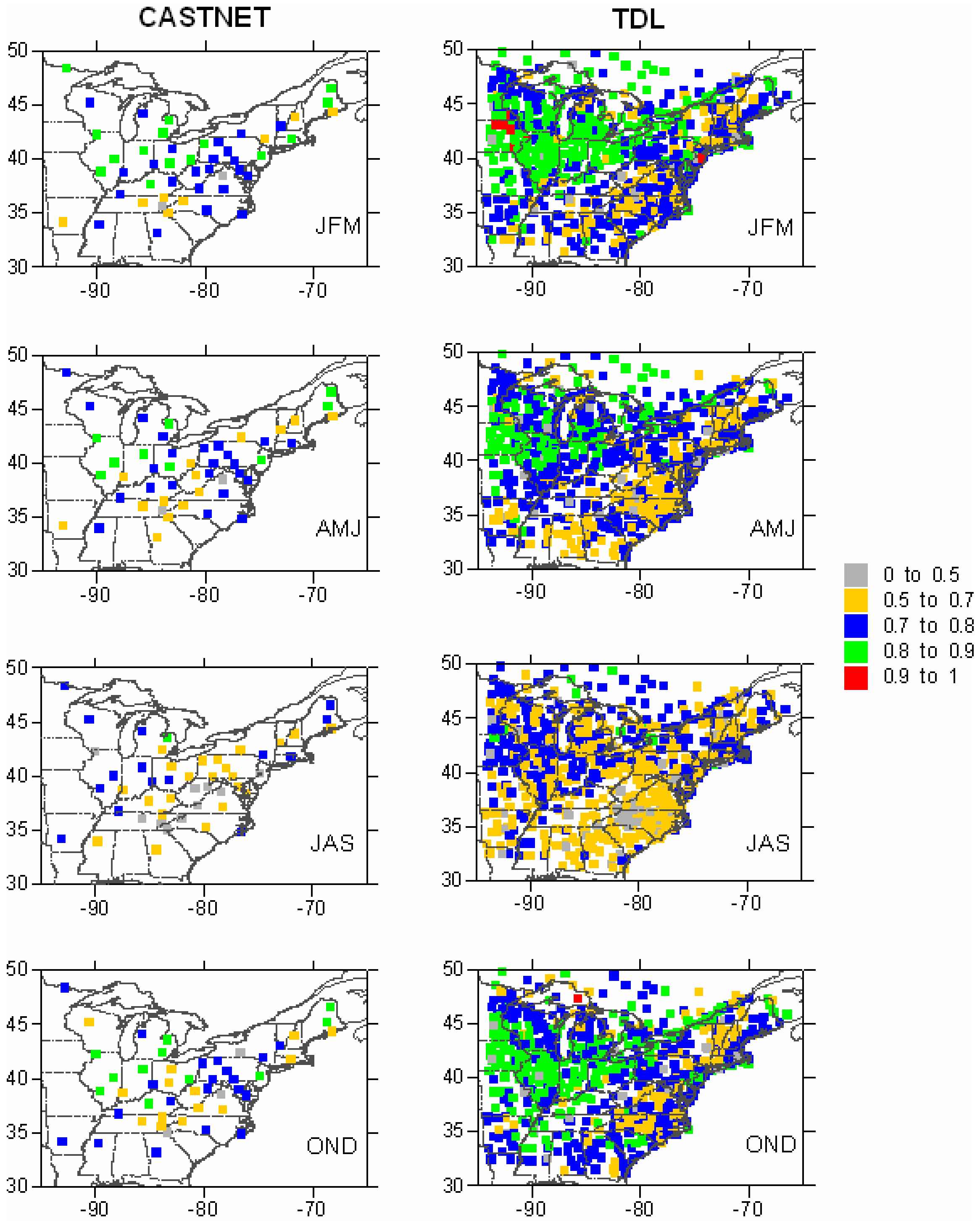


Figure 2-4. Quarterly correlation coefficient (r) of hourly wind direction between modeling and measurement for each observation site in 2002

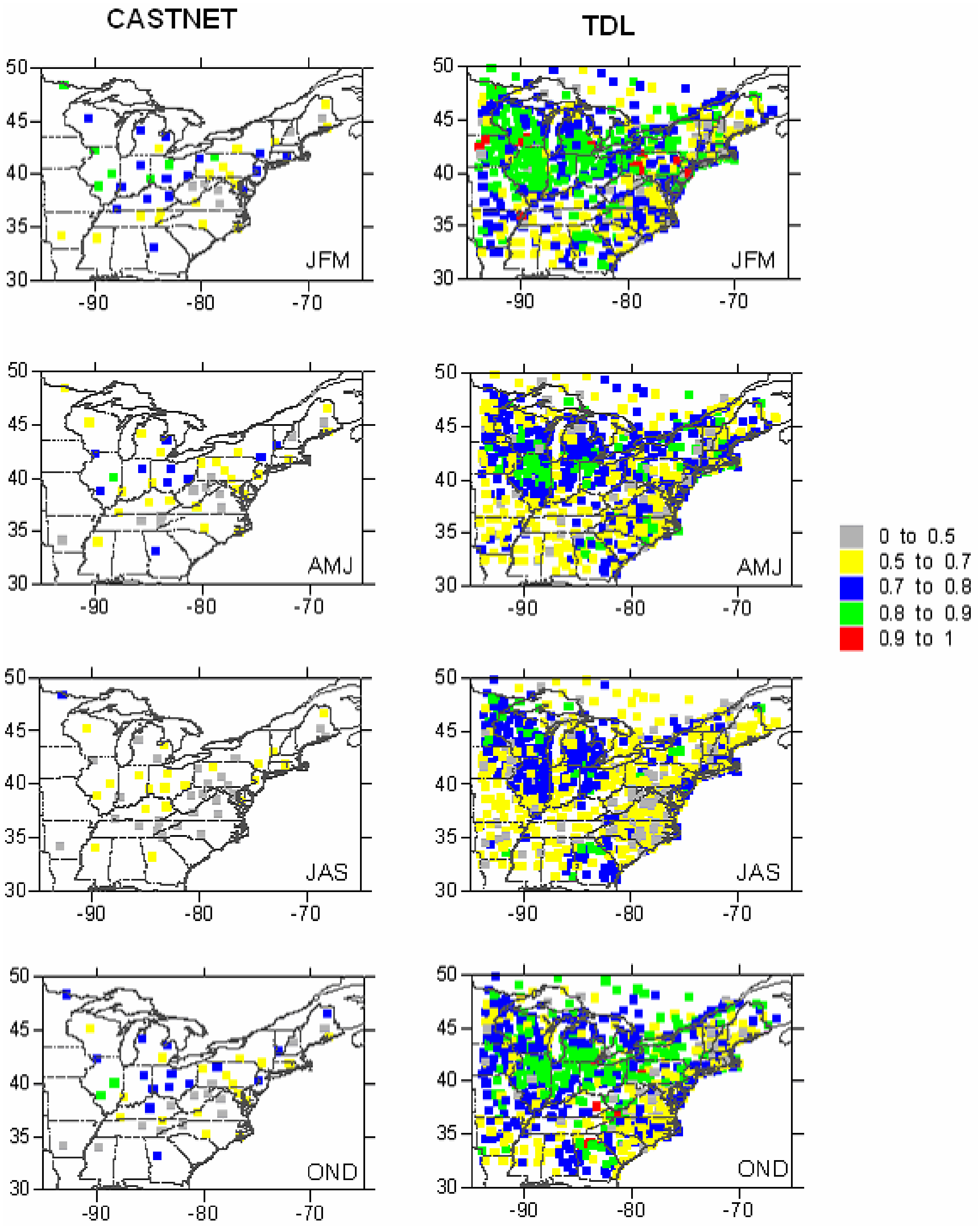


Figure 2-5 presents domain-wide average hourly bias of surface temperature between MM5 results and CASTNET and TDL for every season. MM5 tends to underestimate temperature at TDL sites throughout the year and at CASTNET sites for non-ozone season months. The seasonal mean temperature bias values are from ~-1 K (winter) to ~-0.3 K (summer) for TDL sites and ~-1 K (winter) to ~0.5 K (summer) for CASTNET sites. MM5 predictions show significantly larger variations of temperature bias at CASTNET sites (-4 K~9 K) than at TDL sites (-3 K~1 K).

Domain-wide average hourly IOA values of temperature are shown in Figure 2-6. Model predicted temperatures have significantly better agreement with TDL data (average IOA as ~0.95) than with CASTNET data (average IOA as ~0.85), although both indicate accurate MM5 performance on temperature.

Figure 2-7 shows the spatial distribution of quarterly correlation coefficients between MM5 prediction and measurement of surface temperature. It reveals very strong correlation (>0.95) over most of the domain for TDL data, with strong correlation (>0.8) for the majority of CASTNET sites. No spatial patterns or quarterly variations are apparent. MM5 performs consistently well throughout the year and the domain.

The TDL network also provides humidity measurements. Comparison between MM5 prediction of hourly surface humidity and TDL measurement are presented in Figure 2-8. MM5 captures the general trend of humidity change. It tends to underestimate humidity during the ozone season (seasonal mean bias as ~0.35g/kg), and overestimate it during the rest of year (seasonal mean bias range from ~0.17 to ~0.4). Domain-wide average hourly humidity bias shows a large diurnal variation, as much as 2g/kg. Domain-wide average hourly IOA in Figure 2-9 shows that MM5 predicted humidity values are in good agreement with TDL data (average IOA as ~0.9) throughout year. Spatial distribution of quarterly correlation coefficient in Figure 2-10 shows a distinctive spatial pattern and temporal trend. MM5 results have stronger correlation to TDL data in the northern US than in the Southern US. Through the year, the strongest correlation between MM5 prediction and measurement occurs in the 4th Quarter (>0.95), followed by the 1st and 2nd Quarters, and finally, the 3rd Quarter, which shows the weakest correlation (0.5~0.9).

Based on this statistical comparison between model prediction and data from two networks for wind speed, wind direction, temperature, and humidity, MM5 performs well. An acceptable small bias, high index of agreement and strong correlation with CASTNET and TDL data are shown. Since MM5 uses TDL data for nudging, the model predictions are in better agreement with TDL data than with CASTNET data. MM5 performs better in Midwest and Northeast than Southeastern US.

Figure 2-5. 2002 Seasonal Hourly Average Bias of Temperature

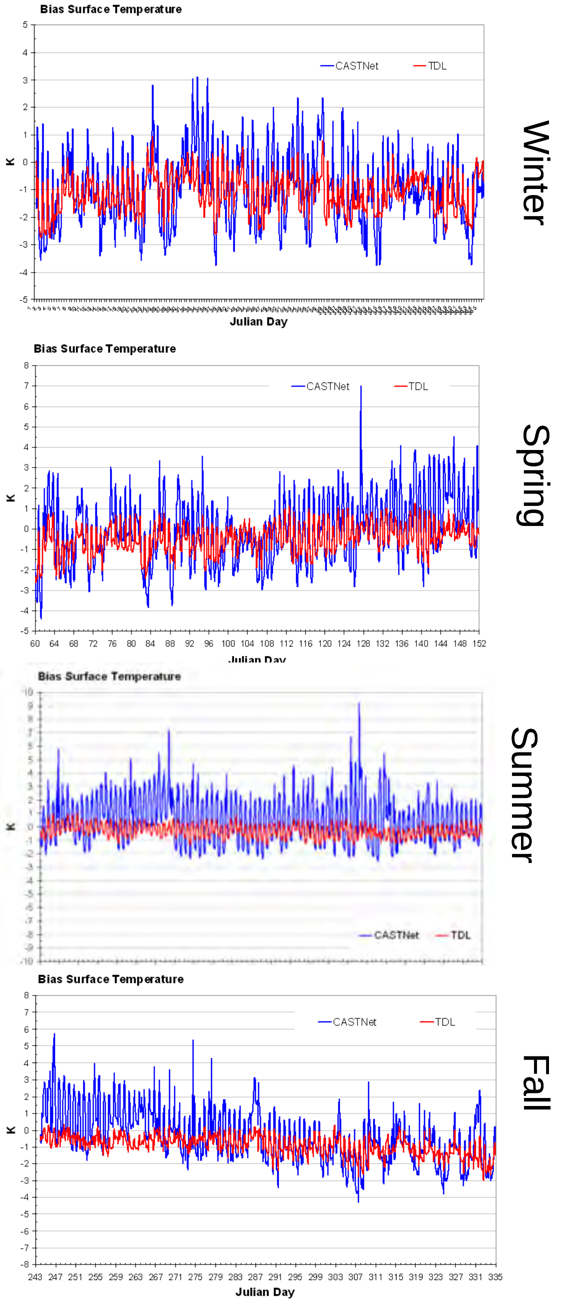


Figure 2-6. 2002 Seasonal Hourly Average Index of Agreement

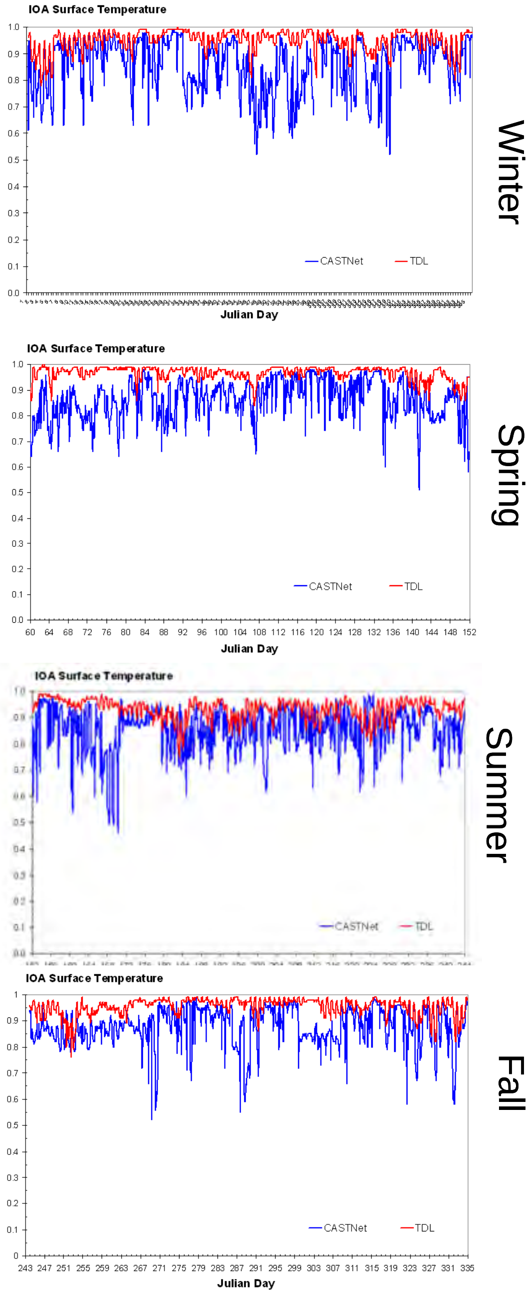


Figure 2-7. Quarterly correlation coefficient (r) of hourly temperature between modeling and measurement for each observation site in 2002

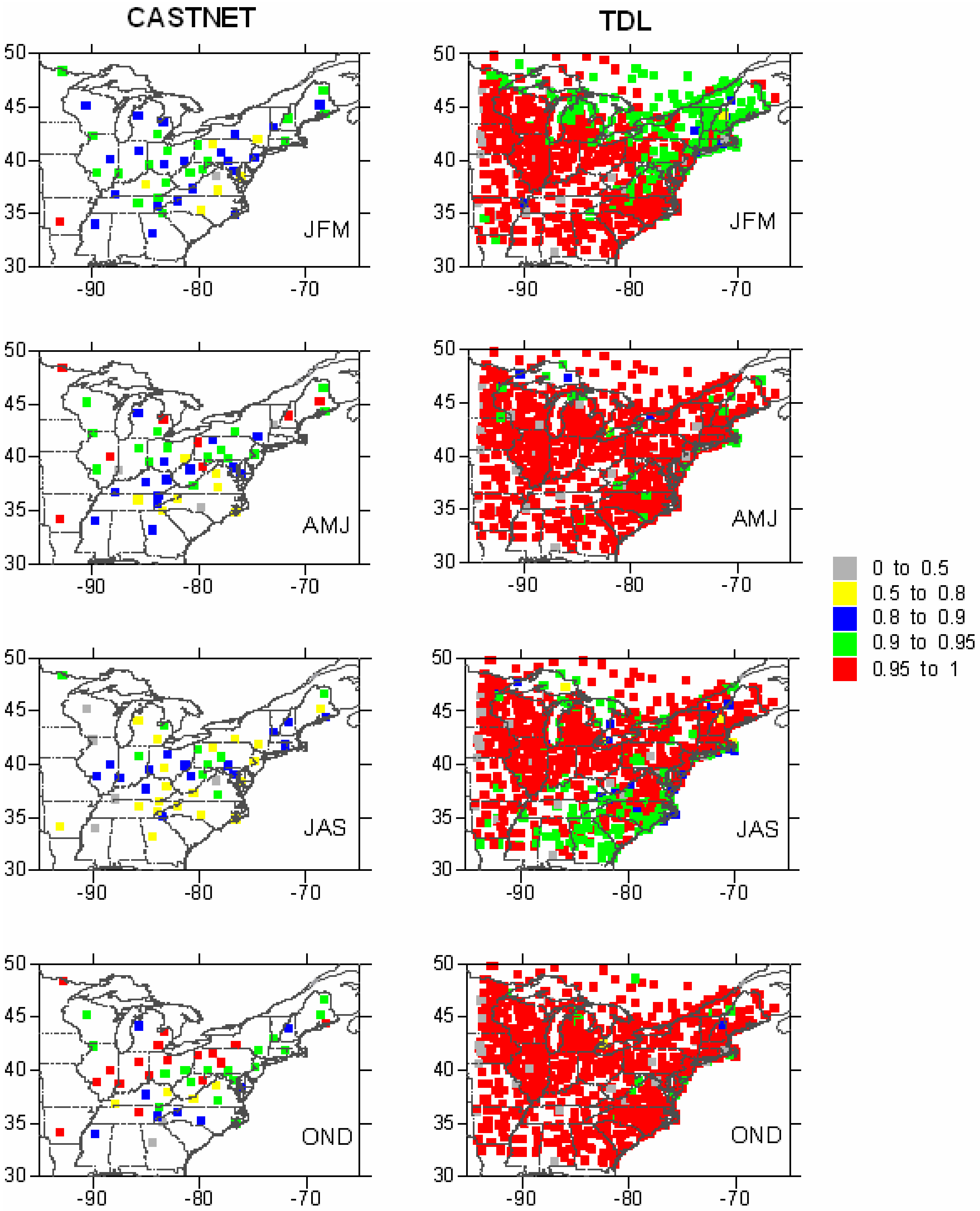


Figure 2-8. 2002 Seasonal average hourly bias of humidity

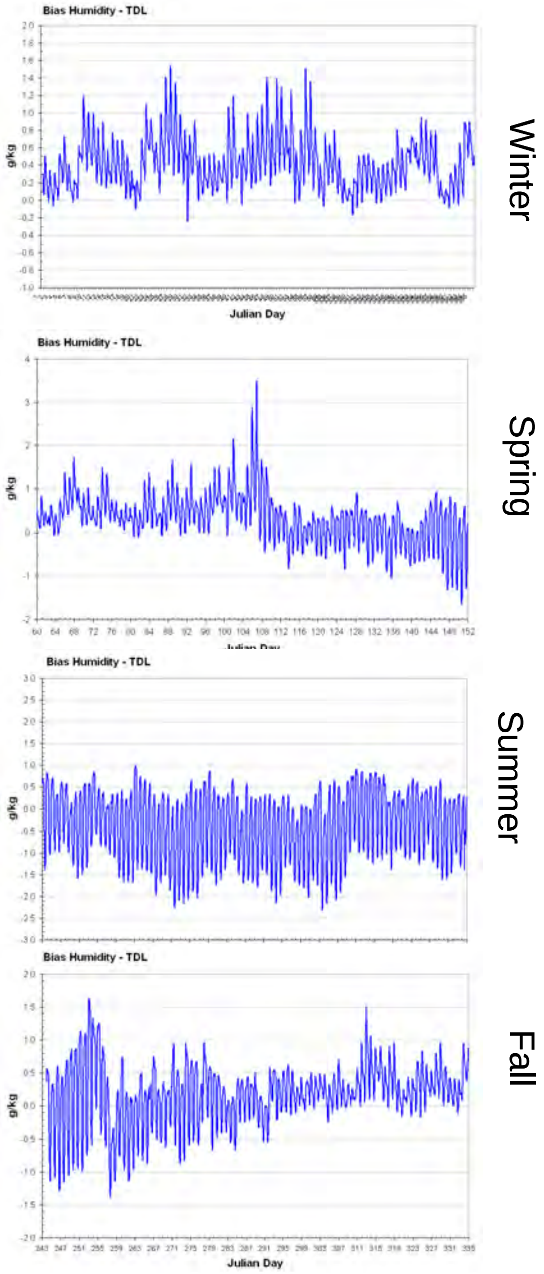


Figure 2-9. 2002 seasonal hourly average index of agreement

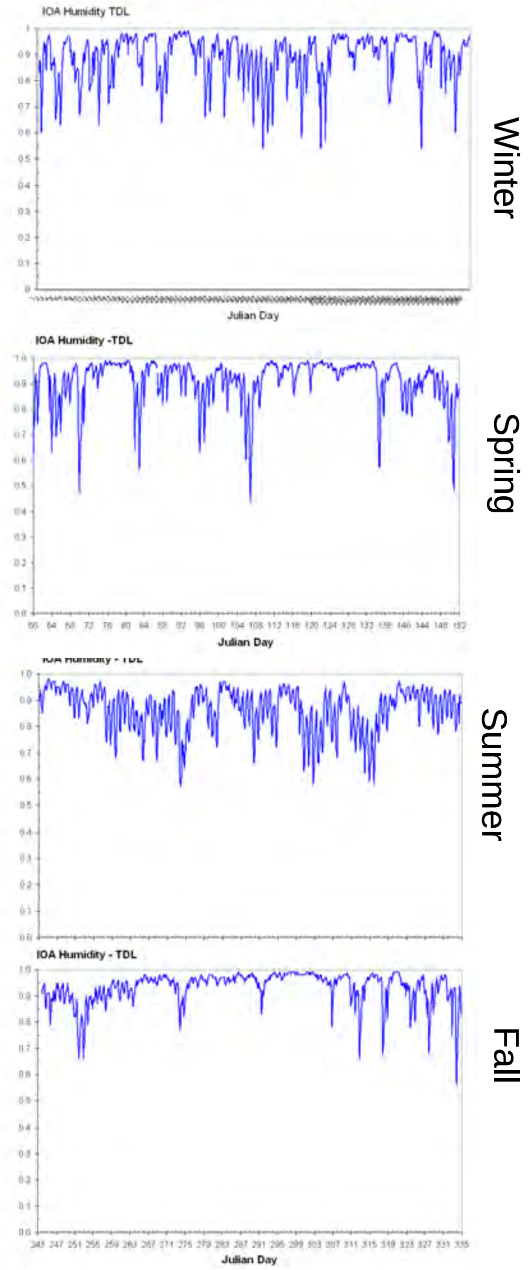
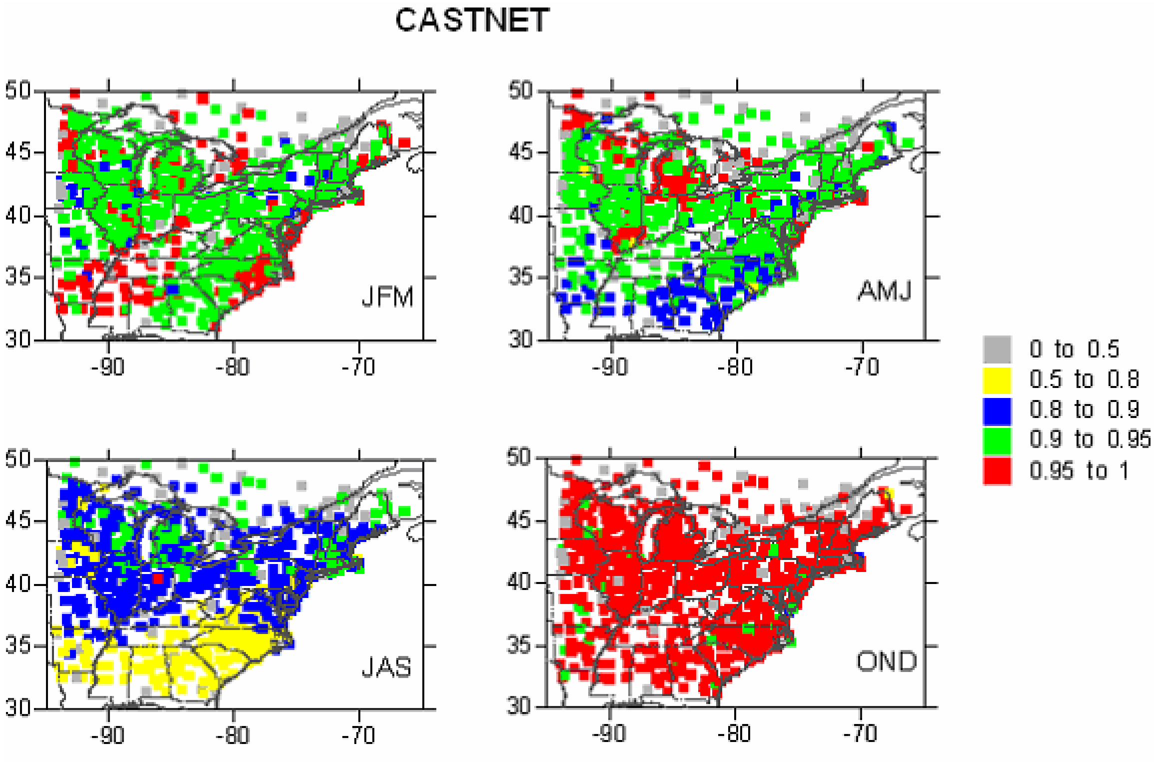


Figure 2-10. Quarterly correlation coefficient (r) of hourly humidity between modeling and measurement for each observation site in 2002



2.2. Model Evaluation

CMAQ modeling has been conducted for the year 2002 (completed by cooperative modeling efforts from NYDEC, UMD, NJDEP, Rutgers, VADEP, and NESCAUM) under the Base B4 emission scenario described in Chapter 1. CMAQ performance for $PM_{2.5}$ species and visibility is examined based on this CMAQ run on a 12 km resolution domain. Measurements from IMPROVE and STN networks are paired with model predictions by location and time for evaluation. Figure 2-11 presents the domain-wide paired comparison of $PM_{2.5}$ species (sulfate, nitrate, OC, EC, fine soil, and $PM_{2.5}$) daily average concentration from the CMAQ simulation and two sets of observations (STN and IMPROVE). It shows that predicted $PM_{2.5}$ sulfate (top row left panel) and measured sulfate are in a good 1:1 linear relationship with r^2 varying from 0.6 to 0.7. $PM_{2.5}$ nitrate (top row right panel) also has close to a 1:1 linear relationship between the model and observations, although the r^2 values are much lower (from ~0.2 to ~0.5) than for sulfate. Paired OC (middle row left panel) concentrations have a scattered distribution with over- and under-estimation and a very weak linear relationship (r^2 of ~0.1). CMAQ tends to overestimate EC (middle row right panel) and fine soil (bottom row left panel) concentrations.

EC and soil are inert species not involved in chemical transformation. Poor emission inventory data may be the main cause for the weak linear relationships between prediction and measurement. In addition, there are no fire emissions considered in CMAQ modeling. The wild fire in Quebec, Canada in early July of 2002 led to high concentrations of observed OC, EC, and fine soil that are not predicted by CMAQ.

Because sulfate is the dominant $PM_{2.5}$ species, modeled $PM_{2.5}$ (bottom row right panel) shows a relatively strong near 1:1 linear relationship (slope between 0.7–0.8 with r^2 of 0.4–0.5). Figure 2-12 describes the spatial distribution of the correlation coefficient of sulfate between CMAQ prediction and observations (STN data on the top row and IMPROVE data on the bottom row) at network sites. CMAQ predictions show a similar spatial pattern of correlation with both networks.

Generally, the northern region of the domain has stronger correlations than does the southern region. Correlation coefficients within the MANE-VU region are highest (~0.9 on average) compared to other RPO regions. The spatial distribution of correlation coefficient for $PM_{2.5}$ is presented in Figure 2-13. The $PM_{2.5}$ correlation coefficient spatial pattern follows $PM_{2.5}$ sulfate correlation coefficient, although at the same observation site coefficient values are ~0.1 lower than the sulfate coefficient value. Like $PM_{2.5}$ sulfate, CMAQ also performs the best for $PM_{2.5}$ in the MANE-VU region with a ~0.7 annual average for the correlation coefficient.

The goal and the criteria for $PM_{2.5}$ evaluation suggested by Boylan and Baker (2004) have been adopted by every RPO for SIP modeling. The proposed performance goals are: Mean Fractional Error (MFE) $\leq +50\%$, and Mean Fraction Bias (MFB) $\leq \pm30\%$; while the criteria are proposed as: MFE $\leq +75\%$, and MFB $\leq \pm60\%$.

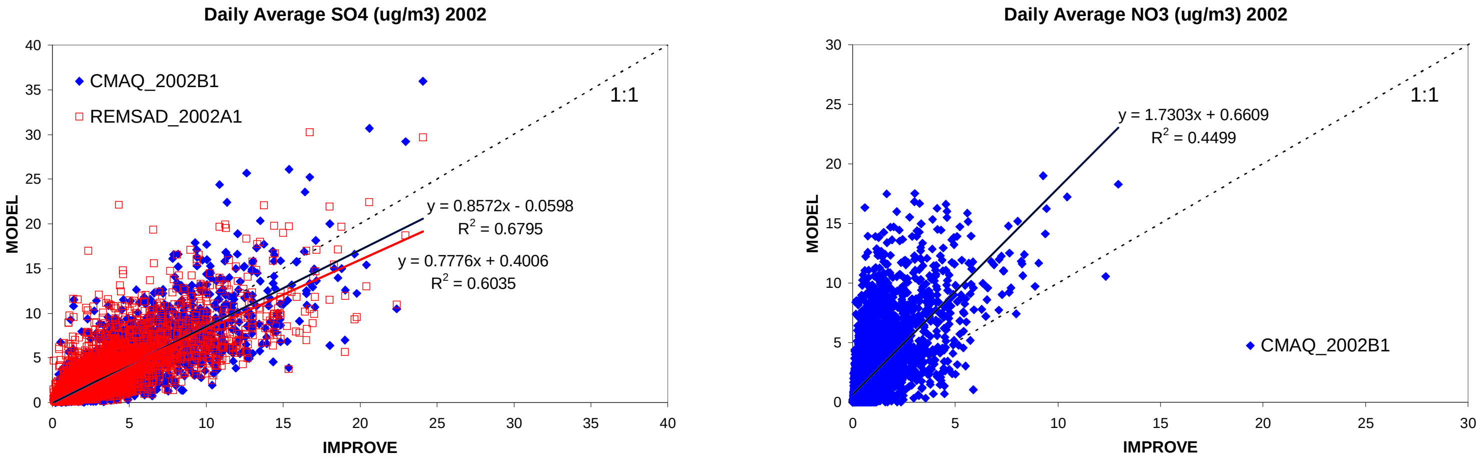
CMAQ prediction of $PM_{2.5}$ species from 40 STN sites and 17 IMPROVE sites within MANE-VU region are paired with measurements and statistically analyzed to generate MFE and MFB values. Figure 2-14 presents MFE of $PM_{2.5}$ sulfate, nitrate, OC, EC, fine soil, and $PM_{2.5}$, and curves of the goal and criteria. MFB values are shown in Figure 2-15. Considering CMAQ performance in terms of MFE and MFB goals, sulfate, nitrate, OC, EC, and $PM_{2.5}$ all have the majority of data points within the goal curve, some are between the goal and acceptable criteria, and only a few are outside the criteria curve. Only fine soil has the majority of points outside the criteria curve, but there are some sites still within the goal. For the MANE-VU region, CMAQ performs best for $PM_{2.5}$ sulfate, followed by $PM_{2.5}$, EC, nitrate, OC, and then fine soil.

Regional haze modeling also requires a CMAQ performance evaluation for aerosol extinction coefficient (B_{ext}) and the haze index. Modeled daily aerosol extinction at each IMPROVE site is calculated following the IMPROVE formula with modeled daily $PM_{2.5}$ species concentration and relative humidity factors from IMPROVE. The approaches used here and throughout this analysis, have used natural background visibility estimates and the haze index following EPA Guidance.

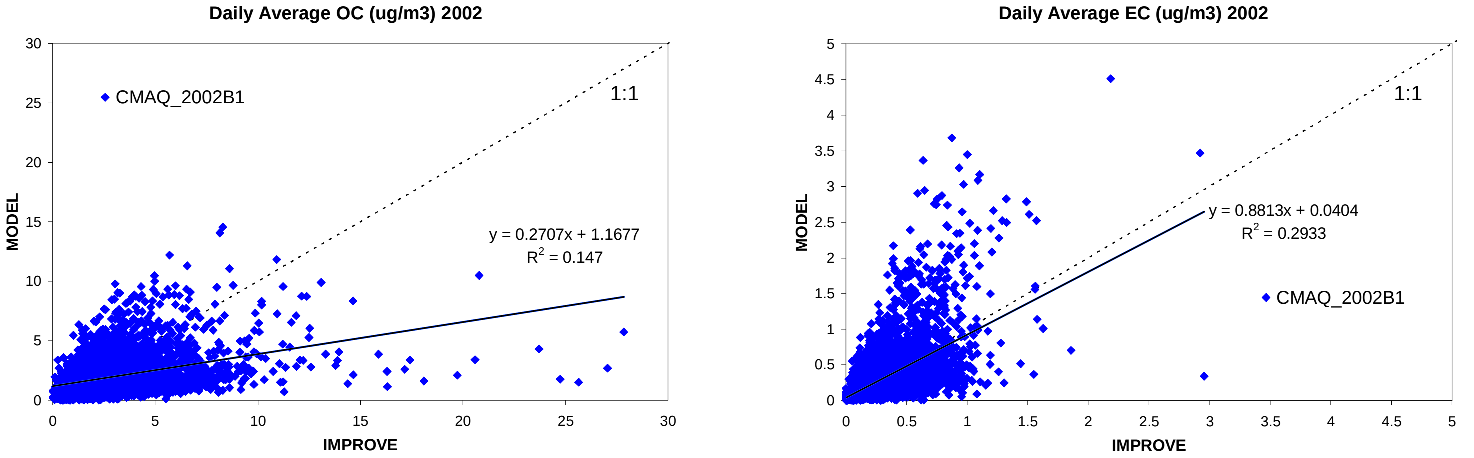
Figure 2-16 shows the paired comparison between prediction and measurement of daily B_{ext} from seven sites for 2002. The modeled B_{ext} shows a near 1:1 linear relationship (slope of 0.78 and r^2 of 0.46) with IMPROVE observed B_{ext}. The regression excluded three points from July 7, 2002; the monitors were directly impacted by Canadian fires whose emissions were not modeled.

CMAQ prediction of the B_{ext} agrees well with IMPROVE observation because CMAQ performs well on sulfate, which dominates aerosol extinction. Further, the modeled haze index (HI) is calculated based on modeled B_{ext}. Figure 2-17 presents the paired comparison between CMAQ prediction and IMPROVE measurement for 2002 of HI values at seven Class I sites in the eastern U.S.. Acadia and Moosehorn show the best model performance with regression slopes of 0.97 and r^2 of ~0.6., The poorest model performance occurs at Lye Brook and Shenandoah, with regression slopes less than 0.6 and r^2 of ~0.3. Note the regression equations and best fit lines are not plotted.

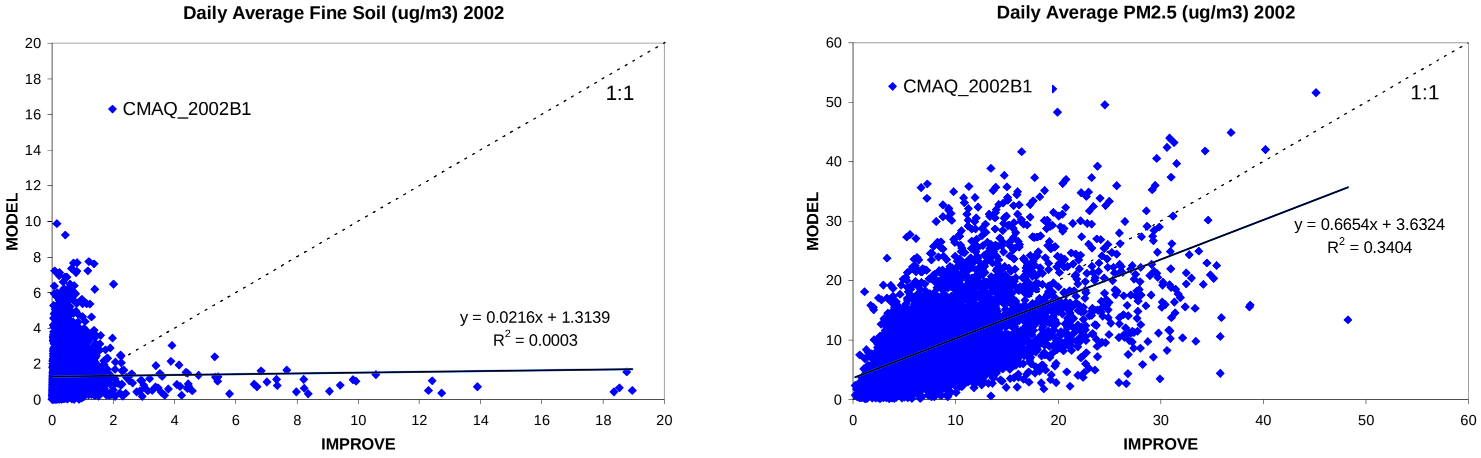
Figure 2-11. Domain-wide paired comparison of daily average $PM_{2.5}$ species between CMAQ predictions and measurements from IMPROVE networks


$PM_{2.5}$ **Sulfate**

$PM_{2.5}$ **Nitrate**


$PM_{2.5}$ **Organic Carbon**

$PM_{2.5}$ **Elemental Carbon**


$PM_{2.5}$ **Soil**

$PM_{2.5}$

Figure 2-12. Spatial distribution of correlation coefficient between $PM_{2.5}$ Sulfate and measurement

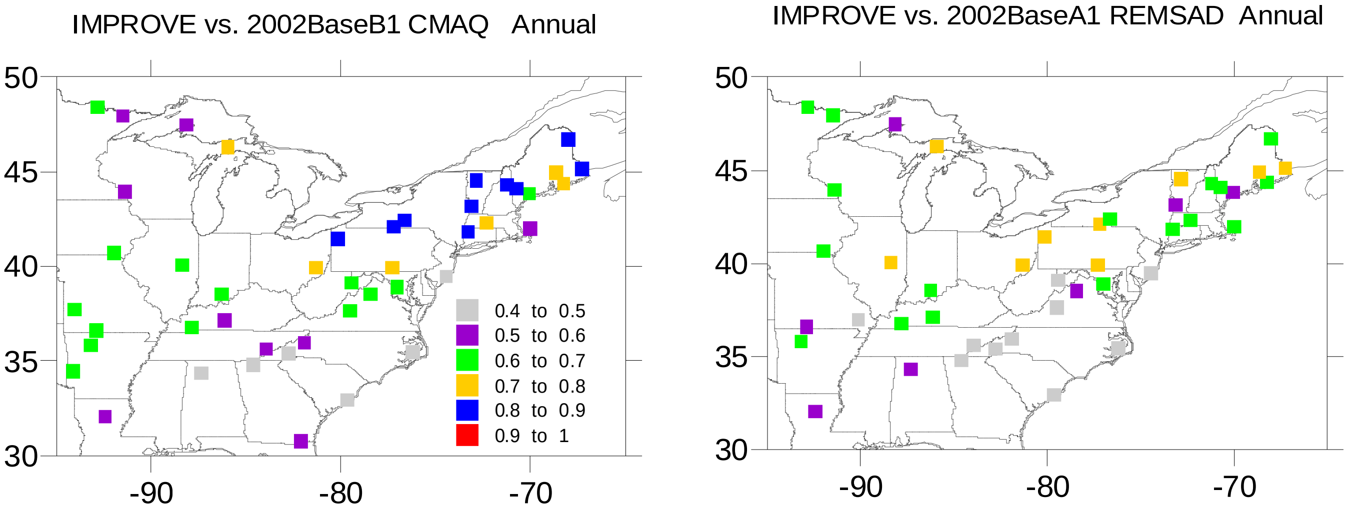


Figure 2-13. Spatial distribution of correlation coefficient between $PM_{2.5}$ and measurement

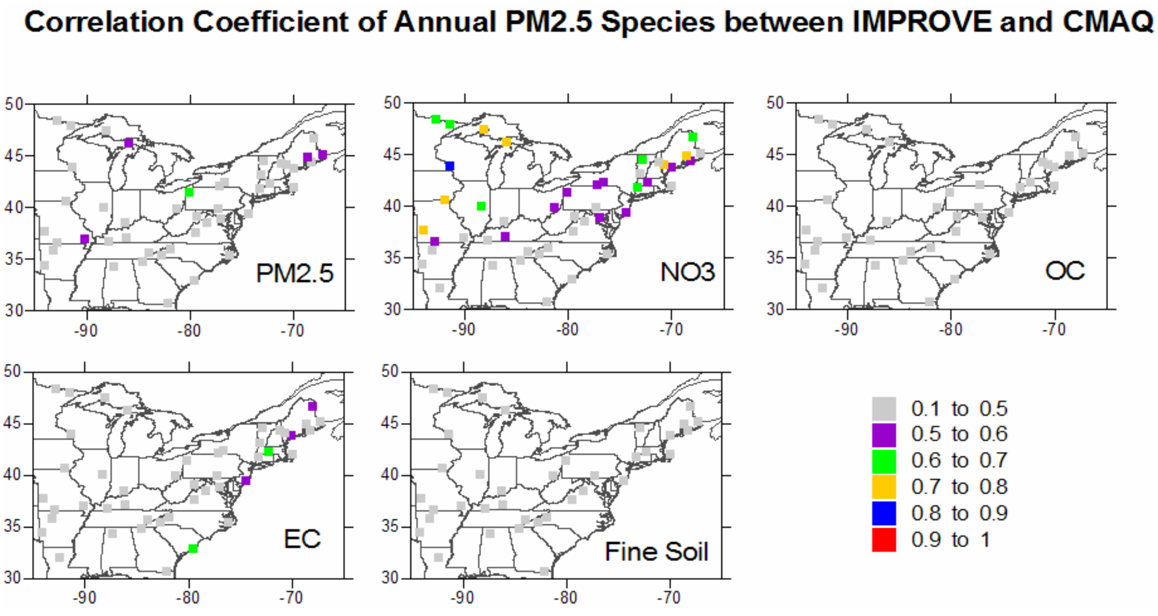
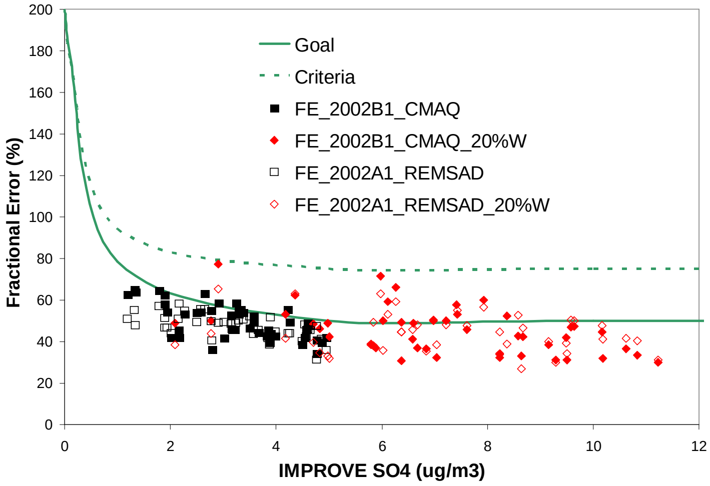
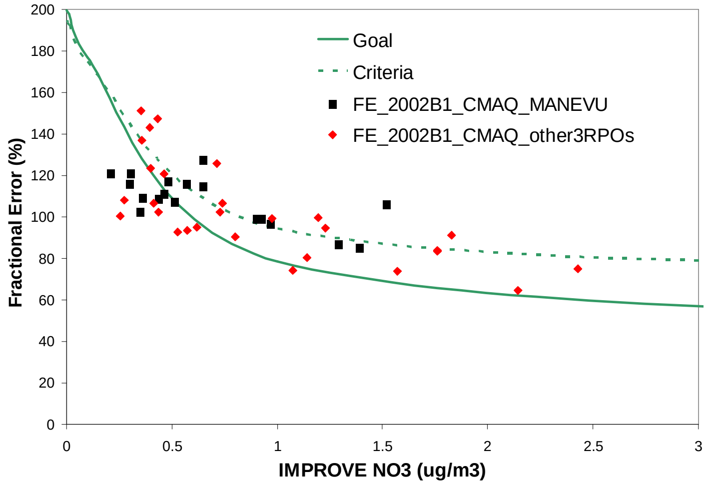


Figure 2-14. Mean Fractional Error of $PM_{2.5}$ species within MANE-VU region

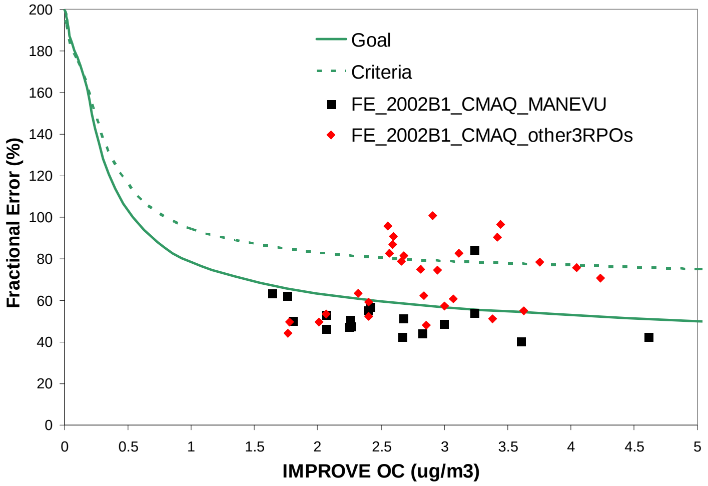
$PM_{2.5}$ Sulfate



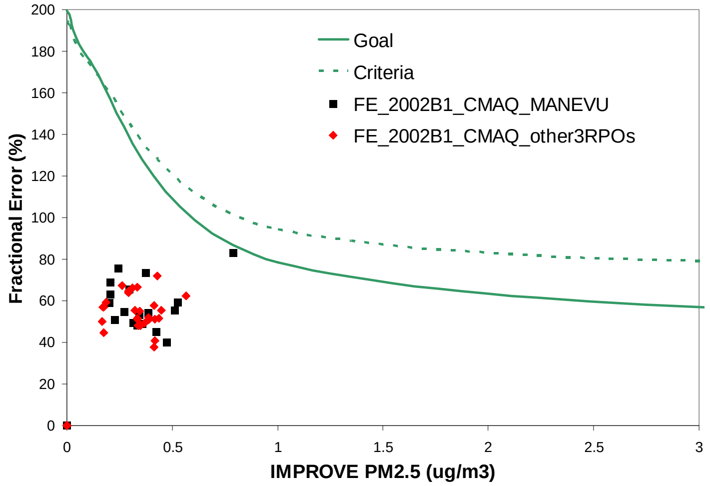
$PM_{2.5}$ Nitrate



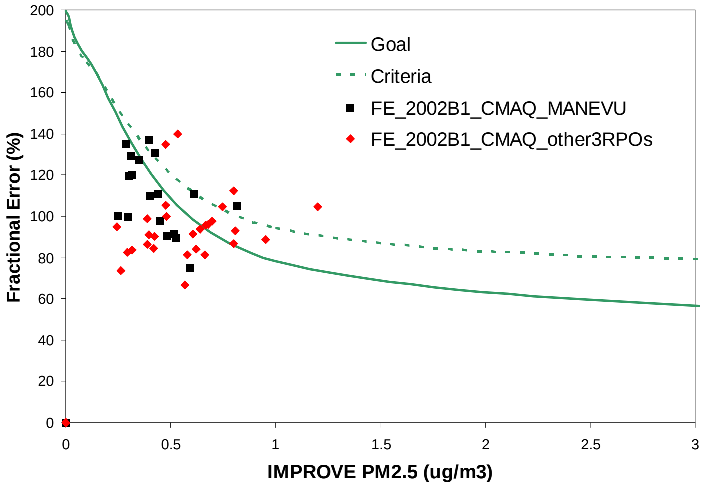
$PM_{2.5}$ Organic Carbon



$PM_{2.5}$ Elemental Carbon



$PM_{2.5}$ Soil



$PM_{2.5}$

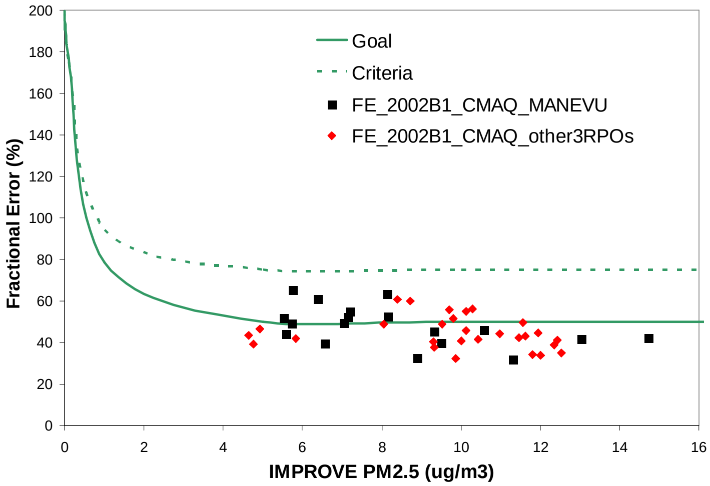
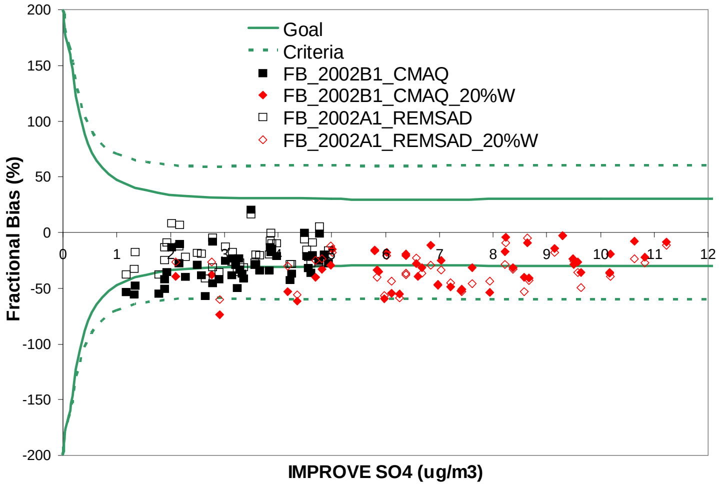
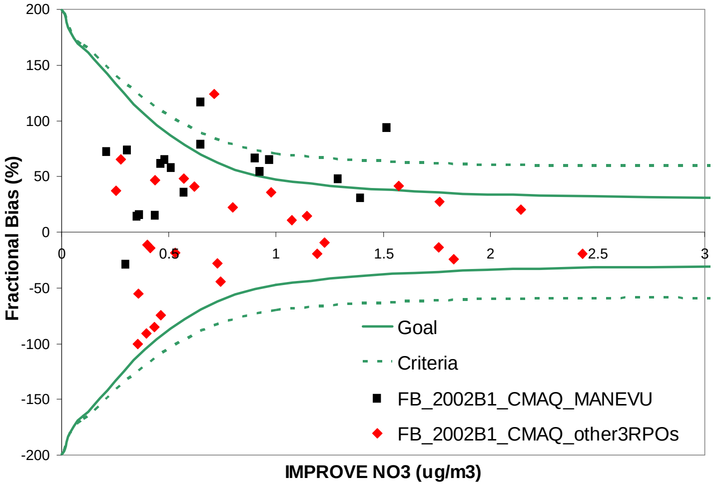


Figure 2-15. Mean Fraction Bias of $PM_{2.5}$ species within MANE-VU region

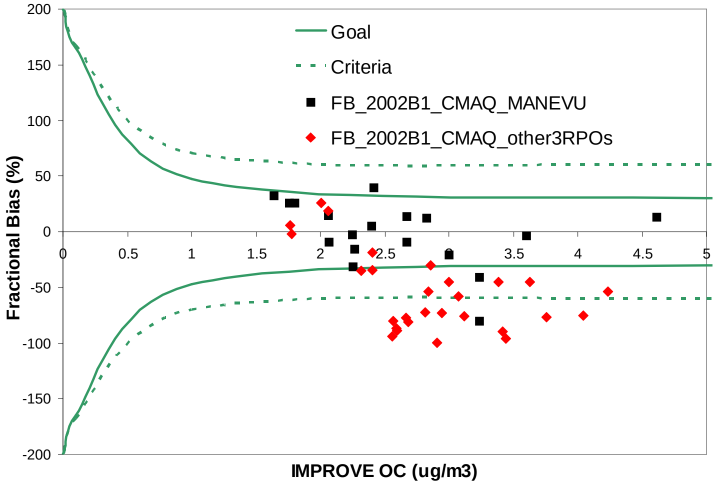
$PM_{2.5}$ Sulfate



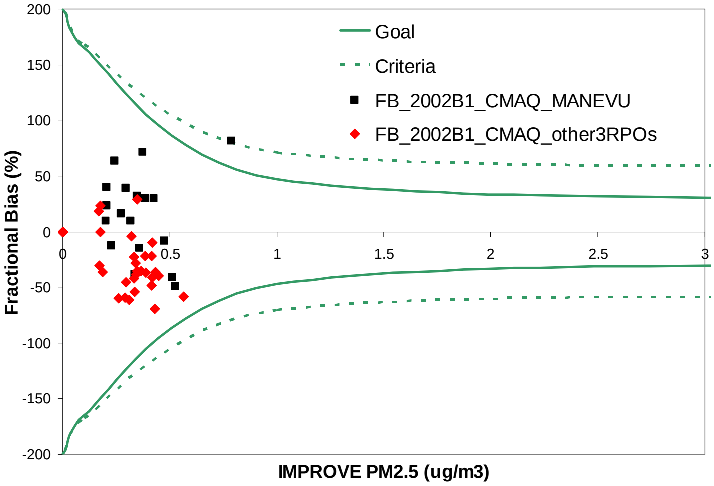
$PM_{2.5}$ Nitrate



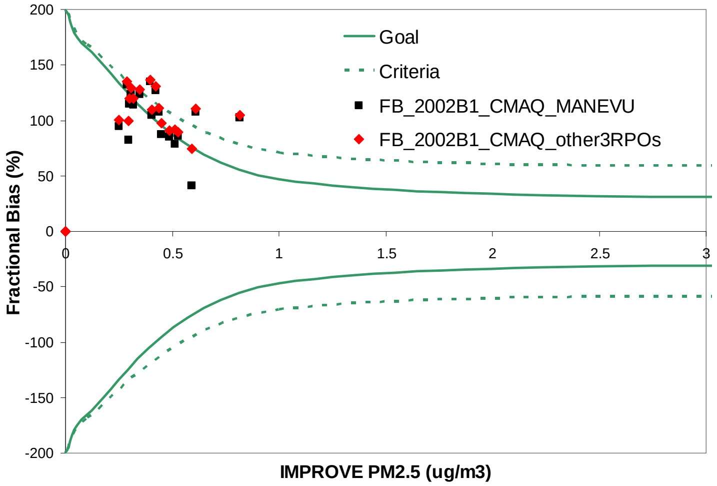
$PM_{2.5}$ Organic Carbon



$PM_{2.5}$ Elemental Carbon



$PM_{2.5}$ Soil



$PM_{2.5}$

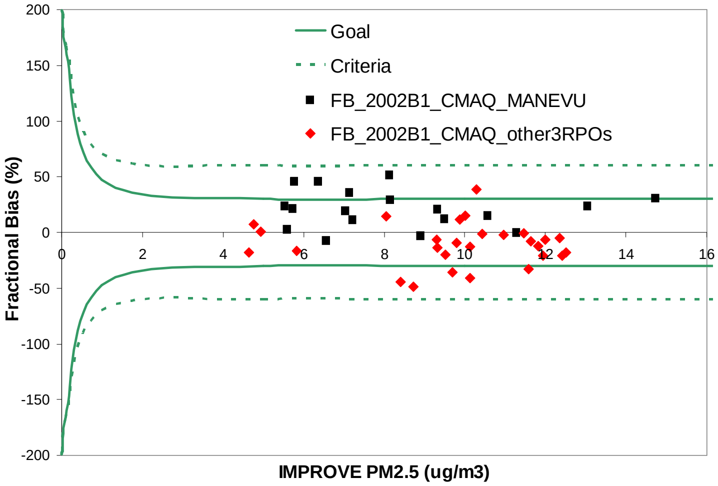


Figure 2-16. Paired comparison of extinction coefficient between CMAQ prediction and IMPROVE measurement

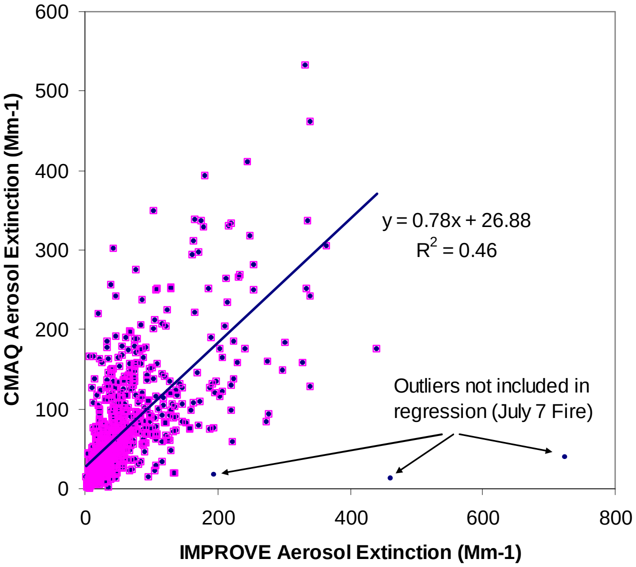
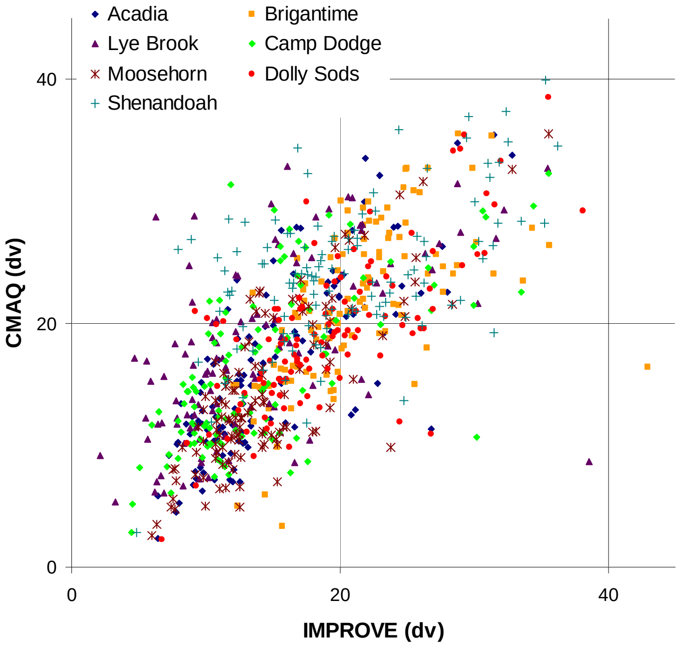


Figure 2-17. Paired Comparison of Haze Index between CMAQ prediction and IMPROVE measurement at selected Class I sites



3. 2018 BOTW PROJECTIONS

In order to assess the projected visibility improvement at MANE-VU Class I areas prior to consideration of potential reasonable measures for adoption in a long-term emissions management strategy, a simulation of the MANE-VU "Beyond on the Way" (BOTW-1) inventory was conducted. As indicated in Chapter 2, this inventory/scenario combination represents additional measures beyond existing regulations that have been accepted by the OTC Modeling Committee for attainment of the 8-hour ozone and $PM_{2.5}$ NAAQSs. These measures include regulations on portable fuel containers, architectural and maintenance (AIM) coatings, and some consumer products. In addition, at the point that this inventory was "closed" for further changes, most states had indicated a willingness to adopt regulations limiting fuel sulfur content of distillate fuel oil to 500 ppm or lower.[4] While all states have subsequently agreed that they will pursue regulation of distillate AND residual fuel oil and that these regulations would cap distillate at 15 ppm fuel sulfur content by 2018, this additional level of reduction is not reflected in the BOTW-1 simulation discussed below.

The BOTW-1 scenario was processed through SMOKE for 2009 by NYDEC and for 2018 by NESCAUM and distributed to the other modeling centers in a manner similar to the 2002 base year scenario that was SMOKE processed by NYDEC. After each center had completed its portion of the processing, NESCAUM obtained the results for all projection years for analysis of haze metrics.

The results of this run are shown in Table 3-1 and Figures 3-1 and 3-2, which show relative reduction factors at each Class I area by species and the overall projected improvement in visibility in deciviews based on the 2009 (NYDEC) and 2018 (NESCAUM) BOTW-1 projections, respectively.

Table 3-1. 2018 twenty percent worst days relative reduction factors.

	Shenandoah	Dolly Sods	Brigantine	Great Gulf	Lye Brook	Moosehorn	Acadia
Sulfate	0.49	0.51	0.53	0.59	0.58	0.63	0.60
Nitrate	0.46	0.63	0.95	0.87	0.91	0.73	0.80
EC	0.58	0.71	0.62	0.73	0.67	0.77	0.75
OC	0.88	0.92	0.98	0.86	0.93	0.95	0.95
Sea Salt	1	1	1	1	1	1	1
Soil	1.27	1.26	1.28	1.16	1.13	1.09	1.10

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[4] Delaware and Vermont had not given an indication by the time the inventory was closed.

Figure 3-1. Projected improvement in visibility at four Northeast sites based on 2009 and 2018 BOTW-1 projections.

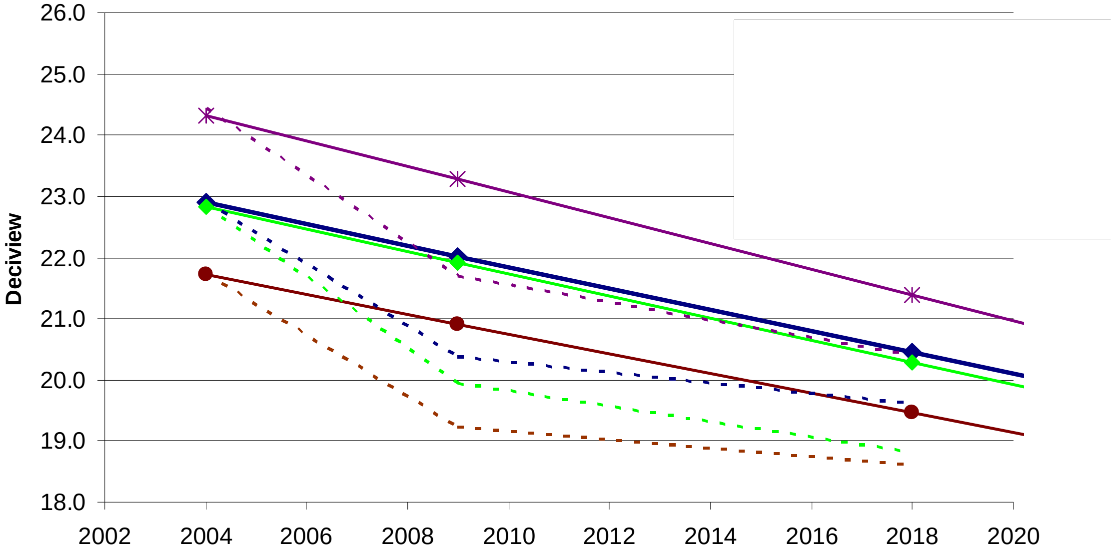
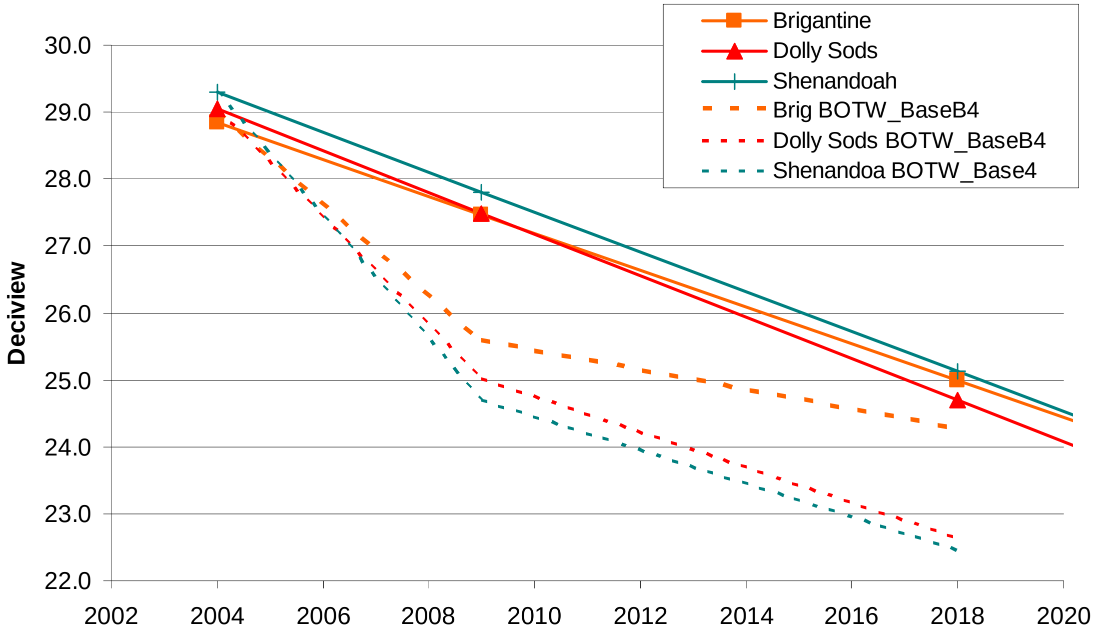


Figure 3-2. Projected improvement in visibility at three Mid-Atlantic sites based on 2009 and 2018 BOTW-1 projections.



The projections for the BOTW-1 scenario indicate that the adoption of 500 ppm distillate regulations by all MANE-VU states is sufficient to achieve visibility improvements beyond the uniform rate of progress defined by the 2064 natural conditions visibility goal. However, it should be noted that USEPA guidance for setting reasonable progress goals asks states to consider reviewing all measures identified through the four-factor analysis process and to adopt each measure that is determined to be reasonable.

While the interpretation of USEPA guidance on this subject continues to be debated by various stakeholders and some states outside the MANE-VU region, MANE-VU believes that the four-factor analysis provisions in the Clean Air Act requires states to analyze additional measures and adopt those that are reasonable. We have identified and analyzed several additional measures for consideration in determining regional haze reasonable progress goals and these options are explored in Chapter 5.

4. 2018 POLLUTION APPORTIONMENT

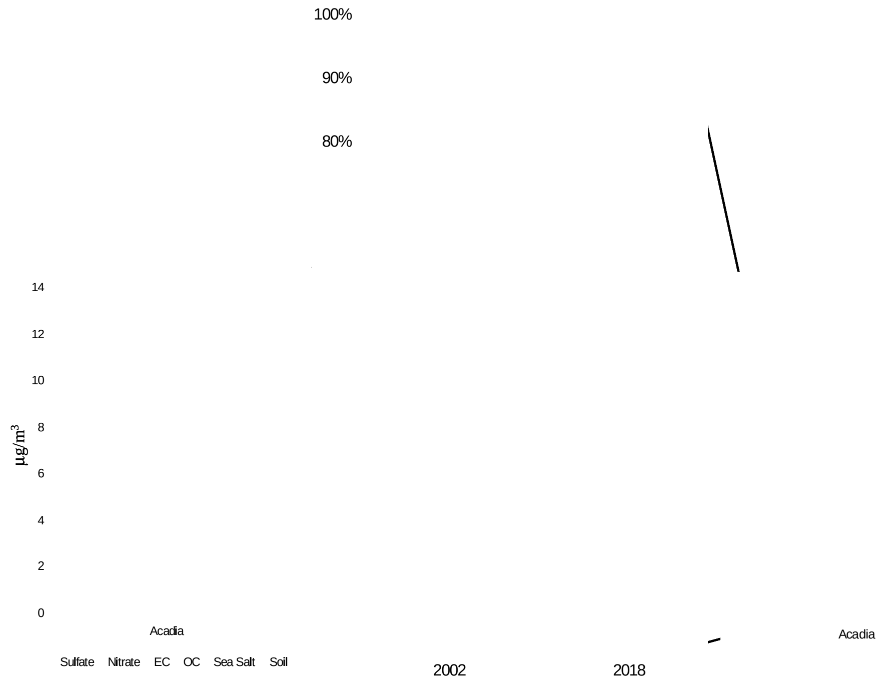
One requirement of the regional haze rule is a “pollution apportionment” that provides an assessment of the major contributors to MANE-VU visibility impairment by geographical region or by sector. MANE-VU had conducted an extensive apportionment of 2002 visibility impairment from sulfate in the prior *Contribution Assessment* report (NESCAUM, 2006a) and conceptual description (NESCAUM, 2006b). In order to update this work to reflect changes in the contributions by various states to visibility impairment projected for 2018, we have utilized the 2018 BOTW emission inventory and tagged all SO_2 emissions from each of 29 states in the eastern U.S. This required three separate runs with 11 tags per run. In addition, three tags for baseline (2002) boundary conditions (**N**orth, **S**outh_**E**ast, and **W**est) provide an estimate for sulfate contributions external to the model domain. Note their contribution includes emissions that originated within the domain, but were advected out of the modeling domain only to recirculate back into the domain (i.e. the state-specific tagged contributions represent, in this sense, a lower-bound).

This tagging scheme provides a comprehensive reporting of the influence of most of these states to visibility impairment within the model domain. It also provides a partial accounting of the influence of several states along the western and southern edge of the model domain where only a portion of the states’ emissions were tracked.

Results indicate that the relative contribution of states within the domain will decrease significantly due, in large part, to the anticipated SO_2 emissions reductions from the CAIR program. As a result, we see large *increases* in the *relative* contribution from Canada and the boundaries. This apparent increase is simply due to the fact that we are showing relative contributions and as a share of the total, these fixed contributions contribute a larger share after CAIR has reduced the contribution within the domain.

Figures 4-1 through 4-5 show the absolute magnitude of measured and projected sulfate at each MANE-VU class I monitor as well as the relative contributions of each state to that sulfate as contrasted against their 2002 contributions.

Figure 4-1. a. Measured and projected mass contributions in 2002 and 2018 at Acadia National Park on twenty percent worst visibility days.



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

b. 2002 and 2018 sulfate mass from at Acadia National Park, twenty percent worst days apportioned by REMSAD

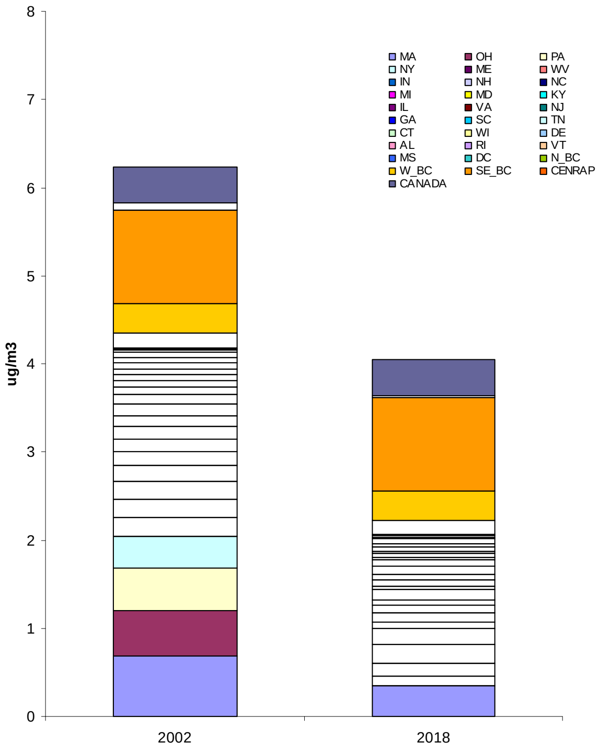
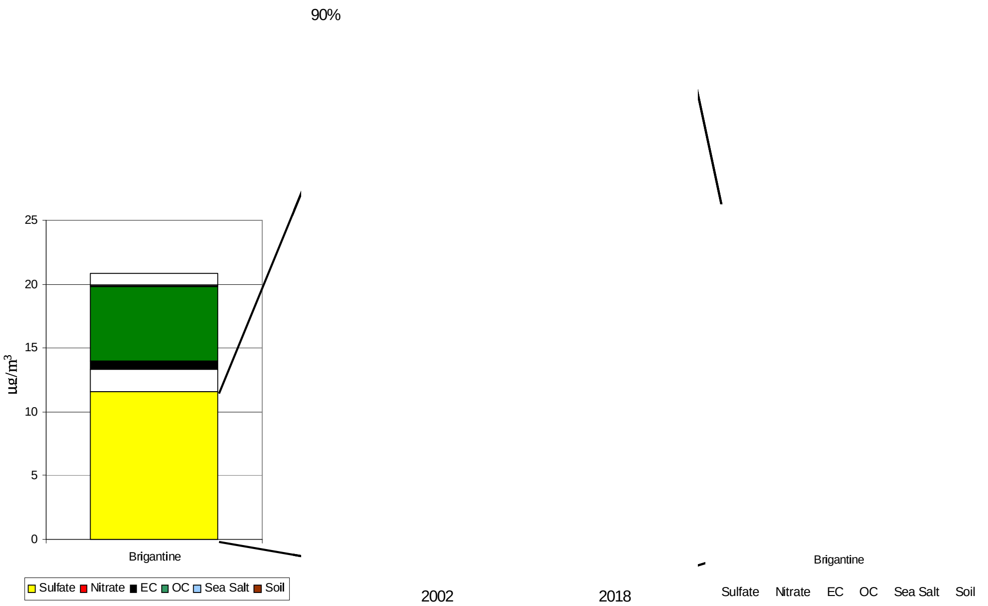


Figure 4-2. a. Measured and projected mass contributions in 2002 and 2018 at Brigantine Wildlife Refuge on twenty percent worst visibility days.



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

b. 2002 and 2018 sulfate mass from Brigantine Wildlife Refuge, twenty percent worst days from REMSAD

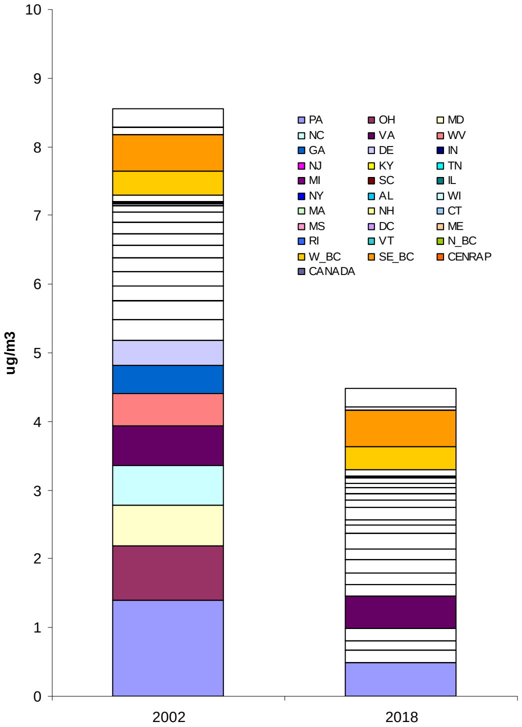
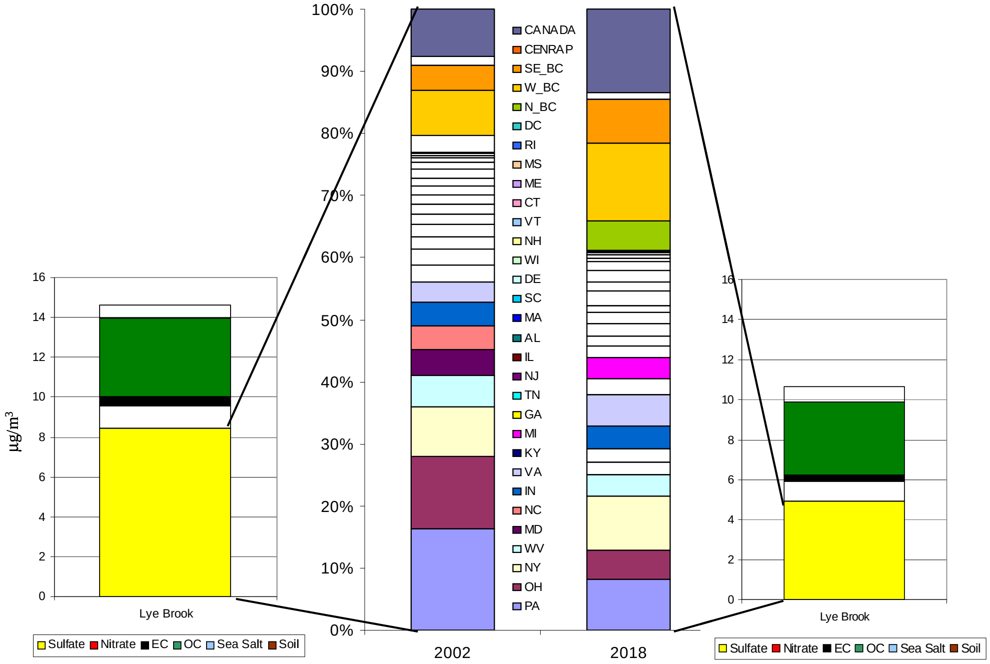


Figure 4-3. a. Measured and projected mass contributions in 2002 and 2018 at Lye Brook Wilderness Area on twenty percent worst visibility days.



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

b. 2002 and 2018 sulfate mass from Lye Brook Wilderness Area, twenty percent worst days from REMSAD

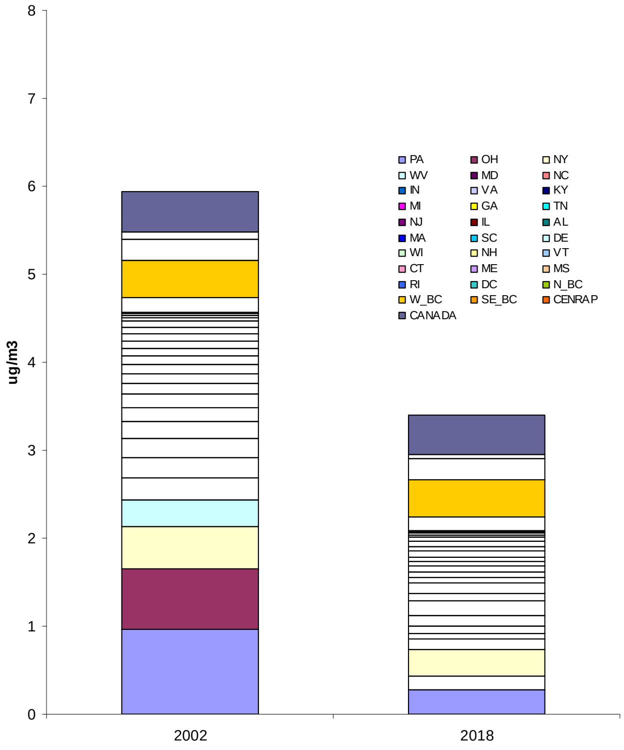
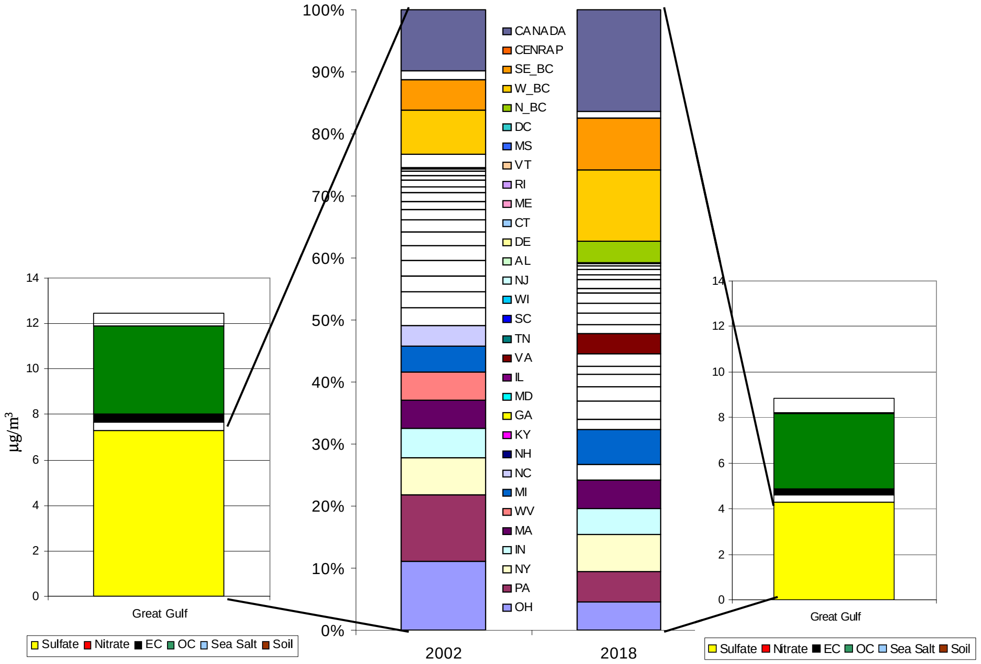


Figure 4-4. a. Measured and projected mass contributions in 2002 and 2018 at Great Gulf Wilderness Area on twenty percent worst visibility days.



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

b. 2002 and 2018 sulfate mass from Great Gulf Wilderness Area, twenty percent worst days from REMSAD

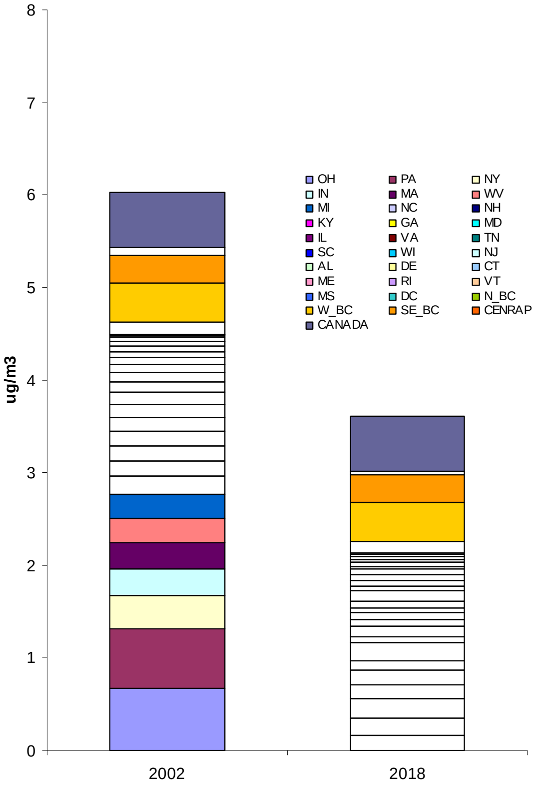
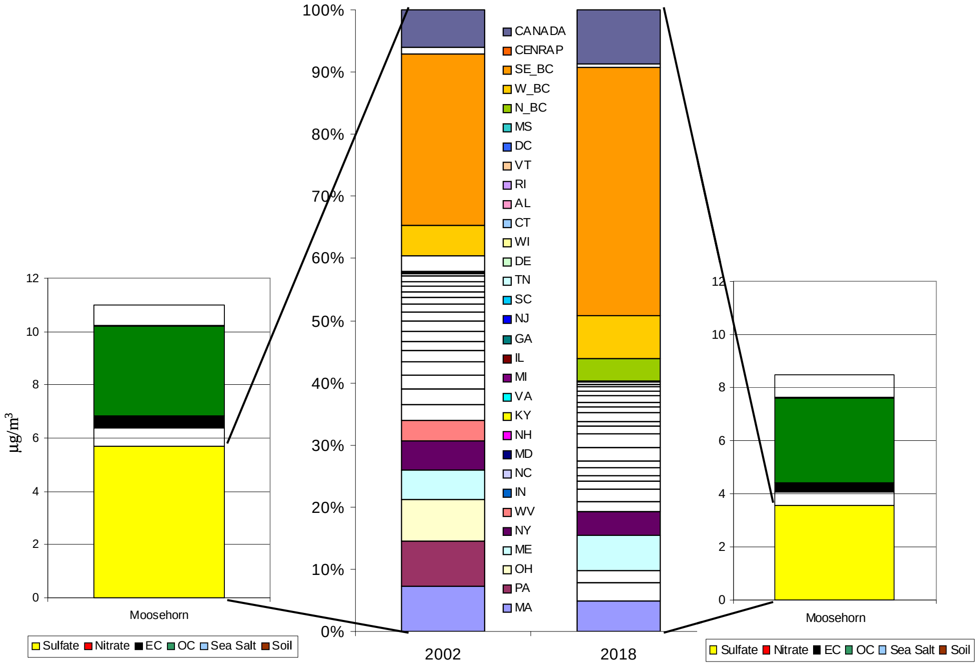
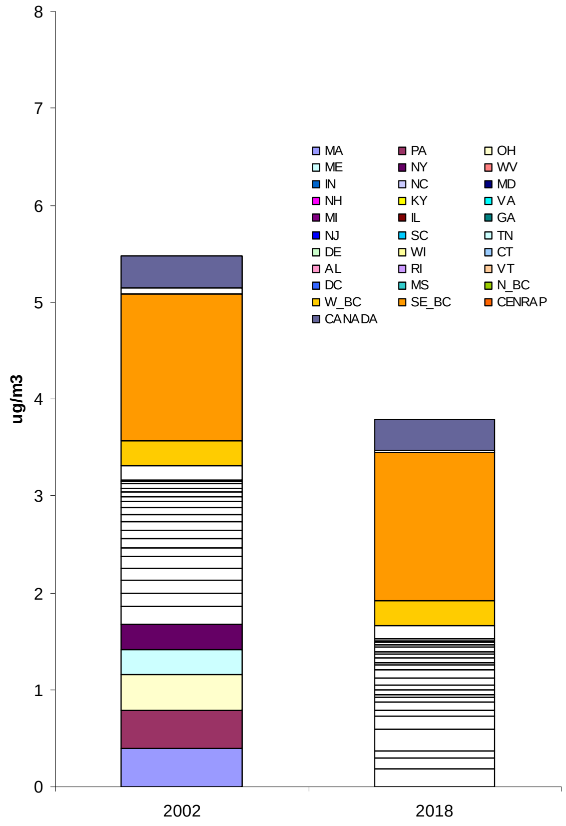


Figure 4-5. a. Measured and projected mass contributions in 2002 and 2018 at Moosehorn National Wildlife Refuge on twenty percent worst visibility days.



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

b. 2002 and 2018 sulfate mass from Moosehorn National Wildlife Refuge, twenty percent worst days from REMSAD



5. CONTROL STRATEGY EVALUATION

We evaluated the visibility benefits of four potential control strategies aimed at reducing regional haze at Class I areas in the MANE-VU region beyond what has been included in the “OTB/OTW” scenario described earlier. These programs include two separate but linked low-sulfur content fuel initiatives (the S1 and S2 strategies), the BART provisions of the Regional Haze Rule, and controls on EGUs at the 167 stacks most likely to affect MANE-VU Class I areas (“167 EGU strategy”). This chapter reviews the control strategies in more detail, describes the potential emissions reductions, and evaluates the potential visibility benefits of each strategy in combination with the others.

5.1. Reduced sulfur fuel content (S1 and S2)

The MANE-VU states have agreed through consultations to pursue a low sulfur fuel strategy within the region. This phased strategy would be implemented in two steps; however, both components of the strategy are to be fully implemented by 2018. We have analyzed both steps of the program as separate strategies, but it is the combined benefit of implementing the program that is relevant to the question of program benefits in 2018.

The S1 strategy involves the lowering of fuel-sulfur content in distillate (No. 2 oil) from current levels that range between 2,000 and 2,300 ppm down to 500 ppm by weight. It also restricts the sale of heavier blends of residual oil (No. 4 fuel oil and No. 6 bunker fuels) that have sulfur content greater than 0.25 percent sulfur and 0.5 percent sulfur by weight, respectively. The S2 strategy further reduces the fuel-sulfur content of the distillate fraction to 15 ppm sulfur by weight. The residual oil is maintained at the same S1 level for this strategy.

The S1 strategy and S2 strategy are to be implemented in sequence with slightly different timing for an “inner zone”[5] and the remainder of MANE-VU. All states, however, have agreed to pursue the adoption and implementation of an “emission management” strategy, as appropriate and necessary, to reduce the sulfur content of distillate oil and residual fuel oil as specified in the MANE-VU statements adopted June 20, 2007 by the MANE-VU Board. Thus for the purposes of this analysis, we have examined the benefits of the S1 and S2 strategies separately below.

Based on the fuel sulfur limits within the S1 strategy, we estimated a decrease of 140,000 tons of SO_2 emitted from distillate combustion and 40,000 tons of SO_2 from residual combustion in MANE-VU. Figure 5-1 displays the resulting average change in 24-hr average $PM_{2.5}$ between the baseline case (OTB/OTW) and the control case where the S1 fuel strategy has been implemented.

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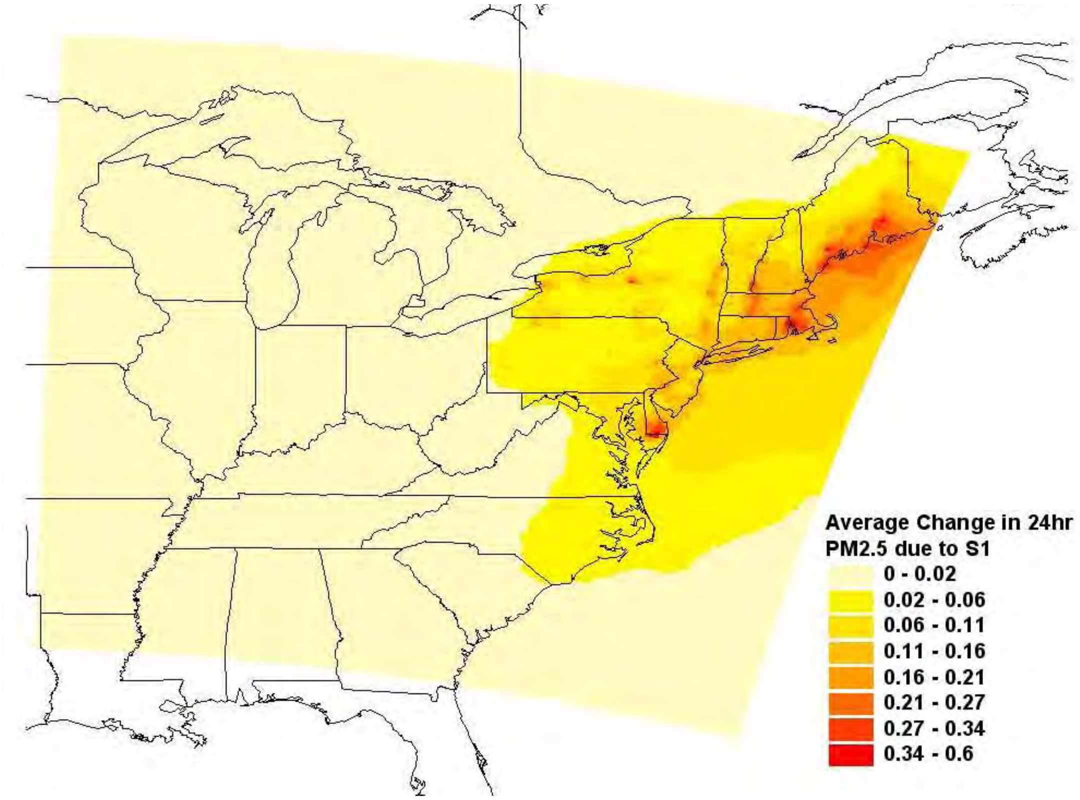
[5] The inner zone includes New Jersey, Delaware, New York City, and potentially portions of eastern Pennsylvania.

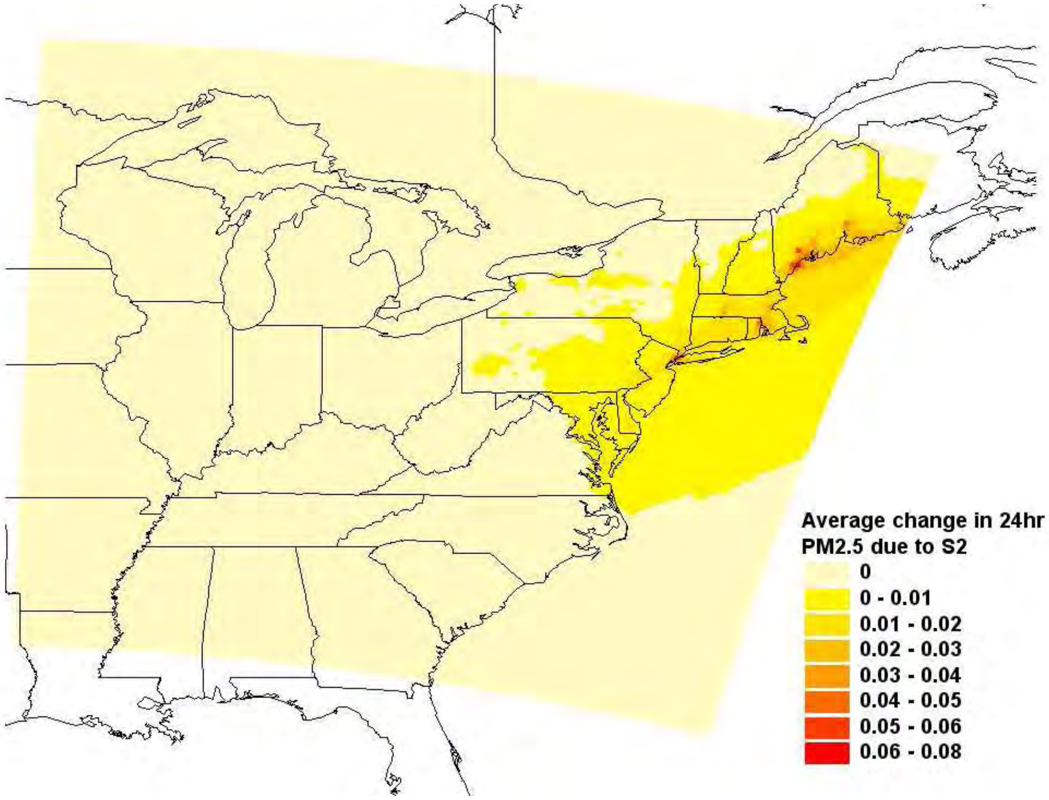
Figure 5-1. Average change in 24-hr $PM_{2.5}$ due to S1 emission reductions ($\mu g/m^3$)



We used the concentration changes in Figure 5-1 above to derive visibility benefits. Because the S1 fuel sulfur program only affects sources within MANE-VU, that region sees the largest $PM_{2.5}$ reduction and the greatest visibility benefits.

The S2 fuel strategy further reduces the sulfur content of distillate from 500 ppm to 15 ppm while keeping the sulfur limits on residual oils to 0.25 percent and 0.5 percent for No. 4 and No. 6 oils, respectively. By lowering the distillate fuel sulfur limit from 500 ppm to 15 ppm, we estimate an additional reduction of 27,000 tons of SO_2 emissions in MANE-VU from distillate combustion in 2018. Figure 5-2 displays the average change in 24-hr $PM_{2.5}$ calculated from CMAQ modeled concentrations between the S1 scenario and the S2 scenario. It reflects the predicted change in $PM_{2.5}$ due solely to the change from 500 ppm to 15 ppm distillate. Due to a high baseline fuel sulfur level, the incremental change in $PM_{2.5}$ concentration is much smaller between 500 ppm and 15 ppm than the baseline to 500 ppm levels observed in the S1 scenario.

Figure 5-2. Average change in 24-hr PM$_{2.5}$ due to S2 emission reductions, relative to S1 (μg/m^3)



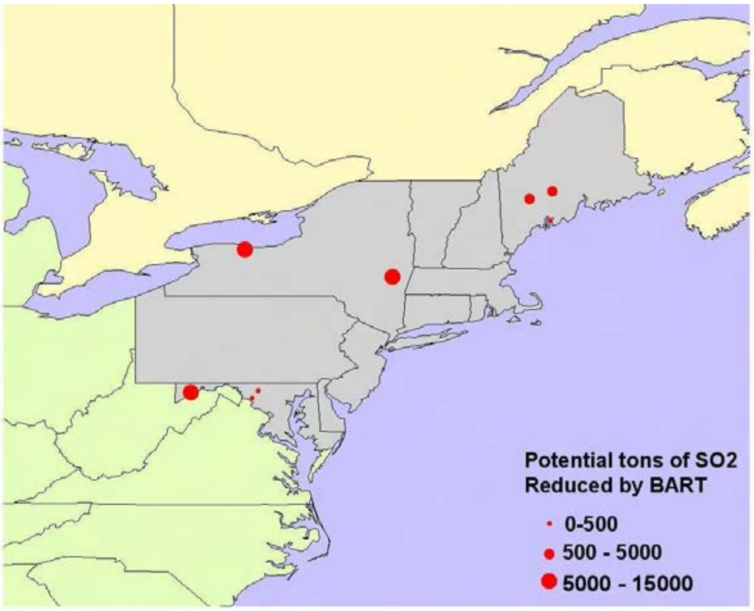
To determine the full benefit of the fuel strategies being considered relative to the OTB/OTW baseline, we can look at the combined benefits from the S1 (500 ppm distillate and 0.25/0.5 percent residual oil) strategy *and* the S2 (15 ppm distillate) strategy. The combined benefits can be gauged in Figures 5-6 through 5-14 and are shown in the results presented in Table 5-2 at the end of this section.

5.2. Best Available Retrofit Program (BART)

To assess the impacts of the implementation of the BART provisions of the Regional Haze Rule, we included estimated reductions anticipated for BART-eligible facilities in the MANE-VU region in the 2018 CMAQ modeling analysis. An inital survey of state staff indicated that these 14 units would likely be controlled under BART alone and were modeled in this analysis. These states provided potential control technologies and levels of control, which were in turn incorporated into the 2018 emission inventory projections. NESCAUM (2007) provides the survey approach. Updates to this preliminary assessment (including the removal of six Pennsylvania sources with combined emissions reductions of 6600 tons of SO_2) will be incorporated into the Best and Final modeling run scheduled to be completed in March, 2008. Figure 5-3 displays the locations of the BART sources and estimated SO_2 reductions expected in

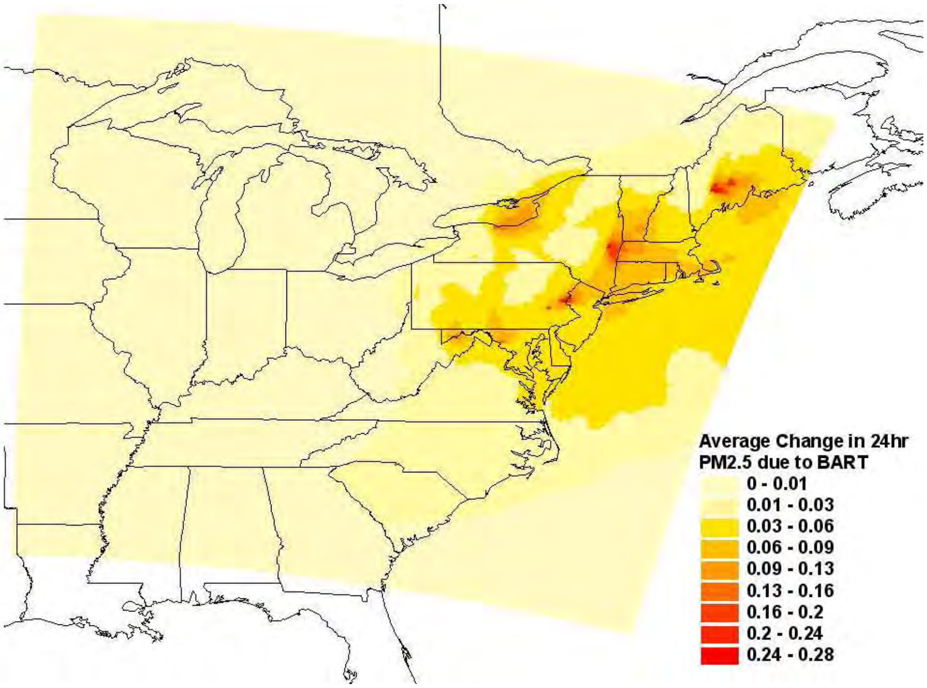
2018. Additional visibility benefits are likely to result from installation of controls at BART-eligible facilities that are located in adjacent RPOs. These benefits are not accounted for in the present analysis.

Figure 5-3. Potential reductions from BART-eligible sources in the MANE-VU region (tons)



We applied the SO_2 reductions at the initial 14 facilities relative to the 2018 OTB/OTW emissions inventory. Figure 5-4 shows the average change in 24-hr $PM_{2.5}$ concentrations within the modeling domain used to calculate the visibility benefits.

Figure 5-4. Average change in 24-hr $PM_{2.5}$ due to BART emission reductions ($\mu g/m^3$)



5.3. 167 EGU Strategy

The MANE-VU states have recognized that SO_2 emissions from power plants are the single largest contributing sector to the visibility impairment experienced in the Northeast's Class I areas. The SO_2 emissions from power plants continue to dominate the inventory. Sulfate formed through atmospheric processes from SO_2 emissions are responsible for over half the mass and approximately 70-80 percent of the extinction on the worst visibility days (NESCAUM, 2006a,b). In order to ensure that EGU controls are targeted at those EGUs with the greatest impact on visibility in MANE-VU, a modeling analysis was conducted to determine which sources those were. A list of 167 EGU stacks was developed (MANE-VU, 2007) that includes the 100 largest impacts at each MANE-VU Class I site during 2002. MANE-VU is currently asking for 90 percent control on all units emitting from those stacks by 2018 as part of consultations within MANE-VU and with other RPOs. MANE-VU recognizes that this level of control may not be feasible in all cases. The Best and Final modeling run currently underway will incorporate State comments gathered during the inter-RPO consultation process.

The "167 EGU strategy," if implemented as defined here, could lead to large reductions in SO_2 emissions due to installation of stack control technologies such as SO_2 scrubbers. To determine the possible health benefits of this EGU control program, we modeled 2018 emissions for the 167 EGUs in the Northeast, Southeast, and Midwest at levels equal to 10 percent of their 2002 emissions. We used CMAQ to model sulfate concentrations in 2018 after implementation of this control program and converted sulfate concentrations to $PM_{2.5}$ concentrations. Figure 5-5 displays the average change in 24-hr $PM_{2.5}$ seen between the OTB/OTW baseline and the EGU stack control program.

Figure 5-5. Average change in 24-hr $PM_{2.5}$ due to 167 EGU emission reductions ($\mu g/m^3$)

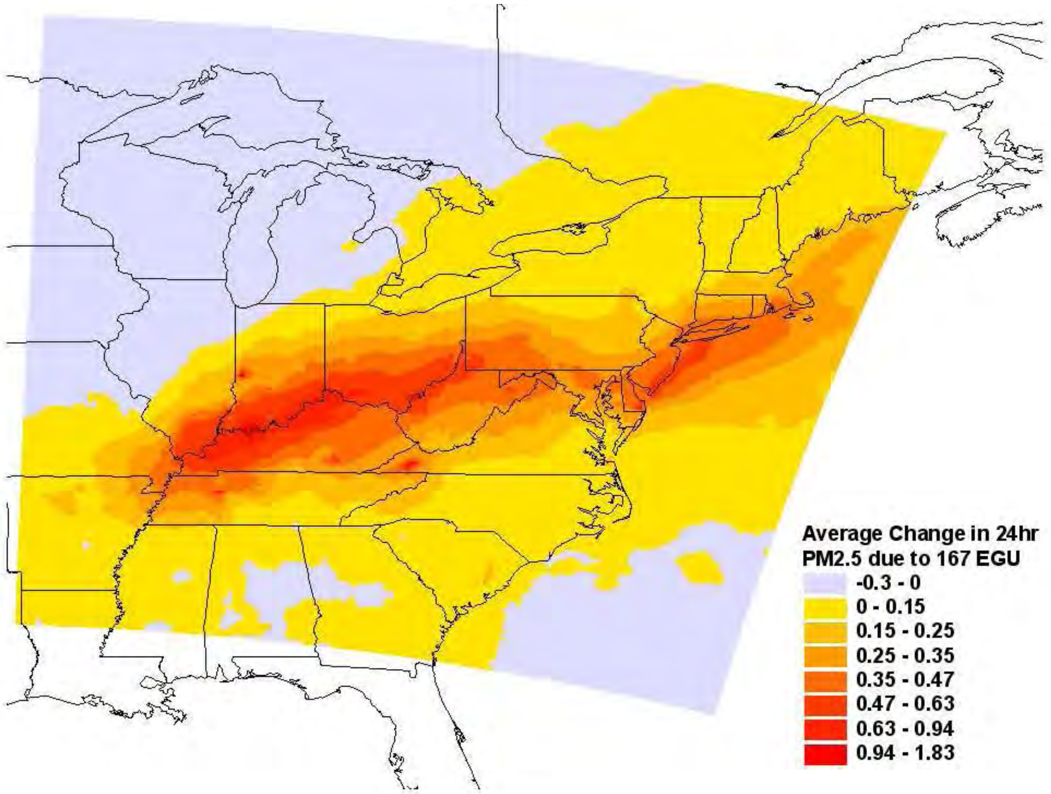


Figure 5-5 shows that significant reductions of $PM_{2.5}$ are predicted for the MANE-VU region as well as for portions of the VISTAS and Midwest RPO regions as a result of the targeted EGU strategy.

Figures 5-6 through 5-14 show the visibility benefits – relative to the uniform rate of progress determined our national visibility goal of natural conditions in 2064 – of the OTB/OTW scenario as well as for the four potential measures analyzed here. In addition to these measures, MANE-VU has asked neighboring RPOs to consider non-EGU emissions reductions comparable to our low sulfur fuel strategies, which are expected to achieve a greater than 28 percent reduction in non-EGU SO_2 emissions in 2018. The figures indicate that additional progress could be achieved depending upon what strategies are identified by VISTAS and the Midwest RPO in response to this request.

Figure 5-6. Visibility improvement relative to uniform rate of progress at Acadia National Park

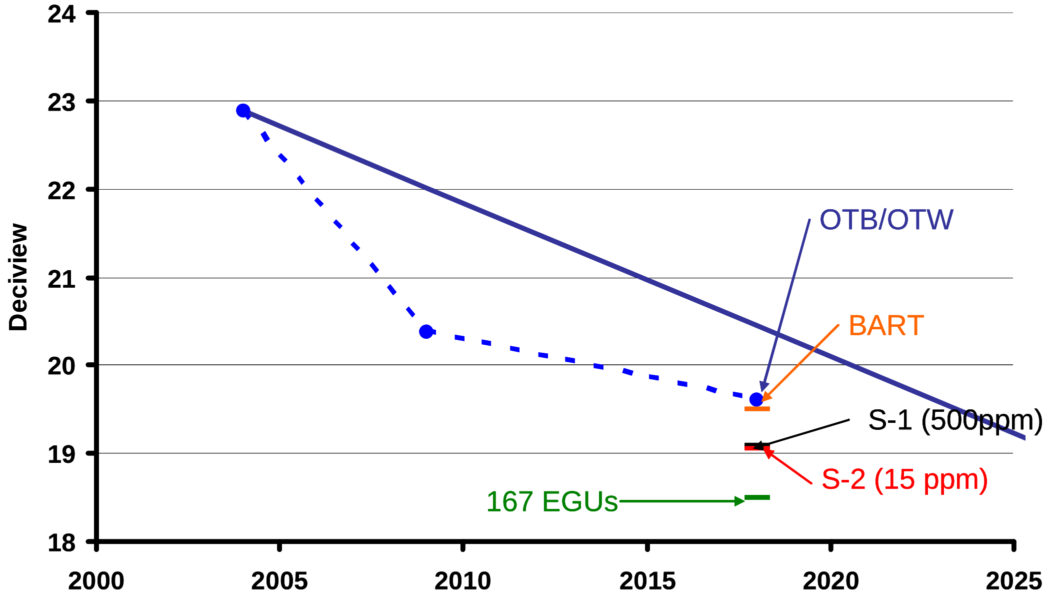


Figure 5-7. Visibility improvement relative to uniform rate of progress at Brigantine National Wildlife Refuge.

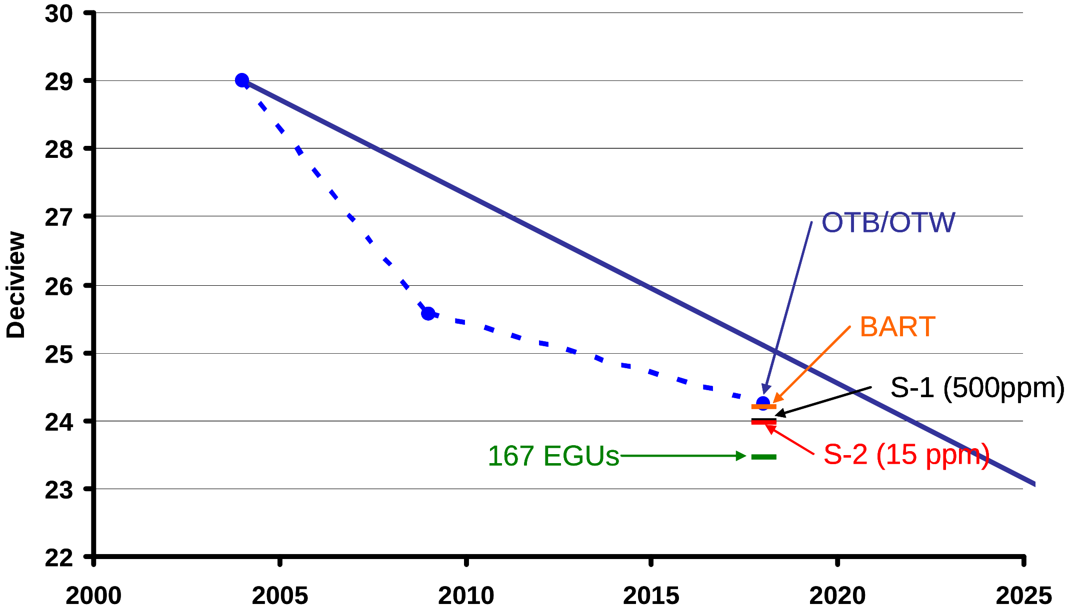


Figure 5-8. Visibility improvement relative to uniform rate of progress at Great Gulf Wilderness Area

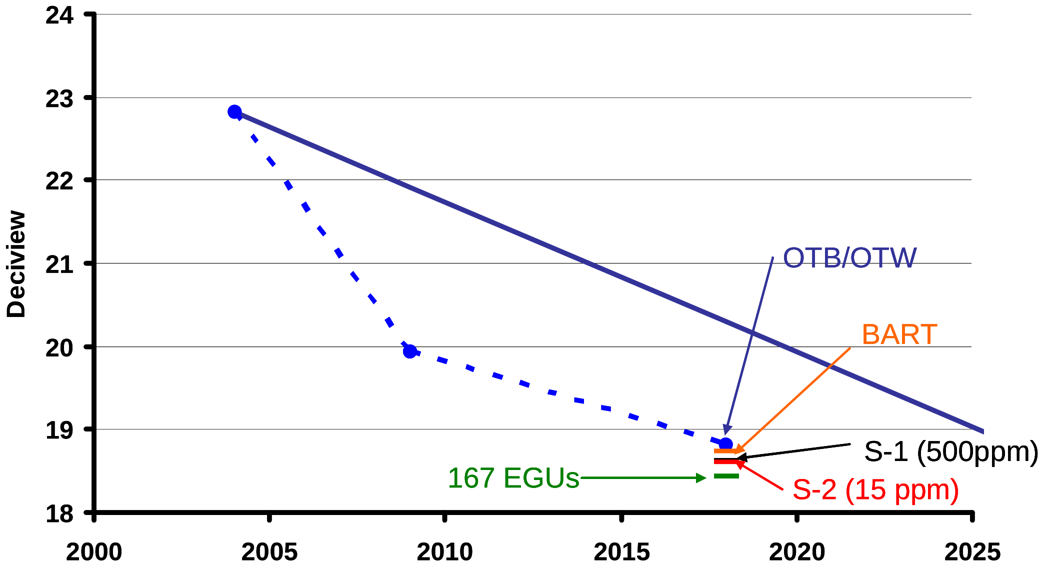


Figure 5-9. Visibility improvement relative to uniform rate of progress at Lye Brook Wilderness Area

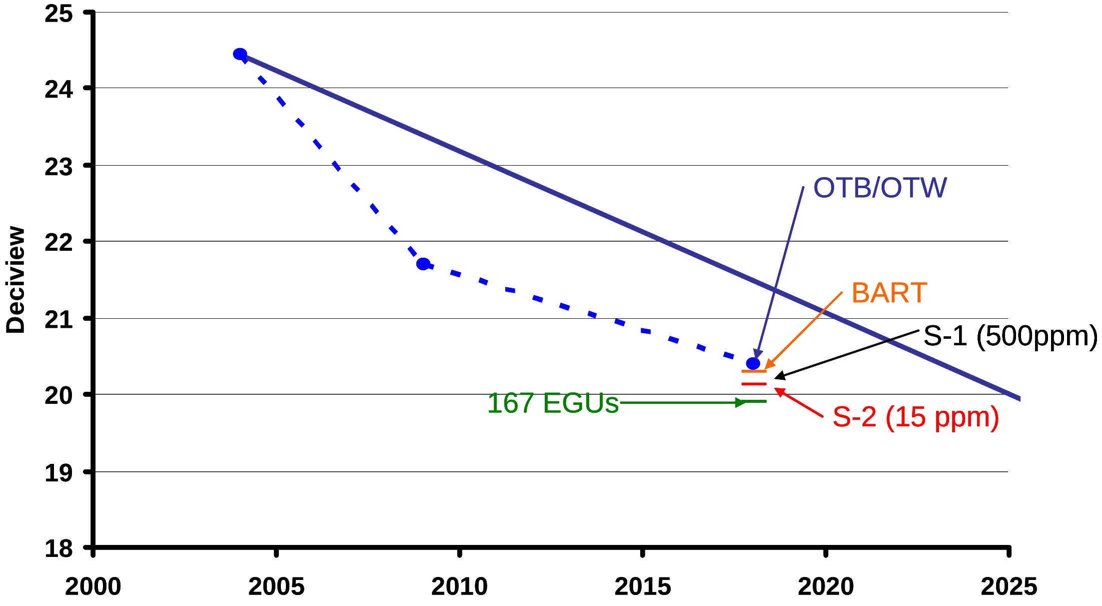


Figure 5-10. Visibility improvement relative to uniform rate of progress at Moosehorn National Wildlife Refuge

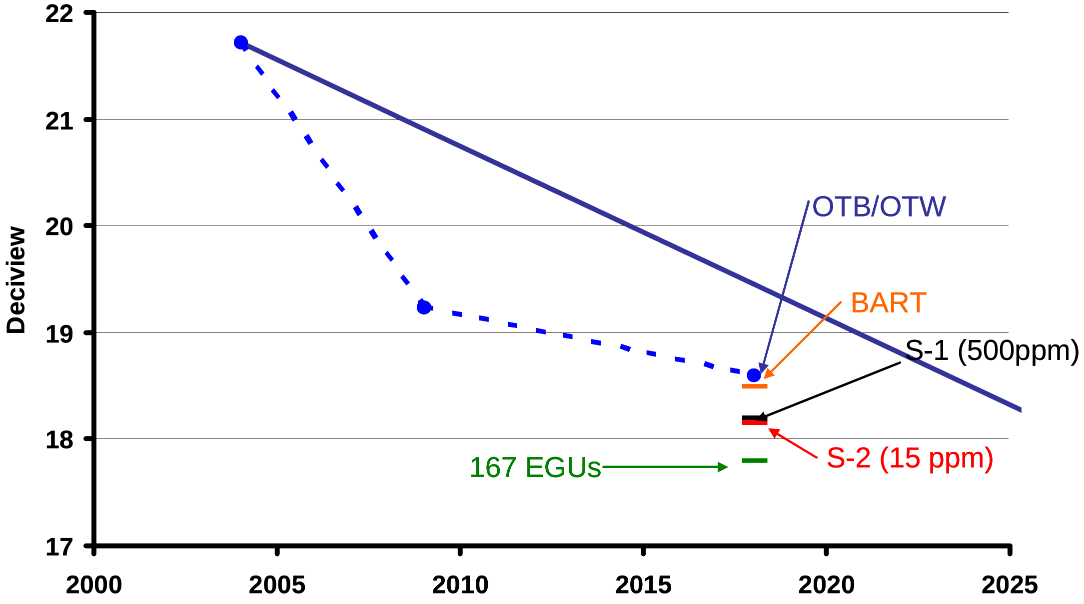


Figure 5-11. Visibility improvement relative to uniform rate of progress at Shenandoah National Park

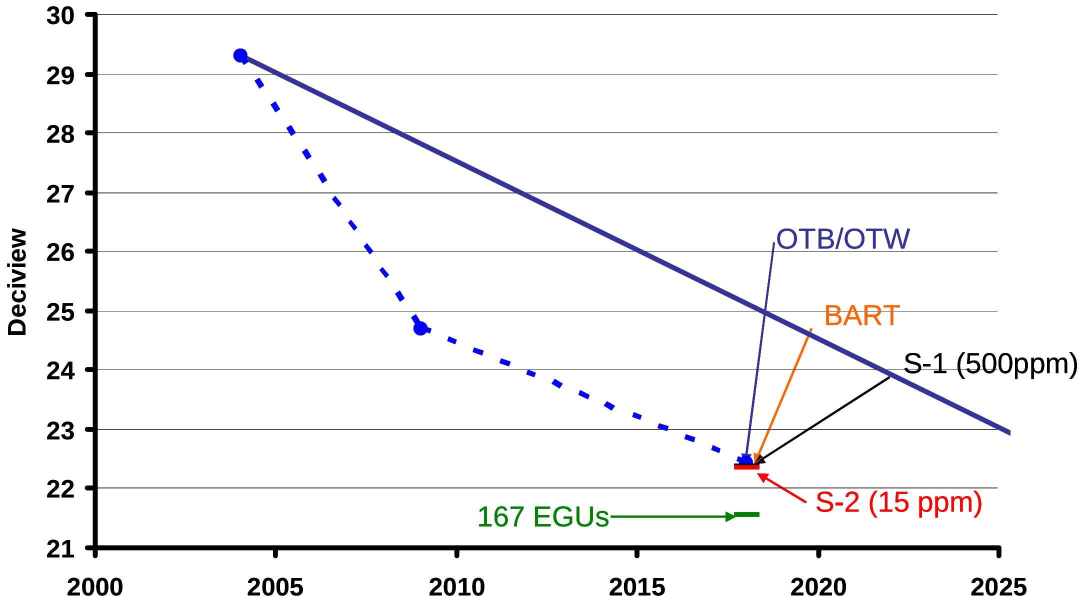


Figure 5-12. Visibility improvement relative to uniform rate of progress at Dolly Sods Wilderness Area

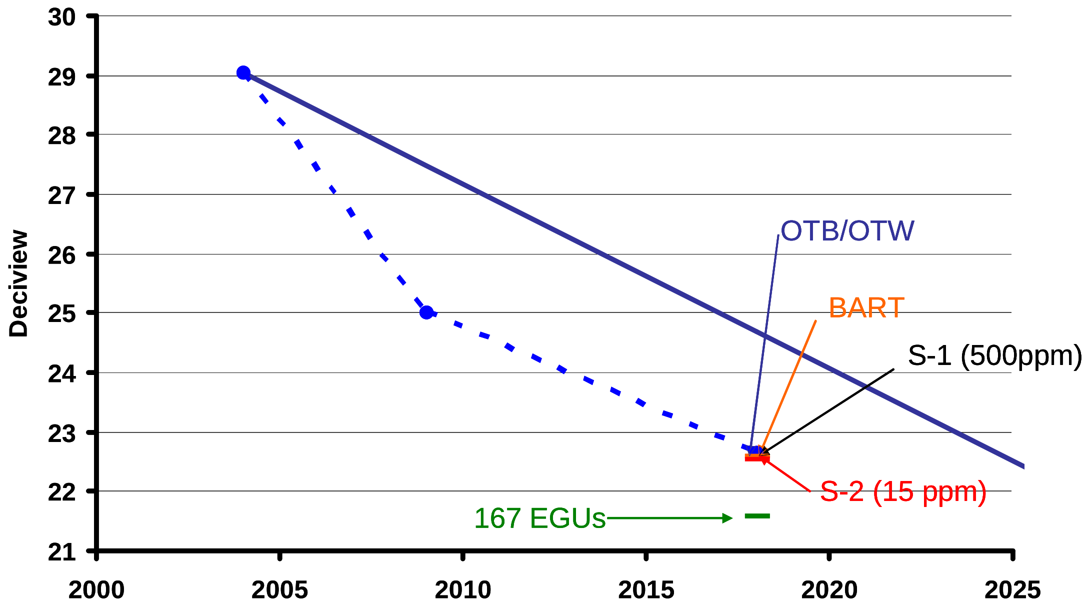


Figure 5-13. Visibility improvement relative to uniform rate of progress at Presidential Range-Dry River Wilderness Area

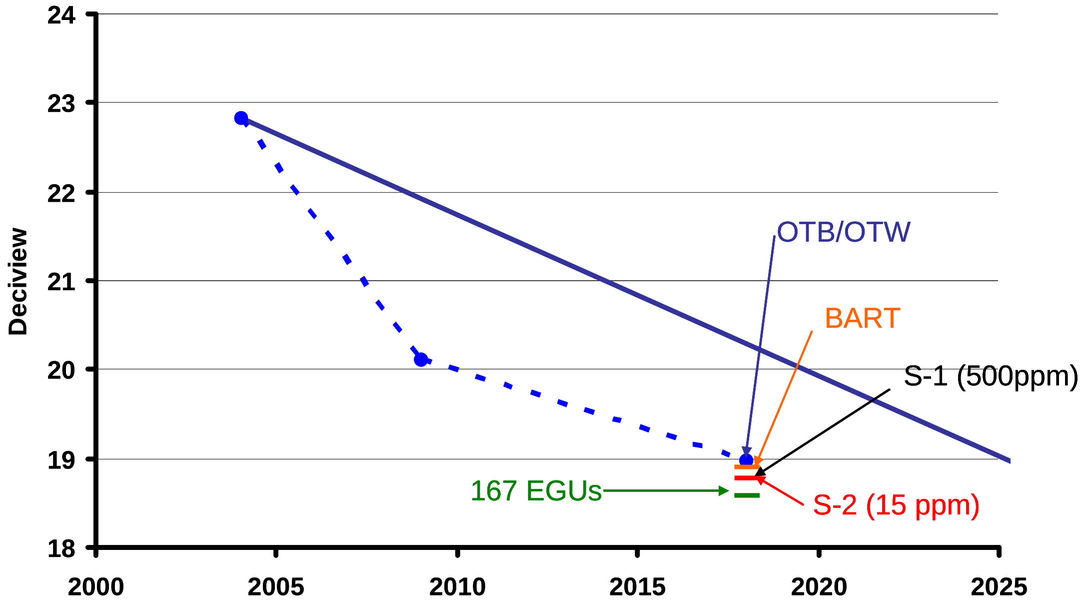
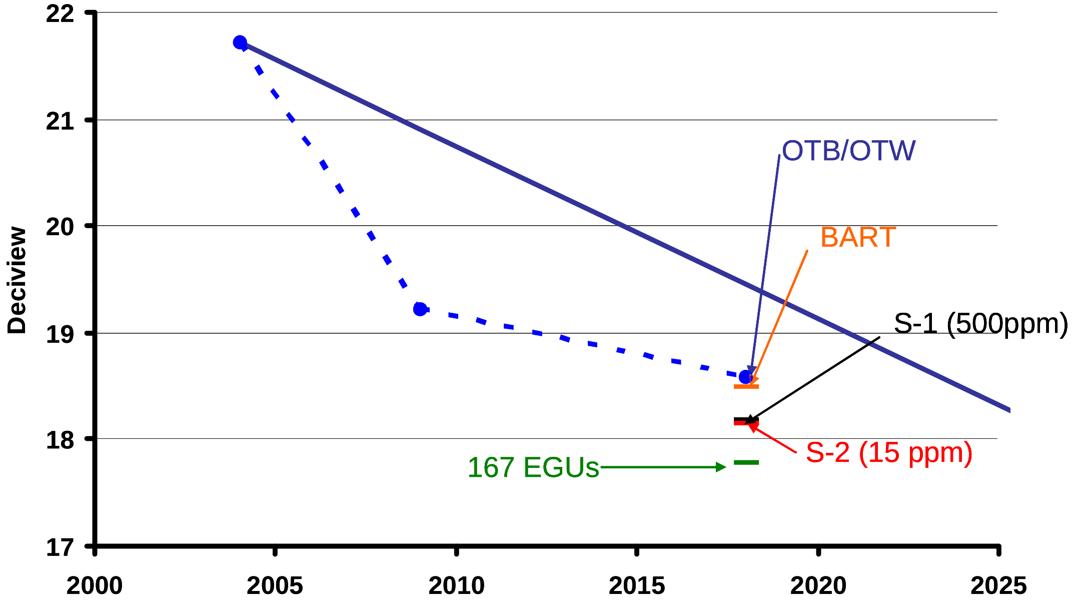


Figure 5-14. Visibility improvement relative to uniform rate of progress at Roosevelt-Campobello International Park



Tables 5-1 and 5-2 summarize the sulfate mass reductions and the deciview targets that represent the progress shown in the prior figures.

Table 5-1. Projected 2018 twenty percent worst day sulfate mass reduction at MANE-VU Class I areas under various control assumptions.

MANE-VU Class I Area	Baseline [2000-2004]	OTB/OTW [2018]	BART	S-1	S-2	167 EGUs
Acadia National Park, ME	6.32	2.40	0.08	0.29	0.03	0.37
Brigantine Wilderness, NJ	11.58	5.35	0.07	0.20	0.02	0.51
Great Gulf Wilderness, NH	7.28	2.96	0.06	0.09	0.01	0.13
Lye Brook Wilderness, VT	8.46	3.49	0.09	0.13	0.01	0.18
Moosehorn Wilderness, ME	5.67	2.03	0.07	0.21	0.03	0.24
Presidential Range – Dry River Wilderness, NH	7.28	2.96	0.06	0.09	0.01	0.13
Roosevelt-Campobello International Park, NB	5.67	2.03	0.07	0.21	0.03	0.24

Notes on Table 5-1:

1. Baseline values represent the average sulfate mass ($\mu g/m^3$) over the 5 year baseline period on the 20 percent worst days.
2. OTB/OTW represents the combined estimated mass reduction ($\mu g/m^3$) due to all “on the books” measures.
3. BART mass reduction reflects preliminary estimates of emission reductions resulting from BART determinations. These determinations are still in the process of being conducted, however, and thus are subject to change.
4. S-1 oil strategy assumes the adoption of 500 ppm distillate, 0.25 percent S for all No. 4 oil and 0.5 percent S for all No. 6 residual oil.
5. S-2 oil strategy assumes the adoption of 15 ppm distillate, 0.25 percent S for all No. 4 oil and 0.5 percent S for all No. 6 residual oil.
6. 167 EGU strategy benefits are based on net reductions after each of the 167 stacks is controlled to at least the 90 percent level and after the identified emissions reductions (beyond 2018 projections contained in the Base B emissions files) are redistributed among all other CAIR-eligible EGUs in the modeling domain.

Table 5-2. Projected 2018 twenty percent worst day deciview goals for MANE-VU Class I areas under various control assumptions

MANE-VU Class I Area	Baseline [2000-2004]	OTB/OTW [2018]	+BART	+S-1	+S-2	+167 EGUs
Acadia National Park, ME	22.89	19.62	19.51	19.10	19.05	18.50
Brigantine Wilderness, NJ	29.01	24.26	24.19	24.00	23.98	23.47
Great Gulf Wilderness, NH	22.82	18.81	18.74	18.62	18.61	18.43
Lye Brook Wilderness, VT	24.45	20.40	20.29	20.13	20.12	19.90
Moosehorn Wilderness, ME	21.72	18.59	18.50	18.20	18.16	17.80
Presidential Range – Dry River Wilderness, NH	22.82	18.98	18.90	18.78	18.77	18.59
Roosevelt-Campobello International Park, NB	21.72	18.58	18.49	18.19	18.15	17.79

Notes on Table 5-2:

1. Baseline values represent the 5-year average baseline conditions (dv) on the 20 percent worst days.
2. OTB/OTW represents the projected deciview goal due to all OTB/OTW measures.
3. Pluses indicate that the deciview goals assume implementation of all measures to the left of and including the column indicated.
4. BART reflects preliminary estimates of emissions reductions due to BART determinations. These determinations are still in the process of being conducted and thus are subject to change.
5. S-1 oil strategy assumes the adoption of 500 ppm distillate, 0.25 percent S for all No. 4 oil and 0.5 percent S for all No. 6 residual oil.
6. S-2 oil strategy assumes the adoption of 15 ppm distillate, 0.25 percent S for all No. 4 oil and 0.5 percent S for all No. 6 residual oil.
7. 167 EGU strategy benefits are based on net reductions after each of the 167 stacks is controlled to at least the 90 percent level and after the identified emissions reductions (beyond 2018 projections contained in the Base B emissions files) are redistributed among all other CAIR-eligible EGUs in the modeling domain.

6. CONCLUSIONS

This report provides details on modeling platforms and input data as well as a description of the processing steps that were undertaken to prepare inputs for use in simulating future air quality on an eastern U.S. domain that includes MANE-VU Class I areas. The findings are consistent with previous work documenting the role of SO_2 emissions in the formation of visibility impairing fine particulate in the eastern U.S. (NESCAUM, 2006a, b). This report goes further, however, in terms of providing detailed simulations of (1) projected visibility impairment in 2018 under a "beyond on the way" scenario that represents a starting point for the regional haze program; (2) state-by-state apportionment of 2018 emissions for that 2018 "beyond on the way" scenario; and (3) sensitivity analysis of the projected benefits of several additional measures that are being considered by the MANE-VU states for inclusion in reasonable progress goals.

The findings of these simulations suggest that:

- The "beyond on the way" scenario – defined by CAIR with other "on the books" measures and the limitation of fuel sulfur content to 500 ppm for all No. 2 "distillate" fuel oil sold in the MANE-VU region – is sufficient to achieve visibility improvement beyond the so-called "uniform rate of progress" defined by uniform visibility improvement between now and 2064, the planning horizon for the regional haze program.
- The 2018 pollution apportionment suggests that this improvement is due to significant reductions in the relative contributions of almost all eastern U.S. states, resulting in a *relative* increase (though not an absolute increase) in the projected contribution from areas outside the modeling domain (e.g., Canada and the model domain boundary conditions).
- Potential additional emissions reduction strategies (including the reduction of fuel sulfur content of No. 2 distillate to 15 ppm, limits on sulfur content of residual oil, control of BART-eligible sources, and additional EGU controls beyond CAIR) could yield significant further reductions of sulfate and corresponding significant visibility improvements at MANE-VU Class I areas and should be considered with respect to the four statutory factors in setting reasonable progress goals.

As MANE-VU states consider these results and conduct consultations with each other and neighboring RPOs, NESCAUM will prepare a "best and final" modeling scenario for 2018 that may assist the Class I states in setting reasonable progress goals based on their assessment of which measures are reasonable to implement. This final model run is anticipated to be complete in March 2008.

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Mid-Atlantic/Northeast Visibility Union
MANE-VU

Reducing Regional Haze for
Improved Visibility and Health

Members
Connecticut
Delaware
District of Columbia
Maine
Maryland
Massachusetts
New Hampshire
New Jersey
New York
Pennsylvania
Penobscot Indian Nation
Rhode Island
St. Regis Mohawk Tribe
Vermont

Nonvoting Members
U.S. Environmental Protection Agency
National Park Service
U.S. Fish and Wildlife Service
U.S. Forest Service

MANE-VU Class I Areas

ACADIA NATIONAL PARK
ME

BRIGANTINE WILDERNESS
NJ

GREAT GULF WILDERNESS
NH

LYE BROOK WILDERNESS
VT

MOOSEHORN WILDERNESS
ME

PRESIDENTIAL RANGE
DRY RIVER WILDERNESS
NH

ROOSEVELT CAMPOBELLO
INTERNATIONAL PARK
ME/NB, CANADA

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

The federal Clean Air Act and the Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas. Most pollutants that affect visibility also cause unhealthy concentrations of ozone and fine particles. In order to assure protection of public health and the environment, air pollutant emission reductions required to meet the 2018 reasonable progress goal for regional haze should be achieved as soon as practicable.

To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast States request that States outside of the MANE-VU region that are identified as contributing to visibility impairment in the MANE-VU mandatory Class I Federal areas pursue a course of action designed to assure reasonable progress toward preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such actions may provide for the protection of public health and the environment. This request for a course of action includes pursuing the adoption and implementation of the following control strategies, as appropriate and necessary:

- timely implementation of BART requirements; and
- A 90% or greater reduction in sulfur dioxide (SO_2) emissions from each of the electric generating unit (EGU) stacks identified by MANE-VU (Attachment 1- comprising a total of 167 stacks – dated June 20, 2007) as reasonably anticipated to cause or contribute to impairment of visibility in each mandatory Class I Federal area in the MANE-VU region. If it is infeasible to achieve that level of reduction from a unit, alternative measures will be pursued in such State; and

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

- continued evaluation of other measures including measures to reduce SO2 and nitrogen oxide (NOx) emissions from all coal-burning facilities by 2018 and promulgation of new source performance standards for wood combustion. These measures and other measures identified will be evaluated during the consultation process to determine if they are reasonable.

This long-term strategy to reduce and prevent regional haze will allow each state up to 10 years to pursue adoption and implementation, of reasonable NOx and SO_2 control measures.

Adopted by the MANE-VU States and Tribes on 20 June 2007

David Littell, Commissioner – Maine Dept. of Environmental Protection
Chair

Final Draft Report

Comparison of CAIR and CAIR Plus Proposal using the Integrated Planning Model (IPM®)

Prepared for

Mid-Atlantic Regional Air Management Association (MARAMA)

Prepared by

ICF Resources, L.L.C.
9300 Lee Highway
Fairfax, VA 22031

May 30, 2007

Table of Contents

A. Overview

MARAMA has awarded a contract to ICF Resources, L.L.C. (ICF), seeking ICF's services to evaluate the impact of EPA's CAIR Policy and the Mid-Atlantic/Northeast Visibility Union (MANE-VU) CAIR Plus proposal on the electric generating sector for the contiguous United States using the Integrated Planning Model (IPM$^{®}$).

IPM is a dynamic linear optimization model that can be used to examine air pollution control policies for various pollutants throughout the contiguous U.S. for the entire electric power system. The dynamic nature of IPM enables the projection of the behavior of the power system over a specified future period. The optimization logic determines the least-cost means of meeting electric generation and capacity requirements while complying with specified constraints including air pollution regulations, transmission bottlenecks, and plant-specific operational constraints. The versatility of IPM allows users to specify which constraints to exercise and populate IPM with their own datasets.

This report summarizes the analysis that ICF has performed in evaluating the impact of the CAIR Plus proposal in the CAIR Plus region on the electricity generating sector by using IPM (hereafter, the analysis is referred to as the MARAMA analysis). As part of this analysis, ICF has also developed a Base Case that implements EPA's CAIR, CAMR and CAVR policies. The model assumptions and data used in this analysis are presented in Section B. The results are presented in Section C and the analysis limitations are presented in Section D.

Since the modeling is based on analyses developed by U.S. EPA, VISTAS and LADCO, we have summarized only the incremental changes that were proposed by MARAMA as part of this analysis. The documentation for EPA's v2.1.9 and v3.0 base cases is available at http://www.epa.gov/airmarkets/progsregs/epa-ipm. The VISTAS study assumptions are summarized in Appendix 1 and 2.

B. Modeling Assumptions and Changes Made to VISTAS Run

The MARAMA analysis is based on the recent IPM based analysis performed for VISTAS except for changes made by MARAMA. These runs are based on the VISTASII_PC_1f run that was developed for VISTAS in 2005. As per direction from MARAMA, the following assumptions for modeling the MARAMA Base Case-CAIR/CAMR/CAVR (MARAMA 5c) and MARAMA CAIR Plus Policy Case (MARAMA 4c) were implemented. Detailed assumptions are summarized in Appendix 3.

a) Run year configuration: The run year configuration was updated to separate out the key analysis years of 2009, 2012 and 2018. The revised configuration is summarized in Table 1:

Table 1: Run Years in MARAMA Base Case and MARAMA CAIR Plus Policy Case

Run Year	Calendar Years
2008	2007-2008
2009	2009-2009
2010	2010-2011
2012	2012-2012
2015	2013-2017
2018	2018-2018
2020	2019-2022
2026	2023-2030

b) Natural Gas Prices: As per direction from MARAMA, ICF implemented the EPA Base Case v3.0 natural gas supply curves that were based on ICF's NANGAS (North American Natural Gas Analysis System) model as part of this analysis. These gas supply curves are documented in the EPA Base Case v3.0 documentation published on its website. The gas supply curves used in the VISTAS analysis were based on the EPA Base Case v2.1.9. The gas supply curves used in the MARAMA analysis will result in higher gas prices as compared to the VISTAS analysis. For example, for a 5 quad gas consumption in the power sector, the Henry hub gas price using the EPA Base Case v3.0 gas supply curves will result in a gas price that is approximately 40-60% (based on the run year) higher than if EPA Base Case v2.1.9 gas supply curves were used.

c) Fuel Oil Prices: The fuel oil price projections from AEO 2006 were implemented in the MARAMA analysis and are higher as compared to the VISTAS analysis. The fuel oil price projections used in the VISTAS analysis were based on AEO 2005. The AEO 2006 assumptions are documented in the EPA Base Case v3.0.

d) SCR and Scrubber Feasibility Limits: Table 2 summarizes the cumulative SCR and scrubber feasibility limits that were implemented (in the MARAMA analysis) in the years 2008, 2009 and 2010. These limits are beyond existing control installations and prevent the model from projecting a level of SCR and scrubber builds in the short-term that was higher than the industry's capability to deliver. The feasibility limits in 2008 and 2009 are based on actual planned SCR and scrubber installations. The 2010 limit for scrubbers is based on a projection for installation of SO_2 scrubbers under CAIR. It is based on an internal analysis that accounted for the 2008/2009 feasibility limits. In the VISTAS study, feasibility limits for SCR and scrubbers were not applied in 2008, 2009 and 2010.

Note that in 2008, 2009 and 2010 run years, the individual unit level decisions were not hardwired but IPM will choose to build only the most economic SCRs and scrubbers up to those limits.

Table 2: Cumulative SCR and FGD Feasibility Limits in MARAMA Base Case and MARAMA CAIR Plus Policy Case Runs

Year	SCR (GW)	Scrubbers (GW)
2008	9	31
2009	15	51
2010	No Limit	69

Note: The above limits are incremental to those that are already installed on existing units as assumed in NEEDS.

e) CAVR (Clean Air Visibility Rule): Consistent with U.S. EPA's implementation of the CAVR rule, MARAMA has implemented the CAVR rule beginning in the run year 2015 within the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs.

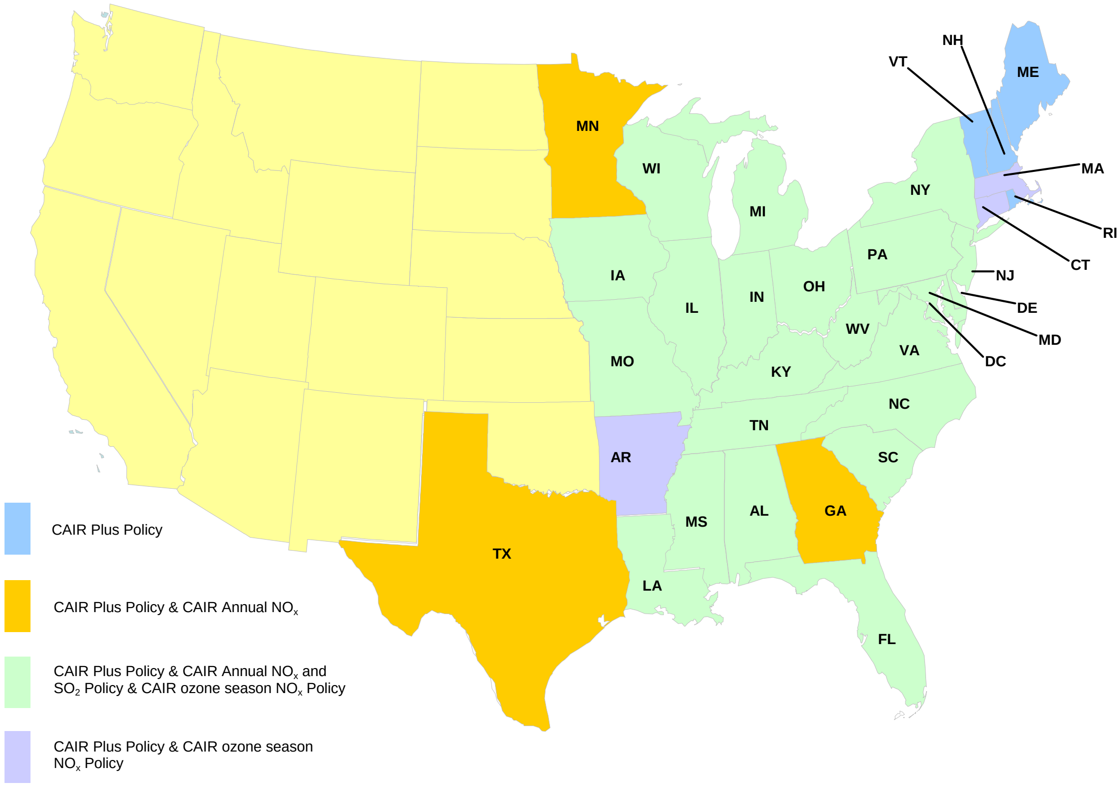
> *CAVR SO_2 Requirements*: All CAVR eligible, unscrubbed, non CAIR and non WRAP affected sources larger than 200 MW are required to meet an output emission rate of 0.15 lbs/MMBtu of SO_2 or achieve 95% removal. However, only the option to meet the 0.15 lbs/MMBtu of SO_2 emission rate was provided in IPM. This assumption was based on the results from a comparison of output SO_2 emission rates of unscrubbed CAVR affected units in the VISTAS analysis when adjusted for a 95% removal with 0.15 lbs/MMBtu. The 0.15 lbs/MMBtu rate limit was always higher and hence is a lower cost strategy.
>
> *CAVR NO_x Requirements*: All CAVR eligible, non CAIR affected sources larger than 200 MW are required to install combustion controls. SCRs are also required if the affected units are cyclone fired. All existing SCRs are required to operate annually.

Note that CAVR eligible sources in the above discussion imply the list of CAVR affected sources that U.S. EPA had modeled in their CAVR analysis using IPM. A list of units affected by the CAVR SO_2 and NO_x requirements are shown in Appendix 3 (tables A3.5a and A3.5b respectively).

f) Title IV SO_2 Bank: The IPM modeling time period in the MARAMA analysis is 2007-2030. In order to capture the dynamics of the SO_2 allowance market pre 2007, MARAMA has implemented a Title IV SO_2 allowance bank of 6.43 million tons going into the year 2007. This assumption is based on an internal ICF analysis of the current market conditions.

g) Applicable States for Programs: The MARAMA CAIR Plus Policy Case run is based on the MARAMA Base Case run with the MARAMA CAIR Plus Policy Case proposal implemented as a replacement of the CAIR policy. Figure 1 shows a U.S. map with states affected by CAIR and CAIR Plus policies highlighted.

Figure 1: States affected by CAIR and MARAMA CAIR Plus Policies



h) NO$_x$ and SO$_2$ Budgets: Table 3 summarizes the NO$_x$ budgets implemented in the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs, and Table 4 summarizes SO$_2$ allowance retirement ratios implemented in the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs. The NO$_x$ budgets under the Base Case and CAIR Plus policy cases in Table 3 are not comparable because there are more states in the CAIR Plus domain as compared to the CAIR domain in the Base Case. In IPM, emissions budgets are modeled as a cap that all affected sources together are required to comply with. These sources can buy or sell emission allowances among themselves and bank for future use under favorable economics.

The SO$_2$ allowance retirement ratio is the number of Title IV SO$_2$ allowances that need to be surrendered for each ton of SO$_2$ emissions in the CAIR/CAIR Plus region. In IPM, a CAIR/CAIR Plus policy affected source is required to surrender the applicable number of Title IV SO$_2$ allowances determined by the SO$_2$ retirement ratio for every ton of SO$_2$ emission. A non CAIR/CAIR Plus policy affected source surrenders one Title IV SO$_2$ allowance for every ton of SO$_2$ emissions.

Table 3: NO_x Budgets in the CAIR/CAIR Plus Region (Thousand Tons)

	NO_x Ozone Season Budget		NO_x Annual Budget	
Year	MARAMA Base Case	MARAMA CAIR Plus Policy Case	MARAMA Base Case	MARAMA CAIR Plus Policy Case
2009	568	623	1,722*	1,553*
2010	568	623	1,522	1,353
2012	568	415	1,522	902
2015	518	395	1,370	858
2018	485	382	1,268	829

* Includes NO_x Compliance Supplement Pool of 199,997 tons included in 2009.

Note: The 2015 budgets as modeled in IPM are the average of the budgets over the period 2013-2017. The actual ozone season NO_x budgets proposed are 485 thousand tons in CAIR and 382 thousand tons in CAIR plus for 2015. The actual annual NO_x budgets proposed are 1,268 thousand tons in CAIR and 829 thousand tons in CAIR plus for 2015.

Table 4: SO_2 Allowance Retirement Ratios in the CAIR/CAIR Plus Region

	SO_2 Allowance Retirement Ratio	
Year	MARAMA Base Case	MARAMA CAIR Plus Policy Case
2009	1.00	1.00
2010	2.00	2.50
2012	2.00	2.94
2015	2.52	3.32
2018	2.86	4.16

Note: The 2015 retirement ratios as modeled in IPM are the average of the retirement ratios over the period 2013-2017. The actual retirement ratios are 2.86 for CAIR and 3.57 for CAIR Plus for 2015.

i) SO_2 and NO_x emission allowances were allowed to be banked in any year and then withdrawn from the bank in a future year under the CAIR program in the base case and the CAIR Plus programs.

C. Results

In this section, ICF has presented the costs, control installations, emissions, allowance market impacts, delivered fuel prices, generation, power plant retirements and new builds from the MARAMA Base Case and then compared these results with those from the MARAMA CAIR Plus Policy Case run. Appendix 5 summarizes the SO_2 and NO_x emission results and production cost components on a state and RPO level. The following paragraphs discuss the results from the two runs.

1. Production Costs

IPM projects the production cost of the U.S. power sector for each of the modeled run years. The production cost includes the annualized capital costs of new investment decisions (includes control equipment costs and new build costs), fuel costs and the total variable and fixed operation and maintenance (O&M) costs of power plants. Allowance costs are not listed as a separate category because on a region wide basis the net cost is zero (number of allowances purchased is equal to the number of allowances sold). The administrative costs related to the purchase and sale of allowances are not modeled in IPM. The annualized incremental cost[1] of the MARAMA CAIR Plus Policy as compared to MARAMA Base Case is summarized in Table 5. The analysis projects a total cost of $10.7 billion in 2009 & $2.6 billion in 2018 respectively. Note that the cost of the policy is highest in 2009 (higher fuel costs being the main contributor of higher production costs) and then decreases starting 2010. This is because in 2009 there are limitations to the number of units that can install SCRs. In 2010 however, these limits are relaxed. In order to comply with the tight NO_x regulations and the limitations on SCR installations, the power sector increases natural gas-fired generation. In 2009 in the MARAMA CAIR Plus Policy Case the gas consumption increases by 812 TBtu and $0.85/MMBtu. This increase in gas consumption and the gas price result in a spike in fuel costs. Note that these costs are for the entire U.S. power sector and the policy could affect states that are within and outside the CAIR Plus region.

Table 5: Incremental Cost of the MARAMA CAIR Plus Policy Case Compared to MARAMA Base Case -- US Power Sector (1999 Billion Dollars)

	2008	2009	2010	2012	2015	2018
Variable O&M Cost	0.04	0.01	0.32	0.51	0.41	0.28
Fixed O&M Cost	0.01	-0.03	0.12	0.29	0.20	0.13
Fuel Cost	0.04	10.40	0.17	-0.90	0.04	0.23
Annualized Capital Cost	0.26	0.31	1.58	2.43	2.12	1.93
Total Production Cost	0.36	10.69	2.19	2.33	2.77	2.57

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856

The marginal costs[2] of emission reductions as manifested in the projected allowance prices in the MARAMA Base Case and the MARAMA CAIR Plus Policy Case are shown in Table 6. The SO_2 and NO_x allowance prices in the CAIR Plus region in the MARAMA CAIR Plus Policy Case run are high starting in 2009 due to the relatively tighter policies applied to the CAIR Plus region as compared to the SO_2 and NO_x policies in the MARAMA Base Case. Tighter policies result in more expensive compliance options being chosen resulting in higher allowance prices. The NO_x allowance prices are high in 2009 and drop in 2010 because the SCR feasibility limits are relaxed starting in 2010. In 2009, due to limitations on SCR installations, a significant increase in natural gas fired generation occurs, driving up the annual NO_x allowance prices. Starting in 2010, SCRs are installed resulting in a reduction in the use of more expensive NO_x reduction options such as natural gas generation, driving down the annual NO_x allowance prices.

The compliance options available to power plants to reduce both annual NO_x emissions and the ozone season NO_x emissions are same. In addition the plants affected by the ozone season NO_x policy and the annual NO_x policy in the MARAMA CAIR Plus Policy Case are identical. A plant that installs a NO_x control option such as a SCR will be able to reduce emissions in both the ozone season and the non ozone season and hence simultaneously affect CAIR/CAIR Plus annual NO_x and ozone season NO_x allowance markets. It appears that complying with the annual NO_x policy results in an over compliance with the ozone season NO_x policy and is highlighted by the zero ozone season NO_x allowance price starting 2010.

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[1] Annual Incremental Production Cost = Annualized Production Cost of MARAMA CAIR Plus Policy Case – Annualized Production Cost of MARAMA Base Case.

[2] Marginal cost is defined as the cost of reducing one additional ton of emissions.

Table 6: Allowance prices (Marginal Costs) of Emission Reductions in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 \$/ton)

CAIR/CAIR Plus Policy	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
SO_2	640	692	748	809	943	1,106
NO_x – Ozone[3]	14,580	15,760	0	0	0	0
NO_x - Annual	NA	3,047	1,149	1,155	1,337	1,567
MARAMA CAIR Plus Policy Case						
SO_2	806	872	942	1,019	1,188	1,392
difference wrt MARAMA Base Case	166	180	194	210	245	286
NO_x – Ozone	14,710	11,150	0	0	0	0
difference wrt MARAMA Base Case	130	-4,610	0	0	0	0
NO_x - Annual	NA	17,920	4,240	4,586	5,346	6,266
difference wrt MARAMA Base Case	NA	14,873	3,091	3,431	4,009	4,699

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856.

2. Projected Control Technology Retrofits

Installation of controls is one of the strategies that the power sector opts for complying with the CAIR Plus proposal requirements. This strategy is in addition to other compliance strategies such as changes to fuel switching, plant retirements, plant dispatch and new builds. Under the MARAMA CAIR Plus Policy Case, an additional 19.5 GW of SO_2 scrubbers and 77.8 GW of selective catalytic reduction (SCRs) are installed by 2012 (see Table 7). In the MARAMA CAIR Plus Policy Case, the SCR feasibility limits in 2008 and 2009 run years and the SO_2 scrubber limits in 2008 and 2010 run years are achieved.

Table 7: Incremental Pollution Control Installations by Technology in the MARAMA CAIR Plus Policy Case with the MARAMA Base Case (GW)

Technology	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
Scrubber	24.9	31.4	59.7	65.6	87.5	98.7
SCR	9.0	15.0	38.5	42.1	58.6	66.3
MARAMA CAIR Plus Policy Case						
Scrubber	30.5	38.9	69.5	85.1	106.4	115.3
difference wrt MARAMA Base Case	5.6	7.5	9.8	19.5	18.9	16.6
SCR	9.0	15.0	115.2	120.0	124.5	131.2
difference wrt MARAMA Base Case	0.0	0.0	76.8	77.8	65.9	64.9

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[3] The 2008 NO_x ozone season allowance price is for the SIP Call policy. Starting 2009 it is for the CAIR/CAIR Plus ozone season NO_x policy.

3. Emissions

Tables 8 and 9 summarize the SO_2 and NO_x emissions from all units including both fossil and nonfossil units in the MARAMA Base Case and the MARAMA CAIR Plus Policy Case in the 2008, 2009, 2010, 2012, 2015 and 2018 run years. The projected state-level emissions for SO_2 and NO_x for the MARAMA CAIR Plus Policy Case and the MARAMA Base Case are presented in Tables A5.1-A5.3 in Appendix 5.

Note, that the CAIR/CAIR Plus policies are not applied to the WRAP region in the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs, and hence the SO_2 and NO_x emissions in the two runs in the WRAP region are similar. The CAIR/CAIR Plus NO_x programs start in 2009. Hence, the NO_x emissions are lower starting in 2009. The NO_x emissions in CAIR Plus region in Table 9 do not match the corresponding NO_x budgets in Table 3 because NO_x emissions in Table 9 include emissions from both CAIR Plus affected and not affected units.

The CAIR/CAIR Plus SO_2 programs start in 2010. However, the SO_2 emissions are lower prior to 2010 because Title IV SO_2 allowances that are banked prior to 2010 can be used to comply with the CAIR/CAIR Plus provisions starting 2010.

Both the CAIR and CAIR Plus programs are cap and trade policies. Therefore, while the CAIR Plus policy is more stringent than the CAIR policy, emissions can still go up in individual states in MARAMA CAIR Plus Policy Case as compared to MARAMA Base Case.

Table 8: Annual SO_2 Emissions from the U.S. Electric Power Sector (All Units including Fossil and Non-fossil units) (Thousand Tons)

	2008	**2009**	**2010**	**2012**	**2015**	**2018**
MARAMA Base Case						
MANE-VU	802.1	650.2	518.3	462.7	410.5	393.8
LADCO	1,950.5	1,785.1	1,594.8	1,593.4	1,490.5	1,437.7
VISTAS	2,879.6	2,702.0	2,094.5	1,981.2	1,689.7	1,398.2
CENRAP	1,395.3	1,391.1	1,397.3	1,385.4	1,158.9	1,136.8
WRAP	508.1	507.5	533.2	533.6	477.8	419.1
CAIR Plus Policy States	6,760.0	6,260.7	5,334.7	5,150.3	4,605.0	4,219.8
National Total	7,535.6	7,036.0	6,138.1	5,956.3	5,227.4	4,785.6
MARAMA CAIR Plus Policy Case						
MANE-VU	734.6	555.5	396.4	376.7	311.9	270.7
difference wrt MARAMA Base Case	-67.5	-94.8	-121.8	-86.0	-98.6	-123.1
LADCO	1,775.5	1,660.3	1,454.9	1,448.0	1,332.6	1,275.1
difference wrt MARAMA Base Case	-174.9	-124.8	-139.9	-145.4	-157.9	-162.6
VISTAS	2,696.8	2,049.4	1,769.9	1,461.5	1,190.6	991.8
difference wrt MARAMA Base Case	-182.9	-652.6	-324.7	-519.7	-499.1	-406.4
CENRAP	1,390.5	1,325.0	1,385.1	1,314.1	1,014.8	961.8
difference wrt MARAMA Base Case	-4.8	-66.1	-12.2	-71.3	-144.1	-175.0
WRAP	503.0	506.1	550.4	552.3	497.8	440.8
difference wrt MARAMA Base Case	-5.1	-1.4	17.1	18.7	20.0	21.7
CAIR Plus Policy States	6,331.6	5,324.1	4,735.4	4,325.7	3,705.2	3,350.8
difference wrt MARAMA Base Case	-428.4	-936.6	-599.3	-824.6	-899.8	-869.1
National Total	7,100.4	6,096.3	5,556.7	5,152.6	4,347.6	3,940.3
difference wrt MARAMA Base Case	-435.2	-939.7	-581.5	-803.8	-879.8	-845.3

Table 9: Annual NO_x Emissions from the U.S. Electric Power Sector (All Units including Fossil and Non-fossil units) (Thousand Tons)

MARAMA Base Case	2008	2009	2010	2012	2015	2018
MANE-VU	386.0	271.9	213.2	208.7	202.3	198.8
LADCO	803.9	483.4	413.0	409.0	389.5	382.1
VISTAS	1,207.6	699.9	622.0	621.1	502.0	452.9
CENRAP	754.5	604.1	603.0	616.0	539.4	538.3
WRAP	601.1	606.3	610.1	613.5	483.4	493.5
CAIR Plus Policy States	2,944.5	1,847.6	1,642.5	1,643.8	1,488.0	1,426.5
National Total	3,753.1	2,665.6	2,461.3	2,468.5	2,116.6	2,065.6
MARAMA CAIR Plus Policy Case						
MANE-VU	375.9	228.0	158.8	162.1	152.7	145.6
difference wrt MARAMA Base Case	-10.1	-43.9	-54.4	-46.7	-49.6	-53.2
LADCO	804.2	425.9	251.2	249.2	244.7	241.8
difference wrt MARAMA Base Case	0.4	-57.5	-161.8	-159.8	-144.8	-140.3
VISTAS	1,215.7	597.6	350.8	351.2	346.2	350.3
difference wrt MARAMA Base Case	8.0	-102.3	-271.2	-269.9	-155.8	-102.6
CENRAP	754.5	577.5	420.9	431.6	361.6	351.7
difference wrt MARAMA Base Case	0.1	-26.6	-182.1	-184.4	-177.8	-186.6
WRAP	600.5	606.5	610.0	615.2	485.5	495.7
difference wrt MARAMA Base Case	-0.6	0.2	-0.1	1.7	2.1	2.2
CAIR Plus Policy States	2,942.9	1,614.1	972.8	982.6	957.1	941.4
difference wrt MARAMA Base Case	-1.6	-233.4	-669.7	-661.2	-530.9	-485.1
National Total	3,750.9	2,435.5	1,791.6	1,809.3	1,590.7	1,585.1
difference wrt MARAMA Base Case	-2.2	-230.2	-669.7	-659.1	-525.8	-480.5

4. Allowance Market

Tables 10a and 10b summarize the CAIR/CAIR Plus SO_2 and NO_x allowance market as implemented in the CAIR/CAIR Plus region in the MARAMA Base Case and the MARAMA CAIR Plus Policy Case.

The going into 2007 Title IV SO_2 bank is assumed to be 6.43 million tons. In IPM, SO_2 emission allowances are banked in 2008 and 2009 and withdrawn in subsequent years. Allowances are not banked in later years as the CAIR/CAIR Plus policy starts in 2010 resulting in reduced opportunities for over complying. Annual NO_x emission allowances are banked in 2010 and not in 2009 in the MARAMA CAIR Plus Policy Case because restrictions on SCR installations prevent over compliance of the NO_x cap in 2009.

Starting 2010 in both the CAIR/CAIR Plus ozone season NO_x policies, the number of ozone season NO_x allowances that are withdrawn from the bank are less than the allowances that are banked. This occurs because of a surplus of ozone season NO_x allowance availability and is highlighted by the zero ozone season NO_x allowance price. On a separate note, the allowances banked in the SIP Call budget program are allowed to be banked and used in the ozone season NO_x program starting in 2009. The going into 2007 NO_x SIP Call bank is assumed to be zero.

Table 10a: Summary of SO_2 and NO_x Allowance Market in MARAMA Base Case (Thousand Tons)

Run Year	2008	2009	2010	2012	2015	2018	2020
Years Mapped to Run Year	2007-2008	2009	2010-2011	2012-2012	2013-2017	2018	2019-2022
CAIR - SO_2							
Annual Emissions at Affected Units (Fossil Units > 25 MW)	7,333	6,831	5,942	5,760	5,029	4,586	4,171
Allowances Banked	5,245	2,449	0	0	0	0	0
Allowances Withdrawn from Bank	0	0	-1,072	-888	-1,072	-1,143	-722
CAIR – Ozone Season NO_x							
Ozone Season Emission Budget	497	568	568	568	518	485	485
Ozone Season Emissions at Affected Units (Fossil Units > 25 MW in CAIR Region)	492	579	558	558	502	482	465
Allowances Banked	5	0	10	10	16	3	20
Allowances Withdrawn from Bank	0	-11	0	0	0	0	0
CAIR – Annual NO_x							
Annual Emission Budget	NA	1,722	1,522	1,522	1,370	1,268	1,268
Annual Emissions at Affected Units (Fossil Units > 25 MW in CAIR Region)	NA	1,722	1,522	1,522	1,363	1,298	1,268
Allowances Banked	NA	0	0	0	6	0	0
Allowances Withdrawn from Bank	NA	0	0	0	0	-30	0

Note: The 2008 NO_x ozone season results reflect those from the SIP Call NO_x program and starting 2009 reflect those from the CAIR ozone season NO_x policy.

Table 10b: Summary of SO_2 and NO_x Allowance Market in MARAMA CAIR Plus Policy Case (Thousand Tons)

Run Year	2008	2009	2010	2012	2015	2018	2020
Years Mapped to Run Year	2007-2008	2009	2010-2011	2012-2012	2013-2017	2018	2019-2022
CAIR Plus - SO_2							
Annual Emissions at Affected Units (Fossil Units > 25 MW)	6,898	5,900	5,360	4,956	4,151	3,739	3,205
Allowances Banked	5,680	3,380	0	0	0	0	0
Allowances Withdrawn from Bank	0	0	-1,353	-1,424	-1,094	-1,234	-691
CAIR Plus – Ozone Season NO_x							
Ozone Season Emission Budget	497	623	623	416	395	382	382
Ozone Season Emissions at Affected Units (Fossil Units > 25 MW in CAIR Plus Region)	497	623	404	412	398	395	389
Allowances Banked	0	0	219	4	0	0	0
Allowances Withdrawn from Bank	0	0	0	0	-3	-13	-7
CAIR Plus – Annual NO_x							
Annual Emission Budget	NA	1,553	1,353	902	858	829	829
Annual Emissions at Affected Units (Fossil Units > 25 MW in CAIR Plus Region)	NA	1,553	918	927	898	882	867
Allowances Banked	NA	0	436	0	0	0	0
Allowances Withdrawn from Bank	NA	0	0	-25	-39	-53	-38

Note: The 2008 NO_x ozone season results reflect those from the SIP Call NO_x program and starting 2009 reflect those from the CAIR ozone season NO_x policy.

5. Fuel Consumption and Prices

Table 11a summarizes the coal and natural gas consumption in the U.S. power sector as projected by IPM in the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs. Table 11b summarizes the delivered coal and natural gas prices solved by IPM in the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs. The delivered gas prices are not inputs to the model but are determined endogenously by equilibrating demand and supply.

In the MARAMA Base Case, the natural gas prices in 2008 are higher than 2009. This is due to differences in the supply curves for the two years. As an example, for a gas consumption level of 5,696 TBtu, the gas price in 2008 is $7.23/MMbtu. However, at the same level of gas consumption, the gas price in 2009 would be at $6.12.

The fuel costs shown in Table 5 are incremental costs (i.e. MARAMA CAIR Plus Policy Case – MARAMA Base Case). The increase in fuel costs of $10.4 billion dollars in 2009 is a result of the incremental increase in natural gas prices of $0.85MMBtu between the two cases (i.e. $7.83/MMBtu in the CAIR Plus Policy case versus $6.98 in the MARAMA Base Case) and an increase in natural gas consumption 812 TBtu.

The gas prices are higher in most years in the MARAMA CAIR Plus Policy Case, in comparison to the MARAMA Base Case. This is a result of an increase in gas consumption as shifting from coal to gas is a compliance option leading to higher gas prices. In 2009 the gas prices increase is the highest because of restrictions on new SCR builds which result in an increase in gas consumption by 812 TBtu.

Table 11a: Fuel Consumption in MARAMA Base Case and MARAMA CAIR Plus Policy Case (TBtu)

	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
Coal	22,938	22,706	25,594	26,050	27,489	29,198
Natural Gas	5,696	6,598	4,619	5,314	5,191	5,444
MARAMA CAIR Plus Policy Case						
Coal	22,863	21,503	25,396	26,099	27,318	28,699
difference wrt MARAMA Base Case	-76	-1,203	-198	49	-171	-500
Natural Gas	5,728	7,410	4,679	5,186	5,209	5,647
difference wrt MARAMA Base Case	32	812	60	-129	18	203

Table 11b: Delivered Fuel Prices in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 $/MMBtu)

	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
Coal	1.09	1.08	1.07	1.05	1.03	1
Natural Gas	7.39	6.98	4.82	4.75	4.15	4.01
MARAMA CAIR Plus Policy Case						
Coal	1.09	1.06	1.06	1.04	1.02	0.99
difference wrt MARAMA Base Case	0	-0.02	-0.01	-0.01	-0.01	-0.01
Natural Gas	7.39	7.83	4.88	4.75	4.19	4.05
difference wrt MARAMA Base Case	0	0.85	0.06	0	0.04	0.04

6. Power Plant Retirements

A tighter environmental policy increases the total production costs of a power plant, including its compliance costs, and thus could make it uneconomic. Table 12 summarizes the power plant retirements in the MARAMA Base Case and the MARAMA CAIR Plus Policy Case. Note that the more stringent CAIR Plus policy results in an increase in total retirements by 4.9 GW in 2009. Oil/gas steam units that are uneconomic to run under the CAIR Plus policy retire. Increase in natural gas use as presented in Table 11a is accounted for by the remaining gas fired units that have relatively lower costs of operation.

Table 12: Power Plant Retirements in MARAMA CAIR Plus Policy Case with the MARAMA Base Case (MW)

	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
Coal Steam	196	196	196	196	196	196
Combined Cycle	2,669	2,669	3,340	3,340	3,464	3,464
Combustion Turbine	2,804	2,804	3,143	3,143	3,143	3,143
Oil/Gas Steam	53,826	53,826	60,763	60,763	60,858	60,858
Other[1]	0	0	0	0	0	0
National Total	59,495	59,495	67,442	67,442	67,661	67,661
MARAMA CAIR Plus Policy Case						
Coal Steam	279	2,269	2,689	2,689	2,689	2,689
difference wrt MARAMA Base Case	83	2,073	2,493	2,493	2,493	2,493
Combined Cycle	2,822	2,822	3,540	3,540	3,541	3,541
difference wrt MARAMA Base Case	153	153	200	200	77	77
Combustion Turbine	2,804	2,804	3,143	3,143	3,143	3,143
difference wrt MARAMA Base Case	0	0	0	0	0	0
Oil/Gas Steam	56,467	56,467	63,023	63,023	63,023	63,023
difference wrt MARAMA Base Case	2,641	2,641	2,260	2,260	2,165	2,165
Other	0	0	0	0	0	0
difference wrt MARAMA Base Case	0	0	0	0	0	0
National Total	62,372	64,362	72,395	72,395	72,396	72,396
difference wrt MARAMA Base Case	2,877	4,867	4,953	4,953	4,735	4,735

Note: The category "Other" includes all plant types other than coal steam, oil/gas steam, combined cycle and combustion turbines.

7. Power Plant Generation

Changes in power plant generation is one of the compliance strategies for meeting a tighter environmental policy. In the MARAMA CAIR Plus Policy Case as compared to the MARAMA Base Case, the generation mix changes towards lower emission intensive fuel and plant types. Table 13 summarizes the generation mix in the MARAMA Base Case and the MARAMA CAIR Plus Policy Case. Note that there is an increase in natural gas fired generation (from combined cycles, combustion turbines and oil/gas steam units) and a reduction in coal fired generation (from coal steam and IGCC units) in all years except 2012. The overall increase in coal fired generation in 2012 occurs because it is the first year when the scrubber feasibility limits are no longer applicable resulting in an increase in scrubber installations and a relatively lower drop in generation from the coal steam units. Coal generation in 2010 is also not higher due to the presence of scrubber limits. In years after 2012, the SO_2 and NO_x policies in the MARAMA CAIR Plus Policy Case continue to become more stringent resulting in an increase in gas based generation.

The electricity demand in both the MARAMA Base Case and the MARAMA CAIR Plus Policy Case are identical. However the power generation in the two runs is different due to differences in transmission and pump storage losses.

Table 13: Generation by Plant Type in the U.S. Electric Power Sector (GWh)

	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
Coal Steam	2,202,868	2,180,582	2,491,528	2,541,830	2,560,775	2,735,709
Combined Cycle	698,066	785,335	589,215	665,117	664,622	687,933
Combustion Turbine	37,735	49,113	30,941	38,341	36,254	49,527
Oil/Gas Steam	48,477	53,885	13,752	20,565	18,459	17,581
IGCC	4,702	4,702	14,142	14,148	192,239	226,262
Nuclear	796,130	796,715	797,725	801,460	810,065	807,698
Hydro (includes Pump Storage)	295,814	289,778	293,886	292,400	295,679	295,911
Biomass	14,301	14,929	17,039	22,183	25,969	29,742
Landfill Gas	13,715	13,747	13,747	13,747	16,063	16,384
Wind	32,308	32,414	32,664	32,782	34,486	36,289
Other	69,259	69,420	75,569	75,931	78,123	75,889
National Total	4,213,375	4,290,620	4,370,208	4,518,504	4,732,734	4,978,925
MARAMA CAIR Plus Policy Case						
Coal Steam	2,194,992	2,067,557	2,451,724	2,530,526	2,541,139	2,663,300
difference wrt MARAMA Base Case	-7,876	-113,025	-39,804	-11,304	-19,636	-72,409
Combined Cycle	703,266	889,217	598,711	650,084	671,380	736,610
difference wrt MARAMA Base Case	5,200	103,882	9,496	-15,033	6,758	48,677
Combustion Turbine	38,778	54,216	31,351	36,534	33,886	37,414
difference wrt MARAMA Base Case	1,043	5,103	410	-1,807	-2,368	-12,113
Oil/Gas Steam	46,979	55,463	12,714	19,655	18,028	17,755
difference wrt MARAMA Base Case	-1,498	1,578	-1,038	-910	-431	174
IGCC	4,702	4,702	41,408	41,408	205,343	259,435
difference wrt MARAMA Base Case	0	0	27,266	27,260	13,104	33,173
Nuclear	796,130	796,715	797,725	801,460	810,065	807,698
difference wrt MARAMA Base Case	0	0	0	0	0	0
Hydro (includes Pump Storage)	294,857	289,566	292,858	292,016	294,154	294,310
difference wrt MARAMA Base Case	-957	-212	-1,028	-384	-1,525	-1,601
Biomass	14,307	14,935	17,421	20,998	26,426	30,466
difference wrt MARAMA Base Case	6	6	382	-1,185	457	724
Landfill Gas	14,259	14,290	14,290	14,290	16,607	16,607
difference wrt MARAMA Base Case	544	543	543	543	544	223
Wind	34,522	34,627	34,877	34,936	35,383	37,187
difference wrt MARAMA Base Case	2,214	2,213	2,213	2,154	897	898
Other	69,259	68,125	75,569	75,931	78,123	75,889
difference wrt MARAMA Base Case	0	-1,295	0	0	0	0
National Total	4,212,051	4,289,413	4,368,648	4,517,838	4,730,534	4,976,671
difference wrt MARAMA Base Case	-1,324	-1,207	-1,560	-666	-2,200	-2,254

Note: The plant type “Other” includes solar, geothermal and waste fired units.

8. New Power Plant Builds

Table 14 summarizes the new power plant builds in the MARAMA Base Case and the MARAMA CAIR Plus Policy Case. In the MARAMA CAIR Plus Policy Case, new builds are higher than in the MARAMA Base Case because of a need to compensate for the increase in power plant retirements as presented in Table 12 and to take advantage of the relatively cleaner emission profiles of the new technologies.

New IGCC's have lower emission rates and lower heat rates making them more valuable under a stringent environmental policy. Hence IGCC's are built in 2010 and 2012 in the MARAMA CAIR Plus Policy Case and not in the MARAMA Base Case.

In 2018, the SO_2 allowance retirement ratio increases from 3.32 to 4.16. This increase results in a drop in coal fired generation and an increase in natural gas fired generation. In order to support this increase, in 2018 there is a significant increase in new combined cycle capacity that is more cost effective for base and intermediate load operation and a corresponding decrease in new combustion turbine capacity that is cost effective for peak load operation.

Table 14: New Power Plant Builds by Plant Type in the United States (MW)

	2008	2009	2010	2012	2015	2018
MARAMA Base Case						
Coal Steam	0	0	38,084	44,332	48,833	75,341
IGCC	0	0	0	0	23,187	27,617
Combined Cycle	6,550	6,550	6,550	8,580	20,518	24,265
Combustion Turbine	4,625	4,625	4,625	4,625	4,848	16,302
Biomass	0	0	349	978	1,570	2,099
Landfill Gas	1,241	1,241	1,241	1,241	1,552	1,595
Wind	5,153	5,153	5,153	5,193	5,739	6,283
National Total	17,569	17,569	56,002	64,949	106,247	153,502
MARAMA CAIR Plus Policy Case						
Coal Steam	0	0	35,674	46,627	52,245	72,806
difference wrt MARAMA Base Case	0	0	-2,410	2,295	3,412	-2,535
IGCC	0	0	3,651	3,651	24,995	32,038
difference wrt MARAMA Base Case	0	0	3,651	3,651	1,808	4,421
Combined Cycle	6,814	6,814	6,814	8,163	21,120	33,615
difference wrt MARAMA Base Case	264	264	264	-417	602	9,350
Combustion Turbine	4,781	4,781	4,781	4,781	4,781	10,473
difference wrt MARAMA Base Case	156	156	156	156	-67	-5,829
Biomass	0	0	349	815	1,570	2,099
difference wrt MARAMA Base Case	0	0	0	-163	0	0
Landfill Gas	1,314	1,314	1,314	1,314	1,625	1,625
difference wrt MARAMA Base Case	73	73	73	73	73	30
Wind	5,843	5,843	5,843	5,863	5,985	6,529
difference wrt MARAMA Base Case	690	690	690	670	246	246
National Total	18,752	18,752	58,426	71,214	112,321	159,185
difference wrt MARAMA Base Case	1,183	1,183	2,424	6,265	6,074	5,683

D. Limitations of Analysis

MARAMA modeling using IPM is based on various economic and engineering input assumptions that are inherently uncertain, such as assumptions for future fuel prices, electricity demand growth and the cost and performance of control technologies. As configured, IPM does not take into account demand response (i.e., consumer reaction to changes in electricity prices).

Appendix 1: Summary of Changes to EPA Base Case v2.1.9 by Vistas

The EPA Base Case v.2.1.9 was developed by ICF under the direction of the U.S. Environmental Protection Agency (EPA). It serves as the starting point for the analysis presented in this report. Subsequent to its release the VISTAS Regional Planning Organization initiated a two-phase study using IPM. Starting with the EPA 2.1.9 as a base, VISTAS, along with study participants from CENRAP and LADCO RPOs, made several changes to the underlying datasets and modeling assumptions. The starting point for the MARAMA analyses discussed in this report was work from the VISTAS study as modeled in the run VISTASII_PC_1f.

VISTAS and its workgroup initiated a review of NEEDS and recommended a large number of changes to the data. This occurred in two phases. In addition to unit level changes, VISTAS and its workgroup made a number of global changes that are reflected in this case. These are briefly described below:

- Demand forecast were changed to reflect unadjusted EIA AEO 2005 national electricity and peak demand values.

- AEO 2005 data was used for all assumptions regarding new builds of conventional technologies. The cost and performance assumptions for these units were as per the AEO 2005 documentation, while assumptions for renewable capacity were the same as those used in the EPA Base Case 2004 v.2.1.9.

- For nuclear units, the cost of continued operation was updated to approximately $27 per kilowatt-year based on AEO 2005.

- Hardwired Duke Power and Progress Energy control technology investment strategies for complying with the North Carolina Clean Smoke Stacks rule.

- The renewable portfolio standards (RPS) is modeled based on the most recent RGGI documentation using a single RPS region for Massachusetts (MA), Rhode Island (RI), New York (NY), New Jersey (NJ), Maryland (MD) and Connecticut (CT). The RPS requirements within these states can be met by renewable generation from New England, New York and PJM. EPA Base Case 2004 v.2.1.9 methodology and EIA AEO 2004 projected renewable builds were used for the rest of the regions.

- The run years used were 2008 (2007-2008), 2009 (2009), 2012 (2010-2013), 2015 (2014-2017), 2018 (2018), 2020 (2019-2022), and 2026 (2023-2030).

- The Clean Air Mercury Rule (CAMR) was modeled.

Appendix 2: MANE-VU IPM Global Parameter Decisions

This section summarizes the decisions as made by MANE-VU for global assumptions to be used in EGU forecasting with IPM as part of the VISTAS analysis. These decisions and changes are made to EPA Base Case version 2.1.9 assumptions.

A. Market Assumptions

1. National Electricity and Peak Demand

Decision: Use unadjusted EIA AEO 2005 national electricity and peak demand values.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

2. Regional Electricity and Demand Breakout

Decision: Use the existing IPM region breakdown as conducted in earlier modeling.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

3. Natural Gas Supply Curve and Price Forecast

Decision: Use fuel supply curves and fuel price forecasts from IPM version 2.1.9. These are the same fuel price forecasts and supply curve assumptions used in EPA's latest CAIR runs.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See e-mail from Megan Schuster dated 7/5/05.)

4. Oil Price Forecast

Decision: Use fuel supply curves and fuel price forecasts from IPM version 2.1.9. These are the same fuel price forecasts and supply curve assumptions used in EPA's latest CAIR runs.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See e-mail from Meagan Schuster dated 7/5/05.)

5. Coal Supply and Price Forecast

Decision: Use fuel supply curves and fuel price forecasts from IPM version 2.1.9. These are the same fuel price forecasts and supply curve assumptions used in EPA's latest CAIR runs.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See e-mail from Megan Schuster dated 7/1/05.)

B. Technical Assumptions

1. Firmly Planned Capacity Assumptions

Decision: Use revisions and new data as provided by RPOs and stakeholders.
Decision: Allow NC Clean Smokestacks 2009 data as provided to define "must run" units.
(These are the same as the assumptions used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

2. Pollution Control Retrofit Cost and Performance [SO2, NOx, Hg]

Decision: Retain pollution control retrofit cost and performance values.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

3. New Conventional Capacity cost and performance assumptions

Decision: Use EIA AEO 2005 cost and performance assumptions for new conventional capacity.
Decision: Retain existing 2.1.9 framework cost and performance for new renewable capacity.
Decision: Exclude constraint on new capacity type builds (i.e., no new coal).
(These are the same as the assumptions used by VISTAS, MRPO, and CENRAP. See 5/11/05 Inter-RPO IPM Global Decisions memo.)

4. SO_2 Title IV Allowance Bank

Decision: Use existing SO2 allowance bank value (4.99 million tons) for 2007.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP.
See 5/11/05 Inter-RPO IPM Global Decisions memo.)

5. Nuclear Re-licensing and Uprate

Decision: Use existing IPM configuration with updated EIA AEO 2005 (~$27/kW) incurrence cost for continued operation.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP.
See 5/11/05 Inter-RPO IPM Global Decisions memo.)

C. Strategy Assumptions

1. Clear Air Mercury Rule (CAMR)

Decision: Include CAMR in future rounds of IPM modeling.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP.
See 5/11/05 Inter-RPO IPM Global Decisions memo.)

2. Renewable Portfolio Standards

Decision**:** Model RPS based on the most recent RGGI documentation using a single RPS region for MA, RI, NY, NJ, MD and CT. The RPS requirements within these states can be met by renewable generation from New England, New York and PJM. EPA 2.1.9 methodology and hardwired EIA AEO 2004 projected renewable builds for the remainder of the country.
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP.
See 5/11/05 Inter-RPO IPM Global Decisions memo.)

D. Other Assumptions

1. Run Years

Decision: Parsed output data will be provided for 2009, 2012 and 2018.
Run years to 2008, 2009, 2012, 2015, 2018, 2020, and 2026.
(Run Year 2008 [2007-2008], Run Year 2009 [2009], Run Year 2012 [2010-2013],
Run Year 2015 [2014-2017], Run Year 2018 [2018], Run Year 2020 [2019-2022] and
Run Year 2026 [2023-2030]
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP.
See 5/11/05 Inter-RPO IPM Global Decisions memo.)

2. Canadian Sources

Decision: Utilize existing v.2.1.9 configuration (no Canadian site specific sources).
(This is the same as the assumption used by VISTAS, MRPO, and CENRAP.
See 5/11/05 Inter-RPO IPM Global Decisions memo.)

Appendix 3: Detailed Assumptions Used in MARAMA analysis

Table A.3.1 shows the run year configuration used in the MARAMA Base Case and Policy Case.

Table A.3.1 Run Year Configuration

Run Year	Calendar Years
2008	2007-2008
2009	2009-2009
2010	2010-2011
2012	2012-2012
2015	2013-2017
2018	2018-2018
2020	2019-2022
2026	2023-2030

Table A3.2 shows the natural gas prices used in the MARAMA analysis. These supply curves are based on ICF's NANGAS model.

Table A3.2 Natural Gas Supply Curve in the MARAMA Analysis

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2008	3.50	20987	21160	173
2008	3.63	20734	21230	496
2008	3.78	20493	21300	807
2008	3.91	20264	21360	1096
2008	4.05	20045	21420	1375
2008	4.19	19836	21480	1644
2008	4.32	19635	21540	1905
2008	4.47	19443	21600	2157
2008	4.60	19258	21660	2402
2008	4.75	19080	21710	2630
2008	4.88	18909	21760	2851
2008	5.01	18744	21810	3066
2008	5.16	18585	21860	3275
2008	5.29	18432	21910	3478
2008	5.44	18284	21960	3676
2008	5.57	18141	22010	3869
2008	5.71	18002	22060	4058
2008	5.85	17868	22100	4232
2008	5.98	17738	22140	4402
2008	6.12	17612	22180	4568
2008	6.26	17489	22220	4731
2008	6.40	17370	22260	4890
2008	6.54	17254	22300	5046
2008	6.67	17141	22340	5199
2008	6.81	17031	22380	5349
2008	6.95	16924	22420	5496
2008	7.09	16820	22460	5640
2008	7.23	16719	22500	5781
2008	7.36	16620	22540	5920
2008	7.50	16524	22570	6046
2008	7.64	16430	22600	6170
2008	7.78	16338	22630	6292
2008	7.92	16248	22660	6412
2008	8.06	16160	22690	6530
2008	8.19	16074	22720	6646
2008	8.33	15990	22750	6760
2008	8.47	15908	22780	6872
2008	8.61	15828	22810	6982
2008	8.75	15749	22840	7091
2008	8.88	15672	22870	7198
2008	9.02	15596	22900	7304
2008	9.16	15522	22930	7408
2008	9.30	15449	22960	7511
2008	9.44	15378	22990	7612
2008	9.57	15308	23020	7712

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2008	9.72	15239	23050	7811
2009	3.22	21520	22270	750
2009	3.36	21235	22340	1105
2009	3.50	20965	22410	1445
2009	3.63	20709	22480	1771
2009	3.78	20465	22540	2075
2009	3.91	20233	22600	2367
2009	4.05	20011	22660	2649
2009	4.19	19799	22720	2921
2009	4.32	19596	22780	3184
2009	4.47	19401	22830	3429
2009	4.60	19214	22880	3666
2009	4.75	19034	22930	3896
2009	4.88	18861	22980	4119
2009	5.01	18695	23030	4335
2009	5.16	18535	23080	4545
2009	5.29	18380	23130	4750
2009	5.44	18230	23180	4950
2009	5.57	18085	23220	5135
2009	5.71	17945	23260	5315
2009	5.85	17809	23300	5491
2009	5.98	17677	23340	5663
2009	6.12	17549	23380	5831
2009	6.26	17425	23420	5995
2009	6.40	17305	23460	6155
2009	6.54	17188	23500	6312
2009	6.67	17074	23540	6466
2009	6.81	16963	23580	6617
2009	6.95	16855	23620	6765
2009	7.09	16750	23660	6910
2009	7.23	16648	23690	7042
2009	7.36	16548	23720	7172
2009	7.50	16451	23750	7299
2009	7.64	16356	23780	7424
2009	7.78	16263	23810	7547
2009	7.92	16172	23840	7668
2009	8.06	16083	23870	7787
2009	8.19	15996	23900	7904
2009	8.33	15911	23930	8019
2009	8.47	15828	23960	8132
2009	8.61	15747	23990	8243
2009	8.75	15668	24020	8352
2009	8.88	15590	24050	8460
2009	9.02	15514	24080	8566
2009	9.16	15439	24110	8671
2009	9.30	15366	24140	8774
2009	9.44	15294	24170	8876
2009	9.57	15224	24200	8976
2009	9.72	15155	24230	9075

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2010	3.22	21688	23220	1532
2010	3.36	21387	23300	1913
2010	3.50	21102	23370	2268
2010	3.63	20832	23440	2608
2010	3.78	20575	23510	2935
2010	3.91	20330	23580	3250
2010	4.05	20097	23640	3543
2010	4.19	19874	23700	3826
2010	4.32	19661	23760	4099
2010	4.47	19457	23820	4363
2010	4.60	19261	23880	4619
2010	4.75	19073	23940	4867
2010	4.88	18892	23990	5098
2010	5.01	18717	24040	5323
2010	5.16	18549	24090	5541
2010	5.29	18387	24140	5753
2010	5.44	18230	24190	5960
2010	5.57	18078	24240	6162
2010	5.71	17931	24290	6359
2010	5.85	17789	24340	6551
2010	5.98	17651	24390	6739
2010	6.12	17518	24430	6912
2010	6.26	17388	24470	7082
2010	6.40	17262	24510	7248
2010	6.54	17140	24550	7410
2010	6.67	17021	24590	7569
2010	6.81	16905	24630	7725
2010	6.95	16793	24670	7877
2010	7.09	16683	24710	8027
2010	7.23	16576	24750	8174
2010	7.36	16472	24790	8318
2010	7.50	16371	24830	8459
2010	7.64	16272	24870	8598
2010	7.78	16175	24910	8735
2010	7.92	16081	24940	8859
2010	8.06	15989	24970	8981
2010	8.19	15899	25000	9101
2010	8.33	15811	25030	9219
2010	8.47	15725	25060	9335
2010	8.61	15641	25090	9449
2010	8.75	15558	25120	9562
2010	8.88	15477	25150	9673
2010	9.02	15398	25180	9782
2010	9.16	15320	25210	9890
2010	9.30	15244	25240	9996
2010	9.44	15169	25270	10101
2010	9.57	15096	25300	10204
2010	9.72	15024	25330	10306
2012	3.22	22121	24260	2139

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2012	3.36	21813	24350	2537
2012	3.50	21522	24430	2908
2012	3.63	21246	24510	3264
2012	3.78	20983	24590	3607
2012	3.91	20733	24670	3937
2012	4.05	20494	24740	4246
2012	4.19	20266	24810	4544
2012	4.32	20048	24880	4832
2012	4.47	19839	24950	5111
2012	4.60	19638	25020	5382
2012	4.75	19445	25080	5635
2012	4.88	19259	25140	5881
2012	5.01	19080	25200	6120
2012	5.16	18908	25260	6352
2012	5.29	18742	25320	6578
2012	5.44	18582	25380	6798
2012	5.57	18427	25430	7003
2012	5.71	18277	25480	7203
2012	5.85	18132	25530	7398
2012	5.98	17991	25580	7589
2012	6.12	17854	25630	7776
2012	6.26	17722	25680	7958
2012	6.40	17593	25730	8137
2012	6.54	17468	25780	8312
2012	6.67	17346	25830	8484
2012	6.81	17228	25880	8652
2012	6.95	17113	25920	8807
2012	7.09	17001	25960	8959
2012	7.23	16892	26000	9108
2012	7.36	16786	26040	9254
2012	7.50	16682	26080	9398
2012	7.64	16581	26120	9539
2012	7.78	16482	26160	9678
2012	7.92	16385	26200	9815
2012	8.06	16291	26240	9949
2012	8.19	16199	26280	10081
2012	8.33	16109	26320	10211
2012	8.47	16021	26360	10339
2012	8.61	15935	26400	10465
2012	8.75	15851	26440	10589
2012	8.88	15768	26480	10712
2012	9.02	15687	26520	10833
2012	9.16	15608	26550	10942
2012	9.30	15530	26580	11050
2012	9.44	15454	26610	11156
2012	9.57	15379	26640	11261
2012	9.72	15306	26670	11364
2015	3.22	22107	25450	3343
2015	3.36	21844	25540	3696

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2015	3.50	21595	25620	4025
2015	3.63	21358	25700	4342
2015	3.78	21132	25780	4648
2015	3.91	20917	25850	4933
2015	4.05	20711	25920	5209
2015	4.19	20514	25990	5476
2015	4.32	20325	26060	5735
2015	4.47	20144	26130	5986
2015	4.60	19970	26190	6220
2015	4.75	19802	26250	6448
2015	4.88	19641	26310	6669
2015	5.01	19485	26370	6885
2015	5.16	19335	26430	7095
2015	5.29	19190	26490	7300
2015	5.44	19050	26540	7490
2015	5.57	18914	26590	7676
2015	5.71	18782	26640	7858
2015	5.85	18654	26690	8036
2015	5.98	18530	26740	8210
2015	6.12	18410	26790	8380
2015	6.26	18293	26840	8547
2015	6.40	18180	26890	8710
2015	6.54	18070	26940	8870
2015	6.67	17963	26980	9017
2015	6.81	17858	27020	9162
2015	6.95	17756	27060	9304
2015	7.09	17657	27100	9443
2015	7.23	17560	27140	9580
2015	7.36	17466	27180	9714
2015	7.50	17374	27220	9846
2015	7.64	17284	27260	9976
2015	7.78	17196	27300	10104
2015	7.92	17110	27340	10230
2015	8.06	17026	27380	10354
2015	8.19	16944	27420	10476
2015	8.33	16863	27460	10597
2015	8.47	16784	27500	10716
2015	8.61	16707	27540	10833
2015	8.75	16631	27570	10939
2015	8.88	16557	27600	11043
2015	9.02	16484	27630	11146
2015	9.16	16413	27660	11247
2015	9.30	16343	27690	11347
2015	9.44	16274	27720	11446
2015	9.57	16207	27750	11543
2015	9.72	16141	27780	11639
2018	3.22	23169	26880	3711
2018	3.36	22871	27010	4139
2018	3.50	22589	27130	4541

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2018	3.63	22321	27250	4929
2018	3.78	22066	27360	5294
2018	3.91	21823	27470	5647
2018	4.05	21591	27580	5989
2018	4.19	21369	27680	6311
2018	4.32	21156	27780	6624
2018	4.47	20952	27880	6928
2018	4.60	20756	27980	7224
2018	4.75	20568	28070	7502
2018	4.88	20387	28160	7773
2018	5.01	20212	28250	8038
2018	5.16	20044	28340	8296
2018	5.29	19881	28420	8539
2018	5.44	19724	28500	8776
2018	5.57	19572	28580	9008
2018	5.71	19425	28660	9235
2018	5.85	19282	28740	9458
2018	5.98	19144	28820	9676
2018	6.12	19010	28890	9880
2018	6.26	18880	28960	10080
2018	6.40	18753	29030	10277
2018	6.54	18630	29100	10470
2018	6.67	18510	29170	10660
2018	6.81	18394	29240	10846
2018	6.95	18281	29310	11029
2018	7.09	18170	29380	11210
2018	7.23	18062	29440	11378
2018	7.36	17957	29500	11543
2018	7.50	17854	29560	11706
2018	7.64	17754	29620	11866
2018	7.78	17656	29680	12024
2018	7.92	17560	29740	12180
2018	8.06	17467	29800	12333
2018	8.19	17376	29860	12484
2018	8.33	17287	29920	12633
2018	8.47	17200	29980	12780
2018	8.61	17114	30030	12916
2018	8.75	17030	30080	13050
2018	8.88	16948	30130	13182
2018	9.02	16868	30180	13312
2018	9.16	16789	30230	13441
2018	9.30	16712	30280	13568
2018	9.44	16636	30330	13694
2018	9.57	16562	30380	13818
2018	9.72	16489	30430	13941
2020	3.22	23815	26120	2305
2020	3.36	23496	26280	2784
2020	3.50	23194	26440	3246
2020	3.63	22907	26590	3683

Year	Price (1999$/MMBtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to electric sector (TBtu)
2020	3.78	22634	26740	4106
2020	3.91	22374	26880	4506
2020	4.05	22126	27020	4894
2020	4.19	21889	27150	5261
2020	4.32	21662	27280	5618
2020	4.47	21445	27410	5965
2020	4.60	21236	27530	6294
2020	4.75	21035	27650	6615
2020	4.88	20842	27770	6928
2020	5.01	20656	27880	7224
2020	5.16	20477	27990	7513
2020	5.29	20304	28100	7796
2020	5.44	20137	28210	8073
2020	5.57	19975	28310	8335
2020	5.71	19818	28410	8592
2020	5.85	19666	28510	8844
2020	5.98	19519	28610	9091
2020	6.12	19376	28710	9334
2020	6.26	19238	28800	9562
2020	6.40	19104	28890	9786
2020	6.54	18973	28980	10007
2020	6.67	18846	29070	10224
2020	6.81	18722	29160	10438
2020	6.95	18602	29250	10648
2020	7.09	18485	29340	10855
2020	7.23	18371	29420	11049
2020	7.36	18260	29500	11240
2020	7.50	18151	29580	11429
2020	7.64	18045	29660	11615
2020	7.78	17941	29740	11799
2020	7.92	17840	29820	11980
2020	8.06	17741	29900	12159
2020	8.19	17644	29980	12336
2020	8.33	17550	30050	12500
2020	8.47	17458	30120	12662
2020	8.61	17368	30190	12822
2020	8.75	17279	30260	12981
2020	8.88	17192	30330	13138
2020	9.02	17107	30400	13293
2020	9.16	17024	30470	13446
2020	9.30	16942	30540	13598
2020	9.44	16862	30610	13748
2020	9.57	16783	30680	13897
2020	9.72	16706	30750	14044

Table A3.3 shows the fuel oil prices used in the MARAMA analysis. These prices based on AEO 2006.

Table A3.3 Residual and Distillate Fuel Oil Prices (1999$/MMBtu)

	Residual Oil		Distillate Oil	
Year	**MAAC**	**New England**	**MAAC**	**New England**
2008	5.13	4.41	8.63	8.69
2009	5.00	4.13	8.30	8.38
2010	4.88	3.87	7.98	8.05
2012	4.75	3.83	8.06	8.12
2015	4.75	3.77	7.90	7.96
2018	5.03	3.90	8.27	8.33
2020	5.06	3.98	8.41	8.47
Source: AEO 2006				

Table A3.4 summarizes the cumulative SCR and scrubber feasibility limits that were implemented in the years 2008, 2009 and 2010. These limits are based on projections of planned installations.

Table A3.4 SCR and Scrubber Feasibility Limits

Year	SCR (GW)	Scrubbers (GW)
2008	9	31
2009	15	51
2010	No Limit	69

Tables A3.5a and 3.5b show the list of CAVR eligible sources for SO_2 and NO_x requirements.

Table A3.5a CAVR SO_2 Requirements: All CAVR eligible, unscrubbed, non CAIR and non WRAP affected sources larger than 200 MW

Unique ID	Plant Name	State
6138_B_1	Flint Creek	Arkansas
6641_B_1	Independence	Arkansas
6009_B_1	White Bluff	Arkansas
6009_B_2	White Bluff	Arkansas
469_B_4	Cherokee	Colorado
470_B_1	Comanche	Colorado
470_B_2	Comanche	Colorado
6248_B_1	Pawnee	Colorado
8219_B_1	Rray d Nixon	Colorado
568_B_BHB3	Bridgeport Harbor	Connecticut
1241_B_2	La Cygne	Kansas
6064_B_N1	Nearman Creek	Kansas
1619_B_1	Brayton Point	Massachusetts
1619_B_2	Brayton Point	Massachusetts
1619_B_3	Brayton Point	Massachusetts
2817_B_1	leland Olds	North Dakota
2817_B_2	leland Olds	North Dakota
2823_B_B1	Milton R Young	North Dakota
6077_B_1	Gerald Gentleman	Nebraska
6077_B_2	Gerald Gentleman	Nebraska
6096_B_1	Nebraska City	Nebraska
2291_B_5	North Omaha	Nebraska
2364_B_2	Merrimack	New Hampshire
8224_B_1	North Valmy	Nevada
2952_B_4	Muskogee	Oklahoma
2952_B_5	Muskogee	Oklahoma
2963_B_3313	Northeastern	Oklahoma
2963_B_3314	Northeastern	Oklahoma
6095_B_1	Sooner	Oklahoma
6095_B_2	Sooner	Oklahoma
6098_B_1	Big Stone	South Dakota

Table A3.5b CAVR NO_X Requirements: CAVR eligible, non CAIR affected sources larger than 200 MW

Unique ID	Plant Name	State
6138_B_1	Flint Creek	Arkansas
6641_B_1	Independence	Arkansas
6009_B_1	White Bluff	Arkansas
6009_B_2	White Bluff	Arkansas
113_B_2	Cholla	Arizona
113_B_3	Cholla	Arizona
113_B_4	Cholla	Arizona
6177_B_U1B	Coronado	Arizona
6177_B_U2B	Coronado	Arizona
4941_B_1	Navajo	Arizona
4941_B_2	Navajo	Arizona
4941_B_3	Navajo	Arizona
469_B_4	Cherokee	Colorado
470_B_1	Comanche	Colorado
470_B_2	Comanche	Colorado
6021_B_C1	Craig	Colorado
6021_B_C2	Craig	Colorado
525_B_H2	Hayden	Colorado
6248_B_1	Pawnee	Colorado
8219_B_1	Ray D Nixon	Colorado
568_B_BHB3	Bridgeport Harbor	Connecticut
6068_B_1	Jeffrey Energy Center	Kansas
6068_B_2	Jeffrey Energy Center	Kansas
1241_B_1	La Cygne	Kansas
1241_B_2	La Cygne	Kansas
1250_B_5	Lawrence	Kansas
6064_B_N1	Nearman Creek	Kansas
1619_B_1	Brayton Point	Massachusetts
1619_B_2	Brayton Point	Massachusetts
1619_B_3	Brayton Point	Massachusetts
6076_B_1	Colstrip	Montana
6076_B_2	Colstrip	Montana
6030_B_1	Coal Creek	North Dakota
6030_B_2	Coal Creek	North Dakota
2817_B_1	Leland Olds	North Dakota
2817_B_2	Leland Olds	North Dakota
2823_B_B1	Milton R Young	North Dakota
2823_B_B2	Milton R Young	North Dakota
6077_B_1	Gerald Gentleman	Nebraska
6077_B_2	Gerald Gentleman	Nebraska
6096_B_1	Nebraska City	Nebraska
2291_B_5	North Omaha	Nebraska
2364_B_2	Merrimack	New Hampshire
2442_B_3	Four Corners	New Mexico
2442_B_4	Four Corners	New Mexico
2442_B_5	Four Corners	New Mexico
2451_B_1	San Juan	New Mexico
2451_B_2	San Juan	New Mexico

Unique ID	Plant Name	State
2451_B_3	San Juan	New Mexico
2451_B_4	San Juan	New Mexico
2341_B_1	Mohave	Nevada
2341_B_2	Mohave	Nevada
8224_B_1	North Valmy	Nevada
2952_B_4	Muskogee	Oklahoma
2952_B_5	Muskogee	Oklahoma
2963_B_3313	Northeastern	Oklahoma
2963_B_3314	Northeastern	Oklahoma
6095_B_1	Sooner	Oklahoma
6095_B_2	Sooner	Oklahoma
6106_B_1SG	Boardman	Oregon
6098_B_1	Big Stone	South Dakota
6165_B_1	Hunter (Emery)	Utah
6165_B_2	Hunter (Emery)	Utah
8069_B_1	Huntington	Utah
8069_B_2	Huntington	Utah
3845_B_BW21	Centralia	Washington
3845_B_BW22	Centralia	Washington
4158_B_BW43	Dave Johnston	Wyoming
4158_B_BW44	Dave Johnston	Wyoming
8066_B_BW71	Jim Bridger	Wyoming
8066_B_BW72	Jim Bridger	Wyoming
8066_B_BW73	Jim Bridger	Wyoming
8066_B_BW74	Jim Bridger	Wyoming
6204_B_1	Laramie River	Wyoming
6204_B_2	Laramie River	Wyoming
6204_B_3	Laramie River	Wyoming
4162_B_2	Naughton	Wyoming
4162_B_3	Naughton	Wyoming
6101_B_BW91	Wyodak	Wyoming

Title IV SO_2 bank – In order to capture the dynamics of the SO_2 allowance market pre 2007, MARAMA has implemented a Title IV SO_2 allowance bank of 6.43 million tons, going into the year 2007.

Tables A3.6 and A3.7 show the national regulations modeled in the MARAMA base case and policy cases respectively, along with the details regarding affected units, policy structure and amount of allowances.

Table A3.6 Trading and Banking Rules in the MARAMA Base Case

	Title IV SO_2	**CAIR Annual NO_x**	**CAIR Ozone Season NO_x**	**CAVR Rule – SO_2**	**CAVR Rule – NO_x**	**CAMR (Clean Air Mercury Rule)**
Coverage	All Fossil units >25 MW	All Fossil units >25 MW *	All Fossil units >25 MW **	All Coal, CAVR Eligible, Non CAIR Unscrubbed and Non WRAP > 200 MW ***	All Coal & CAVR Eligible Outside CAIR > 200 MW	All Coal Units > 25 MW
Timing	Annual	Annual	Ozone Season (May – September)	Annual	Annual	Annual
Size of Initial Bank	6,437 thousand tons starting in 2007	The bank starting in 2009 is assumed to be zero.	The bank starting in 2007 is assumed to be zero.	N/A	N/A	-
Policy Structure	Trading and Banking allowed	Trading and Banking allowed	Trading and Banking allowed	No Trading or banking	No Trading or banking	Trading and Banking allowed
Rules						
Total Allowances (thousand tons except for CAMR is in tons)	2007-2009: 9,470 2010-2030: 8,950	2009: 1,722 2010-2014: 1,522 2015-2030: 1,268	2007-2008: 497[1] 2009-2014: 568 2015-2030: 485	N/A	N/A	2010-2017: 38 2018-2030: 15
Total Allowances Pre 2007 Bank Less NSR and North Carolina SO_2 Allowance Retirements (thousand tons)	2007: 15,805 2008: 9,350 2009: 9,280 2010-2012: 8,813 2013-2030: 8,611	2009: 1,722 2010-2014: 1,522 2015-2030: 1,268	2007-2008: 497[1] 2009-2014: 568 2015-2030: 485	N/A	N/A	2010-2017: 38 2018-2030: 15
Non Cap and Trade Policy Specifications	N/A	N/A	N/A	0.15 lbs/MMBtu	Combustion Controls on units >200MW and SCRs on cyclone fired units	N/A
Retirement Ratio	2010: 2.0 2012: 2.0 2015: 2.52 2018: 2.86	2009-2030: 1.0	2007-2030: 1.0	N/A	N/A	2007-2030: 1.0

* **CAIR Region States**: Alabama, District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, New Jersey, Delaware.

** **CAIR Ozone Season States**: Alabama, Arkansas, Connecticut, Delaware, District of Columbia, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin.

*** **WRAP States**: Arizona, New Mexico, Oregon, Utah, Wyoming

[1] SIP Call

Table A3.7 Trading and Banking Rules in the MARAMA Policy Case

	Title IV SO_2	MARAMA CAIR Plus - Annual NO_x	MARAMA SIP Call and CAIR Plus - Ozone season NO_x	CAVR Rule – SO_2	CAVR Rule – NO_x	CAMR (Clean Air Mercury Rule)
Coverage	All Fossil units >25 MW	All Fossil units >25 MW *	All Fossil units >25 MW **	All Coal, CAVR Eligible, Non CAIR Unscrubbed and Non WRAP > 200 MW ***	All Coal & CAVR Eligible Outside CAIR > 200 MW	All Coal Units > 25 MW
Timing	Annual	Annual	Ozone Season (May – September)	Annual	Annual	Annual
Size of Initial Bank	6,437 thousand tons starting in 2007	The bank starting in 2009 is assumed to be zero.	The bank starting in 2007 is assumed to be zero.	N/A	N/A	-
Policy Structure	Trading and Banking allowed	Trading and Banking allowed	Trading and Banking allowed	No Trading or banking	No Trading or banking	Trading and Banking allowed
Rules						
Total Allowances (thousand tons except for CAMR is in Tons)	2007-2009: 9,470 2010-2030: 8,950	2009: 1,553 2010-2011: 1,353 2012-2014: 902 2015-2030: 829	2007-2008: 497[1] 2009-2011: 623 2012-2014: 416 2015-2030: 382	N/A	N/A	2010-2017: 38 2018-2030: 15
Total Allowances Pre 2007 Bank Less NSR and North Carolina SO_2 Allowance Retirements (thousand tons)	2007: 15,805 2008: 9,350 2009: 9,280 2010-2012: 8,813 2013-2030: 8,611	2009: 1,553 2010-2011: 1,353 2012-2014: 902 2015-2030: 829	2007-2008: 497[1] 2009-2011: 623 2012-2014: 416 2015-2030: 382	N/A	N/A	2010-2017: 38 2018-2030: 15
Non Cap and Trade Policy Specifications	N/A	N/A	N/A	0.15 lbs/MMBtu	Combustion Controls on units >200MW and SCRs on cyclone fired units	N/A
Retirement Ratio	2010: 2.5 2012: 2.94 2015: 3.32 2018: 4.16	2009-2030: 1.0	2007-2030: 1.0	N/A	N/A	2007-2030: 1.0

* **CAIR Plus Policy States**: Alabama, District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, New Jersey, Delaware, Arkansas.

** **CAIR Ozone Season States**: Alabama, Arkansas, Connecticut, Delaware, District of Columbia, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin.

*** **WRAP States**: Arizona, New Mexico, Oregon, Utah, Wyoming

1. SIP Call

Appendix 4: Comparison of Assumptions Used in VISTAS and MARAMA analysis

Table 4.1 Differences in assumptions between the VISTAS and MARAMA projects.

Parameter	**VISTAS**	**MARAMA**
Run Years	2007,2010,2015,2020,2026	2008,2009, 2010,2012,2015,2018,2020,2026
Gas Supply Curve	EPA Base Case v.2.19 (see table below)	EPA Base Case v.3.0 (refer to table A3.2 in Appendix 3.)
Fuel Oil Prices	AEO 2004 (See table below)	AEO 2006 (Refer to table A3.3 in Appendix 3)
SCR and Scrubber Feasibility Limits	No limits applied in 2008, 2009 and 2010	Limits applied in 2008, 2009 and 2010. (Refer to table A3.4 in Appendix 3)
Clean Air Visibility Rule	Not modeled	Implemented the CAVR rule for SO_2 and NO_X
Title IV SO_2 Bank (2007)	4.98 million tons	6.43 million tons

Table A4.2: Natural Gas Supply Curve Used in VISTAS Run

Year	Price (1999$/Mmbtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to power sector (TBtu)
2007	2.75	19411	23560	4149
2007	2.80	19314	23580	4266
2007	2.85	19220	23600	4380
2007	2.90	19128	23620	4492
2007	2.95	19038	23640	4602
2007	3.00	18950	23660	4710
2007	3.05	18863	23680	4817
2007	3.10	18778	23700	4922
2007	3.15	18695	23720	5025
2007	3.20	18614	23730	5116
2007	3.25	18534	23740	5206
2007	3.26	18514	23740	5226
2007	3.30	18457	23790	5333
2007	3.35	18378	23800	5422
2007	3.40	18299	23810	5511
2007	3.44	18243	23820	5577
2007	3.45	18224	23820	5596
2007	3.50	18157	23830	5673
2007	3.55	18090	23840	5750
2007	3.57	18066	23840	5774
2007	3.60	18021	23850	5829
2007	3.65	17952	23860	5908
2007	3.70	17884	23870	5986
2007	3.75	17818	23880	6062
2007	3.80	17753	23890	6137
2007	3.85	17689	23900	6211
2007	3.90	17626	23910	6284
2007	3.95	17564	23920	6356
2007	4.00	17503	23930	6427
2007	4.05	17443	23940	6497
2007	4.10	17384	23950	6566
2007	4.15	17326	23960	6634
2007	4.20	17269	23970	6701
2007	4.25	17212	23980	6768
2007	4.30	17156	23990	6834
2007	4.35	17101	24000	6899
2007	4.40	17047	24010	6963
2007	4.45	16994	24020	7026
2007	4.50	16941	24030	7089
2007	4.55	16889	24040	7151
2007	4.60	16838	24050	7212
2007	4.65	16788	24060	7272
2007	4.70	16738	24070	7332
2007	4.75	16689	24080	7391
2007	4.80	16641	24090	7449
2007	4.85	16593	24100	7507
2007	4.90	16546	24110	7564
2007	4.95	16500	24120	7620

Year	Price (1999$/Mmbtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to power sector (TBtu)
2007	5.00	16454	24130	7676
2007	5.05	16409	24140	7731
2007	5.10	16364	24150	7786
2007	5.15	16320	24160	7840
2007	5.20	16276	24170	7894
2007	5.25	16233	24180	7947
2007	5.30	16190	24190	8000
2007	5.35	16148	24200	8052
2007	5.40	16106	24210	8104
2007	5.41	16064	24220	8156
2010	2.75	19727	23780	4053
2010	2.80	19621	23890	4269
2010	2.85	19517	23990	4473
2010	2.90	19415	24090	4675
2010	2.95	19316	24190	4874
2010	3.00	19219	24290	5071
2010	3.05	19124	24390	5266
2010	3.10	19031	24490	5459
2010	3.15	18940	24590	5650
2010	3.16	18916	24620	5704
2010	3.20	18856	24850	5994
2010	3.25	18766	24970	6204
2010	3.29	18691	25070	6379
2010	3.30	18678	25080	6402
2010	3.35	18597	25130	6533
2010	3.40	18516	25180	6664
2010	3.45	18435	25230	6795
2010	3.46	18411	25240	6829
2010	3.50	18355	25300	6945
2010	3.55	18277	25390	7113
2010	3.60	18200	25480	7280
2010	3.65	18125	25570	7445
2010	3.70	18051	25660	7609
2010	3.75	17978	25740	7762
2010	3.80	17907	25820	7913
2010	3.85	17837	25900	8063
2010	3.90	17768	25980	8212
2010	3.95	17700	26060	8360
2010	4.00	17633	26140	8507
2010	4.05	17567	26220	8653
2010	4.10	17502	26300	8798
2010	4.15	17438	26380	8942
2010	4.20	17375	26460	9085
2010	4.25	17313	26540	9227
2010	4.30	17252	26620	9368
2010	4.35	17192	26700	9508
2010	4.40	17133	26770	9637
2010	4.45	17075	26840	9765
2010	4.50	17018	26910	9892
2010	4.55	16962	26980	10018

Year	Price (1999$/Mmbtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to power sector (TBtu)
2010	4.60	16906	27050	10144
2010	4.65	16851	27120	10269
2010	4.70	16797	27190	10393
2010	4.75	16744	27260	10516
2010	4.80	16691	27330	10639
2010	4.85	16639	27400	10761
2010	4.90	16588	27470	10882
2010	4.95	16538	27540	11002
2010	5.00	16488	27610	11122
2010	5.05	16439	27680	11241
2010	5.10	16390	27750	11360
2010	5.15	16342	27820	11478
2010	5.20	16295	27890	11595
2010	5.25	16248	27960	11712
2010	5.30	16202	28020	11818
2010	5.35	16156	28080	11924
2010	5.40	16111	28140	12029
2010	5.41	16066	28200	12134
2015	2.75	20148	24960	4812
2015	2.80	20060	25140	5080
2015	2.85	19974	25320	5346
2015	2.90	19890	25500	5610
2015	2.95	19808	25670	5862
2015	3.00	19727	25840	6113
2015	3.05	19648	26010	6362
2015	3.08	19599	26120	6521
2015	3.10	19569	26210	6641
2015	3.15	19489	26460	6971
2015	3.18	19442	26610	7168
2015	3.20	19413	26680	7267
2015	3.25	19343	26850	7507
2015	3.30	19273	27020	7747
2015	3.35	19203	27190	7987
2015	3.39	19144	27330	8186
2015	3.40	19134	27350	8216
2015	3.45	19069	27480	8411
2015	3.50	19004	27610	8606
2015	3.55	18939	27740	8801
2015	3.60	18874	27870	8996
2015	3.65	18809	28000	9191
2015	3.70	18744	28130	9386
2015	3.70	18741	28140	9399
2015	3.75	18683	28280	9597
2015	3.80	18623	28430	9807
2015	3.85	18564	28580	10016
2015	3.90	18506	28730	10224
2015	3.95	18449	28880	10431
2015	4.00	18393	29020	10627
2015	4.05	18338	29160	10822
2015	4.10	18283	29300	11017

Year	Price (1999$/Mmbtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to power sector (TBtu)
2015	4.15	18229	29440	11211
2015	4.20	18176	29580	11404
2015	4.25	18124	29720	11596
2015	4.30	18073	29860	11787
2015	4.35	18022	30000	11978
2015	4.40	17972	30140	12168
2015	4.45	17923	30280	12357
2015	4.50	17874	30410	12536
2015	4.55	17826	30540	12714
2015	4.60	17779	30670	12891
2015	4.65	17732	30800	13068
2015	4.70	17686	30930	13244
2015	4.75	17641	31060	13419
2015	4.80	17596	31190	13594
2015	4.85	17552	31320	13768
2015	4.90	17508	31450	13942
2015	4.95	17465	31580	14115
2015	5.00	17422	31710	14288
2015	5.05	17380	31840	14460
2015	5.10	17338	31960	14622
2015	5.15	17297	32080	14783
2015	5.20	17256	32200	14944
2015	5.25	17216	32320	15104
2015	5.30	17176	32440	15264
2015	5.35	17137	32560	15423
2015	5.40	17098	32680	15582
2020	2.75	20782	27560	6778
2020	2.80	20695	27720	7025
2020	2.85	20610	27870	7260
2020	2.90	20527	28020	7493
2020	2.95	20449	28160	7711
2020	2.95	20445	28170	7725
2020	3.00	20369	28320	7951
2020	3.05	20293	28470	8177
2020	3.10	20217	28620	8403
2020	3.15	20141	28770	8629
2020	3.20	20065	28920	8855
2020	3.25	19989	29070	9081
2020	3.29	19935	29180	9245
2020	3.30	19914	29230	9316
2020	3.35	19844	29400	9556
2020	3.40	19774	29570	9796
2020	3.45	19704	29740	10036
2020	3.49	19646	29880	10234
2020	3.50	19636	29900	10264
2020	3.55	19577	30010	10433
2020	3.60	19518	30120	10602
2020	3.65	19459	30230	10771
2020	3.70	19400	30340	10940
2020	3.75	19341	30450	11109

Year	Price (1999$/Mmbtu)	Non electric gas demand (TBtu)	Total gas supply (TBtu)	Gas supply to power sector (TBtu)
2020	3.80	19282	30560	11278
2020	3.85	19223	30670	11447
2020	3.90	19164	30780	11616
2020	3.95	19105	30890	11785
2020	4.00	19046	31000	11954
2020	4.02	19024	31040	12016
2020	4.05	18990	31120	12130
2020	4.10	18936	31240	12304
2020	4.15	18883	31360	12477
2020	4.20	18830	31480	12650
2020	4.25	18778	31600	12822
2020	4.30	18727	31720	12993
2020	4.35	18677	31840	13163
2020	4.40	18627	31950	13323
2020	4.45	18578	32060	13482
2020	4.50	18530	32170	13640
2020	4.55	18482	32280	13798
2020	4.60	18435	32390	13955
2020	4.65	18389	32500	14111
2020	4.70	18343	32610	14267
2020	4.75	18298	32720	14422
2020	4.80	18253	32830	14577
2020	4.85	18209	32940	14731
2020	4.90	18165	33050	14885
2020	4.95	18122	33160	15038
2020	5.00	18080	33270	15190
2020	5.05	18038	33370	15332
2020	5.10	17997	33470	15473
2020	5.15	17956	33570	15614
2020	5.20	17916	33670	15754
2020	5.25	17876	33770	15894
2020	5.30	17837	33870	16033
2020	5.35	17798	33970	16172
2020	5.40	17759	34070	16311

Table A4.3: Fuel Oil Prices Used in VISTAS Run

High Sulfur Residual Oil Prices ($1999/MMBtu)		
	IPM Region	
Year	**MACE**	**New England**
2007	3.51	2.93
2010	3.57	2.98
2015	3.67	3.11
2020	3.76	3.22
Source: AEO 2004		

Low Sulfur Residual Oil Prices ($1999/MMBtu)		
	IPM Region	
Year	**MACE**	**New England**
2007	3.73	3.30
2010	3.79	3.35
2015	3.90	3.47
2020	3.99	3.58
Source: AEO 2004		

Distillate Oil Prices ($1999/MMBtu)		
	IPM Region	
Year	**MACE**	**New England**
2007	4.72	4.80
2010	4.86	4.94
2015	5.23	5.29
2020	5.58	5.60
Source: AEO 2004		

Appendix 5: Emission and Cost Results

Tables A5.1- A5.3 present SO_2 and NO_x emissions from the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs by state in 2008, 2009, 2012, 2015 and 2018 run years. These emissions are from all units and include emissions from fossil and non-fossil units

Tables A5.4- A5.8 present variable O&M costs, fixed O&M costs, annualized capital costs, fuel costs and total production costs from the MARAMA Base Case and MARAMA CAIR Plus Policy Case runs by state in 2008, 2009, 2012, 2015 and 2018 run years.

Table A5.1: State Level Annual SO_2 Emissions in MARAMA Base Case and MARAMA CAIR Plus Policy Case (Thousand Tons)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	3.92	3.97	9.93	12.18	14.71	3.02	3.07	4.29	4.94	5.01	-0.90	-0.90	-5.65	-7.24	-9.70
	Delaware	33.74	32.55	17.58	15.39	14.43	33.74	29.61	28.25	8.08	3.33	0.00	-2.93	10.67	-7.31	-11.09
	District of Columbia	0.00	0.00	0.19	0.29	0.63	0.00	0.00	0.41	0.49	0.69	0.00	0.00	0.22	0.20	0.05
	Maine	38.00	38.37	8.27	8.99	9.87	34.72	33.00	5.23	5.16	4.89	-3.27	-5.37	-3.04	-3.82	-4.98
	Maryland	130.21	65.67	52.98	31.47	35.48	100.07	39.07	33.04	31.42	32.81	-30.13	-26.60	-19.94	-0.04	-2.67
	Massachusetts	78.18	36.10	29.38	29.53	33.89	74.98	37.13	15.75	11.47	8.96	-3.19	1.03	-13.62	-18.05	-24.93
	New Hampshire	7.66	7.66	11.88	13.38	15.17	7.66	4.97	3.38	3.17	3.27	0.00	-2.68	-8.50	-10.21	-11.90
	New Jersey	26.56	25.85	28.02	26.43	23.32	26.23	25.89	26.67	23.82	16.93	-0.34	0.04	-1.35	-2.61	-6.39
	New York	124.38	121.50	102.95	90.74	85.54	110.99	105.26	76.55	72.32	66.51	-13.39	-16.24	-26.40	-18.42	-19.03
	Pennsylvania	359.35	318.52	199.42	179.15	156.97	343.13	277.39	182.70	150.27	127.58	-16.22	-41.13	-16.72	-28.88	-29.39
	Rhode Island	0.00	0.00	1.29	1.77	2.32	0.00	0.00	0.26	0.40	0.42	0.00	0.00	-1.02	-1.37	-1.90
	Vermont	0.06	0.06	0.87	1.16	1.51	0.06	0.06	0.22	0.31	0.32	0.00	0.00	-0.65	-0.86	-1.19
MANE-VU Total		802.06	650.24	462.75	410.48	393.84	734.60	555.46	376.75	311.86	270.72	-67.45	-94.78	-86.00	-98.62	-123.12
LADCO	Illinois	304.36	305.10	260.79	242.83	244.94	299.78	274.23	240.60	222.03	238.38	-4.59	-30.87	-20.19	-20.80	-6.57
	Indiana	496.08	483.36	463.56	414.50	376.78	476.80	410.99	409.93	377.38	332.21	-19.28	-72.38	-53.63	-37.11	-44.57
	Michigan	407.01	407.02	398.16	397.45	399.56	406.35	390.37	397.12	391.05	376.77	-0.66	-16.64	-1.04	-6.40	-22.79
	Ohio	581.77	440.10	317.26	282.43	264.40	431.30	436.33	249.67	194.09	184.86	-150.46	-3.77	-67.58	-88.34	-79.54
	Wisconsin	161.24	149.57	153.59	153.31	152.02	161.30	148.40	150.63	148.06	142.94	0.06	-1.17	-2.96	-5.25	-9.09
LADCO Total		1,950.46	1,785.15	1,593.35	1,490.51	1,437.70	1,775.52	1,660.32	1,447.95	1,332.62	1,275.15	-174.93	-124.83	-145.40	-157.89	-162.56
VISTAS	Alabama	357.18	332.19	286.09	253.71	217.58	336.53	264.83	219.62	185.76	158.36	-20.65	-67.36	-66.47	-67.96	-59.22
	Florida	213.04	210.85	194.80	194.07	165.00	212.81	190.25	157.71	156.67	115.33	-0.22	-20.60	-37.09	-37.40	-49.67
	Georgia	558.02	560.12	312.67	214.82	183.00	573.16	371.67	92.72	94.53	74.99	15.14	-188.45	-219.95	-120.29	-108.01
	Kentucky	386.28	376.19	274.92	274.02	239.92	362.81	328.20	274.84	223.64	203.38	-23.47	-47.99	-0.08	-50.39	-36.54
	Mississippi	82.21	70.23	85.73	27.87	23.15	81.55	62.58	25.44	23.13	24.60	-0.66	-7.65	-60.29	-4.75	1.44
	North Carolina	261.33	167.47	130.55	110.64	101.45	260.58	146.20	121.39	92.23	73.64	-0.74	-21.27	-9.15	-18.41	-27.81
	South Carolina	184.15	171.26	119.43	115.66	114.30	162.00	138.43	119.59	91.30	63.08	-22.15	-32.83	0.16	-24.37	-51.21
	Tennessee	246.52	244.39	235.35	231.69	141.52	237.50	168.68	197.69	136.09	109.20	-9.03	-75.71	-37.66	-95.60	-32.32
	Virginia	200.04	178.64	146.24	117.17	81.50	180.42	156.77	126.48	71.27	46.67	-19.62	-21.88	-19.76	-45.90	-34.84
	West Virginia	390.89	390.67	195.44	150.00	130.75	289.42	221.84	126.03	115.98	122.55	-101.46	-168.83	-69.41	-34.02	-8.20
VISTAS Total		2,879.64	2,702.01	1,981.22	1,689.66	1,398.18	2,696.77	2,049.45	1,461.51	1,190.59	991.81	-182.87	-652.56	-519.71	-499.07	-406.38
CENRAP	Arkansas	82.63	82.63	83.25	40.83	42.15	82.63	81.80	83.30	37.71	40.29	0.00	-0.82	0.05	-3.12	-1.87
	Iowa	145.10	139.66	147.98	143.60	144.93	146.70	130.53	140.02	138.56	137.16	1.60	-9.13	-7.96	-5.04	-7.76
	Kansas	80.16	80.52	81.49	59.32	59.32	78.46	78.82	81.49	59.33	59.35	-1.70	-1.70	0.00	0.01	0.03
	Louisiana	111..31	111..31	75.49	77.24	79.60	111..31	91.70	75.59	77.31	76.61	0.00	-19.61	0.10	0.07	-2.99

		MARAMA Base Case (MARAMA_5c)					**MARAMA CAIR Plus Policy Case (MARAMA_4c)**					**MARAMA_4c - MARAMA_5c**				
RPO	State	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**
	Minnesota	96.56	87.90	86.82	85.30	84.26	95.74	84.24	83.05	69.59	65.86	-0.82	-3.66	-3.76	-15.70	-18.39
	Missouri	266.99	276.53	280.25	279.80	279.97	264.07	248.11	273.51	266.06	224.45	-2.93	-28.42	-6.75	-13.74	-55.53
	Nebraska	73.63	73.63	73.63	37.18	37.18	73.63	73.63	73.63	37.18	37.18	0.00	0.00	0.00	0.00	0.00
	Oklahoma	113.68	113.68	117.28	48.06	50.15	113.68	113.68	119.44	48.08	52.18	0.00	0.00	2.17	0.02	2.03
	Texas	425.27	425.27	439.21	387.56	359.20	424.27	422.47	384.06	280.92	268.72	-1.00	-2.80	-55.15	-106.63	-90.48
CENRAP Total		1,395.34	1,391.13	1,385.39	1,158.90	1,136.76	1,390.49	1,324.98	1,314.08	1,014.75	961.80	-4.85	-66.15	-71.31	-144.15	-174.96
WRAP	Arizona	60.54	60.55	63.28	63.28	56.83	60.54	60.55	63.80	64.22	57.78	0.00	0.00	0.52	0.95	0.96
	California	6.79	6.79	7.53	7.53	7.45	6.79	6.67	7.63	7.63	7.49	0.00	-0.12	0.10	0.10	0.04
	Colorado	87.22	86.55	87.21	52.84	53.62	86.55	86.56	87.21	52.84	53.75	-0.67	0.01	0.00	0.00	0.14
	Idaho	0.05	0.05	1.14	1.14	1.01	0.05	0.05	1.28	1.28	1.08	0.00	0.00	0.14	0.14	0.07
	Montana	19.88	19.88	20.51	20.51	20.46	16.72	16.72	20.60	20.60	20.50	-3.16	-3.16	0.08	0.08	0.04
	Nevada	31.24	31.30	31.96	28.21	29.00	31.24	31.30	32.10	28.44	29.23	0.00	0.00	0.15	0.24	0.23
	New Mexico	52.92	52.92	53.64	53.64	54.42	52.92	52.92	53.77	53.85	54.63	0.00	0.00	0.13	0.21	0.20
	North Dakota	92.63	92.65	93.39	85.04	85.05	96.70	100.00	109.45	101.11	101.91	4.07	7.35	16.06	16.07	16.86
	Oregon	10.18	10.18	16.27	16.27	15.54	10.18	10.18	17.07	17.07	15.91	0.00	0.00	0.79	0.79	0.37
	South Dakota	12.09	12.09	12.09	4.15	4.20	12.09	12.09	12.09	4.18	4.20	0.00	0.00	0.00	0.03	0.00
	Utah	53.16	53.16	53.16	53.16	33.55	53.16	53.16	53.16	53.16	33.55	0.00	0.00	0.00	0.00	0.00
	Washington	11.25	11.25	20.75	20.68	19.29	11.25	11.25	22.18	20.96	22.06	0.00	0.00	1.44	0.28	2.76
	Wyoming	70.13	70.10	72.69	71.37	38.69	64.79	64.64	71.95	72.45	38.72	-5.35	-5.46	-0.74	1.08	0.02
WRAP Total		508.08	507.48	533.62	477.82	419.10	502.97	506.09	552.29	497.79	440.80	-5.11	-1.39	18.67	19.97	21.70
CAIR Plus Policy States		6,760.02	6,260.69	5,150.31	4,604.99	4,219.83	6,331.62	5,324.07	4,325.72	3,705.23	3,350.76	-428.40	-936.62	-824.59	-899.76	-869.07
National		7,535.57	7,036.00	5,956.32	5,227.37	4,785.59	7,100.36	6,096.28	5,152.57	4,347.61	3,940.28	-435.21	-939.72	-803.75	-879.77	-845.31

Table A5.2: State Level Annual NO_x Emissions in MARAMA Base Case and MARAMA CAIR Plus Policy Case (Thousand Tons)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	3.45	3.60	5.07	5.19	5.69	3.42	3.74	3.64	3.81	3.86	-0.03	0.15	-1.43	-1.38	-1.83
	Delaware	12.51	10.72	11.40	10.91	10.72	12.52	10.16	9.68	4.84	3.88	0.01	-0.56	-1.72	-6.07	-6.83
	District of Columbia	0.11	0.13	0.21	0.30	0.48	0.11	0.13	0.33	0.39	0.50	0.00	0.00	0.12	0.10	0.02
	Maine	7.80	7.94	2.66	2.64	2.78	7.42	3.25	1.87	1.89	1.86	-0.38	-4.69	-0.79	-0.75	-0.92
	Maryland	54.68	16.33	16.10	16.76	19.22	54.68	14.38	17.36	17.54	18.73	0.00	-1.96	1.26	0.79	-0.49
	Massachusetts	30.40	24.25	24.57	22.05	22.55	20.90	13.89	12.03	9.89	9.96	-9.49	-10.37	-12.54	-12.16	-12.59
	New Hampshire	3.96	4.07	5.32	5.28	5.65	3.96	2.92	2.45	2.56	2.66	0.00	-1.15	-2.87	-2.72	-2.99
	New Jersey	16.90	10.82	11.00	12.70	12.54	16.88	11.57	10.64	12.06	10.89	-0.02	0.75	-0.36	-0.65	-1.64
	New York	48.33	48.42	46.14	41.52	38.72	47.59	41.00	31.26	30.61	28.72	-0.74	-7.42	-14.88	-10.91	-9.99
	Pennsylvania	207.46	144.89	85.35	83.95	79.34	208.06	126.22	72.38	68.60	64.08	0.60	-18.66	-12.98	-15.35	-15.26
	Rhode Island	0.26	0.59	0.53	0.57	0.67	0.26	0.58	0.23	0.27	0.27	0.00	-0.01	-0.30	-0.30	-0.40
	Vermont	0.13	0.17	0.39	0.40	0.47	0.13	0.16	0.19	0.21	0.23	0.00	0.00	-0.20	-0.18	-0.24
MANE-VU Total		385.99	271.92	208.74	202.25	198.82	375.92	228.00	162.05	152.67	145.64	-10.06	-43.92	-46.69	-49.58	-53.18
LADCO	Illinois	131.60	87.21	73.57	70.99	72.80	130.94	62.34	56.53	54.12	53.33	-0.66	-24.87	-17.03	-16.87	-19.46
	Indiana	219.40	144.58	107.85	96.96	85.08	221.73	136.98	54.83	53.22	51.32	2.33	-7.60	-53.02	-43.74	-33.76
	Michigan	120.64	86.96	85.53	87.16	92.62	120.00	82.48	39.77	40.44	41.42	-0.64	-4.48	-45.76	-46.72	-51.21
	Ohio	272.07	116.53	97.31	89.00	85.95	271.91	101.79	66.96	65.25	63.56	-0.16	-14.75	-30.35	-23.75	-22.39
	Wisconsin	60.14	48.14	44.77	45.39	45.66	59.63	42.34	31.15	31.70	32.17	-0.51	-5.80	-13.63	-13.69	-13.49
LADCO Total		803.86	483.42	409.04	389.50	382.12	804.22	425.92	249.25	244.74	241.79	0.36	-57.50	-159.79	-144.77	-140.32
VISTAS	Alabama	131.82	82.73	68.84	47.15	47.46	134.12	52.64	31.69	31.13	32.74	2.30	-30.10	-37.15	-16.02	-14.72
	Florida	164.71	115.54	78.29	74.45	66.66	164.71	105.40	49.61	49.19	48.58	0.00	-10.13	-28.68	-25.25	-18.07
	Georgia	239.40	96.35	91.57	59.66	51.41	239.40	74.34	37.81	38.67	42.01	0.00	-22.01	-53.76	-20.99	-9.40
	Kentucky	171.39	96.49	88.06	70.17	58.75	176.12	97.11	38.57	37.75	37.35	4.73	0.62	-49.49	-32.42	-21.40
	Mississippi	38.10	31.42	31.53	8.19	9.06	38.10	29.14	7.67	8.53	9.64	0.00	-2.29	-23.87	0.34	0.58
	North Carolina	62.68	55.96	56.86	56.91	56.57	62.71	52.14	52.66	51.01	49.03	0.03	-3.82	-4.19	-5.90	-7.54
	South Carolina	50.92	35.94	39.26	38.95	40.67	52.51	37.72	27.56	27.14	29.35	1.58	1.78	-11.70	-11.81	-11.31
	Tennessee	104.12	48.39	39.34	39.14	29.16	104.92	28.22	20.27	20.23	20.28	0.80	-20.17	-19.07	-18.91	-8.89
	Virginia	65.86	61.62	55.49	48.35	39.70	65.11	56.29	35.25	33.27	31.77	-0.74	-5.34	-20.25	-15.08	-7.93
	West Virginia	178.66	75.42	71.84	59.08	53.44	177.99	64.59	50.12	49.30	49.51	-0.66	-10.83	-21.72	-9.78	-3.93
VISTAS Total		1,207.64	699.87	621.10	502.04	452.87	1,215.69	597.58	351.22	346.21	350.26	8.05	-102.29	-269.88	-155.83	-102.62
CENRAP	Arkansas	45.27	32.09	33.00	34.03	35.42	45.27	32.47	16.46	12.16	13.69	0.01	0.38	-16.54	-21.87	-21.73
	Iowa	74.73	46.67	50.84	47.85	48.69	75.86	41.36	20.33	20.31	19.64	1.14	-5.31	-30.50	-27.54	-29.06
	Kansas	82.69	82.77	82.84	53.35	53.55	82.69	83.10	82.87	53.38	53.55	0.00	0.33	0.03	0.03	0.00
	Louisiana	50.66	31.88	33.58	32.36	34.75	50.79	31.59	14.73	15.69	17.95	0.13	-0.28	-18.85	-16.67	-16.81

		MARAMA Base Case (MARAMA_5c)					**MARAMA CAIR Plus Policy Case (MARAMA_4c)**					**MARAMA_4c - MARAMA_5c**				
RPO	State	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**
	Minnesota	74.90	41.18	40.77	40.40	40.52	74.85	36.54	18.58	17.40	16.71	-0.05	-4.64	-22.20	-23.01	-23.81
	Missouri	121.35	72.43	74.57	67.79	67.90	121.95	67.82	49.68	48.50	45.56	0.60	-4.61	-24.89	-19.30	-22.34
	Nebraska	50.75	50.77	50.77	38.47	38.57	50.82	50.86	50.85	38.56	38.58	0.08	0.08	0.08	0.09	0.01
	Oklahoma	74.02	78.23	77.50	53.42	53.52	73.94	80.88	77.80	56.21	55.85	-0.08	2.64	0.30	2.79	2.33
	Texas	180.11	168.10	172.16	171.74	165.40	178.34	152.86	100.30	99.43	90.16	-1.77	-15.24	-71.86	-72.32	-75.24
CENRAP Total		754.46	604.11	616.04	539.42	538.33	754.51	577.47	431.60	361.63	351.69	0.05	-26.64	-184.44	-177.79	-186.64
WRAP	Arizona	79.45	79.51	82.42	67.94	71.85	79.46	79.50	82.92	68.46	72.74	0.01	-0.01	0.50	0.52	0.89
	California	30.21	33.26	26.83	28.51	31.66	30.18	33.44	26.49	28.19	31.04	-0.03	0.18	-0.34	-0.32	-0.62
	Colorado	68.06	68.82	68.90	60.47	61.54	68.05	68.89	68.94	60.43	61.47	0.00	0.06	0.04	-0.03	-0.06
	Idaho	0.71	0.71	0.79	0.79	0.79	0.71	0.71	0.87	0.87	0.87	0.00	0.00	0.08	0.08	0.08
	Montana	38.43	38.43	38.79	38.79	38.81	38.43	38.44	38.84	38.84	38.86	0.00	0.01	0.05	0.05	0.05
	Nevada	46.56	46.66	47.08	30.70	31.59	46.56	46.80	47.22	30.83	31.84	0.00	0.15	0.13	0.13	0.26
	New Mexico	73.49	73.64	74.31	72.30	73.16	73.49	73.68	74.47	72.55	73.46	0.00	0.04	0.17	0.25	0.30
	North Dakota	71.54	71.71	71.69	39.86	39.93	70.92	71.76	71.76	39.94	39.94	-0.61	0.05	0.07	0.09	0.02
	Oregon	10.84	10.84	14.27	14.27	14.27	10.84	10.84	14.72	14.72	14.72	0.00	0.00	0.45	0.45	0.45
	South Dakota	14.54	14.54	14.55	1.75	1.82	14.57	14.58	14.58	1.80	1.82	0.03	0.04	0.03	0.05	0.00
	Utah	60.79	60.79	60.79	53.39	53.36	60.79	60.79	60.79	53.39	53.36	0.00	0.00	0.00	0.00	0.00
	Washington	25.34	26.23	31.95	21.54	21.54	25.34	25.90	32.42	22.40	22.40	0.00	-0.33	0.47	0.86	0.86
	Wyoming	81.17	81.17	81.18	53.07	53.17	81.18	81.18	81.18	53.07	53.19	0.01	0.01	0.01	0.00	0.01
WRAP Total		601.11	606.30	613.54	483.37	493.48	600.52	606.50	615.20	485.50	495.72	-0.60	0.20	1.66	2.13	2.24
CAIR Plus Policy States		2,944.50	1,847.55	1,643.80	1,487.96	1,426.50	2,942.89	1,614.14	982.59	957.10	941.40	-1.61	-233.41	-661.20	-530.87	-485.10
National		3,753.06	2,665.62	2,468.46	2,116.58	2,065.62	3,750.86	2,435.47	1,809.32	1,590.75	1,585.10	-2.20	-230.15	-659.14	-525.84	-480.52

Table A5.3: State Level Ozone Season NO$_x$ Emissions in MARAMA Base Case and MARAMA CAIR Plus Policy Case (Thousand Tons)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	1.55	1.62	2.20	2.25	2.47	1.54	1.68	1.60	1.66	1.69	0.00	0.06	-0.60	-0.59	-0.78
	Delaware	4.63	4.20	4.98	4.51	4.38	4.64	4.12	3.91	1.96	1.64	0.01	-0.08	-1.07	-2.55	-2.74
	District of Columbia	0.05	0.08	0.09	0.12	0.20	0.05	0.08	0.14	0.17	0.21	0.00	0.00	0.05	0.04	0.01
	Maine	3.59	3.55	1.14	1.13	1.16	3.49	1.31	0.79	0.80	0.81	-0.10	-2.24	-0.34	-0.32	-0.35
	Maryland	12.69	7.18	7.40	7.42	8.59	12.69	6.56	7.84	7.72	8.29	0.00	-0.62	0.43	0.30	-0.30
	Massachusetts	10.68	9.47	10.62	9.07	9.37	6.38	5.60	5.11	4.25	4.16	-4.31	-3.87	-5.51	-4.83	-5.21
	New Hampshire	1.75	1.82	2.32	2.30	2.46	1.75	1.03	1.07	1.08	1.15	0.00	-0.79	-1.25	-1.23	-1.31
	New Jersey	4.67	4.84	4.88	5.70	5.59	4.67	5.25	4.85	5.31	5.10	0.00	0.41	-0.04	-0.39	-0.49
	New York	19.58	19.11	21.09	18.58	17.43	19.27	17.10	14.37	13.68	12.49	-0.31	-2.00	-6.72	-4.91	-4.93
	Pennsylvania	62.25	57.36	36.82	36.24	34.25	62.83	43.56	30.97	29.61	28.35	0.58	-13.80	-5.85	-6.63	-5.89
	Rhode Island	0.16	0.27	0.23	0.24	0.29	0.16	0.27	0.10	0.11	0.12	0.00	-0.01	-0.13	-0.13	-0.17
	Vermont	0.06	0.10	0.17	0.17	0.20	0.06	0.10	0.09	0.09	0.10	0.00	0.00	-0.08	-0.08	-0.10
MANE-VU Total		121.67	109.58	91.93	87.75	86.38	117.54	86.66	70.83	66.43	64.11	-4.13	-22.92	-21.10	-21.32	-22.27
LADCO	Illinois	30.31	28.33	32.45	31.95	31.69	29.03	26.58	24.94	24.00	23.26	-1.28	-1.75	-7.51	-7.95	-8.44
	Indiana	61.31	60.02	46.53	41.46	36.50	63.58	54.08	23.69	23.16	22.42	2.27	-5.93	-22.83	-18.30	-14.09
	Michigan	36.78	36.92	36.29	36.73	38.88	35.96	33.31	16.79	17.24	17.72	-0.82	-3.62	-19.50	-19.49	-21.16
	Ohio	48.38	42.32	41.24	37.73	36.63	49.00	40.18	28.70	28.03	27.74	0.62	-2.13	-12.55	-9.70	-8.88
	Wisconsin	26.45	18.68	19.11	19.68	19.74	26.31	18.10	13.33	13.57	13.92	-0.14	-0.57	-5.77	-6.10	-5.82
LADCO Total		203.23	186.27	175.61	167.55	163.44	203.88	172.26	107.46	106.01	105.05	0.65	-14.01	-68.16	-61.54	-58.39
VISTAS	Alabama	33.72	30.51	30.95	20.94	21.00	36.02	20.24	14.30	14.22	14.73	2.30	-10.27	-16.65	-6.72	-6.27
	Florida	76.17	53.00	36.71	34.10	30.75	76.17	44.39	24.18	22.93	23.06	0.00	-8.61	-12.53	-11.16	-7.68
	Georgia	106.58	43.62	41.36	26.77	23.56	106.58	30.03	17.10	17.48	18.91	0.00	-13.59	-24.26	-9.30	-4.65
	Kentucky	41.98	39.49	38.10	30.09	25.80	46.68	36.23	16.90	16.59	16.52	4.70	-3.26	-21.20	-13.50	-9.28
	Mississippi	17.34	11.93	14.27	3.97	4.33	17.34	11.75	3.70	4.10	4.59	0.00	-0.17	-10.56	0.13	0.26
	North Carolina	21.62	14.73	21.91	24.26	25.43	21.65	18.17	20.95	21.97	21.30	0.03	3.43	-0.96	-2.29	-4.12
	South Carolina	15.98	16.01	17.34	16.81	17.31	17.57	15.09	12.06	11.68	12.91	1.58	-0.91	-5.28	-5.14	-4.40
	Tennessee	15.84	16.04	17.28	17.06	12.44	16.64	9.33	8.94	8.89	8.92	0.80	-6.71	-8.34	-8.17	-3.52
	Virginia	25.68	25.05	24.19	20.22	17.49	25.16	21.60	15.09	14.10	14.16	-0.52	-3.45	-9.10	-6.12	-3.32
	West Virginia	30.03	28.84	30.57	25.42	22.52	29.98	25.48	22.10	21.30	21.46	-0.05	-3.37	-8.46	-4.13	-1.06
VISTAS Total		384.93	279.23	272.67	219.65	200.63	393.79	232.32	155.32	153.27	156.57	8.85	-46.91	-117.35	-66.39	-44.06
CENRAP	Arkansas	20.41	14.25	14.67	15.20	15.84	20.41	14.23	7.34	5.32	6.12	0.00	-0.03	-7.33	-9.88	-9.72
	Iowa	32.58	18.17	22.00	20.63	21.01	33.60	17.55	8.94	8.79	8.43	1.03	-0.62	-13.07	-11.84	-12.58
	Kansas	36.80	36.80	36.86	23.79	23.86	36.80	37.07	36.88	23.81	23.91	0.00	0.27	0.02	0.03	0.04
	Louisiana	23.29	14.60	15.67	15.00	15.97	23.42	13.86	7.29	7.19	8.19	0.13	-0.75	-8.38	-7.81	-7.78

		MARAMA Base Case (MARAMA_5c)					**MARAMA CAIR Plus Policy Case (MARAMA_4c)**					**MARAMA_4c - MARAMA_5c**				
RPO	State	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**
	Minnesota	33.21	18.53	17.78	17.65	17.76	32.89	15.79	8.15	7.61	7.60	-0.32	-2.75	-9.62	-10.04	-10.16
	Missouri	31.11	29.96	32.81	29.80	29.49	31.60	27.90	21.68	20.82	19.65	0.49	-2.06	-11.13	-8.98	-9.84
	Nebraska	22.49	22.51	22.51	17.07	17.11	22.52	22.55	22.55	17.11	17.13	0.03	0.04	0.03	0.04	0.01
	Oklahoma	34.87	38.92	36.74	25.77	25.38	34.79	41.16	37.05	28.43	27.47	-0.08	2.24	0.30	2.66	2.09
	Texas	89.83	84.14	86.94	86.85	85.82	88.29	72.23	50.44	49.58	46.21	-1.54	-11.91	-36.50	-37.27	-39.60
CENRAP Total		324.58	277.90	285.98	251.76	252.23	324.33	262.33	200.31	168.66	164.70	-0.26	-15.57	-85.67	-83.10	-87.53
WRAP	Arizona	35.13	35.14	36.28	30.09	31.66	35.14	35.12	36.48	30.18	32.00	0.01	-0.01	0.19	0.09	0.34
	California	12.71	13.83	11.61	12.53	13.83	12.70	14.10	11.34	12.43	13.55	-0.01	0.27	-0.27	-0.10	-0.28
	Colorado	29.98	30.12	30.17	26.60	27.04	29.98	30.24	30.16	26.62	27.03	0.00	0.12	-0.01	0.01	-0.01
	Idaho	0.31	0.31	0.34	0.34	0.34	0.31	0.31	0.37	0.37	0.37	0.00	0.00	0.03	0.03	0.03
	Montana	17.00	17.00	17.15	17.15	17.16	17.00	17.01	17.17	17.17	17.18	0.00	0.01	0.02	0.02	0.02
	Nevada	20.90	20.93	20.93	13.65	14.06	20.90	20.99	20.98	13.71	14.18	0.00	0.06	0.05	0.06	0.12
	New Mexico	32.68	32.83	33.03	32.13	32.48	32.68	32.84	33.11	32.24	32.64	0.00	0.01	0.08	0.11	0.16
	North Dakota	31.60	31.74	31.73	17.63	17.66	31.18	31.77	31.77	17.68	17.68	-0.41	0.02	0.04	0.06	0.02
	Oregon	4.76	4.76	6.23	6.23	6.23	4.76	4.76	6.42	6.42	6.42	0.00	0.00	0.19	0.19	0.19
	South Dakota	6.44	6.44	6.44	0.77	0.81	6.45	6.46	6.45	0.80	0.81	0.01	0.02	0.01	0.03	0.00
	Utah	26.91	26.91	26.91	23.64	23.60	26.91	26.91	26.91	23.64	23.60	0.00	0.00	0.00	0.00	0.00
	Washington	11.19	11.52	14.01	9.41	9.41	11.19	11.19	14.21	9.77	9.77	0.00	-0.33	0.20	0.37	0.37
	Wyoming	35.93	35.93	35.93	23.49	23.54	35.93	35.93	35.93	23.49	23.54	0.00	0.00	0.00	0.00	0.01
WRAP Total		265.54	267.46	270.77	213.66	217.81	265.13	267.62	271.31	214.53	218.78	-0.41	0.17	0.54	0.87	0.97
CAIR Plus Policy States		940.26	754.74	730.08	660.09	636.33	945.41	652.79	437.45	425.01	421.93	5.16	-101.95	-292.63	-235.08	-214.39
National		1,299.95	1,120.44	1,096.96	940.38	920.49	1,304.66	1,021.20	805.23	708.90	709.22	4.71	-99.24	-291.74	-231.48	-211.27

Table A5.4: State Level Fixed O&M Costs in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 Million Dollars)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	433.6	434.1	457.0	468.9	506.5	436.3	436.8	463.5	478.3	511.6	2.7	2.7	6.5	9.4	5.1
	Delaware	59.0	59.0	66.5	69.5	71.2	55.5	55.5	58.8	62.6	65.7	-3.5	-3.5	-7.8	-6.9	-5.5
	District of Columbia	14.2	14.2	15.4	20.8	22.9	14.2	14.2	16.8	20.7	22.0	0.0	0.0	1.4	-0.1	-1.0
	Maine	61.5	61.5	56.1	60.7	64.1	62.4	62.8	68.8	74.6	76.4	0.9	1.3	12.7	13.9	12.2
	Maryland	460.1	475.4	503.3	587.3	617.0	464.9	480.2	526.9	587.2	605.8	4.8	4.8	23.6	-0.1	-11.2
	Massachusetts	442.0	443.2	427.7	448.2	465.0	441.1	442.3	432.1	460.0	468.6	-0.9	-0.9	4.4	11.7	3.7
	New Hampshire	209.5	209.5	225.7	234.1	240.4	211.2	211.2	227.1	237.8	241.1	1.7	1.7	1.4	3.7	0.7
	New Jersey	856.7	856.7	896.5	919.5	959.3	853.3	853.3	891.3	919.8	970.2	-3.4	-3.4	-5.1	0.3	10.9
	New York	1,429.0	1,429.1	1,502.5	1,563.6	1,604.4	1,426.6	1,426.7	1,506.8	1,544.9	1,607.0	-2.4	-2.4	4.3	-18.7	2.6
	Pennsylvania	1,968.4	1,972.2	2,027.5	2,105.6	2,191.4	1,963.6	1,960.7	2,014.8	2,103.8	2,198.9	-4.8	-11.5	-12.7	-1.8	7.5
	Rhode Island	22.2	22.2	20.5	23.1	25.0	21.3	21.3	21.9	25.1	26.0	-0.9	-0.9	1.4	2.0	1.1
	Vermont	120.2	120.2	123.3	125.2	126.4	120.5	120.5	124.2	126.5	127.1	0.3	0.3	0.9	1.3	0.7
MANE-VU Total		6,076.4	6,097.3	6,322.0	6,626.6	6,893.7	6,070.8	6,085.3	6,352.9	6,641.2	6,920.4	-5.6	-11.9	30.9	14.6	26.7
LADCO	Illinois	2,021.9	2,022.7	2,058.7	2,168.5	2,391.2	2,028.4	2,023.5	2,060.8	2,178.8	2,395.1	6.6	0.8	2.1	10.3	3.9
	Indiana	625.1	634.1	672.6	716.8	727.8	622.8	629.2	680.3	735.0	766.9	-2.3	-5.0	7.8	18.2	39.1
	Michigan	1,094.0	1,094.1	1,094.7	1,132.7	1,236.4	1,084.0	1,084.1	1,101.7	1,141.9	1,200.1	-10.1	-10.1	7.0	9.2	-36.3
	Ohio	1,031.1	1,058.5	1,129.5	1,170.0	1,205.8	1,048.8	1,046.4	1,127.7	1,196.1	1,252.1	17.7	-12.1	-1.8	26.1	46.3
	Wisconsin	515.7	515.9	529.6	552.9	589.7	507.1	507.7	531.1	552.5	578.9	-8.6	-8.2	1.5	-0.5	-10.8
LADCO Total		5,287.7	5,325.4	5,485.1	5,741.0	6,150.8	5,291.0	5,290.8	5,501.6	5,804.3	6,193.0	3.3	-34.5	16.6	63.3	42.1
VISTAS	Alabama	987.4	989.5	1,030.4	1,123.6	1,181.0	987.0	986.7	1,064.0	1,130.5	1,190.9	-0.3	-2.8	33.6	6.9	9.9
	Florida	1,355.1	1,356.0	1,503.5	1,678.5	1,745.0	1,355.2	1,356.1	1,519.8	1,697.1	1,733.5	0.1	0.1	16.3	18.6	-11.4
	Georgia	835.8	857.9	901.2	1,089.1	1,208.6	836.1	878.2	989.8	1,107.1	1,229.5	0.2	20.3	88.6	18.0	20.9
	Kentucky	495.5	496.2	533.6	556.5	569.1	494.7	494.0	542.3	582.2	592.5	-0.8	-2.1	8.6	25.7	23.4
	Mississippi	307.9	311.1	312.8	389.1	411.0	305.9	309.2	333.8	385.2	407.0	-2.0	-2.0	21.0	-4.0	-4.0
	North Carolina	970.1	986.3	1,087.7	1,189.6	1,251.6	969.0	986.1	1,095.3	1,188.7	1,248.9	-1.1	-0.2	7.5	-0.9	-2.8
	South Carolina	936.7	936.8	995.5	1,088.5	1,148.3	936.6	936.6	1,002.3	1,093.9	1,163.2	-0.2	-0.2	6.9	5.3	14.9
	Tennessee	663.6	664.6	735.2	754.3	782.6	663.4	664.4	747.6	785.4	794.3	-0.3	-0.3	12.4	31.1	11.8
	Virginia	625.6	625.6	719.5	789.7	831.7	620.4	614.8	718.0	790.4	826.4	-5.2	-10.7	-1.6	0.7	-5.3
	West Virginia	517.6	529.5	576.1	605.8	613.3	535.9	541.2	584.3	609.5	622.5	18.3	11.7	8.2	3.7	9.2
VISTAS Total		7,695.4	7,753.4	8,395.5	9,264.7	9,742.2	7,704.2	7,767.2	8,597.1	9,369.9	9,808.7	8.8	13.8	201.6	105.3	66.6
CENRAP	Arkansas	383.8	383.8	421.2	465.1	484.1	383.8	383.8	422.9	458.4	485.8	0.0	0.0	1.7	-6.7	1.7
	Iowa	274.5	282.0	285.1	297.5	303.1	275.7	277.7	283.0	286.7	290.9	1.2	-4.3	-2.1	-10.8	-12.2
	Kansas	340.7	341.6	357.5	395.1	414.5	337.5	338.4	354.2	391.9	394.6	-3.3	-3.3	-3.3	-3.2	-19.9
	Louisiana	437.9	437.9	468.7	524.8	583.9	438.1	442.8	471.9	527.6	584.8	0.3	5.0	3.2	2.7	0.9

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**
	Minnesota	443.2	441.2	447.3	447.3	453.0	444.6	439.3	446.4	450.2	454.6	1.4	-1.9	-0.9	3.0	1.6
	Missouri	444.5	447.6	457.3	506.9	538.8	445.3	443.6	455.7	494.6	535.6	0.8	-4.0	-1.6	-12.3	-3.2
	Nebraska	303.8	309.8	313.9	325.3	326.0	304.4	310.4	314.5	325.5	325.9	0.6	0.6	0.6	0.2	-0.1
	Oklahoma	301.4	301.4	350.9	386.1	418.3	301.4	301.4	351.1	385.3	414.0	0.0	0.0	0.2	-0.9	-4.3
	Texas	1,985.4	2,015.4	2,328.6	2,424.2	2,631.0	1,983.1	2,017.0	2,341.9	2,449.9	2,626.5	-2.3	1.7	13.3	25.7	-4.5
CENRAP Total		4,915.3	4,960.7	5,430.4	5,772.5	6,152.8	4,913.9	4,954.5	5,441.5	5,770.2	6,112.7	-1.3	-6.2	11.1	-2.3	-40.1
WRAP	Arizona	711.5	716.5	756.1	756.1	900.0	691.9	696.9	744.5	749.6	893.6	-19.7	-19.7	-11.5	-6.5	-6.4
	California	1,515.4	1,518.2	1,545.8	1,698.7	1,760.8	1,544.9	1,547.6	1,569.3	1,717.1	1,779.2	29.4	29.4	23.5	18.4	18.4
	Colorado	197.0	201.0	204.3	224.7	232.0	196.0	199.9	203.2	223.6	232.1	-1.1	-1.1	-1.1	-1.1	0.1
	Idaho	49.1	49.1	52.9	52.9	52.9	49.1	49.1	53.8	53.8	53.8	0.0	0.0	0.9	0.9	0.9
	Montana	136.5	142.9	147.1	147.1	150.6	136.5	143.0	147.7	147.7	151.2	0.0	0.0	0.6	0.6	0.6
	Nevada	184.7	185.5	197.3	207.4	218.4	184.7	185.5	199.3	210.7	221.7	0.0	0.0	2.0	3.3	3.3
	New Mexico	171.5	171.5	186.3	194.6	205.9	171.5	171.5	187.3	189.8	208.5	0.0	0.0	0.9	-4.8	2.5
	North Dakota	142.1	142.1	147.2	163.5	163.9	140.5	140.5	145.6	152.6	161.9	-1.6	-1.6	-1.6	-10.8	-2.0
	Oregon	252.9	252.9	295.6	295.6	295.6	252.9	252.9	300.9	300.9	300.9	0.0	0.0	5.3	5.3	5.3
	South Dakota	44.2	44.2	44.2	47.9	48.3	44.4	44.4	44.4	48.2	48.3	0.2	0.2	0.2	0.3	0.0
	Utah	162.4	162.4	162.4	164.3	179.6	162.4	162.4	162.4	164.3	179.7	0.0	0.0	0.0	0.0	0.0
	Washington	597.7	598.8	674.6	700.7	700.7	597.7	598.8	682.9	710.8	710.8	0.0	0.0	8.3	10.0	10.0
	Wyoming	228.7	228.7	236.4	236.4	248.3	228.8	228.8	236.4	236.4	248.5	0.0	0.0	0.0	0.0	0.2
WRAP Total		4,393.9	4,413.8	4,650.2	4,889.9	5,157.3	4,401.3	4,421.2	4,677.8	4,905.5	5,190.2	7.4	7.4	27.7	15.6	33.0
CAIR Plus Policy States		23,028.9	23,184.0	24,610.6	26,298.2	27,780.7	23,036.7	23,147.7	24,873.4	26,482.9	27,900.2	7.8	-36.2	262.7	184.7	119.6
National		28,368.7	28,550.7	30,283.1	32,294.7	34,096.7	28,381.2	28,519.1	30,571.0	32,491.1	34,225.0	12.6	-31.5	287.9	196.3	128.3

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856

Table A5.5: State Level Variable O&M Costs in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 Million Dollars)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	45.2	48.4	67.2	71.7	78.7	44.6	51.3	55.4	62.0	63.2	-0.6	2.9	-11.7	-9.6	-15.4
	Delaware	15.9	19.5	24.0	22.7	23.2	15.9	18.7	18.6	11.1	11.0	0.0	-0.8	-5.4	-11.6	-12.2
	District of Columbia	0.0	0.0	1.5	4.6	7.3	0.0	0.0	3.2	5.5	7.1	0.0	0.0	1.8	0.9	-0.2
	Maine	29.6	29.9	23.8	24.0	25.8	28.7	28.7	19.1	21.4	21.6	-0.8	-1.2	-4.7	-2.7	-4.2
	Maryland	102.9	129.6	152.8	196.0	232.0	105.4	130.9	178.2	207.4	228.4	2.5	1.3	25.3	11.4	-3.6
	Massachusetts	115.6	99.3	136.2	133.8	145.9	115.8	98.5	112.3	116.1	119.6	0.2	-0.8	-23.9	-17.8	-26.4
	New Hampshire	29.2	30.7	49.1	51.7	57.0	29.2	29.6	38.2	43.8	45.3	0.0	-1.1	-10.9	-7.9	-11.7
	New Jersey	91.3	96.4	99.8	96.3	100.3	91.3	102.2	98.5	98.0	105.7	0.0	5.8	-1.3	1.7	5.4
	New York	165.0	167.1	284.2	304.1	310.5	167.3	167.6	308.3	317.0	328.7	2.3	0.5	24.1	12.9	18.2
	Pennsylvania	427.8	471.9	537.7	532.4	534.7	432.0	469.1	531.3	528.5	529.1	4.2	-2.8	-6.3	-3.9	-5.6
	Rhode Island	1.9	5.1	6.5	7.6	9.2	1.9	5.1	3.8	5.5	5.7	0.0	0.0	-2.6	-2.1	-3.4
	Vermont	6.0	6.0	9.9	10.3	11.2	6.0	6.0	8.1	9.1	9.1	0.0	0.0	-1.8	-1.2	-2.1
MANE-VU Total		1,030.4	1,104.1	1,392.5	1,455.3	1,535.9	1,038.1	1,107.9	1,375.0	1,425.5	1,474.6	7.7	3.8	-17.5	-29.9	-61.3
LADCO	Illinois	289.8	308.1	367.0	377.8	460.7	292.8	301.3	377.7	392.3	482.3	3.0	-6.7	10.7	14.5	21.6
	Indiana	309.2	353.4	390.3	426.6	432.7	309.5	341.8	426.4	452.1	468.0	0.3	-11.6	36.1	25.6	35.3
	Michigan	190.4	212.8	212.0	247.4	338.6	191.4	219.1	255.4	288.2	318.8	1.1	6.3	43.4	40.8	-19.8
	Ohio	408.3	519.5	568.8	591.5	592.6	429.3	507.4	568.1	600.5	610.4	20.9	-12.1	-0.7	9.0	17.7
	Wisconsin	127.2	129.7	145.7	164.2	185.9	128.9	137.6	166.1	184.3	206.7	1.7	7.9	20.4	20.1	20.8
LADCO Total		1,324.8	1,523.5	1,683.9	1,807.5	2,010.5	1,351.8	1,507.1	1,793.7	1,917.4	2,086.2	26.9	-16.4	109.8	109.9	75.6
VISTAS	Alabama	219.5	256.9	298.0	347.1	377.4	213.3	246.9	336.1	357.0	400.5	-6.2	-10.1	38.1	9.9	23.1
	Florida	325.0	348.4	513.0	581.5	658.2	325.0	345.8	524.7	598.3	627.2	0.0	-2.6	11.6	16.8	-31.0
	Georgia	204.6	252.0	321.3	411.7	465.0	204.6	277.6	445.7	485.3	554.3	0.0	25.5	124.4	73.6	89.3
	Kentucky	267.7	305.5	346.3	362.9	373.9	262.1	281.2	360.1	381.4	386.4	-5.6	-24.3	13.8	18.5	12.6
	Mississippi	56.6	61.3	66.1	104.2	120.8	56.6	72.0	91.0	107.2	126.1	0.0	10.7	25.0	3.0	5.3
	North Carolina	283.9	245.0	293.0	316.7	360.5	284.1	243.9	302.9	323.2	358.9	0.2	-1.1	9.9	6.5	-1.6
	South Carolina	170.8	190.8	243.5	260.3	296.8	166.7	184.9	250.3	269.0	312.6	-4.1	-5.9	6.7	8.7	15.8
	Tennessee	159.8	186.5	195.0	194.1	212.9	155.4	162.7	203.9	213.5	217.9	-4.4	-23.7	8.8	19.4	5.0
	Virginia	121.8	133.7	189.2	212.4	253.9	121.9	130.3	201.6	224.7	255.5	0.0	-3.5	12.3	12.3	1.6
	West Virginia	285.2	326.2	391.7	413.0	419.4	314.3	355.9	407.0	418.5	427.0	29.1	29.8	15.3	5.5	7.6
VISTAS Total		2,095.0	2,306.3	2,857.3	3,203.9	3,538.9	2,104.1	2,301.2	3,123.2	3,378.1	3,666.5	9.1	-5.1	265.9	174.1	127.6
CENRAP	Arkansas	65.6	71.0	81.8	128.4	148.4	65.7	80.4	88.7	137.5	162.2	0.1	9.4	6.9	9.1	13.8
	Iowa	85.2	93.0	96.9	101.5	108.3	86.2	98.0	113.4	115.7	120.5	0.9	5.0	16.5	14.2	12.2
	Kansas	104.9	105.1	105.3	118.2	128.9	104.9	105.8	105.4	118.2	120.2	0.0	0.8	0.1	0.0	-8.8
	Louisiana	80.6	82.2	109.1	137.6	174.0	82.0	94.2	124.2	149.0	182.4	1.4	12.0	15.1	11.3	8.4

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**
	Minnesota	111.9	107.1	105.8	105.7	106.2	111.8	108.0	120.0	124.2	123.4	-0.2	1.0	14.2	18.5	17.1
	Missouri	145.5	172.1	177.7	193.3	218.1	143.9	151.4	182.9	187.6	230.0	-1.6	-20.8	5.3	-5.7	11.9
	Nebraska	47.6	47.7	47.7	73.1	73.1	47.6	47.7	47.7	72.9	72.9	0.0	0.0	0.0	-0.2	-0.2
	Oklahoma	110.7	118.9	151.2	173.3	194.0	110.7	127.0	152.0	178.4	200.6	0.0	8.2	0.8	5.1	6.6
	Texas	601.2	621.5	876.4	935.3	1,030.5	603.3	627.8	950.4	1,021.3	1,081.6	2.1	6.3	74.0	85.9	51.1
CENRAP Total		1,353.3	1,418.6	1,751.9	1,966.5	2,181.6	1,356.1	1,440.5	1,884.7	2,104.9	2,293.9	2.9	21.9	132.8	138.3	112.3
WRAP	Arizona	198.3	199.3	245.3	246.0	302.5	198.4	199.3	253.6	257.0	316.8	0.1	0.0	8.3	11.0	14.2
	California	504.9	528.5	522.1	602.3	648.8	504.0	530.8	513.1	590.5	632.8	-1.0	2.3	-9.0	-11.8	-16.0
	Colorado	93.3	98.4	99.3	112.1	123.3	93.3	99.1	99.3	111.9	124.0	0.0	0.7	0.0	-0.2	0.7
	Idaho	2.5	2.5	9.4	9.4	9.4	2.5	2.5	10.6	10.6	10.6	0.0	0.0	1.2	1.2	1.2
	Montana	48.7	48.7	53.9	53.9	54.2	48.7	48.7	54.6	54.6	54.9	0.0	0.0	0.7	0.7	0.7
	Nevada	91.7	94.4	108.3	113.1	126.7	91.7	94.7	110.7	116.8	130.7	0.0	0.3	2.4	3.8	4.0
	New Mexico	86.3	86.7	101.3	104.6	118.3	86.3	86.8	100.2	102.4	121.6	0.0	0.1	-1.0	-2.2	3.3
	North Dakota	71.8	72.2	72.1	81.9	82.0	69.9	71.2	71.2	77.1	81.0	-1.9	-0.9	-0.9	-4.8	-0.9
	Oregon	23.9	23.9	74.1	74.1	74.1	23.9	23.9	80.6	80.6	80.6	0.0	0.0	6.5	6.5	6.5
	South Dakota	5.4	5.4	5.5	9.6	9.9	5.4	5.5	5.5	9.7	9.9	0.0	0.0	0.0	0.1	0.0
	Utah	88.3	88.3	88.3	88.3	91.8	88.3	88.3	88.3	88.3	91.8	0.0	0.0	0.0	0.0	0.0
	Washington	51.1	53.7	146.4	145.4	145.4	51.1	52.7	157.9	157.9	157.9	0.0	-0.9	11.4	12.4	12.4
	Wyoming	116.8	116.8	117.4	117.4	124.2	116.8	116.8	117.4	117.4	124.4	0.0	0.0	0.0	0.0	0.2
WRAP Total		1,383.1	1,418.8	1,643.5	1,758.2	1,910.5	1,380.3	1,420.3	1,663.2	1,775.0	1,937.0	-2.8	1.6	19.6	16.8	26.4
CAIR Plus Policy States		5,540.3	6,080.8	7,381.3	8,068.7	8,870.8	5,586.8	6,076.1	7,871.6	8,456.2	9,127.4	46.6	-4.8	490.2	387.5	256.6
National		7,186.6	7,771.3	9,329.1	10,191.5	11,177.4	7,230.4	7,777.0	9,839.8	10,600.8	11,458.1	43.8	5.8	510.7	409.3	280.7

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856

Table A5.6: State Level Annualized Capital Costs in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 Million Dollars)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	99.6	99.6	269.5	345.1	413.3	116.9	116.9	287.6	379.6	414.3	17.3	17.3	18.2	34.5	1.0
	Delaware	10.6	10.6	28.7	40.6	49.3	10.8	10.8	18.0	34.9	52.1	0.2	0.2	-10.8	-5.7	2.7
	District of Columbia	1.8	1.8	10.2	42.2	57.5	1.8	1.8	20.3	43.5	52.5	0.0	0.0	10.0	1.4	-4.9
	Maine	34.5	34.5	100.7	129.8	156.2	41.0	42.6	108.5	144.0	157.4	6.4	8.1	7.9	14.2	1.3
	Maryland	91.4	139.0	267.5	708.9	915.7	102.4	150.0	411.4	730.1	858.2	11.0	11.0	144.0	21.2	-57.5
	Massachusetts	209.9	209.9	528.7	670.5	798.6	245.2	245.2	565.7	738.1	803.4	35.4	35.4	37.0	67.7	4.8
	New Hampshire	75.7	75.7	196.0	249.5	297.9	87.5	87.5	208.5	274.1	298.7	11.8	11.8	12.4	24.6	0.9
	New Jersey	23.6	23.6	71.7	147.7	203.1	25.0	25.0	70.6	178.8	289.2	1.5	1.5	-1.1	31.1	86.1
	New York	172.1	172.1	1,097.4	1,426.5	1,494.1	190.1	190.1	1,252.0	1,441.4	1,643.9	18.0	18.0	154.6	14.9	149.8
	Pennsylvania	87.0	91.5	282.7	386.9	431.6	92.6	92.6	291.5	454.7	565.6	5.6	1.1	8.8	67.8	134.0
	Rhode Island	19.2	19.2	55.8	72.1	86.8	22.8	22.8	59.6	79.4	86.9	3.6	3.6	3.8	7.3	0.1
	Vermont	12.1	12.1	35.3	45.7	55.0	14.4	14.4	37.7	50.3	55.1	2.3	2.3	2.4	4.6	0.1
MANE-VU Total		837.4	889.6	2,944.2	4,265.4	4,959.1	950.5	999.8	3,331.4	4,549.0	5,277.3	113.1	110.3	387.2	283.6	318.2
LADCO	Illinois	44.1	44.2	133.6	265.4	801.4	60.0	60.0	170.2	354.8	870.1	15.9	15.8	36.6	89.4	68.7
	Indiana	26.6	43.6	110.4	311.2	349.1	31.3	52.1	222.1	492.8	640.5	4.7	8.5	111.7	181.6	291.4
	Michigan	6.4	6.4	6.4	220.4	753.0	7.2	7.2	172.3	399.3	594.7	0.8	0.8	165.8	178.9	-158.4
	Ohio	97.3	175.0	525.2	748.7	762.4	140.9	169.3	485.0	841.3	990.6	43.5	-5.7	-40.1	92.7	228.2
	Wisconsin	14.9	14.9	50.3	159.9	256.2	0.4	3.9	118.6	236.2	386.0	-14.6	-11.0	68.3	76.3	129.8
LADCO Total		189.3	284.1	825.9	1,705.6	2,922.2	239.7	292.5	1,168.2	2,324.5	3,481.9	50.4	8.4	342.3	618.9	559.7
VISTAS	Alabama	20.8	20.8	83.4	521.4	814.8	17.4	31.6	278.4	553.6	877.3	-3.4	10.8	195.0	32.2	62.5
	Florida	13.0	26.7	941.9	1,717.7	2,125.8	13.0	27.0	1,052.4	1,855.0	2,051.0	0.0	0.3	110.5	137.3	-74.7
	Georgia	1.4	1.4	112.6	864.8	1,343.9	2.6	56.5	508.8	931.3	1,446.5	1.2	55.1	396.2	66.6	102.6
	Kentucky	8.2	9.8	86.6	190.5	230.4	5.8	5.8	169.7	325.0	386.8	-2.4	-3.9	83.0	134.5	156.3
	Mississippi	0.5	0.5	15.0	236.4	365.2	0.7	0.7	109.2	230.1	362.8	0.2	0.2	94.1	-6.3	-2.4
	North Carolina	234.1	275.2	623.4	866.4	1,113.6	234.2	275.1	677.4	878.4	1,117.3	0.1	-0.1	54.0	12.0	3.7
	South Carolina	23.3	23.4	321.4	535.7	748.9	21.8	21.8	381.9	573.7	807.4	-1.5	-1.6	60.5	38.0	58.5
	Tennessee	18.0	18.0	31.6	31.6	107.1	15.7	15.7	80.9	125.8	146.5	-2.3	-2.3	49.4	94.2	39.4
	Virginia	9.7	9.7	307.1	539.7	766.4	10.8	10.8	373.6	591.6	804.4	1.0	1.0	66.4	51.9	37.9
	West Virginia	2.7	2.7	139.8	281.7	313.6	52.0	62.6	202.5	352.8	431.9	49.3	59.9	62.6	71.1	118.4
VISTAS Total		331.9	388.3	2,662.9	5,785.8	7,929.6	374.1	507.7	3,834.8	6,417.4	8,431.9	42.2	119.3	1,171.8	631.6	502.3
CENRAP	Arkansas	0.1	0.1	45.9	191.3	314.3	0.1	0.1	71.0	224.9	349.3	0.0	0.0	25.1	33.7	34.9
	Iowa	0.0	0.7	0.7	10.4	17.3	2.4	4.9	45.6	46.1	52.8	2.4	4.2	44.9	35.7	35.5
	Kansas	0.0	0.0	0.0	22.2	71.5	0.0	0.0	0.0	22.3	39.4	0.0	0.0	0.0	0.0	-32.1
	Louisiana	0.1	0.1	107.6	290.4	508.7	0.1	11.8	149.1	326.0	532.0	0.0	11.6	41.5	35.6	23.3

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**
	Minnesota	45.1	84.0	84.1	84.1	86.9	47.9	88.7	119.2	132.0	132.0	2.8	4.6	35.2	47.9	45.1
	Missouri	2.8	14.1	19.7	91.3	257.6	4.7	5.6	53.6	117.9	307.1	2.0	-8.6	33.9	26.7	49.5
	Nebraska	0.0	0.0	0.0	34.4	35.7	1.2	1.2	1.2	35.3	35.7	1.2	1.2	1.2	0.8	0.0
	Oklahoma	0.5	0.5	237.8	345.3	524.2	0.5	0.5	239.1	351.6	521.5	0.0	0.0	1.2	6.3	-2.7
	Texas	225.6	225.6	2,245.5	2,610.3	3,446.4	243.1	260.7	2,399.5	2,822.6	3,626.5	17.5	35.1	154.0	212.2	180.1
CENRAP Total		274.2	325.2	2,741.4	3,679.7	5,262.7	300.1	373.4	3,078.2	4,078.7	5,596.3	25.9	48.2	336.9	399.0	333.6
WRAP	Arizona	2.8	2.8	264.0	264.0	583.3	2.8	2.8	322.2	357.9	677.7	0.0	0.0	58.2	93.9	94.4
	California	792.1	792.1	980.4	1,506.9	1,691.7	823.0	823.0	964.9	1,453.1	1,637.9	30.9	30.9	-15.4	-53.8	-53.8
	Colorado	0.0	0.0	0.0	42.3	93.4	0.0	0.0	0.0	42.2	102.3	0.0	0.0	0.0	-0.2	8.9
	Idaho	9.0	9.0	61.8	61.8	61.8	9.0	9.0	68.7	68.7	68.7	0.0	0.0	6.9	6.9	6.9
	Montana	5.2	5.2	36.0	36.0	37.5	5.3	5.3	40.1	40.1	41.7	0.1	0.1	4.1	4.1	4.3
	Nevada	0.7	0.7	65.7	70.5	148.6	0.7	0.7	80.2	93.9	171.8	0.0	0.0	14.5	23.4	23.3
	New Mexico	0.6	0.6	68.1	75.4	152.1	0.6	0.6	80.7	90.4	172.8	0.0	0.0	12.6	14.9	20.7
	North Dakota	23.2	23.2	23.2	48.0	48.8	19.3	19.3	19.3	36.2	44.2	-3.8	-3.8	-3.8	-11.8	-4.6
	Oregon	50.2	50.2	346.1	346.1	346.1	50.2	50.2	384.7	384.7	384.7	0.0	0.0	38.6	38.6	38.6
	South Dakota	0.0	0.0	0.0	13.3	14.8	0.5	0.5	0.5	13.9	14.9	0.5	0.5	0.5	0.6	0.1
	Utah	0.0	0.0	0.0	0.0	15.6	0.0	0.0	0.0	0.0	15.7	0.0	0.0	0.0	0.0	0.1
	Washington	95.2	95.2	657.3	657.3	657.3	95.2	95.2	730.5	730.5	730.5	0.0	0.0	73.3	73.3	73.3
	Wyoming	0.0	0.0	0.0	0.0	33.5	0.1	0.1	0.1	0.1	34.9	0.1	0.1	0.1	0.1	1.4
WRAP Total		979.0	979.0	2,502.6	3,121.7	3,884.3	1,006.7	1,006.7	2,692.0	3,311.7	4,097.9	27.7	27.7	189.4	190.0	213.6
CAIR Plus Policy States		1,632.3	1,886.6	8,936.5	15,034.5	20,442.3	1,862.7	2,171.6	11,172.4	16,960.4	22,190.9	230.4	285.0	2,235.8	1,925.9	1,748.7
National		2,611.8	2,866.1	11,677.0	18,558.1	24,958.0	2,871.1	3,180.0	14,104.7	20,681.3	26,885.4	259.3	313.9	2,427.7	2,123.1	1,927.4

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856

Table A5.7: State Level Fuel Costs in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 Million Dollars)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	768.8	806.3	312.3	286.3	289.9	724.6	1,058.0	330.8	278.7	288.6	-44.1	251.7	18.5	-7.6	-1.4
	Delaware	133.8	132.5	126.9	118.1	121.2	134.7	141.9	114.8	63.2	61.2	0.9	9.4	-12.2	-54.9	-60.0
	District of Columbia	0.8	4.6	4.6	14.6	21.7	1.0	5.1	9.4	16.6	20.6	0.1	0.5	4.8	2.0	-1.1
	Maine	594.3	580.6	219.4	203.1	199.9	578.1	569.5	211.6	204.9	201.1	-16.2	-11.1	-7.8	1.7	1.2
	Maryland	548.2	562.5	574.2	691.8	782.3	545.6	567.2	634.3	718.8	760.9	-2.6	4.6	60.1	27.0	-21.4
	Massachusetts	2,558.0	2,382.5	1,509.2	1,097.8	1,088.0	2,530.1	2,474.2	1,488.2	1,103.7	1,194.3	-27.9	91.7	-21.0	5.9	106.3
	New Hampshire	161.6	254.6	197.1	197.5	208.7	158.3	257.9	166.4	178.8	187.3	-3.3	3.3	-30.7	-18.7	-21.4
	New Jersey	791.9	844.7	686.7	575.2	624.8	789.6	1,226.1	676.7	610.3	673.9	-2.4	381.4	-10.0	35.1	49.1
	New York	3,017.9	3,031.9	1,809.5	1,615.5	1,705.7	3,043.8	3,410.1	1,765.3	1,676.8	1,736.8	25.9	378.2	-44.3	61.3	31.1
	Pennsylvania	2,676.7	2,878.9	2,501.0	2,286.8	2,210.0	2,742.5	3,601.3	2,442.4	2,299.3	2,269.6	65.8	722.4	-58.6	12.4	59.6
	Rhode Island	118.9	305.2	33.3	35.7	36.1	118.7	338.1	35.5	33.7	33.4	-0.2	33.0	2.2	-2.0	-2.7
	Vermont	22.4	23.2	34.0	35.3	37.4	22.4	22.8	30.7	34.3	33.9	0.0	-0.4	-3.3	-1.1	-3.5
MANE-VU Total		11,393.4	11,807.5	8,008.2	7,157.8	7,325.7	11,389.3	13,672.2	7,905.9	7,218.9	7,461.5	-4.0	1,864.7	-102.3	61.1	135.8
LADCO	Illinois	1,792.0	1,761.4	1,822.0	1,780.1	1,832.1	1,793.8	1,747.9	1,803.1	1,752.7	1,808.5	1.8	-13.5	-18.9	-27.4	-23.5
	Indiana	1,659.0	1,765.3	1,608.0	1,539.3	1,445.0	1,684.7	2,042.4	1,575.6	1,527.2	1,503.8	25.7	277.1	-32.4	-12.0	58.8
	Michigan	1,511.1	1,599.1	1,445.7	1,458.5	1,572.6	1,528.2	1,991.8	1,488.3	1,459.7	1,458.7	17.1	392.6	42.6	1.2	-113.9
	Ohio	2,198.6	2,389.0	2,162.0	2,099.3	2,058.3	2,161.3	2,640.3	2,067.8	2,069.3	2,033.2	-37.2	251.3	-94.2	-30.0	-25.2
	Wisconsin	752.4	770.8	757.7	716.9	710.5	804.4	859.9	726.2	706.9	699.2	52.0	89.1	-31.5	-10.0	-11.3
LADCO Total		7,913.0	8,285.7	7,795.4	7,594.1	7,618.5	7,972.5	9,282.2	7,661.0	7,515.8	7,503.3	59.5	996.5	-134.4	-78.3	-115.2
VISTAS	Alabama	2,349.4	2,611.5	2,296.2	1,977.2	1,975.6	2,352.9	3,291.0	2,237.1	1,981.0	2,029.4	3.5	679.5	-59.1	3.9	53.8
	Florida	6,214.9	6,265.3	4,440.6	4,101.8	4,245.8	6,215.1	7,332.2	4,264.5	4,167.0	4,416.4	0.2	1,066.9	-176.1	65.2	170.7
	Georgia	3,109.1	3,276.3	2,525.7	2,439.5	2,536.7	3,086.8	3,272.5	2,527.8	2,500.4	2,624.9	-22.3	-3.7	2.1	60.9	88.2
	Kentucky	1,067.2	1,050.9	980.1	1,008.9	1,015.0	1,083.2	1,020.3	969.3	1,011.4	1,017.5	16.0	-30.6	-10.9	2.5	2.6
	Mississippi	884.1	991.6	737.9	720.0	736.8	885.5	1,758.7	745.0	751.7	766.2	1.4	767.1	7.1	31.7	29.4
	North Carolina	1,439.6	1,297.9	1,358.6	1,434.3	1,526.2	1,416.1	1,387.1	1,372.9	1,446.8	1,504.8	-23.5	89.2	14.3	12.5	-21.4
	South Carolina	1,243.8	1,412.2	1,285.7	1,248.7	1,339.1	1,236.8	1,685.0	1,286.4	1,270.4	1,403.1	-7.0	272.8	0.7	21.8	63.9
	Tennessee	820.3	822.1	849.4	816.4	799.5	807.5	717.7	832.5	822.4	801.2	-12.9	-104.5	-17.0	6.0	1.8
	Virginia	1,152.1	1,587.3	1,198.4	1,138.4	1,169.9	1,155.6	1,707.8	1,148.7	1,116.4	1,167.9	3.5	120.5	-49.7	-22.0	-1.9
	West Virginia	1,074.6	1,054.2	1,000.3	1,015.2	1,005.1	1,026.7	1,007.4	960.9	1,014.9	1,013.7	-47.9	-46.8	-39.4	-0.3	8.6
VISTAS Total		19,355.1	20,369.4	16,672.8	15,900.3	16,349.6	19,266.2	23,179.8	16,344.9	16,082.3	16,745.1	-88.9	2,810.4	-327.9	182.0	395.6
CENRAP	Arkansas	1,004.4	1,208.0	1,054.6	928.9	910.6	1,009.3	1,775.0	969.8	904.8	887.5	4.9	567.1	-84.8	-24.1	-23.1
	Iowa	617.8	672.3	631.9	613.2	664.4	630.1	832.7	613.8	629.7	652.0	12.2	160.5	-18.1	16.5	-12.5
	Kansas	450.8	447.3	428.0	420.6	462.5	452.0	503.2	439.3	420.4	430.2	1.2	55.9	11.2	-0.2	-32.2
	Louisiana	1,171.6	1,223.1	994.5	873.6	881.4	1,242.0	1,764.1	983.6	837.2	875.0	70.4	541.0	-10.9	-36.4	-6.4

		MARAMA Base Case (MARAMA_5c)					**MARAMA CAIR Plus Policy Case (MARAMA_4c)**					**MARAMA_4c - MARAMA_5c**				
RPO	State	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**
	Minnesota	510.6	511.0	468.7	453.6	446.2	510.9	505.4	453.1	449.9	440.1	0.3	-5.6	-15.5	-3.6	-6.1
	Missouri	928.1	992.2	1,001.7	976.7	987.2	926.3	972.4	979.3	930.5	897.7	-1.8	-19.9	-22.4	-46.2	-89.5
	Nebraska	261.3	262.8	253.3	245.8	237.9	261.3	264.6	253.3	247.3	238.6	0.0	1.8	0.0	1.5	0.7
	Oklahoma	2,064.3	2,230.8	1,480.1	1,315.1	1,191.4	2,065.1	2,855.6	1,492.8	1,422.1	1,369.9	0.8	624.8	12.6	107.0	178.5
	Texas	11,112.6	11,303.2	6,765.2	6,275.9	6,356.6	11,116.4	12,545.3	6,753.2	6,307.3	6,359.4	3.7	1,242.1	-11.9	31.4	2.9
CENRAP Total		18,121.5	18,850.6	13,077.9	12,103.5	12,138.3	18,213.3	22,018.3	12,938.2	12,149.3	12,150.5	91.8	3,167.7	-139.8	45.8	12.2
WRAP	Arizona	3,549.0	3,407.8	2,509.3	2,289.7	2,346.7	3,552.9	3,765.2	2,479.6	2,191.9	2,334.9	3.9	357.4	-29.7	-97.8	-11.8
	California	6,750.1	7,136.6	4,345.0	4,945.5	5,650.9	6,722.2	7,996.5	4,163.8	4,821.3	5,424.8	-27.9	859.8	-181.1	-124.2	-226.2
	Colorado	509.1	693.8	576.7	581.7	625.6	508.7	765.3	578.2	579.0	610.4	-0.4	71.5	1.4	-2.7	-15.2
	Idaho	117.9	110.9	19.2	18.6	18.0	117.9	124.7	21.4	20.6	20.0	0.0	13.8	2.3	2.0	2.0
	Montana	105.5	104.2	114.0	111.0	107.8	107.5	107.3	114.8	112.0	109.0	2.0	3.1	0.7	1.1	1.2
	Nevada	1,194.4	1,142.9	845.6	774.8	778.6	1,194.5	1,272.6	849.2	778.1	789.1	0.1	129.7	3.5	3.3	10.6
	New Mexico	408.8	414.3	393.5	390.8	446.5	408.7	424.9	400.9	400.5	458.4	-0.1	10.6	7.4	9.7	11.9
	North Dakota	229.8	229.3	223.4	238.5	232.6	231.6	234.8	223.0	238.7	232.3	1.8	5.5	-0.5	0.2	-0.3
	Oregon	877.9	826.8	656.1	585.9	564.7	877.9	926.3	668.2	600.6	578.6	0.0	99.5	12.0	14.6	13.9
	South Dakota	36.3	35.9	35.8	33.9	37.5	36.3	36.8	35.5	34.0	33.5	0.0	0.9	-0.3	0.1	-4.1
	Utah	230.1	223.8	217.8	211.4	206.8	230.1	223.7	219.0	210.1	206.4	0.0	-0.1	1.2	-1.3	-0.4
	Washington	591.6	731.0	603.8	529.8	512.1	591.3	736.9	593.3	554.6	534.7	-0.4	5.9	-10.5	24.8	22.7
	Wyoming	299.9	296.4	295.8	288.1	285.3	303.7	300.1	296.2	286.5	285.0	3.8	3.7	0.5	-1.6	-0.3
WRAP Total		14,900.6	15,353.8	10,836.1	10,999.7	11,813.0	14,883.2	16,915.1	10,643.0	10,827.9	11,616.9	-17.3	1,561.4	-193.1	-171.9	-196.0
CAIR Plus Policy States		54,006.6	56,372.3	43,392.9	40,774.1	41,540.3	54,062.9	64,529.1	42,664.6	40,876.5	41,821.7	56.3	8,156.8	-728.3	102.4	281.4
National		71,683.5	74,667.0	56,390.5	53,755.4	55,245.1	71,724.5	85,067.7	55,493.0	53,794.2	55,477.4	41.0	10,400.7	-897.5	38.8	232.3

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856

Table A5.8: State Level Total Production Costs in MARAMA Base Case and MARAMA CAIR Plus Policy Case (1999 Million Dollars)

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018	2008	2009	2012	2015	2018
MANE-VU	Connecticut	1,347.2	1,388.4	1,105.9	1,172.0	1,288.5	1,322.4	1,663.0	1,137.3	1,198.7	1,277.8	-24.8	274.6	31.4	26.7	-10.7
	Delaware	219.3	221.6	246.2	251.0	264.9	216.9	226.9	210.1	171.9	190.0	-2.4	5.3	-36.1	-79.2	-75.0
	District of Columbia	16.8	20.6	31.7	82.1	109.4	16.9	21.1	49.7	86.3	102.2	0.1	0.5	18.0	4.2	-7.2
	Maine	719.9	706.5	400.0	417.7	446.0	710.2	703.6	408.0	444.8	456.5	-9.7	-3.0	8.1	27.1	10.5
	Maryland	1,202.6	1,306.6	1,497.8	2,184.0	2,547.0	1,218.3	1,328.3	1,750.7	2,243.4	2,453.2	15.6	21.7	253.0	59.4	-93.8
	Massachusetts	3,325.5	3,134.9	2,601.7	2,350.3	2,497.5	3,332.3	3,260.2	2,598.2	2,417.8	2,585.8	6.8	125.3	-3.5	67.5	88.4
	New Hampshire	476.1	570.5	667.8	732.8	804.0	486.3	586.2	640.1	734.6	772.4	10.2	15.7	-27.7	1.8	-31.6
	New Jersey	1,763.5	1,821.4	1,754.7	1,738.7	1,887.5	1,759.2	2,206.6	1,737.2	1,806.9	2,039.0	-4.3	385.2	-17.5	68.2	151.4
	New York	4,784.0	4,800.2	4,693.6	4,909.6	5,114.7	4,827.8	5,194.5	4,832.3	4,980.0	5,316.4	43.8	394.3	138.7	70.4	201.7
	Pennsylvania	5,159.8	5,414.5	5,348.8	5,311.7	5,367.7	5,230.6	6,123.6	5,280.0	5,386.3	5,563.3	70.8	709.1	-68.8	74.6	195.6
	Rhode Island	162.2	351.6	116.1	138.5	157.1	164.6	387.3	120.8	143.7	152.1	2.4	35.7	4.7	5.2	-5.0
	Vermont	160.7	161.6	202.6	216.5	230.0	163.3	163.8	200.7	220.1	225.1	2.6	2.2	-1.8	3.6	-4.9
MANE-VU Total		19,337.5	19,898.4	18,666.9	19,505.1	20,714.4	19,448.7	21,865.2	18,965.2	19,834.6	21,133.8	111.2	1,966.8	298.3	329.5	419.4
LADCO	Illinois	4,147.6	4,136.3	4,381.3	4,591.8	5,485.4	4,175.0	4,132.7	4,411.8	4,678.6	5,556.0	27.3	-3.7	30.5	86.7	70.7
	Indiana	2,619.9	2,796.4	2,781.3	2,993.8	2,954.7	2,648.3	3,065.4	2,904.4	3,207.2	3,379.2	28.5	269.0	123.1	213.3	424.5
	Michigan	2,801.9	2,912.5	2,758.8	3,059.1	3,900.6	2,810.8	3,302.1	3,017.6	3,289.1	3,572.2	8.9	389.6	258.8	230.0	-328.4
	Ohio	3,735.4	4,142.0	4,385.5	4,609.5	4,619.2	3,780.2	4,363.3	4,248.7	4,707.2	4,886.2	44.8	221.3	-136.8	97.7	267.0
	Wisconsin	1,410.2	1,431.4	1,483.3	1,594.0	1,742.3	1,440.7	1,509.2	1,542.0	1,680.0	1,870.8	30.5	77.8	58.7	86.0	128.5
LADCO Total		14,715.0	15,418.6	15,790.2	16,848.2	18,702.1	14,855.0	16,372.7	16,124.5	17,562.0	19,264.4	140.1	954.1	334.3	713.8	562.3
VISTAS	Alabama	3,577.1	3,878.8	3,708.1	3,969.3	4,348.8	3,570.6	4,556.2	3,915.6	4,022.1	4,498.1	-6.4	677.4	207.5	52.9	149.3
	Florida	7,908.1	7,996.4	7,399.0	8,079.4	8,774.7	7,908.4	9,061.2	7,361.4	8,317.4	8,828.2	0.3	1,064.7	-37.7	238.0	53.5
	Georgia	4,151.0	4,387.6	3,860.7	4,805.1	5,554.2	4,130.0	4,484.8	4,472.1	5,024.2	5,855.2	-20.9	97.2	611.4	219.1	301.0
	Kentucky	1,838.6	1,862.3	1,946.7	2,118.8	2,188.4	1,845.8	1,801.4	2,041.3	2,300.0	2,383.2	7.2	-60.9	94.6	181.1	194.8
	Mississippi	1,249.2	1,364.6	1,131.8	1,449.8	1,633.9	1,248.8	2,140.6	1,279.0	1,474.2	1,662.1	-0.4	776.0	147.2	24.4	28.2
	North Carolina	2,927.7	2,804.4	3,362.7	3,807.0	4,251.9	2,903.5	2,892.3	3,448.5	3,837.0	4,229.9	-24.2	87.8	85.8	30.1	-22.1
	South Carolina	2,374.7	2,563.2	2,846.1	3,133.3	3,533.1	2,361.9	2,828.2	2,920.9	3,207.1	3,686.3	-12.9	265.0	74.8	73.8	153.2
	Tennessee	1,661.8	1,691.3	1,811.2	1,796.3	1,902.1	1,642.0	1,560.5	1,864.9	1,947.0	1,959.9	-19.8	-130.8	53.7	150.8	57.9
	Virginia	1,909.2	2,356.4	2,414.2	2,680.1	3,021.9	1,908.7	2,463.7	2,441.8	2,723.1	3,054.2	-0.6	107.3	27.6	42.9	32.3
	West Virginia	1,880.1	1,912.5	2,108.0	2,315.6	2,351.3	1,928.9	1,967.1	2,154.7	2,395.7	2,495.2	48.8	54.6	46.7	80.1	143.9
VISTAS Total		29,477.4	30,817.5	30,588.5	34,154.7	37,560.2	29,448.6	33,755.9	31,900.0	35,247.7	38,652.3	-28.8	2,938.4	1,311.5	1,093.1	1,092.1
CENRAP	Arkansas	1,453.8	1,662.8	1,603.6	1,713.7	1,857.4	1,458.9	2,239.3	1,552.5	1,725.7	1,884.7	5.1	576.5	-51.1	12.0	27.3
	Iowa	977.6	1,048.0	1,014.5	1,022.7	1,093.2	994.4	1,213.3	1,055.7	1,078.1	1,116.2	16.8	165.4	41.2	55.5	23.0
	Kansas	896.4	894.0	890.8	956.2	1,077.4	894.4	947.4	898.9	952.8	984.3	-2.1	53.5	8.0	-3.3	-93.0
	Louisiana	1,690.2	1,743.3	1,679.8	1,826.5	2,148.0	1,762.3	2,312.9	1,728.8	1,839.8	2,174.2	72.1	569.6	48.9	13.3	26.2

		MARAMA Base Case (MARAMA_5c)					MARAMA CAIR Plus Policy Case (MARAMA_4c)					MARAMA_4c - MARAMA_5c				
RPO	State	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**	**2008**	**2009**	**2012**	**2015**	**2018**
	Minnesota	1,110.8	1,143.3	1,105.8	1,090.6	1,092.4	1,115.1	1,141.4	1,138.8	1,156.4	1,150.1	4.3	-1.9	32.9	65.8	57.7
	Missouri	1,520.9	1,626.1	1,656.3	1,768.2	2,001.8	1,520.2	1,572.9	1,671.5	1,730.7	1,970.5	-0.6	-53.2	15.1	-37.6	-31.3
	Nebraska	612.7	620.4	614.9	678.6	672.7	614.4	623.9	616.6	681.0	673.2	1.8	3.6	1.8	2.4	0.5
	Oklahoma	2,477.0	2,651.6	2,220.1	2,219.9	2,327.9	2,477.8	3,284.6	2,234.9	2,337.4	2,506.0	0.8	632.9	14.8	117.5	178.1
	Texas	13,924.8	14,165.7	12,215.7	12,245.8	13,464.5	13,945.9	15,450.9	12,445.1	12,601.0	13,694.0	21.1	1,285.2	229.4	355.3	229.5
CENRAP Total		24,664.2	25,555.2	23,001.6	23,522.2	25,735.3	24,783.4	28,786.7	23,342.6	24,103.1	26,153.3	119.2	3,231.5	341.0	580.8	418.0
WRAP	Arizona	4,461.7	4,326.5	3,774.7	3,555.8	4,132.5	4,446.0	4,664.2	3,799.9	3,556.4	4,223.0	-15.7	337.8	25.2	0.6	90.5
	California	9,562.6	9,975.4	7,393.3	8,753.4	9,752.2	9,594.0	10,897.9	7,211.2	8,582.0	9,474.6	31.4	922.5	-182.1	-171.4	-277.6
	Colorado	799.5	993.2	880.3	960.9	1,074.3	798.0	1,064.3	880.7	956.7	1,068.8	-1.5	71.1	0.4	-4.2	-5.5
	Idaho	178.4	171.4	143.3	142.7	142.1	178.4	185.2	154.5	153.6	153.0	0.0	13.8	11.3	11.0	10.9
	Montana	296.0	301.0	351.2	348.1	350.0	298.0	304.3	357.2	354.5	356.8	2.1	3.2	6.1	6.4	6.8
	Nevada	1,471.5	1,423.5	1,217.0	1,165.8	1,272.3	1,471.6	1,553.4	1,239.5	1,199.5	1,313.4	0.1	130.0	22.5	33.7	41.1
	New Mexico	667.3	673.1	749.3	765.4	922.9	667.1	683.8	769.1	783.1	961.3	-0.1	10.7	19.9	17.7	38.4
	North Dakota	466.9	466.7	465.9	532.0	527.2	461.4	465.9	459.1	504.7	519.5	-5.5	-0.9	-6.8	-27.3	-7.8
	Oregon	1,204.9	1,153.8	1,372.0	1,301.8	1,280.5	1,204.9	1,253.3	1,434.4	1,366.8	1,344.8	0.0	99.5	62.4	65.0	64.3
	South Dakota	85.9	85.5	85.4	104.7	110.6	86.6	87.2	85.9	105.8	106.6	0.7	1.6	0.4	1.2	-4.0
	Utah	480.8	474.6	468.6	464.0	493.8	480.8	474.4	469.8	462.7	493.6	0.0	-0.1	1.2	-1.3	-0.2
	Washington	1,335.7	1,478.7	2,082.1	2,033.2	2,015.5	1,335.3	1,483.7	2,164.6	2,153.8	2,133.9	-0.4	5.0	82.5	120.5	118.4
	Wyoming	645.4	641.9	649.5	641.8	691.2	649.4	645.7	650.1	640.4	692.8	3.9	3.8	0.6	-1.4	1.6
WRAP Total		21,656.5	22,165.3	19,632.4	20,769.5	22,765.1	21,671.5	23,763.4	19,676.1	20,820.0	22,842.1	15.0	1,598.1	43.6	50.5	76.9
CAIR Plus Policy States		84,208.1	87,523.7	84,321.4	90,175.5	98,634.0	84,549.2	95,924.6	86,582.0	92,776.0	101,040.3	341.1	8,400.9	2,260.6	2,600.6	2,406.2
National		109,850.7	113,855.0	107,679.7	114,799.8	125,477.2	110,207.3	124,543.9	110,008.4	117,567.4	128,045.9	356.6	10,688.9	2,328.8	2,767.6	2,568.7

Note: To convert year 1999 dollars to year 2006 dollars, use a conversion factor of 1.1856

Assessment of Control Technology Options for BART-Eligible Sources

Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities

Prepared by
Northeast States for Coordinated Air Use Management
In Partnership with
The Mid-Atlantic/Northeast Visibility Union

March 2005

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MANE - VU
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Submitted to the United States Environmental Protection Agency, Region III in partial fulfillment of requirements for USEPA grant **XA-983799-01-2** to the Ozone Transport Commission

March 2005

ASSESSMENT OF CONTROL OPTIONS FOR BART-ELIGIBLE SOURCES

STEAM ELECTRIC BOILERS, INDUSTRIAL BOILERS, CEMENT PLANTS, AND PAPER AND PULP FACILITIES

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Unit, Species, Acronyms

Acronyms
APCD – Air Pollution Control Device
BACT –Best Available Control Technology
BART – Best Available Retrofit Technology
CAA – Clean Air Act
CAAA – Clean Air Act Amendments
CKD – Cement Kiln Dust
CFBA – Circulating Fluidized-Bed Absorption
CFR – Code of Federal Regulations
DI – Dry Injection
DSI – Dry Sorbent Injection
EGU – Electricity Generating Unit
ESP – ElectroStatic Precipitator
ESFF – Electrostatic Stimulation of Fabric Filtration
FBC – Fluidized Bed Combustion
FF – Fabric Filters (also known as baghouses)
FGD – Flue Gas Desulfurization (also known as scrubbers)
FGR – Flue Gas Recirculation
FOM – Fixed Operating and Maintenance Costs
ICR – Information Collection Request
LAER – Lowest Achievable Emission Rate
LNB – Low NO_X Burner
LSFO – Limestone Forced Oxidation
LSC – Low Sulfur Coal (also known as “compliance coal”)
MACT – Maximum Achievable Control Technology
MANE-VU – Mid-Atlantic/Northeast Visibility Union
MC – Mechanical Collector
NCG – Non Condensable Gases
NESCAUM – Northeast States for Coordinated Air Use Management
NSPS – New Source Performance Standard
NSR – New Source Review
OFA – Over Fire Air
PC – Pulverized Coal
PS – Particulate Scrubber
RACT – Reasonably Available Control Technology
RPO – Regional Planning Organization
SIP – State Implementation Plan
SCR – Selective Catalytic Reduction
SDA – Spray Dry Absorption
SNCR – Selective Non-Catalytic Reduction
SOG – Stripper Off Gases
TDF – Tire-Derived Fuel
US EPA – United States Environmental Protection Agency

Chemical Species
EC – elemental carbon
HSO_4 – bisulfate
H_2SO_4 – sulfuric acid
HNO_3 – nitric acid
NO_X – oxides of nitrogen (NO and NO_2)
NO – nitric oxide
NO_2 – nitrogen dioxide
NO_3 – nitrate
NH_3 – ammonia
$(NH_4)_3H(SO_4)_2$ – letovicite
NH_4HSO_4 – ammonium bisulfate
$(NH_4)_2SO_4$ – ammonium sulfate
NH_4NO_3 – ammonium nitrate
OC – organic carbon
$PM_{2.5}$ – particle matter up to 2.5 μm in size
PM_{10} – particle matter up to 10 μm in size
PM_{coarse} – the difference: $PM_{10} – PM_{2.5}$
S – sulfur
Se – selenium
SO_2 – sulfur dioxide
SO_4 – sulfate
VOC – volatile organic carbon
VOM – Variable Operating and Maintenance Costs

Units

Length
m – meter
μm – micrometer (0.000001m; 10^{-6}m)
km – kilometer (1000 x m; 10^3 m)
Mm – Megameter (1000000 x m; 10^6 m)

Flow Rate
ACFM – Actual Cubic Feet per Minute

Volume
L – liter
m^3 – cubic meter

Mass
lb – pound
g – gram
μg – micrograms (0.000001 x g; 10^{-6} g)
kg – kilograms (1000 x g; 10^3 g)

Power

W – watt (Joules/sec)
kW – kilowatt (1000 x W; 10^3 W)
MW – megawatt (1000000 x W; 10^6 W)

Energy

Btu – British Thermal Unit (= 1055 Joules)
mmBtu – million Btu
MWh – megawatt hour
kWh – kilowatt hour

Concentration

$\mu g/m^3$ – micrograms per cubic meter

Visibility

dv – deciview
km – visual range in kilometers
Mm^{-1} – extinction in inverse megameters

TABLE OF CONTENTS

Executive Summary

This report was prepared by the Northeast States for Coordinated Air Use Management (NESCAUM) as part of an effort to assist states and tribes as they prepare to comply with the Best Available Retrofit Technology Requirements (BART) of the Regional Haze Rule. The Haze Rule requires states to determine the most stringent technologically feasible system of controls that can reasonably be installed at each facility eligible for BART. Criteria that determine whether a specific control technology is deemed reasonable include: cost of the controls, other control technology in use at the source, energy and other non-air quality environmental impacts, remaining useful life of the source as well as the degree of visibility improvement anticipated to result from installation of the controls.

This assessment provides information on available technology options, control efficiency and typical installation costs for four important BART-eligible source categories in the MANE-VU region. These categories include Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input, Fossil-fuel boilers of more than 250 million British thermal units per hour heat input, Portland cement plants, and Kraft pulp mills. While there are 22 other source categories covered by the BART rule (with over 25 BART-Eligible facilities in at least 8 of these source categories in the MANE-VU region), we have chosen to focus on these four categories which include 75 of the 100 MANE-VU BART-Eligible sources identified at this time. *[Editors note: The addition of NY and PA non-EGU facilities will change these numbers]* These source sectors were chosen for a combination of factors including the number of facilities, the typical emission level for these type of facilities and the availability of a generic control technology characterizations for that sector. States will need to conduct an individual analysis for each facility prior to making a BART determination. This information is intended to facilitate that process by collecting available technology information in a single reference document.

The report finds that significant emissions reductions can be achieved through a variety of technologies that target different haze forming pollutants. While wet and dry scrubbing techniques may be cost-effective means of removing SO_2 at EGUs and large industrial boilers, combustion modifications and process changes might be more effective at cement plants and paper and pulp facilities. Similarly for NO_X control, SCR and SNCR are very efficient methods of post-combustion control that can be quite cost-effective on large boilers, but combinations of combustion and post-controls as well as combustion modification and process changes are also viable means of reducing a facility's total NO_X emissions. These approaches need to be carefully considered on a unit-by-unit basis, taking into account fuel used (coal, natural gas, oil, wood, etc.) and capacity or use factors, to ensure that product quality and pollutant co-control issues are handled appropriately. Particulate controls include a variety of technologies, but electrostatic precipitators and fabric-filters (or baghouses) are viable options in different configurations for EGUs, industrial boilers and cement plants. Paper and pulp facilities may also consider demister pads, packed tower technologies and Venturi scrubbers.

1. INTRODUCTION

Under the U.S. Environmental Protection Agency's (USEPA) 1999 "regional haze rule" [64 Fed. Reg. 35714 (July 1, 1999)], certain emission sources that "may reasonably be anticipated to cause or contribute" to visibility impairment in downwind Class I areas are required to install Best Available Retrofit Technology (BART).[1] These requirements are intended to reduce emissions specifically from large sources that, due to age, were exempted from other control requirements of the Clean Air Act (CAA).

BART requirements pertain to 26 specified major point source categories, including power plants, industrial boilers, paper and pulp plants, cement kilns and other large stationary sources. To be considered BART-eligible, sources from these specified categories must have the potential to emit at least 250 tons per year of any haze forming pollutant and must have commenced operation or come into existence in the fifteen year period prior to August 7, 1977 (the date of passage of the 1977 Clean Air Act Amendments (CAAA), which first required new source performance standards).

Because of the regional focus of the 1999 haze rule, it is likely that BART requirements will be applied to a much larger number of sources across a broader geographic region than has been the case historically (i.e. through reasonably attributable visibility impairment requirements in the 1980 haze regulations). In addition, USEPA has for the first time introduced the possibility that source-by-source, command and control type BART implementation may be replaced by more flexible, market-based approaches, provided such alternatives can be shown to achieve *greater* progress toward visibility objectives than the standard BART approach.

In developing future haze state implementation plans (SIPs), states and tribes will need to include an inventory of emissions from potentially BART-eligible facilities in their jurisdictions and specify the timetable and stringency of controls to be applied at those sources. In determining what level of control represents BART, states must address the following considerations for each eligible source or group of eligible sources:

- Compliance costs,
- Energy and non-air quality environmental impacts,
- Any existing pollution control technology in use at the source,
- The remaining useful life of the source, and
- The degree of visibility improvement that may reasonably be anticipated to result from the imposition of BART.

In many respects, the strength of the BART program is dependent upon the interpretation of these factors and in January 2001 USEPA proposed guidelines for the interpretation and implementation of Best Available Retrofit Technology (BART) requirements, including these factors. While no explicit threshold was established for

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[1] There are seven designated Class I areas in the Northeast and Mid-Atlantic States. They include Acadia National Park and Moosehorn Wilderness Area in Maine; Roosevelt-Campobello International Park in New Brunswick and Maine; the Lye Brook Wilderness Area in Vermont; the Great Gulf and Presidential Range-Dry River Wilderness Areas in New Hampshire; and the Brigantine Wilderness Area in New Jersey.

any of these factors, the publication of the BART guidelines as a proposed rule in the Federal Register [66 Fed. Reg. 38108 (July 20, 2001)] initiated a formal rulemaking process to clarify BART requirements specifically.

BART is the primary mechanism identified for regulating haze-forming pollutants from stationary sources for the first implementation period under the Haze Rule and the final BART regulations, anticipated to be published on April 15, 2005, gives urgency to understanding the implications of the final BART guidelines with respect to state planning efforts. Depending on a host of factors, BART may be the primary component of state haze plans or may be eliminated as a potential mechanism for state compliance.[2] Amid such uncertainty, states must continue to plan for the implementation of BART.

To assist MANE-VU states and tribes with BART implementation efforts, MANE-VU has developed a list of BART-eligible sources in the region (NESCAUM, 2001; NESCAUM, 2003).[3] The preliminary list developed in these documents has been refined by state permitting staff to verify identifications and determine eligibility for those sources for which incomplete information was available. The final, state-approved (i.e. each state has approved the list of sources within that state) list is available here as Appendix A. It should be noted that the review of the facilities for BART eligibility was performed prior to the release of the draft BART rule in 2004. Determinations were based upon the guidance provided in EPA draft rule released in 2001. It is anticipated that EPA will release a final BART rule in April 2005 and at that time final BART-eligibility determinations will be made. It is likely that there will be changes to the BART list based upon that final rule.

Once deemed BART-eligible, each source will undergo a BART engineering review to determine what system of controls constitutes BART for each facility. This review will examine impacts for all the BART pollutants. For example, if a facility triggeres BART because it has VOC emissions over 250 tons per year for date-eligible units, the facility will also have to examine the impacts of emissions of NO_X, SO_2, PM_{10} and ammonia, even if emissions of these pollutants are less than 250 tons per year.

In addition, this review must take into account the statutory factors cited earlier including remaining useful life of a source and controls already in place at a source. After review of these criteria and control options, the level of required control will be established. It is anticipated that the final rule will also address the specific aspects relating to the completion of a BART engineering analysis.

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[2] A number of factors in the pending BART regulation may affect the strength of the program. Among these are (1) a final decision on whether USEPA's Clean Air Interstate Rule (CAIR) could serve as BART for affected sources in states that choose this option, (2) final rules for how states may institute a source-by-source exemption test, (3) a decision on whether to aggregate emissions from multiple date-eligible boilers at a facility when comparing to the 250 ton/year emission threshold. An additional factor to consider is a provision contained in Senate Resolution 485 (the Clear Skies Act of 2003 which is expected to be re-introduced early in the 109th congress), which would act in place of the BART requirements of the regional haze rule.

[3] NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and the identified sources are contained in the final list in Appendix A.

As a next step in coordinating BART determinations for MANE-VU states and tribes, we present here (in Chapters 3 through 6 of this report) a preliminary assessment of available control technology options for states to consider as they undertake the specific BART determinations for each of the eligible facilities in four major source categories including EGUs, industrial boilers, cement plants and paper and pulp facilities. These four categories cover 76 of the 101 BART-eligible facilities in MANE-VU.

While a facility specific review will need to be undertaken for each BART-eligibility (either to determine BART controls to be installed, or to determine the magnitude of emissions reductions that must be considered in a BART trading program), the information provided here will give states and tribes a foundation for conducting these reviews.

2. STEAM ELECTRIC PLANTS (EGUs)

Electricity Generating Units or EGUs are the largest source category among the twenty - six source categories covered by the Regional Haze Rule both in terms of total visibility impairing emissions and in terms of number of facilities. Estimates of national emissions for criteria air pollutants prepared by the USEPA show that electric utility power plants that burn coal are significant sources of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM) (USEPA, 2000). Electric utility power plants are the nation's largest source of SO_2 emissions, contributing approximately 68 percent of the estimated total national SO_2 emissions in 1998 (most recent year for which national estimates are available). Over 90 percent of these SO_2 emissions are coal-fired electric utility boilers. Electric utilities contributed 25 percent of total national NO_X emissions in 1998. Again coal combustion is the predominant source of NO_X emissions from the electric utilities (almost 90 percent of the estimated NO_X emissions). Coal-fired electric utility power plants also are one of the largest industrial sources of PM emissions. In general, the high combustion efficiencies achieved by coal-fired electric utility boilers result in low emissions of CO and volatile organic compounds (a precursor for the photochemical formation of ozone in the atmosphere). Although the emphasis of this Chapter is on coal-fired utility boilers, many technologies described here are also applicable to gas and oil-fired units (for example, SCR and SNCR technologies are equally applicable to coal and natural gas/oil units, generally at much lower capital and operating costs; same is true for wet scrubbers for SO2 control and ESPs or baghouses for PM control for oil units).

All coal-fired electric utility power plants in the United States use control devices to reduce PM emissions. Many coal-fired electric utility boilers also are required to use controls for SO_2 and NO_X emissions depending on site-specific factors such as the properties of the coal burned, when the power plant was built, and the area where the power plant is located. Though there are other major stationary source sectors (for example, cement plants, paper and pulp plants, large industrial boilers, combustion turbines, iron and steel industry), coal-fired boilers are by far the largest contributor of all of these three precursors of regional haze.

2.1. Description of generation process and typical technologies

The USEPA ICR (Information Collection Request) of 1999 (the most recent and quite detailed survey of coal-fired EGUs in the U.S. completed in connection with USEPA efforts to develop MACT regulations for mercury from EGUs) indicates that there were about 1,140 coal-fired units in the U.S. (with a maximum capacity to generate in excess of 300,000 MW of power). This USEPA ICR data indicated that coal-fired steam electric generating units in the U.S. burned 786 million tons of coal of which, approximately 52 percent was bituminous and 37 percent was sub-bituminous. Other fuels included lignite, anthracite coal, reclaimed waste coal, mixtures of coal and petroleum coke (pet-coke), and mixtures of coal and tire-derived fuel (TDF). Pulverized coal-fired (PC) boilers represent approximately 86 percent of the total number and 90 percent of total utility boiler capacity. Based on capacity, other types of boilers include cyclone-fired boilers (7.6 percent), fluidized-bed combustors (1.3 percent), and stoker-fired boilers (1.0 percent).

2.2. Review of BART-Eligible EGUs in the MANE-VU Region

There are 53 BART-Eligible EGUs in the MANE-VU region. Table II-1 contains a summary list of these sources by state. A complete list is presented in Appendix A. Both lists are based on a previous NESCAUM report (2001) and follow-up review by state permitting authorities.[4] An estimated 1.2 million tons of SO_2 and three-hundred thousand tons of NO_X are emitted by these facilities and given the available control technology described in subsequent sections of this chapter, BART-Eligible EGUs represent a significant emissions reduction potential for consideration in the regional haze planning process.

Table II-1 BART-Eligible EGUs in the MANE-VU region. (NESCAUM, 2001).

State	Total Number of BART EGUs	Total SO_2 Emissions (1999 NEI)	Total NO_X Emissions (1999 NEI)
Connecticut	5	30,787	8,217
Delaware	3	10,490	4,465
District of Columbia	1	1,432	447
Maryland	6	177,678	63,767
Massachusetts	7	97,854	27,350
Maine	1	6,406	879
New Hampshire	2	37,834	7,043
New Jersey	1	17,260	7,891
New York	13	73,164	31,392
Pennsylvania	14	744,165	151,992
Penobscot Tribe	0	N/A	N/A
Rhode Island	0	N/A	N/A
St. Regis Mohawk Tribe	0	N/A	N/A
Vermont	0	N/A	N/A
Region Total	**53**	**1,197,070**	**303,443**

2.3. Available Control Technologies

A variety of emission control technologies are employed to meet requirements for SO_2, NO_X, and primary PM emissions; the three major precursors of observed regional haze in the atmosphere (SO_2 and NO_X are mostly converted to ammonium sulfate and ammonium nitrate

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[4] NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and any identified sources are contained here and in the final list in Appendix A.

that are formed by the reactions of precursor gases with ammonia in the environment that is emitted mostly from agricultural and cattle related activities). Most utilities control SO_2 by the use of either low-sulfur coal (generally less than 1 percent sulfur by weight) or by wet or dry scrubbing (known as flue gas desulphurization, or FGD). Generally, NO_X emissions are controlled via combustion modification and, more recently, by more advanced post-combustion controls, which are required by the 1990 Clean Air Act and state regulations ("NO_X Transport SIP Call" and the Title IV of the 1990 CAAA are two major examples). Compared to these two precursors, PM emissions are almost universally controlled in the U.S. (almost 100% of units have either electrostatic precipitators (ESPs) or fabric filters (FF) (popularly known as "bag houses"). Based on the 1999 USEPA's ICR (Information Collection Request) data, for post-combustion controls, 77.4 percent of the units have PM control only, 18.6 percent have both PM and SO_2 controls, 2.5 percent have PM and NO_X controls, and 1.3 percent have all three post-combustion control devices.

The different types of post-combustion control devices are briefly described below with detailed descriptions given later in this section:

SO_2 post-combustion control technologies are systems that are classified as wet flue gas desulfurization (FGD) scrubbers, semi-dry scrubbers, or dry injection. Wet FGD scrubber controls remove SO_2 by dissolving it in a solution. A PM control device is always located upstream of a wet scrubber. PM devices that may be used with wet FGD scrubbers include a Particulate Scrubber (PS), Cold Side (CS)-ESP, Hot Side (HS)-ESP, or a fabric filter (FF) or a baghouse. Semi-dry scrubbers include spray dryer absorption (SDA). Dry injection involves injecting dry powdered lime or other suitable sorbent directly into the flue gas. A PM control device (ESP or FF) is always installed downstream of a semi-dry scrubber or dry injection point to remove the sorbent from the flue gas.

NO_X post-combustion control technologies include selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) processes. With both of these methods, a reducing agent such as ammonia or urea is injected into the duct to reduce NO_X to N_2. SCR operates at lower temperatures than SNCR and is much more effective at reducing NO_X, but it has higher capital costs for installation.

Particulate matter (PM) control technologies include electrostatic precipitators (ESPs), fabric filters (FFs) (also called "baghouses"), and particulate scrubbers (PS). ESPs and FFs may be classified as either cold-side (CS) devices [installed upstream of the air heater where flue gas temperatures range from 284 to 320 ºF (140 to 160 °C)] or hot-side [installed downstream of the air heater and operate at temperatures ranging from 662 to 842 ºF (350 to 450 °C)].

For PM controls, ESPs are used on 84 percent of the existing electric utility coal-fired boiler units, and fabric filters or baghouses are used on 14 percent of the utility units. Post-combustion SO_2 controls are less common. Wet flue gas desulfurization (FGD) systems are used on 15.1 percent of the units; and, dry scrubbers, predominantly spray dryer absorbers (SDA), are used on 4.6 percent of units that were surveyed. However, since it is generally more cost effective to install scrubbers on big units, the 20 percent of the units represent about 30% of the installed U.S. capacity. In response to the "Section 110 Transport SIP call" and the implementation of the Federal Title IV acid rain program, the application of post-combustion NO_X controls is becoming more prevalent. For example, based on the current status of electric utility industry, it appears that one third of the coal-based capacity (about 100,000 MW out of the installed base of about 300,000 MW) has been or is currently being retrofitted with the advanced SCR technology .

2.3.1. Emission Characteristics of Regional Haze Precursors from Coal Combustion

Sulfur Dioxide

SO_2 emissions, mostly from the combustion of fossil fuels and by metallurgical processes, are the result of oxidation of sulfur in the coal during the combustion process. Coal deposits contain sulfur in amounts ranging from trace quantities to as high as eight percent or more. Most of this sulfur is present as either pyritic sulfur (sulfur combined with iron in the form of a mineral that occurs in the coal deposit) or organic sulfur (sulfur combined directly in the coal structure). During combustion, sulfur compounds in coal are oxidized to gaseous SO_2 or SO_3. When firing bituminous coal, almost all of the sulfur present in coal is emitted as gaseous sulfur oxides (on average, ninety eight percent). The more alkaline nature of ash in some subbituminous coals causes a portion of the sulfur in the coal to react to form various sulfate salts; these salts are emitted as fly ash or retained in the boiler bottom ash. Generally, the percentage of sulfur in the as-fired coal that is converted to sulfur oxides during combustion does not vary with the utility boiler design or operation. (USEPA, 1982; Buonicore and Davis, 1992).

Nitrogen Oxides

The NO_X formed during coal combustion by oxidation of molecular nitrogen (N_2) in the combustion air is referred to as “thermal NO_X.” The oxidation reactions converting N_2 to NO and NO_2 become very rapid once gas temperatures rise above 1,700°C (3,100°F). Formation of thermal NO_X in a coal-fired electric utility boiler is dependent on two conditions occurring simultaneously in the combustion zone: high temperature and an excess of combustion air. A boiler design feature or operating practice that increases the gas temperature above 1,700 °C, the gas residence time at these temperatures and the quantity of excess combustion air affects thermal NO_X formation. The formation of NO_X by oxidation of nitrogen compounds contained in the coal is referred to as “fuel NO_X.” The nitrogen content in most coals ranges from approximately 0.5 to 2 percent. The amount of nitrogen available in the coal is relatively small compared with the amount of nitrogen available in the combustion air. However, depending on the combustion conditions, significant quantities of fuel NO_X can be formed during coal combustion. (USEPA, 1991; Buonicore and Davis, 1992).

Both NO and NO_2 are formed during coal combustion by oxidation of molecular nitrogen that is present in the combustion air or nitrogen compounds contained in the coal. Overall, total NO_X formed during combustion is composed predominantly of NO mixed with small quantities of NO_2 (typically less than 10 percent of the total NO_X formed). However, when NO is formed during coal combustion, the NO is oxidized to NO_2 and is emitted to the atmosphere.

Particulate Matter

Primary PM emissions from coal-fired electric utility boilers consist primarily of fly ash. Ash is the unburned carbon char and the mineral portion of combusted coal. The amount of ash in the coal, which ultimately exits the boiler unit as fly ash, is a complex function of the coal properties, furnace-firing configuration, and boiler operation. For the dry-bottom, pulverized-coal-fired boilers, approximately 80 percent of the total ash in the as-fired coal exits the boiler as fly ash. Wet-bottom, pulverized-coal-fired boilers emit significantly less fly ash: on the order of 50 percent of the total ash exits the boiler as fly ash. In a cyclone furnace boiler, most of the ash is retained as liquid slag; thus, the quantity of fly ash exiting the boiler is typically 20 to 30 percent of the total ash. However, the high operating temperatures unique to these designs may also promote ash vaporization and larger fractions of submicron fly ash compared to dry bottom designs. Fluidized-bed combustors emit high levels of fly ash since the coal is fired in suspension and the ash is present in dry form. Spreader-stoker-fired boilers can also emit high levels of fly ash. However, overfeed and underfeed stokers emit less fly ash than spreader stokers, since combustion takes place in a relatively quiescent fuel bed.

In addition to the fly ash, PM emissions from coal-fired EGUs result from reactions of the SO_2 and NO_X compounds as well as unburned carbon particles carried in the flue gas from the boiler. The SO_2 and NO_X compounds are initially in the vapor phase following coal combustion in the furnace chamber but can partially chemically transform in the stack, or near plume, to form fine PM in the form of nitrates, sulfur trioxide (SO_3), and sulfates. Firing configuration and boiler operation can affect the fraction of carbon (from unburned coal) contained in the fly ash. In general, the high combustion efficiencies achieved by pulverized-coal-fired boilers and cyclone-fired boilers result in relatively small amounts of unburned carbon particles in the exiting combustion gases. Those pulverized-coal-fired electric utility boilers that use special burners for NO_X control tend to burn coal less completely; consequently, these furnaces tend to emit a higher fraction of unburned carbon in the combustion gases exiting the furnace.

Another potential source of PM from coal-fired EGUs can be found in the flue gas and the use of a dry sorbent-based control technology. Solid sorbent particles are injected into the combustion gases to react with the air pollutants and then recaptured by a downstream control device. Sorbent particles that escape capture by the control device are emitted as PM to the atmosphere. (USEPA, 1982; Buonicore and Davis, 1992).

2.3.2. Control Technologies used for Coal-fired EGUs

In addition to BART requirements, all EGUs in the U.S. must comply with applicable federal and state standards and programs that specifically regulate criteria air emissions from coal-fired electric utility boilers. The federal regulations and programs include New Source Performance Standards (NSPS), the CAA Title IV Acid Rain Program, the 1997 “Transport NO_X SIP call,” and the CAA Title V Operating Permits Program. The USEPA has delegated authority to individual state and local agencies for implementing many of these regulatory requirements

Additionally, some of the states in the Northeast, including Connecticut, Massachusetts, New Hampshire, New Jersey, and New York, have recently implemented new regulations or legislation that are more stringent than the federal requirements. Electric utility companies use one or a combination of the following three control strategies to comply with the specific set of requirements applicable to a given coal-fired boiler.

Pre-combustion Controls. Control measures in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.

Combustion Controls. Control measures in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.

Post-combustion Controls: Control measures in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

Table II-2 shows the national distribution of emissions control strategies for SO_2, NO_X, and PM used for coal-fired electric utility boilers in 1999 as reported in the Part II USEPA ICR data (USEPA, 2001). Approximately two-thirds of the total coal-fired electric utility boilers use either a low-sulfur fuel or a post-combustion technology (a wet or a dry scrubber) to control SO_2 emissions. The methods used for controlling SO_2 emissions from EGUs are discussed first. All coal-fired electric utility boilers in the United States are controlled for PM emissions by using some type of post-combustion controls. These particulate emission control types are discussed next. Although approximately two-thirds of the coal-fired electric utility boilers are controlled for NO_X emissions, these units are not necessarily the same units controlled for SO_2 emissions. The predominant strategy for controlling NO_X emissions is to use combustion controls. Later in this section, the application of NO_X emission controls to coal-fired electric utility boilers is described in detail.

Table II-2 Criteria air pollutant emission control strategies as applied to coal-fired electric utility boilers in the United States for the year 1999 (USEPA, 2001).

Criteria Air Pollutant	Percentage of Coal-fired Electric Utility Boilers Using Control Strategy as Reported in Phase II USEPA ICR Data a,b			
	Meet Applicable Standards Without Additional Controls	Pre-combustion Controls	Combustion Controls	Post-combustion Controls
Particulate Matter	0 %	0 %	0 %	100 %
Sulfur Dioxide	37 %	40 %	3 %	20 %
Nitrogen Oxides	40 %	0 %	57 %	3 %

(a) Approximately 1.5 % of the boilers use a combination of pre-combustion and post-combustion SO_2 controls.

(b) Approximately 1% of the boilers using post-combustion NO_X controls also use some type of combustion controls.

SO_2 Emission Controls

Sulfur dioxide emissions from most coal-fired electric utility boilers are controlled using either of two basic approaches. The first approach is to use pre-combustion measures, namely, firing coal that contains lower amounts of sulfur. The low-sulfur coal may be naturally occurring or the result of coal cleaning. The other approach is to remove the sulfur compounds from the flue gas before the gas is discharged to the atmosphere. These post-combustion processes are collectively called “flue gas desulfurization” or “FGD” systems. All FGD systems can be further classified as wet or dry flue gas scrubbing systems. The SO_2 control approaches include a number of different technology subcategories that are now commercially used in the United States, Europe, or Pacific Rim countries.

Table II-3 presents the 1999 nationwide distribution of SO_2 controls used for coal-fired electric utility boilers by total number of units and by percentage of nationwide electricity generating capacity. For approximately one-third of the boilers, no SO_2 controls were reported in the Part II USEPA ICR data. The other two-thirds of the units reported using some type of control to meet the SO_2 emission standards applicable to the unit. Pre-combustion control by burning a low-sulfur content coal was reported for approximately 40 percent of the boilers. Post-combustion control devices for SO_2 removal are used for approximately 20 percent (representing 30% of the capacity in megawatts) of the boilers. Wet FGD systems are the most commonly used post-combustion control technique. The newer technologies of spray dryer systems or dry injection are limited in their application to existing units. The remaining 3 percent of the boilers use fluidized-bed combustion (FBC) with limestone.

Low-sulfur Coal

Coal with low sulfur content can be burned and meet applicable SO_2 emission standards without the use of additional controls is sometimes referred to as “compliance coal.” Coals naturally low in sulfur content may be mined directly from the ground. Alternatively, the sulfur content of coal fired in the boiler may be lowered first by cleaning the coal or blending coals obtained from several sources. However, burning low-sulfur coal may not be a technically feasible or economically practical SO_2 control alternative for all boilers. In some cases, a coal with the required sulfur content to meet the applicable standard may not be available or cannot be fired satisfactorily in a given boiler unit design. Even if such a coal is available, use of the low-sulfur coal that must be transported long distances from the mine may not be cost-competitive with burning higher sulfur coal supplied by closer mines and using a post-combustion control device.

Table II-3 Nationwide distribution of existing SO_2 emissions controls used for coal-fired electric utility boilers for the year 1999 as reported in the Part II USEPA ICR data (USEPA, 2001).

SO_2 Control Type	Abbreviation Code	Phase II USEPA ICR Data		
		Number of Boilers	Percent of Nationwide Total Number of Units	Percent of Nationwide Electricity Generating Capacity
Burn low-sulfur coal (“compliance coal”)	LSC	455	39.9 %	38.2 %
Wet FGD system	FGD	173 (a)	15.2 %	23.8 %
Spray dryer system	SDA	52 (b)	4.6%	3.4 %
Fluidized-bed coal combustion with limestone	FBC	37 (a,c)	3.2%	1.1 %
Dry injection	DI	2	0.2 %	< 0.1 %
No controls reported (d)		421	36.9 %	33.5 %
Nationwide Total		1,140 (e)	100 %	100 %

(a) Includes one FBC boiler unit using a wet FGD system.
(b) Includes three FBC boilers using spray dryer systems.
(c) FBC boilers using no downstream post-combustion SO_2 controls.
(d) Entry in ICR response indicated none or was left blank.
(e) Does not include the three IGCC units.

Various coal cleaning processes may be used to reduce the sulfur content of the coal. A significant portion of the pyritic sulfur minerals mixed with the mined coal can usually be removed by physical gravity separation or surface property (flotation) methods. However, physical coal cleaning methods are not effective for removing the organic sulfur bound in coal. Another method of reducing the overall sulfur content of the coal burned in a given boiler unit is to blend coals with different sulfur contents to meet a desired or target sulfur level.

Wet FGD Systems

The SO_2 in flue gas can be removed by reacting the sulfur compounds with a solution of water and an alkaline chemical to form insoluble salts that are removed in the scrubber effluent. These processes are called “wet FGD systems” in this report. Most wet FGD systems for control of SO_2 emissions from coal-fired electric utility boilers are based on using either limestone or lime as the alkaline source. At some of these facilities, fly ash is mixed with the limestone or lime. Several other scrubber system designs (e.g., sodium carbonate, magnesium oxide, dual alkali) are also used by a small percentage of the total number of boilers.

The basic wet limestone scrubbing process is simple and is the type most widely used for control of SO_2 emissions from coal-fired electric utility boilers. Limestone sorbent is inexpensive and generally available throughout the United States. In a wet limestone scrubber, the flue gas containing SO_2 is brought into contact with limestone/water slurry. The SO_2 is absorbed into the slurry and reacts with limestone to form an insoluble sludge. The sludge, mostly calcium sulfite hemihydrate and gypsum, is disposed of in a pond specifically constructed for the purpose or is recovered as a salable byproduct.

The wet lime scrubber operates in a similar manner to the wet limestone scrubber. In a wet lime scrubber, flue gas containing SO_2 is contacted with hydrated lime/water slurry; the SO_2 is absorbed into the slurry and reacts with hydrated lime to form an insoluble sludge. The hydrated lime provides greater alkalinity (higher pH) and reactivity than limestone. However, lime-scrubbing processes require appropriate disposal of large quantities of waste sludge.

The SO_2 removal efficiencies of existing wet limestone scrubbers range from 31 to 97 percent, with an average of 78 percent. The SO_2 removal efficiencies of existing wet lime scrubbers range from 30 to 95 percent. For both types of wet scrubbers, operating parameters affecting SO_2 removal efficiency include liquid-to-gas ratio, pH of the scrubbing medium, and the ratio of calcium sorbent to SO_2. Periodic maintenance is needed because of scaling, erosion, and plugging problems. Recent advancements include the use of additives or design changes to promote SO_2 absorption or to reduce scaling and precipitation problems.

Spray Dryer Absorber

A spray dryer absorber (sometimes referred to as wet-dry or semi-dry scrubbers) operates by the same principle as wet lime scrubbing, except that the flue gas is contacted with a fine mist of lime slurry instead of a bulk liquid (as in wet scrubbing). For the spray dryer absorber process, the combustion gas containing SO_2 is contacted with fine spray droplets of hydrated lime slurry in a spray dryer vessel. This vessel is located downstream of the air heater outlet where the gas temperatures are in the range of 120 to 180 °C (250 to 350 °F). The SO_2 is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate as in a wet lime scrubber. The water is evaporated by the hot flue gas and forms dry, solid particles containing the reacted sulfur. These particles are entrained in the flue gas, along with fly ash, and are collected in a PM collection device. Most of the SO_2 removal occurs in the spray dryer vessel itself, although some additional SO_2 capture has also been observed in downstream particulate collection devices, especially fabric filters. This process produces dry reaction waste products for easy disposal.

The primary operating parameters affecting SO_2 removal are the calcium-reagent-to-sulfur stoichiometric ratio and the approach to saturation in the spray dryer. To increase overall sorbent use, the solids collected in the spray dryer and the PM collection device may be recycled. The SO_2 removal efficiencies of existing lime spray dryer systems range from 60 to 95 percent.

Dry Injection

For the dry injection process, dry powdered lime (or another suitable sorbent) is directly injected into the ductwork upstream of a PM control device. Some systems use spray humidification followed by dry injection. This dry process eliminates the slurry production and handling equipment required for wet scrubbers and spray dryers, and produces dry reaction waste products for easier disposal. The SO_2 is adsorbed and reacts with the powdered sorbent. The dry solids are entrained in the combustion gas stream, along with fly ash, and collected by the PM control device. The SO_2 removal efficiencies of existing dry injection systems range from 40 to 60 percent.

Circulating Fluidized-bed Absorber

In the circulating fluidized-bed absorber (CFBA), the flue gas flows upward through a bed of sorbent particles to produce a fluid-like condition in the bed. This condition is obtained by adjusting gas flow rate sufficiently to support the particles, but not carry them out of the system. Characteristics of the bed are high heat and mass transfer, because of high mixing rates, and particle-to-gas contact. These conditions allow the CFBA's bed of sorbent particles to remove a sorbate from the gas stream with high effectiveness. In a CFBA, material is withdrawn from the bed for treatment (such as desorption) then re-injected into the bed. The SO_2 removal efficiencies for CFBA technologies range from 80 to 98 percent, providing a very effective means of control.

NO_X Emission Controls

Control techniques used to reduce NO_X formation include combustion and post-combustion control measures. Combustion measures consist of operating and equipment modifications that reduce the peak temperature and excess air in the furnace. Post-combustion control involves converting the NO_X in the flue gas to molecular nitrogen and water using either a process that requires a catalyst (selective catalytic reduction) or a process that does not use a catalyst (selective noncatalytic reduction).

Table II-4 presents the 1999 nationwide distribution of NO_X controls used for coal-fired electric utility boilers by total number of units and by percentage of nationwide electricity generating capacity. Approximately one-third of the boilers do not use additional NO_X controls. The other two-thirds of the units use additional controls to meet the applicable NO_X standards. The predominant control NO_X strategy is to use one or more combustion control techniques. Post-combustion NO_X reduction technologies (both catalytic and noncatalytic) accounted for only a small percentage of the NO_X emission controls used in 1999 (approximately three percent of the total units). However, a number of electric utilities have recently retrofitted are currently actively retrofitting a large number of units with advanced SCR technology to meet the requirements of the federal Title IV acid rain program or the Section 110 Transport SIP call.

Combustion Controls

A variety of combustion control practices can be used including low-NO_X burners (LNBs), overfire air, off-stoichiometric firing, selective or biased burner firing, reburning, and burners-out-of-service. Control of NO_X also can be achieved through staged combustion (also called air staging). With staged combustion, the primary combustion zone is fired with most of the air needed for complete combustion of the coal. The remaining air is introduced into the products of the partial combustion in a secondary combustion zone. Air staging lowers the peak flame temperature, thereby reducing thermal NO_X, and lowering the production of fuel NO_X by reducing the oxygen available for combination with the fuel nitrogen. Staged combustion may be achieved through methods that require modifying equipment or operating conditions so that a fuel-rich condition exists near the burners (e.g., using specially designed low- NO_X burners, selectively removing burners from service, or diverting a portion of the combustion air). In cyclone boilers and some other wet bottom designs, combustion occurs with a molten ash layer and the combustion gases flow to the main furnace; this design precludes the use of low NO_X burners and air staging. Low-NO_X burners may be used to lower NO_X emissions by about 25 to 55 percent. Use of overfire air (OFA) as a single NO_X control technique reduces NO_X by 15 to 50 percent. When OFA is combined with low- NO_X burners, reductions of up to 60 percent may result. The actual NO_X reduction achieved with a given combustion control technique may vary from boiler to boiler.

Table II-4 Nationwide distribution of existing NO_X emissions controls used for coal-fired electric utility boilers for the year 1999 as reported in the Part II USEPA ICR data (USEPA, 2001).

NO_X Control Type	Abbreviation Code	Phase II USEPA ICR Data		
		Nationwide Number of Boilers	Nationwide Percentage of Boilers	Percent of Nationwide Electricity Generating Capacity
Combustion controls - low- NO_X burners	CC-LNB	404	35.4 %	43.0 %
Combustion controls - low- NO_X burners + overfire air	CC-LNB/OFA	84	7.4 %	10.4 %
Combustion controls - overfire air	CC-OFA	79	6.9 %	10.6 %
Other combustion controls (a)	CC	83	7.3 %	5.6 %
Selective noncatalytic reduction	SNCR	32	2.8 %	0.6 %
Selective catalytic reduction	SCR	6	0.5 %	1.3 %
No controls reported (b)		452	39.7%	28.5 %
Nationwide Total		1,140 (c)	100 %	100 %

(a) Combustion controls other than low-NO_X burners or overfire air. The controls include burners-out-of service, flue gas recirculation, off-stoichiometric firing, and fluidized-bed combustion.
(b) Entry in ICR response indicated "none," "not applicable," or was left blank.
(c) Does not include the three IGCC units.

Just as the combustion air to the primary combustion zone can be reduced, part of the fuel may be diverted to create a secondary flame with fuel-rich conditions downstream of the primary combustion zone. This combustion technique is termed reburning and involves injecting 10 to 20 percent of the fuel after the primary combustion zone and completing the combustion with overfire air. The fuel injected downstream may not necessarily be the same as that used in the primary combustion zone. In most applications of reburning, the primary fuel is coal and the reburn fuel is natural gas (methane), and the technology is known as "gas reburn."

Other ways to reduce NO_X formation by reducing peak flame temperature include using flue gas recirculation (FGR), reducing boiler load, injecting steam or water into the primary combustion zone, and increasing spacing between burners. By using FGR to return part of the flue gas to the primary combustion zone, the flame temperature and the concentration of oxygen in the primary combustion zone are reduced. Increasing the space between burners provides greater heat transfer to heat-absorbing surfaces. Another combustion control technique involves reducing the boiler load. In this case, the formation of thermal NO_X generally decreases directly with decreases in heat release rate; however, reducing the load may cause poor air and fuel mixing and increase CO and soot emissions.

Selective Catalytic Reduction

The selective catalytic reduction (SCR) process uses a catalyst with ammonia gas (NH_3) to reduce the NO and NO_2 in the flue gas to molecular nitrogen and water. The ammonia gas is diluted with air or steam, and this mixture is injected into the flue gas upstream of a metal catalyst bed (composed of vanadium, titanium, platinum, or zeolite). In the reactor, the reduction reactions occur at the catalyst surface. Typically some ammonia exits the catalyst, on the order of 1-5 ppm in the flue gas; this is called "ammonia slip". The SCR catalyst bed reactor is usually located between the economizer outlet and air heater inlet, where temperatures range from 230 to 400 °C (450 to 750 °F). The catalyst modules take up a considerable amount of space; in addition ductwork must be added for the ammonia injection section. There is not always room in an existing boiler to retrofit an SCR system. As a consequence, fan capacity may have to be increased, owing to the incremental pressure drop from the SCR and associated ductwork. In some cases, the boiler must be modified to increase the economizer exit temperature to the minimum and/or the air preheater must be modified. Installation of an SCR on a boiler is site-specific and this results in a range of capital costs for SCR systems on boilers.

SCR catalysts in coal- and oil-fired boilers oxidize a small fraction of the SO_2 in the flue gas to produce SO_3. The SO_3 in the flue gas from an SCR may only be on the order of 10 ppm (depending on the sulfur-content of the fuel), but it can have impacts on the downstream equipment and emissions. The combination of ammonia slip and increased SO_3 can form deposits of ammonium bisulfate in the air preheater. SO can condense in the flue gas in the form of a fine aerosol of sulfuric acid, which can cause a visible plume, the so-called "blue plume".

Selective Noncatalytic Reduction

The selective noncatalytic reduction (SNCR) process is based on the same basic chemistry of reducing the NO and NO_2 in the flue gas to molecular nitrogen and water but does not require the use of a catalyst to prompt these reactions. Instead, the reducing agent is injected into the flue gas stream at a point where the flue gas temperature is within a very specific temperature range. Currently, two SNCR processes are commercially available: the THERMAL DeNO$_X$ and the NO$_X$OUT (USEPA, 1998). The THERMAL DeNO$_X$ uses ammonia gas as the reagent and requires the gas be injected where the flue gas temperature is in the range of 870 to 1090 °C (1,600 to 2,000 °F). Consequently, the ammonia gas is injected at a location upstream of the economizer. However, if the ammonia is injected above 1,090 °C (2,000 ºF), the ammonia will oxidize and will result in the formation of excess NO$_X$ emissions. Once the flue gas temperature drops below the optimum temperature range, the effectiveness of the process drops significantly. By adding hydrogen gas or other chemical enhancers, the reduction reactions can be sustained to temperatures down to approximately 700 °C (1,300 °F). The NO$_X$OUT is a similar process but uses an aqueous urea solution as the reagent in place of ammonia.

Using nitrogen-based reagents requires operators of SNCR systems to closely monitor and control the rate of reagent injection. If injection rates are too high, NO$_X$ emissions may increase, and stack emissions of ammonia in the range of 10 to 50 ppm may also result. A portion (usually around 5 percent) of the NO reduction by SNCR systems results from transformation of NO to N_2O, which is a global warming gas.

Particulate Matter Emission Controls

Four types of control devices are used to collect PM emissions from coal-fired electric utility boilers: electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers. Table II-5 presents the 1999 nationwide distribution of PM controls on coal-fired electric utility boilers by total number of units and by percentage of nationwide electricity generating capacity. Electrostatic precipitators are the predominant control type used on coal-fired electric utility boilers both in terms of number of units (84 percent) and total generating capacity (87 percent). The second most common control device type used is a fabric filter. Fabric filters are used on about 14 percent of the coal-fired electric utility boilers. Particle scrubbers are used on approximately three percent of the boilers. The least used control device type is a mechanical collector. Less than one percent of the coal-fired electric utility boilers use this type of control device as the sole PM control. Other boilers equipped with a mechanical collector use this control device in combination with one of the other PM control device types.

Electrostatic Precipitators

Electrostatic precipitator (ESP) control devices have been used to control PM emissions for over 80 years. These devices can be designed to achieve high PM collection efficiencies (greater than 99 percent), but at the cost of increased unit size. An ESP operates by imparting an electrical charge to incoming particles, and then attracting the particles to oppositely charged metal plates for collection. Periodically, the particles collected on the plates are dislodged in sheets or agglomerates (by rapping the plates) and fall into a collection hopper. The dust collected in the ESP hopper is a solid waste that must be disposed of.

Table II-5 Nationwide distribution of existing PM emission controls used for coal-fired electric utility boilers for the year 1999 (USEPA, 2001).

PM Control Type	Abbreviation Code	Phase II USEPA ICR Data		
		Number of Boilers	Percent of Nationwide Total Number of Units	Percent of Nationwide Electricity Generating Capacity
Electrostatic precipitator (Cold-side)	CS- ESP	822 (a)	72.1 %	74.7 %
Electrostatic precipitator (Hot-side)	HS-ESP	122	10.8 %	11.3 %
Fabric filter	FF	155 (b)	13.6 %	9.4 %
Particle scrubber	PS	23 (c)	2.0%	3.0 %
Mechanical collector (d)	MC	5	0.4 %	0.2 %
Multiple control device combinations (e)		13	1.1 %	1.4 %
Nationwide Total		1,140 (f)	100 %	100 %

(a) Includes 10 boilers with cold-side ESP in combination with upstream mechanical collector.
(b) Includes eight boilers with baghouse in combination with upstream mechanical collector.
(c) Includes two boilers with particle scrubber in combination with upstream mechanical collector.
(d) Boilers using mechanical collector as only PM control device.
(e) Boilers using a combination of two or more different control device types other than mechanical collectors. Includes two boilers that use a hot-side ESP in series with a cold-side ESP.
(f) Does not include the three IGCC units.

The effectiveness of particle capture in an ESP depends largely on the electrical resistance of the particles being collected. An optimum value exists for a given ash. Above and below this value, particles become less effectively charged and collected. Table II-6 presents the PM collection efficiency of an ESP compared with the other control device types. Coal that contains a moderate to high amount of sulfur (more than approximately three percent) produces an easily collected fly ash. Low-sulfur coal produces a high-resistivity fly ash that is more difficult to collect. Resistivity of the fly ash can be changed by operating the boiler at a different temperature or by conditioning the particles upstream of the ESP with sulfur trioxide, sulfuric acid, water, sodium, or ammonia. In addition, collection efficiency is not uniform for all particle sizes. For coal fly ash, particles larger than about 1 to 8 μm and smaller than about 0.3 μm (as opposed to total PM) are typically collected with efficiencies from 95 to 99.9 percent. Particles near the 0.3 μm size are in a poor charging region that reduces collection efficiency to 80 to 95 percent.

An ESP can be used at one of two locations in a coal-fired electric utility boiler system. For many years, every ESP was installed downstream of the air heater where the temperature of the flue gas is between 130 and 180 °C (270 and 350 °F). An ESP installed at this location is referred is as a "cold-side" ESP. However, to meet SO_2 emission requirements, many electric utilities switched to burning low-sulfur coal (discussed in Section 2.3.2 under SO_2 controls). These coals have higher electrical ash resistivities, making the fly ash more difficult to capture downstream of the air heater. Therefore, to take advantage of the lower fly-ash resistivities at higher temperatures, some ESPs are installed upstream of the air heater, where the temperature of the flue gas is in the range of 315 to 400 °C (600 to 750 °F). An ESP installed upstream of the air heater is referred to as a "hot-side" ESP. (Buonicore and Davis, 1992; USEPA, 1998).

Fabric Filters

Fabric filters (FF) have been used for fly ash control from coal-fired electric utility boilers for about 30 years. This type of control device collects fly ash in the combustion gas stream by passing the gases through a porous fabric material. The buildup of solid particles on the fabric surface forms a thin, porous layer of solids or a filter, which further acts as a filtration medium. Gases pass through this cake/fabric filter, but the fly ash is trapped on the cake surface. The fabric material used is typically fabricated in the shape of long, cylindrical bags. Hence, fabric filters also are frequently referred to as "baghouses."

Table II-6 Comparison of PM collection efficiencies for different PM control device types (Buonicore and Davis, 1992).

PM Control Type	Representative PM Mass Collection Efficiency Range	
	Total PM	**PM less than 0.3 µm**
Electrostatic precipitator (Cold-side)	99 to 99.7 %	80 to 95 %
Electrostatic precipitator (Hot-side)	99 to 99.7 %	80 to 95 %
Fabric filter	99 to 99.9 %	99 to 99.8%
Particle scrubber	95 to 99 %	30 to 85 %
Mechanical collector	70 to 90 %	0 to 15 %

Gas flow through a FF becomes excessively restricted if the filter cake on the bags becomes too thick. Therefore, the dust collected on the bags must be removed periodically. The type of mechanism used to remove the filter cake classifies FF design types. Depending on the FF design type, the dust particles will be collected either on the inside or outside of the bag. For designs in which the dust is collected on the inside of the bags, the dust is removed by either mechanically shaking the bag (called a "shaker type" FF) or by blowing air through the bag from the opposite side (called a "reverse-air" FF). An alternate design mounts the bags over internal frame structures, called "cages" to allow collection of the dust on the outside of the bags. A pulsed jet of compressed air is used to cause a sudden stretching then contraction of the bag fabric dislodging the filter cake from the bag. This design is referred to as a "pulse-jet" FF. The dislodged dust particles fall into a hopper at the bottom of the baghouse. The dust collected in the hopper is a solid waste that must be disposed of.

An FF must be designed and operated carefully to ensure that the bags inside the collector are not damaged or destroyed by adverse operating conditions. The fabric material must be compatible with the gas stream temperatures and chemical composition. Because of the temperature limitations of the available bag fabrics, location of an FF for use in a coal-fired electric utility boiler is restricted to downstream of the air heater. In general, fabric filtration is the best commercially available PM control technology for high-efficiency collection of small particles.

Electrostatic stimulation of fabric filtration (ESFF) involves a modified fabric filter that uses electrostatic charging of incoming dust particles to increase collection efficiency and reduce pressure drop compared to fabric filters without charging. Filter bags are specially made to include wires or conductive threads, which produce an electrical field parallel to the fabric surface. Conductors can also be placed as a single wire in the center of the bag. When the bags are mounted in the baghouse, the conductors are attached to a wiring harness that supplies electricity. As particles enter the field and are charged, they form a porous mass or cake of agglomerates at the fabric surface. Greater porosity of the cake reduces pressure drop, while the agglomeration increases efficiency of small particle collection. Cleaning is required less frequently, resulting in longer bag life. For felted or nonwoven bags, the field promotes collection on the outer surface of the fabric, which also promotes longer bag life. Filtration velocity can be increased so that less fabric area is required in the baghouse. The amount of reduction is based on an economic balance among desired performance, capital cost, and operating costs. A number of variations exist on the ESFF idea of combining particle charging with fabric filtration. (Buonicore and Davis, 1992; Turner and McKenna, 1989).

Particle Scrubbers and Mechanical Collectors

Particle scrubbers are generally much less efficient than ESPs and baghouses (especially in collecting finer fraction of PM). For this reason and because they entail higher operating costs associated with achieving high collection efficiency, they are not widely used in the industry. Similarly, mechanical collectors have the least collection efficiency and are hardly used in the industry. These two methods are not discussed further in this report. (Buonicore and Davis, 1992).

2.3.3. Emission Control Configurations for Coal-fired Electric Utility Boilers

Table II-7 presents the 1999 nationwide distribution of post-combustion control device configurations used for coal-fired electric utility boilers. For approximately 70 percent of the boilers, the only control device used downstream of the furnace is an ESP. If the unit is subject to SO_2 and/or NO_X emission limit standards, these units do burn low-sulfur coals to meet the SO_2 emission limit and use some type of NO_X combustion controls to meet the NO_X emission limit. Approximately 25 percent of the boilers use some combination of post-combustion control devices. The most common configuration used is an ESP with a downstream wet scrubber for SO_2 control. Less than 2 percent of the units used a combination of PM, SO_2, and NO_X post-combustion control devices.

It is important to note that, for the case of PM, the data on PM control as shown for the year 1999 should not have changed in any significant way. However, for SO_2, the requirements of Phase II (starting in the Year 2000) of the Title IV (acid rain provisions) of the 1990 CAAA, should have resulted in some boilers either switching to low -sulfur coal or the application of wet or dry scrubbers. It appears that the SO_2 scrubber retrofit activity in the U.S. has been rather insignificant since 1999. The most active retrofits have involved the application of SCR, SNCR, and gas reburn (in conjunction with low-NO_X burners where appropriate) to significantly reduce NO_X emissions in the eastern U.S. These reductions, however, are only for ozone season (May 1 to September 30) since the NO_X Transport SIP call applies to ozone season. As of 2003, more than 50 applications of SCRs, SNCRs, or gas reburn have either been completed or are under construction.

Table II-7 Nationwide distribution of post-combustion emission control configurations used for coal fired electric utility boilers for the year 1999 as reported in the Part II USEPA ICR data (USEPA, 2001).

Post-combustion Control Strategy	Post-Combustion Emission Control Device Configuration									Phase II USEPA ICR Data	
	PM control				SO_2 control			NO_X control			
	ESP	FF	PS	MC	WS	SDA	DI	SCR	SNCR	Number of boilers	Percent of nationwide total number
Post-combustion PM controls only	?									791	69.4%
		?								80	7.0%
	?	?								6	0.5 %
			?							5	0.4 %
	?		?							4	0.4 %
				?						2	0.2 %
	?									2 (a)	0.2 %
Post-combustion PM controls and SO_2 controls	?				?					133	11.7 %
		?				?				38	3.3%
			?		?					18	1.6 %
		?			?					13	1.1 %
	?					?				4	0.4 %
				?	?					3	0.2 %
	?						?			2	0.2 %
	?	?			?					1	0.1 %
Post-combustion PM controls and NO_X controls		?							?	12	1.0 %
	?								?	11	0.9 %
	?							?		1	0.1 %
Post-combustion PM controls, SO_2 controls, and NO_X controls		?				?			?	6	0.5 %
		?				?		?		4	0.4 %
		?			?				?	2	0.2%
	?				?			?		1	0.1 %
	?				?				?	1	0.1 %
Total										1,140 (b)	100 %

(a) Units using hot-side ESP in series with a cold-side ESP. Counted as a "multiple control device combination" in Table II-5
(b) Does not include the three IGCC units.

2.4. Costs and Availability of Technology

The technologies to control three of the precursors of regional haze are commercially available. Since 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 large number of small (say, 100 MW) to very large boilers (over 1,000 MW) using different types of coal used. Over the last few years, a large amount of cost data have also become available that clearly indicate that many technologies provide substantial and extremely cost effective reductions.

2.4.1. Detailed Capital Costs, Operating and Maintenance Costs, and Cost Effectiveness

Cost of Controlling SO_2 Emissions

Both wet and dry scrubbers are in wide commercial use in the U.S. The capital costs for new or retrofit wet or dry scrubbers are high when compared to the capital costs for NO_X and PM controls. The recent capital costs range from $180/kW for large units (larger than 600 MW) to as high as $350 for small units (200 to 300 MW). However, the last few years has seen a general trend of declining capital costs due to vendor competition and technology maturation. The cost effectiveness (in dollars per ton) is very attractive, since these devices remove a very large amount of SO_2 (driven by high sulfur content of coal burned). The typical cost effectiveness is in the range of 200 to 500 dollars per ton of SO_2 removed though higher values are obtained for small units operating at low capacity factors and burning low-sulfur coal. The cost effectiveness is determined mostly by the baseline pre-controlled SO_2 emisison rate (or sulfur content of fuel), size and capacity factor of the unit, as well as the capital cost of FGDs (that generally ranges from $150 to $200/kW).

Cost of Controlling NO_X

A representative summary of range of costs associated with various technologies for NO_X control is provided below.

Gas Reburn

In general, the capital costs range from $15/kW to $30/kW for gas reburn and $30/kW to $60/kW when using coal as the reburn fuel. Operating costs are mainly driven by fuel cost differential (certainly gas vs. coal). For other fuels (e.g. coal/orimulsion reburning), fuel preparation costs become more important (micronization, atomization) as there is little or no fuel cost differential. The cost in dollars per ton of NO_X removed is in the range of 500 to 2000 dollars.

Retrofit schedules are directly related to the scope of the retrofit requirements. In most cases, 3-6 weeks are adequate for a reburn retrofit.

Low-NO_X Burners

In general, the capital costs for burners range from $10,000 to 50,000 per burner plus installation. The lower end of this range applies when existing burners are modified instead of replaced to achieve lower NO_X. Operating costs are negligible unless increased unburned carbon results in lost revenues from ash sales. An outage is generally required when implementing this technology, but coal-flow sensors and adjustable orifices are best installed when a mill is out of service. Low-NO_X Burners provide moderate NO_X reductions in the range of 30 to 60% at moderate cost ($200 to 500 per ton of NO_X removed).

Overfire Air (OFA)

OFA technologies have little or no impact on operating costs (other than the potential for an increase in unburned carbon - efficiency loss -, and the resulting impact on ash disposal options). Retrofit costs are site-specific. As such, the economics of these technologies are driven by capital/retrofit costs which typically range from $5-$10/kW, with the lower range reflecting easier application whereas the higher costs are typically associated with more difficult and involved retrofits. The cost effectiveness is in the range of $250 to 600 per ton of NO_X removed.

From a schedule standpoint, OFA retrofit projects can require outages of 3 – 6 weeks, depending on factors such as scope of work, integration with other plant outage requirements, etc.

SCR

Capital costs for retrofit SCR systems to coal-fired power generation sources are specific to the individual site, but have been documented to be within the range of $70/kW to about $190/kW. The lower end of this range applies to retrofits with nominal difficulty. The high end of the range would typically be associated with retrofits having significantly impeded construction access, extensive relocations, and difficult ductwork transitions.

Capital costs for retrofit SCR systems on oil and gas-fired boilers are substantially lower (about half to one third) than costs of coal-fired boiler retrofits. Lower volumes of catalyst are required for gas-fired boilers because of the lack of ash and catalysts poisons like arsenic in the flue gas. Capital costs for oil-fired retrofits are intermediate between coal- and gas-fired retrofits. Oil combustion produces some particulate matter, which necessitates larger SCR catalyst volume as compared to that for natural gas.

Operating costs are mainly driven by cost of reagent, energy penalty (pressure loss, ammonia vaporization), catalyst replacement and dedicated O and M costs. SCR technology offers very high NO_X reductions (from 90 to 95%) and cost effectiveness (in the range of $1,000 to 1500 per ton of NO_X removed).

SNCR

The capital costs for SNCR application are low making it an attractive option for moderate NO_X reductions (25 to 50%). Capital cots range from $10 to $20/kW for power generation boilers.

Operating costs are driven primarily by the consumption of the chemical reagent – usually urea for SNCR - which in turn is dependent upon the efficiency of the control equipment as well as the initial NO_X level and the desired percent reduction. These are typically in the range of \$500-\$700/ton of NO_X.

An additional consideration important in the overall operating costs is the potential contamination of fly ash by ammonia making it potentially unsalable.

Cost of Controlling PM

The costs associated with controlling PM from EGUs generally do not scale on the size of the unit but on the volume of flue gases processed by the control devices (ESPs or fabric filters). The representative costs are provided below.

ESPs

The following values represent typical costs for application of ESPs to units handling a range of flue gas rates (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM):

- Capital: \$15 - \$40/ACFM
- Fixed O&M: Dry ESP's - \$0.25 - \$0.65/yr-ACFM
  Wet ESP's - \$0.15- \$0.50/yr-ACFM
- Variable O&M: Dry ESP's - \$0.45 - \$0.60/yr-ACFM
  Wet ESP's - \$0.25 - \$0.50/yr-ACFM

Fabric Filters

Baghouses have been used extensively for many years in different industries. The EGU sector, while predominantly dominated by ESP's, has started to utilize FF's in the last 20 years.

- Capital: Reverse Air Fabric Filter - \$17 - \$40/ACFM
  Pulse Jet Fabric Filter - \$12 - \$40/ACFM
- Fixed O&M: Reverse Air Fabric Filter - \$0.35 - \$0.75/yr-ACFM
  Pulse Jet Fabric Filter - \$0.50 - \$0.90/yr-ACFM
- Variable O&M: Reverse Air Fabric Filter - \$0.70 - \$0.80/yr-ACFM
  Pulse Jet Fabric Filter - \$.90 - \$1.1/yr-ACFM

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3. INDUSTRIAL BOILERS

Industrial boilers are a significant source of emissions among the twenty-six source categories covered under the Regional Haze Rule. Estimates of national emissions for criteria air pollutants prepared by the USEPA (2000) show that industrial boilers contributed approximately 12 percent of the estimated total national SO_2 emissions and 23 percent of total national NO_X emissions in 1998 (the most recent year for which national estimates are available). Industrial boilers also are one of the largest industrial sources of PM emissions, with 16 percent of the national PM_{10} emissions and 20 percent of the national $PM_{2.5}$ in 1998. Contrast this with the emissions of EGUs for which PM_{10} and $PM_{2.5}$ emissions were 25 percent and 23 percent of national totals in 1998, respectively. In general, the combustion efficiencies achieved by industrial boilers are lower than those of EGUs, resulting in significant emissions of CO (18 percent of the 1998 emissions) and volatile organic compounds (6 percent of the 1998 emissions) from industrial boilers. Industrial boilers also produced 16 percent of the ammonia emissions in 1998. Ammonia is precursor of secondary PM in the atmosphere.

About 46 percent of the SO_2 emissions from industrial boilers are from coal-fired boilers (see Table III-1). The predominant sources of NO_X emissions from industrial boilers are gas-fired boilers (30 percent) and internal combustion boilers (34 percent); coal-fired boilers were only responsible for 17 percent of NO_X emissions from industrial boilers. Although the emphasis of this Chapter is on coal-fired utility boilers, many technologies described here are also applicable to gas and oil-fired units (for example, SCR and SNCR technologies are equally applicable to coal and natural gas/oil units, generally at much lower capital and operating costs; same is true for wet scrubbers for SO_2 control and ESPs or baghouses for PM control for oil units).

Table III-1 Distribution of emissions from industrial fuel boilers from 1998 National Emissions Inventory (USEPA, 2000)

Fuel/Source	NO_X	SO_2	PM_{10}	$PM_{2.5}$
Coal	17%	46%	31%	16%
Oil	7%	27%	18%	16%
Gas	39%	21%	18%	26%
Other	4%	5%	25%	32%
Internal Combustion	34%	1%	7%	10%

3.1. Description of Boiler Process

Typically, industrial boilers generate steam used for process heating or on-site generation of electricity. Industrial boilers burn a wider variety of fuels than EGUs and there are a larger number of boiler designs in use than in the electric power sector. According to information contained in USEPA’s Docket on “National Emission Standards for Hazardous Air Pollutants for Industrial/ Commercial/Institutional Boilers and Process Heaters" (USEPA, 2004) in 1998 there were 63,767 fossil fuel-fired boilers, 1,100 wood-fired boilers and 998 boilers classified as non-fossil-fuel-fired. The fossil fuels fired were natural gas, distillate oil, residual oil, coal and petroleum coke. The majority (75 to 95 percent) of the boilers firing natural gas, residual oil and distillate oil are fire tube boilers; the rest are water tube boilers. Coal-fired boilers include fluidized bed boilers, stokers, cyclone boilers, and pulverized coal-fired boilers (wall-fired or tangentially fired). Wood-fired boilers include fluidized bed boilers, cyclones, stokers and dutch ovens.

3.2. Review of BART-Eligible Industrial Boilers in the MANE-VU Region

There are 10 facilities with BART-Eligible industrial boilers in the MANE-VU region. Table III-2 contains a list of these sources based on a previous NESCAUM report (2003) and follow-up review by state permitting authorities. [5]

Table III-2 BART-Eligible Facilities in the Industrial Boiler Category

State	Company/Facility	City/Town	Category
Connecticut	SPRAGUE PAPERBOARD INC	Versailles	boilers
Massachusetts	GENERAL ELECTRIC AIR (GE Aircraft Engines)	Lynn	boilers
Massachusetts	TRIGEN BOSTON ENERGY-KNEELAND STATION	Boston	boilers
Massachusetts	SOLUTIA INC. (MONSANTO CO.)	Springfield	boilers
Massachusetts	HARVARD UNIVERSITY CAMBRIDGE	Cambridge	boilers
Maine	International Paper - Bucksport	Bucksport	boilers
Maine	Katadhin - Mill W.	Millinocket	boilers
New Hampshire	Annheuser-Busch	Merrimack	boilers
New Hampshire	Dartmouth College	Hanover	boilers
Rhode Island	BROWN UNIVERSITY	Providence	boilers

3.3. Available Control Technologies

A variety of emission control technologies are employed to meet requirements for sulfur dioxide (SO_2), nitrogen oxides (NO_X), and primary PM emissions, the three major precursors of observed regional haze in the atmosphere. SO_2 and NO_X are mostly converted to ammonium sulfate and ammonium nitrate that are formed by the reactions of precursor gases with ammonia, which is emitted mostly from agricultural and cattle-related activities.

Pollutant emission controls are generally divided into three major types:

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[5] NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and any identified sources are contained here and in the final list in Appendix A.

- *Pre-combustion Controls.* Control measures in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.
- *Combustion Controls.* Control measures in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.
- *Post-combustion Controls*: Control measures in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

3.3.1. Emission Characteristics of Regional Haze Precursors from Industrial Boilers

Nitrogen Oxides

The formation of NO_X is an unfortunate byproduct of the combustion of fossil fuels. Both NO and NO_2 (collectively called NO_X) are formed during fossil fuel combustion by oxidation of molecular nitrogen that is present in the combustion air or nitrogen compounds contained in the fuel. The degree to which this conversion occurs is dependent on many factors including both the combustion process itself and the properties of the particular fuel being burned. This explains why similar boilers firing different fuels or similar fuels burned in different boilers will yield different NO_X emissions. Overall, total NO_X formed during combustion is composed predominantly of NO mixed with small quantities of NO_2 (typically less than 10 percent of the total NO_X formed). However, once NO formed during coal combustion is emitted to the atmosphere, the NO is oxidized to NO_2.

The NO_X formed during combustion by oxidation of molecular nitrogen (N_2) in the combustion air is referred to as “thermal NO_X.” The oxidation reactions converting N_2 to NO and NO_2 become very rapid once gas temperatures rise above 1,700°C (3,100°F). Formation of thermal NO_X in a boiler is dependent on two conditions occurring simultaneously in the combustion zone: high temperature and an excess of combustion air. A boiler design feature or operating practice that increases the gas temperature above 1,700 °C, the gas residence time at these temperatures, or the quantity of excess combustion air affects thermal NO_X formation. The formation of NO_X by oxidation of nitrogen compounds contained in the coal is referred to as “fuel NO_X.” The nitrogen content in coal and petcoke ranges from approximately 0.5 to 2 percent; in wood, the nitrogen content is typically 0.1 to 0.2 percent. The amount of nitrogen available in the fuel is relatively small compared with the amount of nitrogen available in the combustion air. However, a significant portion of the fuel nitrogen can be converted to NO in the flame. Local temperature, oxygen concentration and NO concentration affect the conversion of fuel nitrogen to NO and this is exploited in low-NO_X firing systems.

Sulfur Dioxide

SO_2, like NO_X, is a precursor to acid rain and fine particulate matter ($PM_{2.5}$) and is also an undesirable byproduct of the combustion of sulfur-containing fuels. Coal deposits contain sulfur in amounts ranging from trace quantities to as high as 8 percent or more. Natural gas contains virtually no sulfur. Residual oil can have 1 to 2 percent sulfur by weight, while petroleum coke can have as much as 6 percent sulfur. During combustion, sulfur compounds in the fuel are oxidized to gaseous SO_2 or SO_3. When firing bituminous coal, almost all of the sulfur present in coal is emitted as gaseous sulfur oxides (on average, 98 percent). The more alkaline nature of ash in some sub bituminous coals causes a portion of the sulfur in the coal to react to form various sulfate salts; these salts are emitted as fly ash or retained in the boiler bottom ash. When firing petcoke or residual oil, more of the SO_2 is converted to SO_3 because of the oxidation that is catalyzed by vanadium in the ash. In coal-fired boilers, SO_3 levels are typically 10 ppm or less. With petcoke firing, however, SO_3 levels as high as several hundred ppm have been reported (Fernando,2001). Formation of SO_3 is a concern because the temperature of the particulate control device or scrubber is often below the acid dew point, resulting in nucleation and condensation of ultrafine sulfuric acid particles from the SO_3 present in the gas. These particles can contribute to the fine PM emissions from the stack.

Unlike nitrogen in fossil fuels and wood, almost all of the sulfur in fuel is oxidized to form SO_2. This means that the relationship between sulfur content in the fuel and SO_2 production is much more direct than that between fuel nitrogen and NO_X, and as such, it makes fuel switching (for example higher to lower sulfur coal) directly proportional to reductions in SO_2. Generally, the percentage of sulfur in the fuel that is converted to sulfur oxides during combustion does not vary with the boiler design or operation. The exception to this is the fluidized bed boiler in which limestone is added to the bed. The bed is operated at a sufficiently low temperature (compared to other combustion systems) that sulfur is captured effectively in the bed as calcium sulfate.

Particulate Matter

Primary PM emissions from boilers consist primarily of fly ash. Ash is the unburned carbon and the mineral portion of the fuel. Coals contain 4 to 12 percent ash typically. Other liquid or solid fuels (oil, petroleum coke, wood) contain less than one percent ash. The amount of ash that ultimately exits the boiler unit as fly ash is a complex function of the fuel properties, furnace-firing configuration, and boiler operation. For the dry-bottom, pulverized-coal-fired boilers, approximately 80 percent of the total ash in the as-fired coal exits the boiler as fly ash. Wet-bottom, pulverized-coal-fired boilers emit significantly less fly ash: on the order of 50 percent of the total ash exits the boiler as fly ash. In a cyclone-fired boiler, most of the ash is retained as liquid slag; thus, the quantity of fly ash exiting the boiler is typically 20 to 30 percent of the total ash. However, the high operating temperatures unique to these designs promote ash vaporization and this results in larger fractions of submicron fly ash compared to dry bottom designs. Fluidized-bed combustors emit high levels of fly ash since the coal is fired in suspension and the ash is present in dry form. Spreader-stoker-fired boilers can also emit high levels of fly ash. However, overfeed and underfeed stokers emit less fly ash than spreader stokers, since combustion takes place in a relatively quiescent fuel bed.

In addition to the fly ash, PM emissions from boilers result from reactions of the SO_2 and NO_X compounds as well as unburned carbon particles carried in the flue gas from the boiler. The SO_2 and NO_X compounds are initially in the vapor phase following coal combustion in the furnace chamber but can partially chemically transform in the stack, or near plume, to form fine PM in the form of nitrates, sulfur trioxide (SO_3), and sulfates. Firing configuration and boiler operation can affect the fraction of carbon (from unburned fuel) contained in the fly ash. Combustion efficiencies tend to be lower in industrial boilers than in EGUs. Oil or petcoke combustion results in high amounts of sulfur trioxide as compared to coal combustion because of the high vanadium content of residual oil and petcoke.

NO_X control technologies that inject ammonia or amine-based reagents (like Selective Catalytic Reduction or Selective Non-Catalytic Reduction) produce ammonia, generally with concentrations less than 10 ppm. This ammonia can also form fine particulate in the stack, if it persists through the air pollution control devices.

3.3.2. Control Technologies used for Industrial Boilers

Application Status

According to the 1998 survey of industrial boilers by USEPA (2004), only 2 percent of gas-fired boilers and 3 percent of oil-fired boilers had any kind of air pollution control device. More coal-fired boilers had air pollution control devices: 47 percent had some control device and these were largely PM controls.

For PM controls, ESPs were used on 12 percent of the coal-fired boiler units in 1998, fabric filters or baghouses were used on 10 percent of the boiler units, mechanical collectors were used on 21 percent of the units, and particulate scrubbers were only used on 2 percent of the units. 66 percent of wood-fired boilers used mechanical collectors for PM control, while 10 percent used PM scrubbers and another 10 percent used ESPs.

Post-combustion SO_2 control was used by less than one percent of industrial boilers in 1998, with the exception of boilers firing petcoke: 2 percent of boilers firing petroleum coke had acid scrubbers. A small percentage of industrial boilers had combustion controls in place in 1998, although since 1998, additional low-NO_X firing systems may have been installed.

SO_2 Reduction Overview

Almost all SO_2 emission control technologies fall in the category of reducing SO_2 after its formation, as opposed to minimizing its formation during combustion. The exception to the nearly universal use of post-combustion controls is found in fluidized bed boilers, in which limestone is added to the fluidized bed combustion. Typically 90 percent of the sulfur can be captured in a coal-fired fluidized bed using limestone with Ca/S molar ratios of 2 to 2.5, depending on the sulfur content of the fuel, the reactivity of the limestone and the operation of the combustor.

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 technology used. SO_2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) and/or "Scrubbers" 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).

Within each technology category, multiple variations are possible and typically involve the type and preparation of the reagent, the temperature of the reaction (for dry processes), the use of enhancing additives, etc. Because these variations mostly involve complex process chemistry, but are fundamentally similar, this summary focuses on the major categories of SO_2 control technologies, their applicability, performance and cost.

Pre-Combustion Control

A coal with sufficiently low sulfur content that when burned in the boiler meets the applicable SO_2 emission standards without the use of additional controls is sometimes referred to as “compliance coal.” Coals naturally low in sulfur content may be mined directly from the ground. Alternatively, the sulfur content of coal fired in the boiler may be lowered first by cleaning the coal or blending coals obtained from several sources. However, burning low-sulfur coal may not be a technically feasible or economically practical SO_2 control alternative for all boilers. In some cases, a coal with the required sulfur content to meet the applicable standard may not be available or cannot be fired satisfactorily in a given boiler unit design. Even if such a coal is available, use of the low-sulfur coal that must be transported long distances from the mine may not be cost-competitive with burning higher sulfur coal supplied by closer mines and using a post-combustion control device.

Various coal cleaning processes may be used to reduce the sulfur content of the coal. A significant portion of the pyritic sulfur minerals mixed with the mined coal can usually be removed by physical gravity separation or surface property (flotation) methods. However, physical coal cleaning methods are not effective for removing the organic sulfur bound in coal. Another method of reducing the overall sulfur content of the coal burned in a given boiler unit is to blend coals with different sulfur contents to meet a desired or target sulfur level.

In-Process Controls

Fluidized bed boilers generally operate at lower temperatures than other combustion systems, 800 to 870^{o}C (1500 to 1600^{o}F). The lower temperatures allow the use of limestone or dolomite to be added to the bed to capture sulfur. Limestone ($CaCO_3$) is converted to CaO at approximately 800^{o}C (1500^{o}F). SO_2 released from the fuel reacts with CaO to form $CaSO_4$, which is thermodynamically stable at bed temperatures. By recycling some of the solids leaving the bed, which contain unsulfated calcium, 90 percent removal of SO_2 can be achieved with Ca/S molar ratios of 2 to 2.5 in circulating fluidized beds. Higher Ca/S ratios are required in bubbling beds. In either case, the sorbent is removed with the ash from the bed and sent to disposal.

Post-Combustion Controls

Wet Processes

Wet FGD "scrubbers" date back to the 1960s with commercial applications in Japan and the U.S. in the early 1970s. They represent the predominant SO_2 control technology in use today with over 80% of the controlled capacity in the world and the U.S.

In a wet scrubber, the SO_2-containing flue gas passes through a vessel or tower where it contacts an alkaline slurry, usually in a counterflow arrangement. The intensive contact between the gas and the liquid droplets ensures rapid and effective reactions that can yield greater than 90 percent SO_2 capture. Currently, advanced scrubber designs have eliminated many of the early problems, primarily related to reliability, but have also demonstrated very high SO_2 reduction capabilities with some units providing over 95 percent control.

Variations of the basic technology, in addition to equipment improvements made over the years, include reagent and byproduct differences. Limestone, lime, sodium carbonate and even seawater-based processes are commercial. Limestone is by far the most widely used with commercial-grade gypsum (wallboard quality) being produced in the so-called Limestone Forced Oxidation (LSFO) process. The use of other reagents, as mentioned, is driven by site-specific criteria, such as local reagent availability, economics, efficiency targets, etc.

Dry Processes

Dry processes include spray dryer absorbers (SDA) and Dry Sorbent Injection (DSI) technologies. SDA refers to a configuration where the reaction between SO_2 and the sorbent takes place in a dedicated reactor or scrubber hence the common reference to "dry scrubber"; conversely, DSI uses the existing boiler/duct system as the "reactor" and several configurations are possible based on the temperature window desired. This can occur at furnace (~2200ºF), economizer (800-900ºF) or duct temperatures (~250ºF). Dry processes are more compatible with low to medium sulfur coals due to limitations in reaction rates and sorbent handling (e.g., atomization). Therefore, high-sulfur applications are not likely. In addition, another common feature among them is the need for particulate control downstream of the sorbent injection. Usually this is accomplished through the use of fabric filters (baghouses) which are, not only efficient collectors of particulates, but also provide additional SO_2 removal as the flue gas passes through unreacted sorbent collected on the filters.

Dry SO_2 controls vary significantly in performance, with SDAs being able to achieve about 80 percent removal rates, whereas the various forms of DSI are capable of 40 to 75 percent efficiencies.

NO_X Reduction Overview

As a result of the complex interactions in the formation of NO_X, an equally large number of approaches to minimize or reduce its emissions into the atmosphere have been and continue to be developed. A relatively simple way of understanding the many technologies available for NO_X emission control is to divide them into two major categories: (1) those that minimize the formation of NO_X during the combustion process (e.g., smaller quantities of NO_X are formed); and (2) those that reduce the amount of NO_X formed during combustion prior to exiting the stack into the atmosphere. In industry "language" it is common to refer to the first approach under the "umbrella" of *Combustion Modifications* whereas technologies in the second category are termed Post-*Combustion Controls.*

Within each of these categories, several technologies and variations of the same technology exist. Finally, combinations of some of these technologies are not only possible but often desirable as they may produce more effective NO_X control than the application of a stand-alone technology.

The following summaries describe the major technologies in each category.

Combustion Modifications

Combustion modifications can vary from simple "tuning" or optimization efforts (similar to a "tune-up" in a car) to the deployment of dedicated technologies such as Low-NO_X Burners (LNB), Overfire Air (OFA) or gas recirculation (GR).

Boiler Tuning or Optimization

Combustion optimization efforts can lead to improvements in NO_X emissions of 5 to 15 percent or even higher in cases where a unit may be badly "de-tuned." It is important to remember that optimization results are truly a function of the "pre-optimization" condition of the power plant or unit (just as the improvement in a car from a "tune-up" depends on how "bad" it was running prior to it), and as such have limited opportunity for drastic emission reductions.

Recent development of "intelligent controls" - software-based systems that "learn" to operate a unit and then maintain its performance during normal operation, are expected help in keeping plants well-tuned, as they gain acceptance and become common features in combustion control systems.

Low-NO_X Burners and Overfire Air

LNBs and OFA represent practical approaches to minimizing the formation of NO_X during combustion. Simply, this is accomplished by "controlling" the quantities and the way in which fuel and air are introduced and mixed in the boiler (usually referred to as "fuel or air staging").

These technologies are the most prevalent in the power industry at present. For example, plants that have had to comply with Title IV of the CAAA of 1992 have largely used these technologies for compliance. Competing manufacturers have proprietary designs, geared towards application in different boiler types, as well as reflecting their own design philosophies. LNBs and OFA, which can be used separately or as a system, are capable of NO_X reductions of 40 to 60 percent from uncontrolled levels. Again, the type of boiler (e.g., dry versus wet-bottom, wall- versus tangential-fired, NSPS versus pre-NSPS) and the type of fuel (e.g., bituminous versus sub-bituminous) will influence the actual performance achieved.

Furthermore, all combustion modification approaches face a common challenge: that of "striking a balance" between NO_X reduction and fuel efficiency. The concern is exemplified by the typically higher carbon levels in the fly ash, which reflect lower efficiency (more fuel needed for the same electrical output), but also the contamination of the fly ash itself possibly making it unsuitable for reutilization (e.g., cement industry).

LNBs/OFA have little or no impact on operating costs (other than by the potential for the above-mentioned efficiency loss).

From a schedule standpoint, LNB/OFA retrofit projects have "lead" times of 10 to 14 weeks and can require outages of 6 to 10 weeks, depending on factors such as scope of work, integration with other plant outage requirements, etc.

Post-Combustion Controls

Readily available post-combustion NO_X controls are limited to Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). They are fundamentally similar, in that both use an ammonia-containing reagent to react with the NO_X produced in the boiler, and convert it to harmless nitrogen and water, SNCR accomplishes this at higher temperatures (1700ºF-2000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 700ºF) and hence needs a catalyst to produce the desired reaction between ammonia and NO_X.

While this difference between the two technologies may seem minor, it yields significant difference in performance and costs. This is because in the case of SNCR, the reaction occurs in a somewhat uncontrolled fashion (e.g., the existing upper furnace becomes the "makeshift" reactor which is not what it was originally designed to be), while in the SCR case, a dedicated reactor and the reaction-promoting catalyst ensure a highly controlled, efficient reaction. In practice, this means that SNCR has lower capital costs (no need for a reactor/catalyst); higher operating costs (lower efficiency means that more reagent is needed to accomplish a given reduction in NO_X); and finally, has limited NO_X reduction capability (typically 30 to 40 percent with some cases achieving reductions in the 50 percent range). SCR, on the other hand, offers lower operating costs and the opportunity for very high NO_X reductions (up to 90 percent and higher).

Operating costs are driven primarily by the consumption of the chemical reagent – usually urea for SNCR and ammonia for SCR, - which in turn is dependent upon the efficiency of the process (usually referred to in terms of reagent utilization) as well as the initial NO_X level and the desired percent reduction. Two additional parameters important in the overall operating costs are: (1) the potential contamination of coal fly ash by ammonia making it unsaleable; and (2) the life cycle of the catalyst due to premature "poisoning."

Selective Catalytic Reduction

The selective catalytic reduction (SCR) process uses a catalyst with ammonia gas (NH3) to reduce the NO and NO_2 in the flue gas to molecular nitrogen and water. The ammonia gas is diluted with air or steam, and this mixture is injected into the flue gas upstream of a metal catalyst bed (composed of vanadium, titanium, platinum, or zeolite). In the reactor, the reduction reactions occur at the catalyst surface. The SCR catalyst bed reactor is usually located between the economizer outlet and air heater inlet. The catalyst modules take up a considerable amount of space; in addition ductwork must be added for the ammonia injection section. There is not always room in an existing boiler to retrofit an SCR system. As a consequence, fan capacity may have to be increased, owing to the incremental pressure drop from the SCR and associated ductwork. In some cases, the boiler must be modified to increase the economizer exit temperature to the minimum and/or the air preheater must be modified. Installation of an SCR on a boiler is site-specific and this results in a range of capital costs for SCR systems on boilers.

Selective Noncatalytic Reduction

The selective noncatalytic reduction (SNCR) process is based on the same basic chemistry of reducing the NO and NO_2 in the flue gas to molecular nitrogen and water but does not require the use of a catalyst to prompt these reactions. Instead, the reducing agent is injected into the flue gas stream at a point where the flue gas temperature is within a very specific temperature range. A minimum of 0.5 seconds of residence time is required at a temperature of about $1800^{o}F$ to achieve high (50 to 60 percent) NO_X removal with SNCR. Good dispersion of the reagent in the flue gas is also needed to get good utilization of the reagent and to avoid excessive ammonia slip from the process. The need for a sufficient volume in the boiler at the right temperature window precludes the application of SNCR in all types of industrial boilers.

PM Reduction Overview

Particulate matter is generated by a variety of physical and chemical processes. It is emitted to the atmosphere through combustion, industrial processes, fugitive emissions and natural sources. In combustion processes, the mineral matter (inorganic impurities) is converted to ash. The particles suspended in the flue gas are known as fly ash. Fly ash constitutes the primary particulate matter, which enters the particulate control device. Particulate matter is in general referred to as "PM", " PM_{10}", " $PM_{2.5}$" (particulate matter (PM) with an aerodynamic equivalent diameter of 10 microns or less and 2.5 microns or less, respectively).

Quantity and characteristics of the fly ash and particle size distribution depend on the mineral matter content of the fuel, combustion system, and operating conditions. Combustion technique mainly determines the particle size distribution in the fly ash and hence the final particulate emissions. Common combustion systems in pulverized coal firing include dry bottom, wall (front, opposed) and corner (tangential) burners and wet bottom furnaces. In dry bottom boilers, 10 to 20 percent of the ash is discharged as dry, bottom ash. In wet bottom boilers, 50 to 60 percent of the ash is discharged at the bottom of the boiler as slag. Stokers or grate-fired boilers are used to burn coal, wood and waste. The majority of the ash falls through the grate and is discharged as bottom ash. Mineral composition of the coal and the amount of carbon in the fly ash determine the quantity, resistivity and cohesivity of the fly ash.

PM emissions from other point source processes involve similar phenomena where particulate matter is carried with the flue gas, in suspension to the stack. Hence, the general technologies applicable to one source are typically suitable for the others as well. Factors such as type and quantity of PM, characteristics of the process gas (temperature, moisture, other contaminants) have a major influence on the selection and design of the PM control technology.

PM Control Technologies

The following four major types of particulate controls technologies are common for a variety of applications:

Wet scrubbers

Scrubbers work on the principle of rapid mixing and impingement of the particulate with the liquid droplets and subsequent removal with the liquid waste. For particulate controls the “venturi scrubber” is an effective technology whose performance is directly related to the pressure loss across the venturi section of the scrubber. Venturi scrubbers are effective devices for particulate control. However, for higher collecting efficiencies and a wider range of particulate sizes, higher pressures are required. High-energy scrubbers refer to designs operating at pressure losses of 50 to 70 inches of water. Of course, higher pressure translates to higher energy consumption. Performance of scrubbers varies significantly across particle size range with as little as 50 percent capture for small (<2 microns) sizes to 99 percent for larger (>5 microns) sizes, on a mass basis.

Electrostatic Precipitators (ESP)

ESP's operate on the principle of electrophoresis, by imparting a charge to the particulates and collecting them on opposed charged plates. Dry vs. wet refers to whether the gas is water cooled and saturated prior to entering the charged plate area, or is collected dry on the plates. In gases with high moisture content, dry ESPs are not suitable because the wet gas would severely limit the ability to collect the "sticky" particulates from the plates. The wet ESP technology is capable of very high removal efficiencies and is well suited for the wet gas environments. Both types of ESPs are capable of greater than 99 percent removal of particle sizes above 1 micron on a mass basis.

Fabric Filters

These are essentially "giant" vacuum cleaners. As in the case of the dry ESP, Fabric Filters (FFs, sometimes called baghouses) are not well suited for wet gas applications. However FFs are extremely efficient in collecting PM including fine (submicron) size fractions.

Cyclones

Cyclones are devices that separate particulates from the gas stream through aerodynamic/centrifugal forces. However, the technology is only effective in removing larger size particles (greater than about five microns).

3.4. Costs of Technology

3.4.1. NO_X Technologies

A representative summary of range of costs associated with various technologies for NO_X control in industrial boilers is provided in Table III-4, taken from Reference 4. Capital costs and pollutant removal costs (in $/ton of pollutant removed) are given for three different boiler sizes: 1000, 500, and 100 MMBtu/hr. For each boiler size, the range of costs corresponds to a range of capacities from about low (5 to 14 percent of capacity) to high (86 to 93 percent of capacity). Industrial boilers have a wider range of sizes than EGUs and often operate over a wider range of capacities.

Low-NO_X Burners (LNBs)

The capital costs for coal burners range from $2,500 to $5,100 per MMBtu/hr of boiler size. The lower end of this range applies when existing burners are modified instead of replaced to achieve lower NO_X. Operating costs are negligible unless increased unburned carbon results in lost revenues from ash sales. An outage is generally required when implementing this technology, but coal-flow sensors and adjustable orifices are best installed when a mill is out of service. Low-NO_X Burners provide moderate NO_X reductions in the range of 30 to 50 percent at moderate to high cost ($200 to $3,000 per ton of NO_X removed). The size of the boiler affects both the capital cost and the cost per ton. The combination of LNBs and overfire air (OFA), with or without flue gas recirculation (FGR), is more expensive but NO_X reduction is higher, as high as 80 percent for gas-fired boilers. From a schedule standpoint, LBB/OFA retrofit projects can require outages of 3 to 6 weeks, depending on factors such as scope of work, integration with other plant outage requirements, etc.

SNCR

The capital costs for SNCR application are low making it an attractive option for moderate NO_X reductions (about 40 percent). As discussed above, the NO_X reduction that can be achieved will vary from one boiler to another, and depend on the residence time available in the boiler in which the temperatures fall within the window for the SNCR chemistry to take place. Capital costs range from \$2,000 to \$4,000 per MMBtu/hr for industrial boilers. Operating costs are driven primarily by the consumption of the chemical reagent – usually urea for SNCR - which in turn is dependent upon the efficiency of the control equipment as well as the initial NO_X level and the desired percent reduction. These are typically in the range of \$1,300 to \$10,000/ton of NO_X.

An additional consideration important in the overall operating costs for coal-fired boilers is the potential contamination of fly ash by ammonia, making it potentially unsalable.

SCR

Capital costs for retrofit SCR systems to industrial boilers are mostly within the range of \$4,000 to \$15,000 per MMBtu/hr. Installation of an SCR on a boiler is site-specific and this results in a range of capital costs for SCR systems on boilers. Coal-fired boilers have higher capital costs. The systems must be larger to allow for flow of fly ash through the catalyst without plugging. Catalyst activity deteriorates faster in coal-fired boilers because of the higher levels of contaminants in the flue gas (like arsenic) and the deposition of ash on the catalyst. Catalysts must be replaced more frequently in coal-fired systems, which increases the operating cost. The lower end of this range applies to retrofits with nominal difficulty. The high end of the range would typically be associated with retrofits having significantly impeded construction access, extensive relocations, and difficult ductwork transitions.

In addition to catalyst replacement costs, operating costs are mainly driven by cost of reagent, energy penalty (pressure loss, ammonia vaporization) and dedicated O and M costs. SCR technology offers very high NO_X reductions (80 percent or better); the cost per ton of NO_X removed is considerably higher than SNCR, although the overall NO_X reduction is higher.

3.4.2. SO_2 Technologies

Both wet and dry scrubbers are in wide commercial use in the U.S. The capital costs for new or retrofit wet or dry scrubbers are high when compared to the capital costs for NO_X and PM controls (Khan, 2004b). Dry sorbent injection (DSI) has lower capital costs than a spray dryer absorber (SDA), although DSI can only achieve about 40 percent SO_2 reduction. SDA systems can achieve 90 percent reduction. Capital costs for DSI are in the range of $8,600 to $26,000 per MMBtu/hr, depending on the size of the system and on the sulfur content of the fuel. Capital costs for SDA systems are about double that for DSI systems, but the cost per ton of SO_2 removed is similar: $400 to $4,000 per ton of SO_2 removed. These costs are higher than the costs for scrubbers on EGUs, which are only $100 to $200 per ton of SO_2 removed.

Wet FGD systems also remove 90 percent and higher of the SO_2, but the capital cost is about 50% higher than the cost for an SDA system. The costs per ton of SO_2 removed are similar to the costs for SDA for coal-fired boilers. Costs per ton of SO_2 are estimated to be about twice as high for oil-fired boilers as compared to coal-fired boilers.

3.4.3. PM Technologies

As with most control technologies, the costs of PM controls involve both capital and operating costs. A cost-effectiveness indicator, such as $/ton as is typically used for other technologies (e.g. NO_X and SO_2), is very difficult to address for generic PM control costs, as the range of PM reductions for different fuels and processes is so wide that cost ranges become useless. An attempt to summarize costs in terms of capital and O&M components is presented below.

Capital

While it is customary to indicate capital costs on a $/kW basis for power generation applications, this is not relevant for non-power applications since no electricity is generated. However, one of the main parameters dictating the “sizing” and hence, the costs of a PM control device, is the quantity of flue gas it must handle. As a result, it is more appropriate to generalize capital costs per actual cubic feet per minute (ACFM) of gas flow and is given on a “$/ACFM” basis. The following values represent typical costs for several of these technologies (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM))

- Dry ESPs - $15 - $40/ACFM
- Wet ESPs - $15 - $40/ACFM
- Reverse Air Fabric Filter - $17 - $40/ACFM
- Pulse Jet Fabric Filter - $12 - $40/ACFM
- Venturi Scrubber - $5 - $20/ACFM
- Cyclone - $1 - $5/ACFM

O&M

O&M costs are difficult to generalize for such a variety of technologies and applications, as they are affected by many parameters that include type of fuel, type of process, local ash disposal options, local cost of power, etc. O&M costs include fixed costs (FOM) and variable costs (VOM). The costs provided below are presented in $/year-ACFM and reflect costs for coal-based fuels but should reasonably apply to other sources as well.

Fixed O&M

- Dry ESPs - $0.25 - $0.65/yr-ACFM
- Wet ESPs - $0.15- $0.50/yr-ACFM
- Reverse Air Fabric Filter - $0.35 - $0.75/yr-ACFM
- Pulse Jet Fabric Filter - $0.50 - $0.90/yr-ACFM
- Venturi Scrubber - $0.25 - $0.65/yr-ACFM
- Cyclone – Not applicable

Variable O&M

- Dry ESPs - $0.45 - $0.60/yr-ACFM
- Wet ESPs - $0.25 - $0.50/yr-ACFM
- Reverse Air Fabric Filter - $0.70 - $0.80/yr-ACFM
- Pulse Jet Fabric Filter - $.90 - $1.1/yr-ACFM
- Venturi Scrubber - $1.2 - $1.8/yr-ACFM
- Cyclone – Not applicable

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Table III-4. NO_X reduction and control costs for industrial boilers (Khan, 2004a).

Fuel	**Technology**	**NO_X Reduction**	**$/Ton of Pollutant vs. Boiler Size**			**Capital Costs $/ MMBtu/hr vs. Boiler Size**		
		%	1000 MMBtu/hr	250 MMBtu/hr	100 MMBtu/hr	1000 MMBtu/hr	250 MMBtu/hr	100 MMBtu/hr
Gas	LNB/OFA	60	280 - 5260	424 - 7973	559 - 10521	1280	1940	2554
Gas	LNB/OFA/GR	80	368 - 6204	543 - 9415	700 - 12374	2000	3031	3991
Oil	LNB/OFA(1)	30	306 - 2630	464 - 3986	612 - 5260	1280	1940	2554
Oil	LNB/OFA/GR (1)	50	326 - 2505	477 - 3790	615 - 4973	2000	3031	3991
Oil	LNB/OFA/GR (2)	30	741 - 5694	1085 - 8613	1399 - 11303	2000	3031	3991
Coal	LNB (subbit.)	51	256 - 1520	389 - 2305	512 - 3033	2554	3872	5097
Coal	LNB/OFA (subbit.)	65	306 - 1727	454 - 2608	593 - 3428	3649	5531	7281
Coal	LNB/OFA (bit)	51	392 - 2197	581 - 3317	757 - 4358	3649	5531	7281
Gas	SNCR	40	1842 - 14165	2193 - 20870	2521 - 27105	2111	3200	4212
Oil	SNCR (1)	40	1485 - 4271	1670 - 5892	1840 - 7399	2045	3100	4081
Oil	SNCR (2)	40	1628 - 5497	1889 - 7753	2123 - 9842	2045	3100	4081
Coal	SNCR	40	1285 - 2962	1473 - 4015	1625 - 4970	2639	4000	5266
Gas	SCR	80	986 - 14815	1354 - 21095	1689 - 26859	4014	6084	8009
Oil	SCR (1)	80	760 - 10458	997 - 14443	1245 - 18544	5547	8407	11067
Oil	SCR (2)	80	1017 - 14601	1343 - 20113	1694 - 25838	5547	8407	11067
Coal	SCR	80	876 - 4481	1123 - 5924	1349 - 7262	7298	11062	14562

Notes

(1) 0.5 lb/MMBtu inlet NO_X

(2) 0.36 lb/MMBtu inlet NO_X

Table III-5. SO_2 reduction and control costs for industrial boilers (Khan, 2004b).

Fuel	**Technology**	**SO_2 Reduction**	**$/Ton of Pollutant vs. Boiler Size**			**Capital Costs $/ MMBtu/hr vs. Boiler Size**		
		%	1000 MMBtu/hr	250 MMBtu/hr	100 MMBtu/hr	1000 MMBtu/hr	250 MMBtu/hr	100 MMBtu/hr
Coal	DSI high S coal	40	633 - 1703	763 - 2471	943 - 3543	12508	18838	26835
Coal	DSI lower S coal	40	697 - 1986	849 - 2952	1075 - 4283	8648	12987	17995
Coal	SDA	90	381 - 1500	569 - 2611	790 - 3920	20275	36226	54679
Coal	Wet FGD high S coal	90	373 - 1789	528 - 2708	664 - 3513	32313	48857	64240
Coal	Wet FGD lower S coal	90	461 - 2273	661 - 3460	836 - 4495	29888	45283	59598
Oil	Wet FGD	90	693 - 5082	1011 - 7801	1285 - 10160	27455	41604	54761

4. PORTLAND CEMENT KILNS

Portland cement is a main ingredient for concrete and other common building materials. Portland cement is mainly composed of clinker, a material formed by heating limestone and other ingredients to temperatures over 2,650°F. High combustion temperatures require significant amounts of fuel and can result in significant emissions of NO_X and SO_2. Crushing of ingredients and finished clinker can release dust and particles. Ammonia is sometimes produced during the heating of limestone.

The cement industry has seen significant growth in capacity and technology over the last 30 years. In 2000, the U.S. had 201 cement kilns with the annual capacity to produce 84 million metrics tons of concrete, with production projected to grow to 109 million metric tons in 2004 (Portland Cement Association, 2000).

4.1. Description of Cement-Making Processes

Concrete is a combination of Portland cement, sand, and gravel. The key component of Portland cement is clinker, a material produced by heating limestone and other raw materials to temperatures over 2,650°F, requiring combustion temperatures of about 3,000°F. These high temperatures are normally achieved in a rotary kiln, as shown in Figure IV-1. Feed material is added at the elevated end of the rotating, refractory-lined, cylindrical kiln and the feed gradually tumbles to the high-temperature end of the kiln and the main combustion zone, sometimes referred to as the "Burn Zone." The tilted design of the cement kiln allows gravity to assist the motion of the clinker material while hot exhaust gases move upward and exit at the elevated end of the kiln.

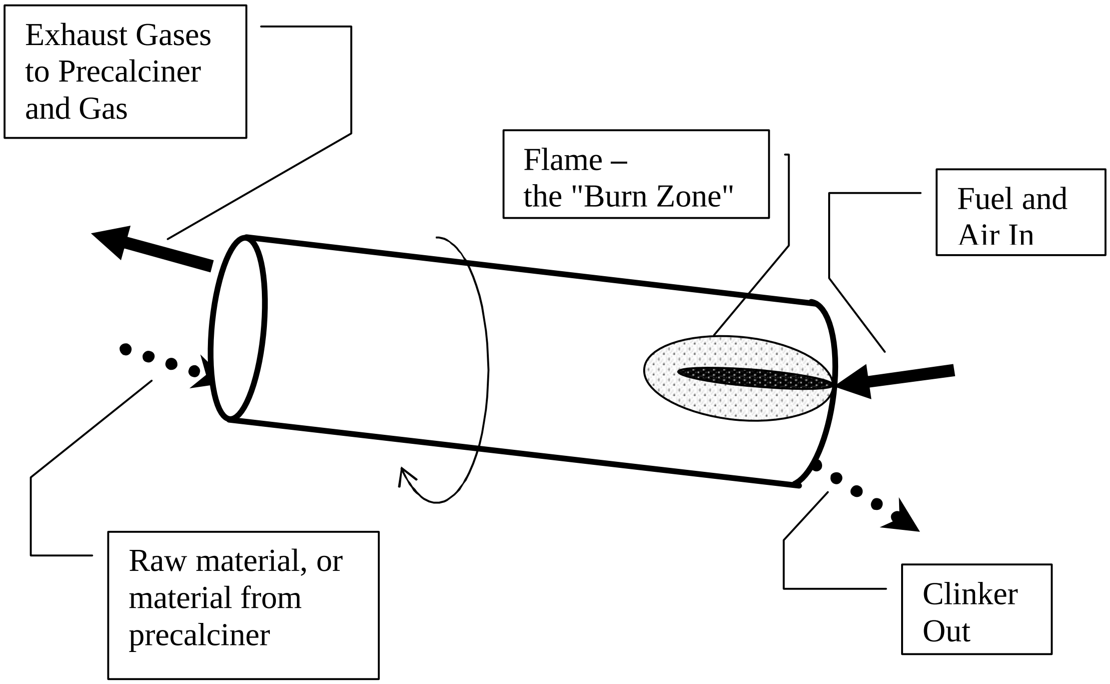

Figure IV-1. Simplified Sketch of a Rotary Kiln.

Cement kilns fall into four general process categories. Preheater kilns preheat and partially calcine feed material in a series of cyclones or grates prior to admitting the feed to the rotary kiln. This additional heat supplements the heat in the exhaust from the kiln. The calcined feed then enters the rotary kiln at about 1,500ºF to 1,650ºF. Precalciner kilns, on the other hand, utilize a burner in a separate vessel along with a series of cyclones or grates to preheat and calcine the feed. In long kiln systems, the raw feed material is added to the rotary kiln itself as either a powder (“dry”) or a slurry (“wet”). Long wet and long dry kilns do not have preheaters and have much longer rotary kilns, with wet process kilns being the longest - normally several hundred feet long. Preheater and precalciner kilns are more energy efficient than long wet or long dry kilns and typically have greater capacity. A preheater kiln is similar, but fuel is not added and there is no burner on the cyclonic preheater portion. Preheaters could also be replaced with suspension preheaters, but these are less common. If past trends continue, many of the existing long wet kilns and dry kilns are expected to be replaced with precalciner and preheater kilns since precalciner and preheater kilns are more energy efficient and also typically have greater capacity.

Coal is the fuel of choice in cement kilns, primarily because of its low cost, but also because the coal ash contributes somewhat to the product. The current fuel use in cement kilns is about 82% coal; 4% natural gas; and 14% other fuels, mainly combustible waste (industrial waste, tires, sewage sludge, etc.). Fuel nitrogen therefore contributes a small but significant amount to the total NO_X for nearly all cement applications (see the section on NO_X controls included later).

Recent years have seen Portland cement plant capacity stretched by high demand, making technologies that can increase capacity without increased capital expenditures very attractive. The industry is therefore developing technologies that improve facility’s outputs or reduce their operating costs. Incidentally, some of these technologies also offer the potential to reduce NO_X and other emissions.

4.2. Review of BART-Eligible Cement Kilns in the MANE-VU Region

NESCAUM’s analysis of BART-eligible sources in the MANE-VU Region[6] (NESCAUM, 2004) identified two Portland cement facilities as being eligible for BART. The facilities are shown in Table IV-1. *[Editor’s note: Additional facilities are likely to be added when PA and NY inventories are complete]*

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[6] NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and any identified sources are contained here and in the final list in Appendix A.

Table IV-1 BART-Eligible Portland Cement facilities in MANE-VU Region

Facility	Kiln type	Capacity, thousands tons/yr	Primary Fuel(s)
St. Lawrence Cement (Hagerstown, MD)	Dry	550	Coal
Dragon Products (Thomaston, ME)	Wet	392	Coal, petcoke

4.3. Available Control Technologies

A number of technologies exist for controlling emissions from cement kilns. Secondary (post-combustion) control devices can be helpful in reducing emissions, and a variety of these are available. Many technologies and techniques have been developed in response to a specific environmental need and target a specific pollutant, sometimes achieving reduction in other pollutants at the same time. Both secondary controls and process changes are discussed below, grouped by their targeted pollutant. When additional emissions reductions are possible, they are noted with the targeted pollutant. Controls are examined for SO_2, NO_X, PM, and VOCs.

4.3.1. SO_2 Controls

In contrast with electric utility boilers, SO_2 emissions from rotary kilns producing cement clinker under oxidizing conditions are nearly independent of fuel sulfur input, but, rather, are closely related to the amount of sulfide (e.g. pyrite) in kiln feed and to the molar ratio of total sulfur to total alkali input to the system. In cement kilns SO_2 emissions generally depend on:

- Inherent SO_2 removal efficiency of kiln system,
- Form of sulfur (e.g. pyritic) and sulfur concentrations in raw material,
- Molecular ratio between sulfur and alkalis,
- Prevailing conditions (oxidizing or reducing) and their location within kiln, and
- Temperature profile in the kiln system.

Depending upon the level of sulfur in a plant’s limestone compared to the sulfur content of its heating fuel, fuel switching may not be sufficient to reduce SO_2 emissions (Tanna and Schipholt, 2004). However, when fuel sulfur levels are high, fuel switching may have a significant benefit of reducing SO_2 levels.

In addition to the control techniques used in the electric utility boilers, cement plants may also resort to other basic reductions techniques involving reduction of sulfur input to the kiln, by switching fuels or changing the limestone, or reduction of SO_2 emissions from reducing both the sulfur in the sources and using a secondary control device. It is common to achieve some level of SO_2 reductions when seeking to reduce another pollutant, usually NO_X (technologies targeting another pollutant, but also reducing SO_2, are described in the NO_X and PM sections below). In addition to considering a change in the primary fuel for the kiln, staged combustion with mid-kiln injection of a low-sulfur fuel may be considered for reducing SO_2. Including high-pressure air injection at a mid-kiln firing site can limit oxygen in the kiln and suppress SO_2 formation (Hansen, 2002). Since these techniques are primarily used to reduce NO_X, more information about mid-kiln fuel injection can be found in the section on NO_X emissions, but other specific SO_2 control technologies applicable to cement kilns are listed below.

Fuel Switching

Selecting a fuel with lower sulfur content, a strategy commonly adopted in the utility boilers, is less effective in cement-making systems, where SO_2 emissions are not strongly dependent on fuel sulfur content. Depending upon the level of sulfur in a plant's limestone compared to the sulfur content of its heating fuel, fuel switching may not be sufficient to reduce SO_2 emissions (Tanna and Schipholt, 2004). However, when fuel sulfur levels are high, fuel switching may have a significant benefit in SO_2 levels.

Inherent Removal

Raw materials, primarily limestone, are preheated in the cement-making process either in the preheater tower or in the rotary kiln. In either case, the limestone comes in contact with hot combustion exhaust gases. The calcium in the lime reacts with SO_2 in the gas, providing in-process removal of sulfur in the kiln system. Removal efficiencies in rotary kiln systems range between 38% and 99% of sulfur input, and 50% to 70% of the remaining SO_2 is removed from exhaust gases when passing through an in-line raw mill system (Miller et al., 2001).

Process Alterations

The following methods to remove and prevent formation of SO_2 by modifying or controlling conditions in the system are available due to the nature of the Portland cement manufacturing process:

- The oxygen concentration of the exhaust gases can be controlled to ensure sufficient oxygen exists to stabilize alkali and calcium sulfate compounds formed in the process. Concentrations of O_2 and, more importantly CO, have a strong influence on the stability of alkali and calcium sulfates in the burning zone. Control of burning- zone O_2 and CO concentrations is a widely used industrial practice, and a control technique applicable to all rotary kilns producing cement clinker. The downside of this technique is the more favorable conditions created for generation of NO_X in the rotary kiln.
- Burning-zone flame shape can be modified to minimize localized reducing conditions. It has been observed (Hansen, 1986) that flame impingement in the hot zone had a major effect on SO_2 emissions from the kiln, even if total oxygen is sufficient to fully combust all fuel. Avoiding flame impingement in the burning zone minimizes SO_2 formation. Avoiding flame impingement on the clinker, a technique applicable to all rotary

kilns producing cement clinker, requires proper solid fuel preparation and proper flame shaping and control.

- Raw materials can be altered to affect the alkali/sulfur molar ratio. SO_2 concentrations in kiln exit gases vary with the molar ratio of alkali to sulfur; when alkalis are in excess of sulfur, SO_2 emissions are typically low, due to more sulfur being retained in clinker as alkali sulfates. Also, kiln feed containing carbon seems to directly cause SO_2 emissions. Changing raw materials may reduce SO_2 emissions. Substituting a raw material containing pyritic sulfur or organic sulfur with one containing lesser amounts of these compounds reduces SO_2 emissions. Replacement of raw materials, however, is often constrained by economic considerations, while alkali input increase may also be limited by cement product quality specifications on total alkali in cement.
- Alterations to system can influence SO_2 emissions. It has been found that an improved distribution of kiln feed may equalize temperatures in bottom stage cyclones and reduce SO_2 emission by as much as 20% (Miller, 2001).

Scrubbers

Dry Reagent Injection

Steuch and Johansen (1991) found that $Ca(OH)_2$ (hydrated lime) was the most effective scrubbing agent, particularly when added to the kiln feed and when the exhaust gases were near the dew point. Adding quicklime or hydrated lime into the upper preheater cyclones demonstrated up to 70% removal efficiency (Nielse, 1991).

Several dry reagent systems are available:

- The RMC Pacific process (Sheth, 1991) injects dry $Ca(OH)_2$, and with different stoichiometric ratios (40:1 to 50:1), has obtained efficiencies ranging from 55% to 65%. SO_2 removal of 80% was obtained with injection into the roller mill.
- Krupp Polysius Polydesox process uses hydrated lime where SO_2 in the raw feed tends to form from pyrites and obtains removal efficiencies of up to 85% (Miller, 2001).
- De-SoX Cyclone, by Fuller Company (Miller, 2001), reduces SO_2 emissions in a precalciner kiln by removing a portion of the gases from the precalciner outlet to a cyclone, and from there to the Stage II cyclone where pyritic sulfur in kiln feed is decomposed into SO_2. The feed (or “raw meal”), containing freshly produced lime, is discharged into the outlet duct of the second stage (this process is known as hot meal injection). Removal efficiencies of 5 to 30% are claimed.

Lime/Limestone Spray Dryer Absorber

Design stoichiometric ratios of calcium to sulfur for spray dryer systems in utility boilers are typically between 0.9 and 1.5, with most below 1.0. These SO_2 scrubbers are designed for removal efficiencies in excess of 80%.

SO_2 reacts with $CaCO_3$, to form $CaSO_4$, a reaction that becomes more complete as the temperature and the fineness of $CaCO_3$ increase. The presence of water vapor also increases conversion.

Most of the spray dryer type SO_2 control technologies in the cement industry are applied to preheater or preheater/precalciner kilns. Exhaust gases from long dry kilns are cooled by either spray water introduced into the feed end of the kiln or by dilution air-cooling after the gases leave the kiln. Adding a conditioning tower to replace water sprays or dilution air enables the alkaline slurry system to be used to reduce SO_2 emissions (the equivalent of a spray dryer). The range of temperatures for exit gases from long wet kilns does not allow the use of an alkaline slurry spray dryer type scrubber because the addition of the lime slurry may drop the exhaust gases temperature below the acid dew point, creating significant plugging and corrosion problems in the downstream Particulate Control Device (PCD), duct work, and induced draft (ID) fan.

RMC Pacific's Alkaline Slurry Injection System (Sheth, 1991)

RMC Pacific uses a hydrated lime, spray dryer absorber to reduce SO_2 emissions. The captured sulfur compounds are returned as a portion of the raw material feedstock to the roller mill, which results in no scrubber effluent or sludge disposal. When SO_2 emissions are high and preheater exit gas temperatures are low, sufficient lime slurry cannot be added to reduce SO_2 to acceptable levels. With different stoichiometric ratios (40:1 to 50:1), the process has obtained efficiencies ranging from 55% to 65%. SO_2 removal of 80% was obtained with injection into the roller mill.

EnviroCare Microfine Lime System (Miller, 2001)

This system uses the existing gas conditioning tower to introduce the scrubbing reagent (water suspension of finely pulverized calcium hydroxide, $Ca(OH)_2$). The small size of the lime particles (3-10 microns) allows the particles to dissolve in water droplets quickly and react with SO_2 as it is absorbed into the water droplet. The dried lime continues to react with any remaining SO_2 in the downstream kiln system and PCD. Lime injection rate can be optimized through a feedback control loop from an SO_2 monitor. EnviroCare claims an SO_2 removal efficiency of greater than 90%.

Wet SO_2 Scrubbers

Wet scrubbers have been used successfully in the utility industry. Calcium sulfate scaling and cementitious buildup when a wet scrubber is used for acid gas control applied to the exhaust gas from a cement kiln can be avoided if these systems are installed downstream of a high efficiency PCD (e.g., fabric filter). Failure of the PCD can pose difficult problems for a downstream wet scrubber.

Fuller Company (FLS Miljø) (Miller, 2001)

The Monsanto Dyna Wave wet SO_2 scrubber has been installed by the Fuller Company and used on several cement kilns in the U.S. This wet scrubber is designed to remove SO_2, halide gases, and some particulate matter.

The scrubber, typically located downstream from the kiln PCD and operated under positive pressure, uses limestone as the absorbent. A slurry (approximately 20% limestone and 80% water) produced in the mixing tank is sprayed countercurrent to the gas flow to cool the gases and react with SO_2 forming calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$), which precipitates. Air is sparged into the sump at the bottom of the tower to oxidize $CaSO_3$ to $CaSO_4+2H_2O$ (gypsum).

Monsanto EnviroChem DynaWave (Miller, 2001)

DynaWave is a "Reverse Jet" scrubber that can simultaneously accomplish several gas cleaning/process needs: hot gas quenching, particulate removal, and acid gas absorption. The reverse jet is an annular orifice scrubber having one to three large-bore nozzles through which a relatively large volume of scrubbing liquid is injected counter to the gas flow to create a froth zone. The gas collides with the liquid, forcing the liquid radialy outward toward the wall. A standing wave, created at the point the liquid is reversed by the gas, is an extremely turbulent region where the gas absorption and particulate collection occurs.

The system is a tailpipe system generally installed downstream of the PCD, and operates with a saturated gas stream. Therefore, it would likely be applicable to most if not all the cement kilns. A single-stage DynaWave scrubber in full-scale operation has a reported SO_2 removal efficiency of about 90%. Monsanto EnviroChem claims that multiple units may be installed in series to achieve whatever removal efficiency is required (e.g., 99.9%).

4.3.2. NO_X Controls

The following sections discuss the formation of NO_X in cement kilns, potential NO_X control techniques, NO_X control in the cement industry, and the cost effectiveness of applicable controls.

NO_X Formation in Kiln Systems

Nitrogen oxides (NO_X) are formed during the combustion of fuels in the cement-making process. In kiln exhaust gases, more than 90% of NO_X is NO, with NO_2 generally making up the remainder from rotary kilns producing cement clinkers (Gardeik, 1984). There are three different NO_X formation mechanisms - thermal, fuel, and feed NO_X - typically contributing to NO_X emissions.

Thermal NO_X

Thermal NO_X is formed by oxidation of atmospheric molecular nitrogen at high temperatures (>1,200 °C). Most NO_X formed in the high-temperature environment of the main combustion zone (burning zone) of a kiln is "thermal NO_X". Since the flame temperature in a kiln is significantly above that threshold, a considerable amount of thermal NO is generated in the burning zone.

While conditions in the burning zone of a cement kiln favor formation of thermal NO_X, those prevalent in secondary combustion zones (e.g. calciners, preheater riser ducts and mid-kiln firing in long wet or dry kilns) with temperatures below 1200°C, are less conducive to significant thermal NO_X formation. In that zone, formation of fuel NO_X and feed NOx is more prevalent.

The amount of thermal NO_X produced is related to fuel type, burning zone temperature, and oxygen content. Therefore, raw materials that are hard to burn (i.e., materials that require more heat input per ton of clinker produced) generate more NO_X.

Fuel NO_X

Fuel NO_X is the result of oxidation of nitrogen compounds in fuel. Fuel nitrogen is only partially converted into NO_X during combustion. The amount formed depends on fuel type, precalciner type and precalciner temperature. NO_X formed in the secondary combustion zone, primarily fuel NO_X (Gardeik, 1984), depends on:

- Nitrogen concentration in the fuel,
- Oxygen concentration in the combustion zone,
- Initial NO concentration in the combustion gas,
- Volatile concentration in the (solid) fuel, and
- Temperature in the secondary combustion zone.

As opposed to the burning zone of the kiln, where higher temperatures result in much higher NO_X formation, higher temperatures (up to 1100°C) in the precalciner may actually reduce NO_X emissions when a fuel containing nitrogen is used (Nielsen, 1990).

In the design of modern low-NO_X calciners, high temperatures and reducing conditions are proven methods for suppressing the formation of fuel NO_X generated in the precalciner, and for destroying thermal NO_X generated in the burning zone of the rotary kiln (Keefe and Shenk, 2002).

Feed NO_X

NO_X emissions can also result from the oxidation of nitrogen compounds in the raw material feed to the kiln (feed NO_X). The range of nitrogen concentrations in various kiln feeds is 20-1000 ppm (Gartner, 1983) and the potential contribution of feed NO_X to total NO_X emissions is 0.2-10 lbs of NO_X per ton of clinker.

Up to 50% of feed nitrogen may be converted to NO_X, if raw materials are heated slowly: with rapid heating, the conversion rate is much lower.

The following conclusions can be made for rotary kiln systems (Young and von Seebach, 1999):

- Formation of thermal NO_X in the burning zone is the major contributor to NO_X emissions from the kiln
- Fuel NO_X is the major contributor in the secondary combustion zone of precalciner and riser duct fired preheater kilns
- Feed NO_X is usually a minor contributor to the total NO_X generated in rotary kiln systems.

It should be further noted that, due to the dynamic nature of kiln operations, NO_X formation can be highly variable so each kiln will tend to have unique NO_X emission characteristics, inherent to the variability in cement manufacturing process. Figure IV-2 illustrates the wide range of NO_X emissions from different types of kilns.

NO_X emissions rates are also site- and kiln-specific, and may be quite dissimilar between two apparently identical kilns, for causes not fully understood, but, probably connected to the raw materials used. Other causes for NO_X emissions rate differences may result from different types or classes of cement products being produced; chemical variations between these different products can influence cement kiln operating parameters and thus NO_X emissions. Short-term process transients such as kiln feed rates and fuel quality also affect NO_X emissions. All of these factors can influence the applicability and costs of incorporating NO_X controls.

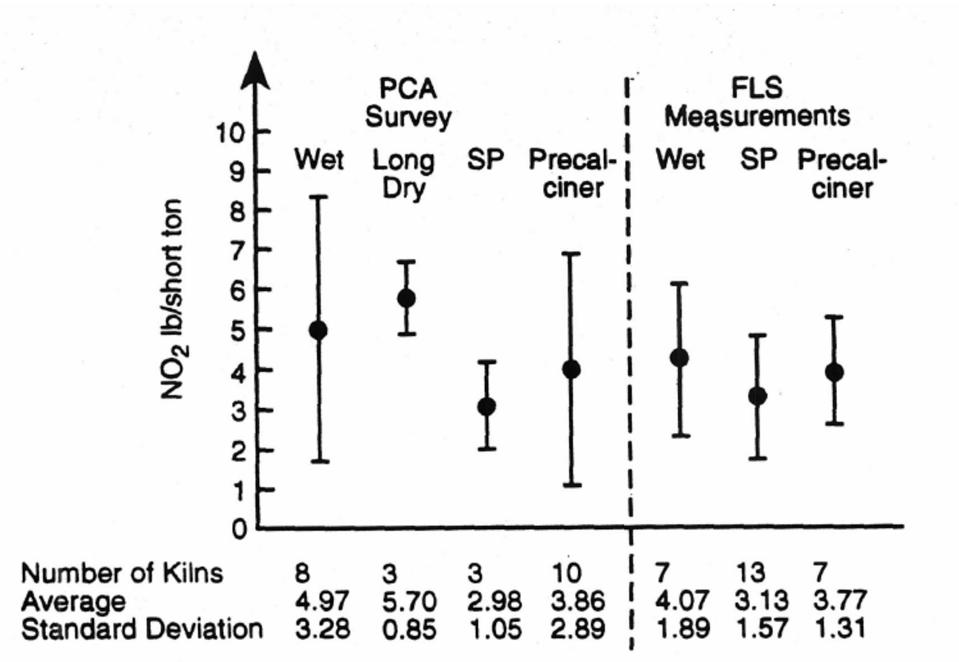

Figure IV-2. NO_X emissions for various cement kiln types (USEPA, 1994).
(SP: Suspension Preheater kilns)

NO_X Control Techniques

There are two broad categories of NO_X reduction techniques for cement kilns: 1) process controls, including combustion modifications, that rely on reducing or inhibiting the formation of NO_X in the manufacturing process (modifications for cement kilns include low-NO_X Burners (LNB), secondary combustion, and staged combustion); and 2) post-combustion (secondary) controls, where flue gases are treated to remove NO_X that has already been formed.

It should be noted that the quality of clinker produced in a kiln varies with characteristics of the combustion, so primary controls need to be selected carefully. Dry low-NO_X (DLN) operation, for example, has seen varied levels of success. The main firing zone of the kiln requires very high temperatures and is not compatible with the lower flame temperature used by DLN to reduce NO_X. Low excess air and air-staging are problematic control options for kilns because the kilns need an oxidizing environment not provided by those techniques. Despite these problems, indirect firing in combination with a LNB has been successfully used in some facilities, including California Portland Cement. Low-NO_X combustion methods can be used in the precalciner because high temperatures are not required in that part of the process.

Indirect firing is a method that permits use of LNBs in the primary kiln burning zone. When indirect firing is used, pulverized coal is fed to and collected in a particulate matter collection system (a cyclone separator that exhausts gas through a fabric filter).

The pulverized coal is then temporarily stored in a bin or hopper, where it is fed to the burner. This method allows less primary air to be used in the burner than with a direct-fired coal mill, resulting in less thermal NO_X.

LNBs can be used when indirect firing is employed. When implementing indirect firing with LNBs, other process improvements are often implemented, such as better process controls. According to Portland Cement Association (1998), 20%-30% NO_X reductions can be achieved from the use of indirect firing with LNBs and associated process modifications.

Combustion modifications are less successful at reducing NO_X emissions in thermal processing applications (like cement kilns) than in boilers for steam and/or power production. Chemical reactions producing cement clinker require high material and gas temperatures, and product quality also requires an oxidizing atmosphere in the combustion zone of a cement kiln. Excessively high temperatures in the burning zone pose equipment damage risk, while temperatures too low will no longer produce a salable product.

NO_X emissions can also be affected by kiln feed chemical characteristics, feed chemical uniformity, and specific fuel consumption. As stated by EPA’s NO_X Alternative Control Technique Document for the Cement Manufacturing Industry (USEPA, 1994), "For any given type of kiln, the amount of NO_X formed is directly related to the amount of energy consumed in the cement-making process. Thus, measures that improve the energy efficiency of this process should reduce NO_X emissions in terms of lb of NO_X / ton of product."

Following are some of the more common process modifications that have been made to reduce NO_X emissions from cement kilns (NESCAUM, 2001):

- Changing fuel (e.g. natural gas to coal firing).
- Improving kiln feed chemical uniformity, for more stable kiln operations:
    - Modifications to quarry operations,
    - Raw material blending facilities, and
    - On-line analytical control systems for raw material proportioning (e.g. kiln feed blending systems).
- Modifications to improve thermal efficiency, including:
    - Reducing excess air infiltration,
    - Increasing efficiency of cyclones in preheater kilns,
    - Reducing the amount of moisture in slurry (wet process kilns only),
    - Revising kiln chain systems in long wet or long dry kilns,
    - Modifying or replacing clinker coolers to improve heat recovery and cooler efficiency,
    - Initiating operator training programs, and

  - Returning as much cement kiln dust (CKD) as possible to the kiln system (without adversely affecting product quality).
- Installing or upgrading kiln system sensors and instrumentation.
- Installing or upgrading computer controls of kiln systems to stabilize kiln operation and avoid burning zone temperature variations.

According to Young and von Seebach (1999), industry data and experience show that control of burning zone temperature is the primary process control method applicable to lowering thermal NO_X formation. Process modifications that allow better control of the kiln burning zone temperature will result in reducing thermal NO_X formation and minimizing NO_X spikes. Stable kiln operation, through feed chemical uniformity, results in overall NO_X reductions of 10% - 15%, while poor kiln feed chemical uniformity results in overfiring the kiln, and higher NO_X emissions.

Fuel Switching

Switching to a lower-nitrogen fuel in a precalciner may reduce NO_X emissions, but the nitrogen content of the fuel burned in the burning zone has little or no effect on NO_X generation. Generally, no relationship has been found between fuel nitrogen content and the NO_X emissions from a cement kiln (Miller and Egelov, 1980).

Process Optimization and Automated Control

Process optimization is a common method for reducing NO_X emissions from cement kilns. In principle, any effort that reduces the amount of fuel being fired to produce clinker will result in a reduction in NO_X generation. In practice, process optimization often entails the use of advanced computer controls and instrumentation. Many of the primary NO_X control technologies described are implemented along with process optimization to take advantage of their combined effects and to improve overall facility operation. NO_X reductions reported in this Chapter are generally attributed to the changed combustion process (for example, mid-kiln firing). Combined reductions reported in a case study (NESCAUM, 2001) equivalent to 55% reduction in average NO_X emissions - from 845 lb/hr to 383 lb/hr – were achieved largely by reducing the variability of the process with a computer-automated optimization system. Mid-kiln firing provided additional NO_X reduction for an overall NO_X emission reduction of 59% from controls.

Flue Gas Recirculation

Flue gas recirculation (FGR) or water/steam injection into the main flame to reduce flame temperatures and NO_X formation is not a viable method of reducing NO_X in a cement kiln burning zone. FGR's effectiveness relies on cooling the flame and generating an oxygen deficient (reducing) atmosphere for combustion to reduce NO_X formation, conditions that are not compatible with cement kiln operation. High flame temperature and an oxidizing atmosphere are process requirements to produce a quality clinker product.

Indirect Firing

Conversion from a direct coal firing system to an indirect firing system kiln with a low NO_X burner may result in NO_X reductions ranging from 0% to about 20% (Kupper et al., 1990; Schrsemli, 1990). Incorrect use of multi-channel (low NO_X) burners can increase NO_X rather than reduce NO_X, and it has been found (Hansen, 1985) that less excess air in the kiln combustion gases results in less NO formation at the same burning zone temperature. NO_X reductions of 15% were reported.

Low-NO_X Burners

LNBs have been successfully used in the primary burn zone and especially in the precalciner kilns.

Secondary combustion zones have proven effective at reducing NO_X emissions in cement kilns. In long kilns, secondary combustion can be partly accomplished by mid-kiln injection of fuel (less than 20% of kiln fuel). NO_X emissions are reduced because less fuel is burned in the high temperature environment of the burning zone. Another NO_X reducing technique is the use of fuel in the riser duct of preheater kilns, although, because of high prevailing temperatures, such reductions do not always occur. With precalciner kilns, which employ a secondary combustion zone at a much lower temperature than the burning zone, typically 60% of the fuel is burned in the precalciner, with the combustion air coming directly from the clinker cooler, and NO_X emissions for these kilns are less than from long wet, long dry, or preheater kiln systems because 60% of the total fuel requirement is burned under lower temperature conditions where negligible amounts of thermal NO_X are formed. Furthermore, precalciner kilns have the potential for staged combustion as a NO_X control technique. All major equipment suppliers offer "low-NO_X" precalciner designs. Fuel burned in a sub-stoichiometric O2 environment creates a strongly reducing atmosphere (relatively high concentrations of CO) that inhibits formation of fuel NO_X and destroys a portion of the NO_X formed in the kiln burning zone. Additional tertiary combustion air is added later to complete combustion of the fuel.

Staged combustion has become a well-known method for reducing NO_X emissions from cement plants, but as NO_X and CO emissions limits become more stringent, control via fuel and air staging are coming under reconsideration. Low- NO_X calciners combine high temperature combustion and firing under reducing conditions without staging fuel/air.

Low-NO_X Precalciners

Precalciner kilns can employ LNBs because the temperature in the precalciner can be low enough to reduce thermal NO_X but still be effective in heating the limestone.

Since roughly 60% of the fuel burned in a precalciner kiln is fired in the precalciner, NO_X reductions can be substantial. All new precalciner kilns are equipped with low-NO_X burners in the precalciner. Low-NO_X precalciners have been shown to reduce NO_X by 30%-40% compared to conventional precalciners (Young and von Seebach, 1998). This reduction is from the precalciner-generated NO_X, not for the entire kiln.

Several precalciner kilns in the U.S. have recently been retrofitted with these "two-NO_X" calciners, and several new kiln lines have been installed using low-NO_X precalciner technology. Operating experience indicates a noticeable reduction in NO_X per ton of clinker. Industry reports place the NO_X reduction potential of staged combustion with a low-NO_X precalciner at 30% - 40% when compared to a conventional precalciner kiln system.

Low-NO_X precalciner is a proven way to reduce NO_X emissions in a cement-making system, and all new cement-making systems are expected to be built with it. They come in two types, “in-line”, commonly used with “normal” fuels (e.g. coal, oil, gas), or “separate-line”, selected for difficult-to-burn fuels (e.g. petroleum coke and anthracite) because its high oxygen atmosphere ensures improved fuel burnout. In-line calciners have lower specific NO_X emissions than separate-line ones, but both are capable of meeting current CO/NO_X emission standards for any combination of fuel and feed, and both are dependent on the presence of strong reduction and oxidation zones.

CemStar

Another approach that has been proven effective in reducing NO_X is the patented CemStar process, originally developed and sold as a method to increase production of clinker from existing kilns while minimizing capital expenditures (Young, 1995; Young, 1996). In the CemStar process, steel or blast furnace slag is introduced as feed material into the kiln. The slag is generally added at the inlet to the rotary kiln (typically after the precalciner or preheater), regardless of kiln type. Unlike normal cement materials, which require significant processing to achieve adequate grain size, the slag need only be crushed to 3/4 to 1-1/2 inch pieces. Minimal processing is necessary because the slag has a low melting temperature and its chemical nature is very similar to the desired clinker. Minimal slag processing permits the equipment for the CemStar to be inexpensive and also reduces energy consumption per unit of clinker produced. Moreover, the CemStar process can be implemented on a kiln quickly with minimal impact to facility operations. The equipment needed is mostly material handling equipment.

The CemStar approach has many advantages: energy input can be reduced, NO_X emissions (both lbs/hr and lbs/ton of clinker) can be reduced, and kiln capacity can be increased. Since the steel slag more closely resembles the desired kiln product than do the normal raw materials, kilns with CemStar require less intense firing and allow for a significant reduction of peak burn-zone temperature. The lower burn zone temperature results in less thermal NO_X generation. NO_X reduction may be expected to be in the range of 20% or more for most kilns. If initial, uncontrolled NO_X is high due to thermal NO_X, CemStar is likely to provide reductions on the order of 40%-50%. Results of controlled testing of CemStar with baseline conditions resulted in 20% reduction in NO_X, corresponding with a reduction in average burn-zone temperature of over 200°F. Kiln capacity is increased because each ton of steel slag added to the kiln results in about a ton of additional production, though the precise amount of additional kiln production is dependent on the mineral characteristics of the local raw material. This capacity increase is the reason that many facility owners may initially choose to use CemStar.

TXI, the developer of CemStar, reports that more than 10 plants are currently equipped with the technology. NESCAUM (2001) discusses one application of CemStar on a long-wet process kiln.

Mid-Kiln Firing

Mid-kiln firing entails injecting a fuel, usually tires, mid-way through long dry and long wet kilns. This method has been shown to reduce NO_X by about 30% with mid-kiln heat input comprising about 20% of the total heat input (Portland Cement Association, 1998). Results of tests of mid-kiln firing on several kilns are summarized in Table 2 (NESCAUM,2001). The average NO_X reduction for these kilns is about 27%. Mid-kiln firing reduces the heat needed, and therefore the thermal NO_X produced in the primary burn zone. Fuel NO_X will also be reduced because tires and other mid-kiln fuels have low nitrogen contents. Nitrogen content in tires is roughly one fifth that of coal on a mass basis, while heating value on a mass basis is similar (Schrama et al., 1995; Stillwater and Wahlquist, 1998). Coal can be used as a mid-kiln firing fuel, but tires are preferable because they provide a revenue source when kiln operators are paid a tipping fee for taking whole tires. Other revenue-generating fuels could potentially be used as well.

Table IV-2 NO_X Reduction at Cement Kilns Using Mid-Kiln Technology (NESCAUM,2001)

Initial NO_X (ppm)	936	1372	1342	1359	565	513
Final NO_X (ppm)	790	994	600	883	488	456
% Reduction	16%	28%	55%	35%	14%	11%

High-pressure air injection, mentioned in the previous section as a potential control for SO_2 emissions, was primarily developed as a NO_X reduction strategy (Hansen, 2002). The technique was designed for use with staged fuel combustion (mid-kiln firing) and mixing air. Mid-kiln firing with mixing air creates stratified thermal layers in the kiln, preventing immediate combustion of the mid-kiln fuel and lowering exit oxygen levels enough that additional CO is produced. Injecting high-pressure air into the kiln provides energy to mix the layers, lowering the main flame temperature and creating a reducing area between the fuel and air injection points, which encourages the destruction of NO_X. The technique has been shown to reduce NO_X by about 50%, while also reducing CO by 47% and SO_2 by 97%.

Biosolids Injection

Biosolids Injection (BSI) is a technology that was developed in the 1990's by the cement industry for NO_X reduction in precalciner and preheater kilns (Biggs, 1995). BSI adds dewatered sewage sludge to the mixing chamber of the precalciner. The dewatered biosolids provide a source of ammonia, producing an SNCR reaction to reduce NO_X. At a Mitsubishi Cement Kiln in California, BSI provided about 50% reduction in NO_X from about 250 ppm (at 12% oxygen) to 120-125 ppm (at 12% oxygen). BSI has the additional benefit of offering a potential revenue stream because many communities are willing to pay a tipping fee for accepting biosolids. BSI technology may require significant capital equipment expenditures, however. The material handling equipment needed and the moisture in the dewatered biosolids is sufficient to strain the capacity of the fans of many existing facilities. It appears that biosolids injection may be an effective approach for NO_X reduction, but it will depend on the specifics of the kiln.

Selective Non-catalytic Reduction

Selective Non-catalytic Reduction (SNCR) of NO_X is based on the injection of a reagent, typically NH3 or urea, into the kiln system at a location with an appropriate temperature window 1140 – 2010oF (870 - 1100°C). Some researchers have found that the most effective temperature range is narrower, about 1650 – 2000°F (900 - 1000°C). Temperature is critical because no catalyst is used. At temperatures too high, the reagents will form additional NO_X, and, at low temperatures, the reactions proceed slowly and promote the escape of substantial amounts of unreacted ammonia. Under optimum conditions about one mole of NH3 is required to reduce one mole of NO_X, but the amount of NH3 is always critically dependent on the reaction temperature. Ammonia slip, which increases rapidly when the molar ratio of NH3 to NO is above one, causes a detached plume and can increase opacity of the stack gases.

Preheater and precalciner kilns operate with kiln gas exit temperatures in the appropriate temperature range. SNCR systems have been used on some preheater kilns in Europe. For wet and long dry kilns, these temperatures exist midway through the kiln. Access to this area is possible only through ports in the kiln shell as used in mid-kiln firing or with scoops used to return cement kiln dust. Ammonia must be added continuously in a fixed molar ratio to NO_X in order to be effective and to minimize ammonia slip. Therefore, SNCR is not technically feasible at this time on long wet process or long dry process kilns.

SNCR has been tested in the U.S. on precalciner kilns and is planned for commercial use in other countries (Steuch et al., 1994; Sun et al., 1994). Experience is limited to only a few units worldwide, but some tests have reported significant reductions. Table 3 lists commercial installations of urea SNCR on precalciner kilns and the results of some demonstration programs. Effective operation of SNCR requires availability of a section of kiln with the proper temperature and residence time characteristics for good reduction. The specifics of the installation will determine the level of reduction that is possible. It is unlikely that SNCR can be used effectively on many long kilns (wet or dry) because of the need for access to the proper temperature region for injecting urea or ammonia reagent. However on some precalciner kilns the access to the proper temperature zone is good.

Although SNCR technology has the potential to offer significant reductions on some precalciner kilns and it is being used in numerous cement kilns in Europe, it has been tested in only one facility in the U.S.

Table IV-3 NO_X Reduction Performance of Urea SNCR on Precalciner Cement Kilns (NESCAUM, 2001)

Company / Location	Unit Type	Size (MMBtu/hr)	NO_X Baseline	Reduction (%)	NH_3 SLIP, (ppm)
Ash Grove Cement Seattle, WA (Demo)	Cement Kiln/ Precalciner	160 tons solids/hr	350-600 lb/hr	>80	< 10
Korean Cement Dong Yang Cement, Korea (Demo)	New Suspension Precalciner	na	1.27 lb/MMBtu	45	na
Taiwan Cement Units #3, #5, & #6	Cement Kiln/ Precalciner	260 697 658	1.29 lb/MMBtu 1.58 lb/MMBtu 0.92 lb/MMBtu	50 45 25	15 15 15
Wulfrath Cement Germany (Demo)	Cement Kiln	140	1000 mg/Nm^3 500 ppm	90	na

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) uses ammonia, in the presence of a catalyst (e.g. titanium dioxide; vanadium pentoxide), to selectively reduce NO_X emissions from exhaust gases. SCR has been extensively and quite successfully used in a very cost effective manner on coal- and gas-fired utility boilers, industrial boilers, gas turbines and internal combustion diesel engines in the U.S. Typically, anhydrous ammonia, usually diluted with air or steam is injected into hot flue gases, which then pass through a catalyst bed where NO_X is reduced to N_2 gas and water. The optimum temperature for SCR depends on the catalyst but is usually between 570 and 840^{o}F (300 and 450°C).

Exit gas temperatures from dust collectors on wet kilns, for long dry kilns, and for dust collectors in preheater kilns that use in-line raw mills for grinding and drying raw materials are relatively low and flue gases would have to be reheated before employing SCR. This technology so far has not been applied to the cement kilns but is being evaluated by some of the state air permitting agencies as Best Available Control Technology (BACT) for some of the new cement kilns being proposed in the U.S.

Combination of Technologies

It is not uncommon to combine combustion technologies with post-combustion technologies for other source types, and this could be done for cement kilns in some cases. It is also possible to combine multiple combustion technologies on cement kilns. For example, one of the case studies in *Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines; Technologies and Cost Effectiveness* (NESCAUM, 2001) combines indirect firing and mid-kiln firing to reduce NO_X by a combined amount approaching 50%. It is also reasonable to expect that technologies such as CemStar might be combined with a combustion technology such as mid-kiln firing to provide combined benefits, and it may be feasible to use SNCR or SCR in combination with other controls for cement kilns. The exact amount of reduction will depend upon the regulatory requirements and technical limitations. In some cases the NO_X reductions may not be additive.

4.3.3. $PM_{2.5}$ Controls

The particulate matter exiting the kiln system with the exhaust gases is relatively coarse, with most of the particuate matter having diameters greater than 10 microns, but the concentrations of particles in the exhaust can be several times higher than in a coal-fired power plant. Particulate control devices for cement plants must be able to clean gases with fairly high dust loading.

As is the case for many other industrial sectors, the main control options for fine particles are baghouses (more formally known as Fabric Filters) and electrostatic precipitators (ESPs), described in Section 2.3.2 (EGUs). The following section describes some issues specifically related to cement kilns and the use of these devices, including a new filter system combining a baghouse and an ESP.

Cement kilns primarily utilize baghouses of the reverse-air and pulse-jet types. Both types are usually configured so that the bags can be cleaned during an “off-line” cycle, in which a section of the baghouse is closed off from the main exhaust flow for cleaning. This tends to reduce the need for a high-pressure pulse that causes additional wear on the filtration fabric, allows less time for particles to be collected in the hopper during its brief and frequent use, and requires additional power for operation. The choice between a reverse-air and pulse-jet system is generally made on the basis of the volume of exhaust and production from the kiln. In general, kilns producing less than 1650 stpd (with exhaust volumes below 128,000 acfm) are most efficiently served by a jet-pulse system (D’Lima and Pirwitz, 2000). The decision is more complex for kilns up to 6600 stpd (with exhaust volumes up to 853,000 acfm), for which initial equipment costs are similar but lifetime operation costs are more complicated. D’Lima and Pirwitz (2000) concluded that jet-pulse systems are appropriate for the smallest kilns and reverse-air systems are preferred for all larger kilns, even though they may have higher installation costs for kilns of more modest size.

Corrosion in baghouses has been an important topic in the cement kiln control literature (Jansen and Mazeika, 2003; Biege and Shenk, 2001). A 2002 EPA rule [40 CFR Part 63 Subpart LLL (2002)] requires gas temperatures entering the control device not to exceed 400°F (205°C) in order to control dioxin emissions. Water sprays are usually utilized to control exhaust temperature, but adding water vapor to the exhaust stream while lowering exhaust temperature brings the gas near the dew point of some corrosive components. Corrosion issues can be addressed in a number of ways, but all add cost to the use of the control system.

The three components of corrosion are corrosive gases, condensation, and a corrodible surface; reducing any component will reduce corrosion. Corrosive gases can be reduced in a roller mill; this may be one of the most effective methods to reduce corrosion. Many of the gases are absorbed by the feed during the milling process and are therefore not available to form acids in the exhaust. Changing the feed may also reduce some of the acidic gases. Condensation is prevented most easily by keeping the exhaust temperature hot; however, when this is not allowed, it is best to maintain the exhaust temperature as high as possible, preventing drops which may allow acidic condensation. Insulating surfaces and carefully sealing unused sections of the control device can prevent exhaust from leaking into cool areas where it can condense and cause corrosion. Finally, corrosive-resistant materials and acid-resistant coatings can help reduce corrosion in control equipment.

Instead of a baghouse or an ESP, a combined system has become available, utilizing components of both systems. Whereas an in-series, hybrid system has the ESP and baghouse systems in independent compartments, this technology is described as “an ESP in which every other row of discharge electrodes is replaced by a single row of filter bags” (Gebert et al., 2003). In this new system, where the filter bags are directly adjacent or parallel to the ESP electrical field, ESP zones alternate with filter zones, allowing primary collection by the ESP and pre-ionization of the remaining dust for collection on the filter bags. A highly efficient expanded polytetrafluoroethylene (ePTFE) membrane is used as the filter fabric, which can remove an order of magnitude more of fine particulate than ordinary bags. During a pilot system test of a 225 m3/min (9000 acfm) slipstream from a coal-fired power plant in South Dakota, greater than 99.99% removal efficiency was shown. With the ESP fully engaged, bag cleaning was required only every 300 minutes, compared to every fifteen minutes when the ESP was not used. This system has been utilized in full-scale commercial operation at a cement kiln in Italy since September 2002, capturing dust from the cement kiln, raw mill and clicker cooler. Another similar filter is in operation since October 2002 at the coal-fired power plant in South Dakota mentioned above.

The synergy between the two technologies enables operation of the filter bags at high air-to-cloth (A/C) ratios, and, combined with the new compact size for filters, provides the following benefits for a cement plant:

- Ability to reach high control efficiencies in all operation modes,
- Continuous stable operation, and

- Lower operating costs, due to reduced number of system components.

4.3.4. VOC Controls

No controls which specifically targeted VOCs were identified for cement kilns.

4.4. Costs and Availability

4.4.1. Sulfur Dioxide Control

The SO_x control techniques applicable to the cement industry and the assumed SO_x reductions that the various control technologies can achieve are summarized in Table IV-4.

The achievable SO_x reductions vary greatly. Even when the same control technology is applied to kilns of the same type, the removal efficiency will depend on kiln operating parameters, uncontrolled SO_x emissions rate, and many other site-specific factors.

Wet-limestone scrubbers and spray dryers can be used as secondary control devices to reduce SO_2 emissions from a cement kiln.

Capital and operating costs for spray dryers and wet scrubbers as applied to cement kilns were computed by Young (2002). Both technologies were assumed to be installed *after* the existing APCD, which would allow the CKD to be recycled back to the kiln. If CKD is not recycled, there is a negative impact on the operating cost of the plant. Table IV-5 summarizes the capital and operating costs in terms of $ per ton of clinker produced for different types of kilns. The capital and operating costs of the spray dryer include a baghouse, new stack and new ID (induced draft) fan. The capital and operating costs for the wet scrubber include new fans and a new stack as well as a new wastewater treatment facility.

Another installation was made in 1998 at Castle Cement’s Ribblesdale (UK) facility (Castle Cement, 2004). Scrubber installation cost £5 million and operational costs are about £750,000 annually. Emissions from one unit were reduced by 90%.

Table IV-4 SO_2 Control Techniques Applicable to Cement Kilns (Miller, 2001)

SO_2 reduction technique	Applicable to kiln type				Range of removal efficiency
	Long wet	Long dry	Preheater	Precalciner	
Process alterations	x	x	x	x	0-100%
Dry reagent injection			x	x	25-85%
Hot meal injection			x	x	0-30%
Spray dryer absorber		x	x	x	50-90%
Wet SO_2 scrubber	x	x	x	x	80-95%

Table IV-5 Capital and operating costs of spray dryers and wet scrubbers applied to cement kilns (Young, 2002)

		Spray Dryer		Wet Scrubber	
	Clinker capacity, tpy	Capital Cost, $/ton clinker	Annual Operating Cost, $/ton clinker	Capital Cost, $/ton clinker	Annual Operating Cost, $/ton clinker
Small wet kiln	300,000	$54.67	$20.02	$47.00	$22.59
Medium wet kiln	600,000	$38.17	$14.09	$32.67	$17.58
Medium dry kiln	600,000	$39.75	$14.79	$31.83	$17.21
Large dry kiln	1,200,000	$23.17	$9.43	$20.42	$13.05
Medium preheater kiln	600,000	$17.92	$7.51	$15.83	$9.85
Medium precalciner kiln w/ bypass	600,000	$25.17	$10.20	$19.33	$11.42
Large preheater kiln	1,200,000	$10.96	$5.41	$10.83	$8.14

An alternative secondary control device for SO_2 was designed and applied as part of U.S. Department of Energy's Clean Coal Technology program. A co-project of Passamaquoddy Technology and Dragon Products Company in Thomaston, ME, the Passamaquoddy Technology Recovery Scrubber^{TM} (Recovery Scrubber^{TM}) utilizes cement-kiln dust as a reagent for removing SO_2 from kiln exhaust gases (USDOE, 2001). Waste heat from the kiln is used to crystallize K_2SO_4, a saleable, fertilizer-grade by-product. The remaining cement kiln dust is returned to the kiln, significantly reducing particulate emissions, eliminating the need for removal of the dust to a landfill, and reducing the requirement for raw materials by about 10 percent. Sulfur dioxide was reduced by 82 to 98.5%, depending on scrubber inlet SO_2 rates. In addition, NO_X was reduced by about 25% and VOCs by 70%. Capital costs for a Recovery Scrubber^{TM} were estimated at about \$10.5 million in 1996 dollars, with operating and maintenance costs of \$150,000 per year and electricity costs of \$350,000 per year (787 kW at \$0.06/kW).

4.4.2. Nitrogen Oxides Control

Table 6 presents a summary of NO_X controls that are feasible for cement kilns, the range of potential NO_X reductions from applying these controls, the cost effectiveness of the controls, and effects on other emissions when using these controls.

Table IV-6 Summary of the Feasibility of NO_X Controls for Cement Kilns

NO_X Reduction Technique	**Technical Feasibility**	**NO_X Reduction Potential (%)[1]**	**Cost Effectiveness ($/ton NO_X removed)**	**Effect on Other Emissions**	**Reference**
Process Modifications	In full-scale use	0 - 30 [15]	3,100 - 8,800	Unknown	16
Low NO_X Burners w/ Indirect Firing	In full-scale use	0 – 20 [10]	5,800 - 8,100	Unknown	16
Low NO_X Burners w/ Indirect Firing and Mid-kiln Tire Injection	In full-scale use	[49]	1 - 1,800	Unknown	17
Mid-Kiln Injection of Fuel, Riser Duct Firing Calciners	In full-scale use	0 – 30 [15]	5,100 -11,500	May increase CO, SO; hydrocarbon emission	16
CemStar	Wet kilns	20 - 50 [20]	0-600	Unknown	17
Low NO_X Precalciner	Have been installed on several full-scale kilns - Offered by several different vendors.	30 – 40 [30]	2,700 - 3,600	May Increase emissions CO, S02, and/ or hydrocarbons	16
SNCR	May be applicable only on preheater or precalciner kilns - limited data	15 – 65 [45]	900 - 1,200	May Increase emissions CO, NH3, and NH4+salts (detached plume)	17
Biosolids Injection	May be applicable only on preheater or precalciner kilns - limited data	[50]	100-1,800	May Increase emissions CO, NH3, and NH4+salts (detached plume	17

[1] Values in brackets are the assumed NO_X reductions used to calculate the estimated cost effectiveness of each Technology.

4.4.3. $PM_{2.5}$ Control

As discussed above, control of particulate matter in cement kilns is accomplished using baghouses and electrostatic precipitators. These processes are also used in electric utility generating units and industrial boilers. Capital and operating costs for fabric filters and ESPs as applied to cement kilns were computed by Young (2002) and are summarized in Table IV-7. The costs include the addition of a new fan.

Table IV-7 Capital and operating costs of baghouses and ESPs applied to cement kilns (Young, 2002)

		New ESP		New baghouse	
	Clinker capacity, tpy	**Capital Cost, $/ton clinker**	**Annual Operating Cost, $/ton clinker**	**Capital Cost, $/ton clinker**	**Annual Operating Cost, $/ton clinker**
Small wet kiln	300,000	$14.00	$3.35	$16.67	$3.81
Medium wet kiln	600,000	$11.00	$2.49	$13.00	$2.92
Medium dry kiln	600,000	$10.50	$2.54	$12.00	$2.78
Large dry kiln	1,200,000	$7.33	$1.51	$8.67	$1.96
Medium preheater kiln	600,000	$4.33	$1.03	$5.17	$1.17
Medium precalciner kiln w/ bypass	600,000	$5.33	$1.42	$6.33	$1.53
Large preheater kiln	1,200,000	$3.33	$0.74	$4.00	$0.90

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5. KRAFT PULP MILLS

5.1. Description of pulp and paper processes

Kraft pulping processes consists of wood preparation, pulping, pulp washing, oxygen delignification and/or bleaching of pulp and chemical recovery as illustrated in Figure V-1. Beginning with wood preparation, logs are debarked, ground into wood chips, and then screened to remove chips of unacceptable sizes. During the pulping process, the wood chips enter the digester where they are cooked with liquor and broken down into a pulp slurry. The pulp slurry is transferred to a blow tank while the spent liquor is sent to a flash tank. The pulp slurry then enters the pulp washing process where knots, shives, and short fibers are removed, spent cooking chemicals are recovered from the pulp slurry, and the pulp slurry is thickened for later processes. Next, the pulp enters the oxygen delignification process where the lignin content of the pulp is reduced to increase brightness of the pulp. The brightness of the pulp is further enhanced by bleaching, a multi step process that removes residual lignin by using chemicals to oxidize and dissolve the lignin compounds. Lastly, the chemical recovery process recovers the spent cooking liquor using the following methods: evaporation to reduce water content in spent liquor, combustion of concentrated spent liquor, and recovery of chemicals from

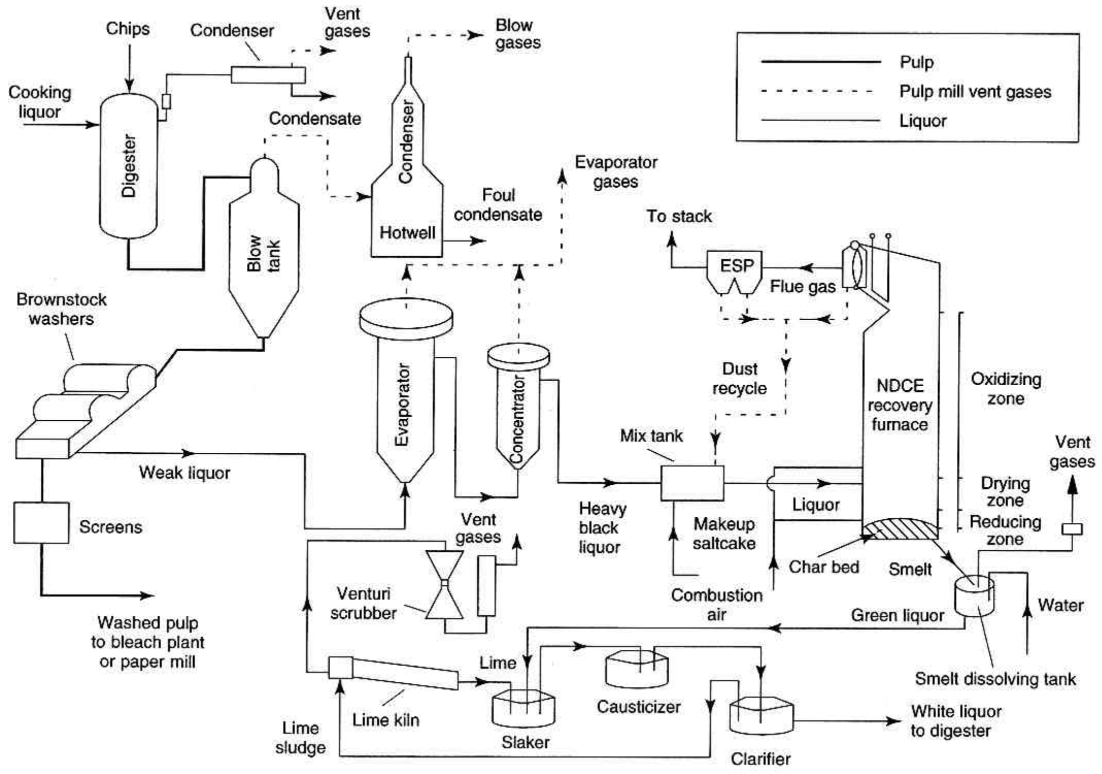

Figure 1. Schematic of the Kraft Pulping and Recovery Process (Someshwar and Pinkerton, 2000).

combustion products. The regeneration of lime, which is used for recovering sodium, is an additional step of the kraft chemical recovery process not found in the acid sulfite, mechanical, or semi chemical processes.

Acid Sulfite and semi chemical processes are very similar to the kraft process, however, the acid sulfite process differs from the kraft process in the type of cooking liquor used and the semi chemical process differs from the kraft process in the use of lower temperatures, more dilute cooking liquor or shorter cooking time, and mechanical disintegration. Mechanical pulping uses high-energy refining systems to produce pulp from chips and bleaching agents are used to decolorize lignin instead of removing lignin. (Someshwar and Pinkerton, 2000; Pinkerton, 2000).

5.2. Review of BART-Eligible Pulp and Paper facilities in the MANE-VU Region

There are 10 facilities with BART-Eligible industrial boilers in the MANE-VU region. Table III-2 contains a list of these sources based on a previous NESCAUM report (2003) and follow-up review by state permitting authorities. [7] *[Editor's note: additional facilities may be added after NY and PA have completed their inventory].*

Table V-1 BART-eligible pulp and paper facilities.

State	Company/Facility	City/Town	Category
Maryland	WESTVACO FINE PAPERS	Luke	kraft pulp
Maine	Domtar - Pulp & Paper	Baileyville	kraft pulp
Maine	Fort James - OldTown	Old Town	kraft pulp
Maine	IP Androscoggin	Jay	kraft pulp
Maine	Lincoln Pulp and Paper	Lincoln	kraft pulp
Maine	Madison Paper	Madison	kraft pulp
Maine	Mead WestVaco	Rumford	kraft pulp
Maine	SD Warren - Somerset	Skowhegan	kraft pulp
Maine	SD Warren Co.	Westbrook	kraft pulp
New Hampshire	Pulp & Paper Mills (33007-00001-11)	Berlin	kraft pulp

5.3. Available Control Technologies

The pulp and paper production, consisting of chemical, mechanical, and semi chemical processes, has a number of potential sources of SO_x, NO_X, particulates, and VOC emissions (Pinkerton, 2000). The major chemical wood pulping processes are kraft, acid sulfite, and semi chemical pulping. Kraft pulping accounts for 80% of the

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[7] NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and any identified sources are contained here and in the final list in Appendix A.

pulp produced in the U.S, mechanical and semi chemical pulping, for 10% and 6%, respectively and sulfite or soda chemical process accounts for the remaining pulping capacity (Someshwar and Pinkerton, 2000).

A variety of technologies exist for controlling emissions from pulp and paper facilities. Secondary control devices can be helpful in reducing emissions, and a number of them are available. Many facilities have found that significant emissions reductions can be achieved through process changes at the facility. Both secondary controls and process changes are discussed below, grouped by their targeted pollutant. When additional emissions reductions are possible, they are noted with the main (or targeted) pollutant. The sections below will describe the potential sources of significant SOx, NO_X, particulates, and VOC emissions in the major pulping processes and the measures used to control them.

5.3.1. SO_2 Controls

In a kraft mill, SO_2 is a product of the incineration of black liquor in the recovery furnace; black liquor is made up of 3-5% sulfur by weight of dissolved solids. The majority of the sulfur exits the furnace in the smelt; however, typically less than 1% can be emitted as a gas or particulate, resulting in average SO_2 concentrations of 0-500 ppm in stack gases. Recovery furnace SO_2 emissions are a function of liquor properties such as sulfidity (sulfur-to-sodium ratio), heating value, and solids content; combustion air and liquor firing patterns; furnace design features; furnace load; auxiliary fuel use; and stack gas oxygen content. To reduce SO_2 emissions from the recovery furnace, the temperature in the lower furnace must be uniform. This has been achieved by optimizing liquor and combustion air properties and firing patterns. Reducing liquor sulfidity has also been used as a control strategy for SO_2 emissions. Flue gas desulfurization as an effective control strategy is uncertain due to the mostly low and unpredictable levels of SO_2 emitted.

In a lime kiln, SO_2 is produced from the combustion of fuel oil or non condensable gases (NCG). On average, lime kiln SO_2 emissions are very low due to the capture of SO_2 from the alkaline material inside the kiln and the venturi scrubber usually installed immediately after the kiln.

In semi chemical processes, only neutral sulfite semi chemical (NSSC) pulping emits SO_2 emissions as a result of the combustion of sulfur-containing semi chemical spent liquor in a fluidized bed combustor. Limited data shows an SO_2 emission factor for a fluidized bed combustor burning NSSC liquor as 1 lb SO_2/a.d. ton of pulp.

A major source of SO_2 in acid sulfite processes is from the digester and blow tank areas. During a hot blow, significant quantities of SO_2 can be released into the blow gases ranging from 10 to 70 pounds per ton of pulp. Using an alkaline solution to scrub the blow gases, 97% of SO_2 can be recovered and returned to the acid-preparation system. While this approach is possible using sodium and NH_3 bases, magnesium and calcium bases need slurry scrubbers deemed less practical. Scrubbing becomes impractical when during a cold blow, only 4 to 20 pounds SO_2 per pulp are released into the blow gases.

SO_2 can also escape from acid bisulfite washers and screens which can result in uncontrolled emissions generally ranging from 1 to 4 lb SO_2/ton pulp but can get up to as much as 16 lb SO_2/ton pulp. The gases emitted from the washers and screens are hooded and then directed to a direct-contact scrubber where the SO_2 is scrubbed from the gases. (Someshwar and Pinkerton, 2000; Pinkerton, 2000).

5.3.2. NO_X Controls

NO_X is produced from the incineration of black liquor in the kraft recovery furnace with black liquor containing 0.05% to 0.25% nitrogen by weight of liquor solids content. Normal NO_X emissions from kraft recovery furnaces are less than 100 ppm. NO_X emissions are mainly a result of fuel NO_X since the maximum temperature in the recovery furnace is approximately 2400^{o}F and the temperature required for formation of significant amounts of thermal NO_X is greater than 2800^{o}F. NCASI studied the origins of NO_X emissions from kraft recovery furnaces and concluded that the two most important factors affecting NO_X emissions, in order of importance, were the black liquor nitrogen content and excess oxygen in the zone where most of the liquor combustion occurs. Since it is difficult to alter the liquor N content, the best approach to minimizing NO_X in recovery furnaces is staged-air combustion. Currently, most recovery furnaces already optimally use staged combustion and emit less than 100ppm NO_X.

NO_X is produced in the kraft lime kiln from the combustion of fossil fuels, such as natural gas and residual fuel oil. Due to the design of the lime kiln, SNCRs and SCRs are not viable NO_X reduction techniques. Installing Low-NO_X Burners (LNBs) is also not a practical NO_X reduction technique according to a BACT analysis conducted on a new lime kiln in 1997. The installation of LNBs had a negative influence on the efficiency, energy usage, and calcining capacity of the lime kiln. Hence, like the recovery furnace, combustion modification such as decreasing excess air is the best way to reduce NO_X emissions. However, since the mechanisms of NO_X formation and NO_X emission reduction are not completely known, NO_X reduction strategies should be considered on a case-by-case basis.

Some NO_X emissions result from the burning of stripper off gases (SOGs) with significant ammonia and methanol content and combustion of NCG in the kiln, thermal oxidizer, or boiler. When SOGs containing methanol and ammonia are incinerated, the ammonia could potentially oxidize to produce NO_X. NH_3 will oxidize to NO_X when injected into gases above 2000^{o}F to 2200^{o}F, reduce NO_X to N_2 when gas temperatures range from about 1600^{o}F to 2200^{o}F, and remain as NH_3 in temperatures below 1600^{o}F. However, the degree of NH_3 conversion to NO_X and the expected baseline level of NO_X emissions from pulp process units burning NCG and SOGs are not known.

NO_X emissions are expected during combustion of liquor in recovery furnaces for both semi chemical and acid sulfite processes. (Pinkerton, 2000; Someshwar, 1999).

5.3.3. $PM_{2.5}$ Controls

Measurable particulate emissions sources in a kraft mill are recovery furnaces, smelt-dissolving tanks, and lime kilns while fugitive particulate emissions sources are coal piles, paved and unpaved roads, bulk material handling such as lime, limestone, or starch, and wood handling. Particulate emissions from recovery furnaces are controlled by ESPs with particulate removal efficiencies of 90% in older units and 99% in newer units. Demister pads, packed towers or venturi scrubbers are used to achieve particulate emissions control in smelt-dissolving tanks, and venturi scrubbers and ESPs are used for control in lime kilns. Controlled mean particulate emission factors from smelt dissolving tank vents and kraft lime kilns are 0.13 lb/ton black liquor solids and 1.82 lb/ton of reburned lime product, respectively. Fugitive emissions are controlled by wetting; using chemical agents, building enclosures, and windscreens; paving or wetting roads; and modifying handling equipment.

In semi chemical processes, particulate emissions only become a concern when recovery furnaces are used. These emissions are controlled by using ESPs, wet ESPs or venturi scrubbers. In acid sulfite processes, the burning of both ammonium and magnesium base liquors will result in the release of particulate matter in the form of ammonium salts and magnesium oxide, respectively. The ammonium salts are removed when the flue gas exiting the absorption unit enters a series of fabric mesh pads called "candles." The magnesium oxide particulates are removed using multiple cyclones, a series of 3 or 4 packed tower absorbers, and in addition, some mills use venturi scrubbers and/or a SO_2 scrubber. Controlled particulate emissions of ammonia salt particles are <0.5 gr/dscf @ 8% O2 and for magnesium oxide, 0.05 to 0.1 gr/dscf correct to 8% O2. (Someshwar and Pinkerton, 2000).

5.3.4. VOC Controls

VOC emissions sources in a kraft mill are recovery furnaces and lime kilns. In a recovery furnace, VOC emissions are produced from incomplete combustion or from the contact between the black liquor and flue gas where volatile material from the liquor can transfer to the flue gas. Factors that affect recovery-furnace VOC emissions are the level of excess air used and the degree of mixing achieved within the furnace. To lower recovery-furnace VOC emissions, the residence time, oxygen content, temperature, and level of turbulence in the furnace combustion zone must be increased. However, increasing these parameters will increase NO_X emissions.

VOC emissions from lime kilns are also produced from incomplete combustion. In addition, VOC emissions can be a result of VOCs entering the kiln with the liquid part of the lime mud and VOCs being present in the scrubber makeup water. These additional VOCs are then emitted into the flue gas when the lime mud is heated and the flue gas exiting the kiln strips the VOCs from the scrubber makeup water. VOC emissions from lime kilns tend to be small with the majority being methanol.

In semi chemical and acid sulfite pulping processes, VOC emissions are a product of incomplete combustion in the fluidized bed combustor or in a specialized recovery furnace. Semi chemical VOCs can also be introduced into the flue gas if flue gas comes in contact with pulping liquor. VOCs from both semi chemical and acid sulfite pulping processes can enter the flue gas if the flue gas is able to strip organic compounds such as methanol from the scrubber makeup water. According to limited data, VOC emissions can significantly be reduced by improving combustion conditions and controlling liquor firing.

Mechanical pulping processes only emit VOCs and steam into the atmosphere. The VOCs in wood are emitted with the steam when wood undergoes cooking and refining processes. A study conducted by NCASI showed that VOC emission rates were proportional to steam emission rates. This data suggests that in order to decrease VOC emissions, the temperature in the exhaust gas must be reduced below the boiling point of water. (Someshwar and Pinkerton, 2000; Pinkerton, 2000).

5.4. Costs and availability

According to John Pinkerton at the National Council of the Paper Industry for Air and Stream Improvement (NCASI) (Pinkerton, 2004), pulp and paper industry representatives have been working with several engineering firms to evaluate to assess the costs and emission reduction potential of SO_2 and NO_X control technologies. Many of the technologies are candidates for evaluation as part of a BART site-specific engineering analysis. Particulate matter (PM) control strategies were also evaluated by NASCI. Information on applicability and cost is summarized in Tables V-2 through V-5 for Kraft Recovery Furnaces, Lime Kilns, Wood and Wood/Gas boilers and Wood/Coal and Wood/Oil boilers.

Information on the technologies referenced in the tables was collected by NASCI based on installation of processes or evaluation of these processes as part of New Source Review (NSR) Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) analyses, state Reasonably Available Control Technology (RACT) evaluations in ozone non-attainment areas, the USEPA NO_X SIP Call, or for other reasons.

The range in costs and emission reductions reflects the fact that site-specific factors play a critical role in determining how cost-effective various technologies will be in practice. Existing facilities do not always adequate or appropriate space for new equipment, which adds uncertainty to the capital and operating cost, as well at to the achievable emissions reductions. Hence the range of costs cited in the tables.

Table V-2 Reduction of NO_X, SO_2 and PM in Kraft Recovery Furnaces (Pinkerton, 2004).

	SO_2	NO_X	PM
Factors affecting emissions	Type of furnace, operating practices, black liquor solids concentration.	Type of furnace, operating practices, nitrogen content of black liquor, black liquor solids concentration.	Type of furnace, ESP efficiency
Current Emission Levels	~0 to 300 ppm	40 to 130 ppm	0.01 – 0.1 gr/dscf
National Emission Standards	none	none	1978 NSPS, 2001 MACT Existing Source – 0.044 gr/dscf. New source MACT is 0.015 gr/dscf
Recent BACT Determinations	50 to 300 ppm	75 to 150 ppm	0.021 to 0.044 gr/dscf
Current Installed End of Pipe Control Technologies	none	none	ESPs
Control Options	Optimize, on site-specific basis, liquor solids and operating practices; install SO_2 scrubber	Staged combustion practices (very site-specific)	Larger ESPs
Applicability of Control Option and Potential Emission Reductions	Scrubbing possible on some units to reduce SO_2 to as low as 10 ppm. Some units have emissions this low or lower at present.	SNCR and SCR not demonstrated as technically feasible.	Larger ESP possible on some units, although retrofit costs highly site-specific. Depending on current ESP design and condition, replacement or expansion of existing ESP can be considered
Cost of Option	Capital $8 million (1.7 MMlb/day BLS DCE unit; $12.8 million (3.7 MMlb/day BLS NDCE unit); Operating costs of $1.1 to $1.3 million (1.7 MMlb/day unit), or $1.6 to 1.8 million/yr (3.7 MMlb/day unit). Lower operating costs are for achieving 50 ppm; higher for achieving 10 ppm. Costs are very site-specific.		Replacement of ESP to achieve 0.015 gr/dscf PM emissions: for a 3.7 MMlb BLS/day NDCE furnace - Capital $29.3 million; operating $1.9 million/yr; for a 1.7 MMlb BLS/day DCE unit: $18.4 million capital; $1.2 million/yr operating. Costs are very site-specific.

Table V-3 Reduction of NO_X, SO_2 and PM in Lime Kilns (Pinkerton, 2004).

	SO_2	NO_X	PM
Factors affecting emissions	Emissions are minimal due to alkaline nature of lime in kiln	Type of fuel (gas vs. oil), operating temperatures, nitrogen content of oil and oxygen availability in flame zone, burning NCGs	Type of control device and control device efficiency
Current Emission Levels	~0 to 20 ppm	0.05 to 0.4 lb/10^6 Btu heat input	0.01 – 0.2 gr/dscf
National Emission Standards	none	none	1978 NSPS – 0.067/0.13 gr/dscf (gas/oil); 2001 MACT Existing Source – 0.064 gr/dscf. New source MACT is 0.01 gr/dscf
Recent BACT Determinations	30 to 80 ppm	100 to 220 ppm	0.015 to 0.13 gr/dscf
Current Installed Control Technologies	none	none	Wet scrubbers, ESPs
Control Options	Wet scrubber with supplemental caustic control	none	Replace wet scrubber with ESP
Applicability of Control Option and Potential Emission Reductions			ESPs have higher removal efficiencies than wet scrubbers; all lime kilns installed in last ten years have ESPs rather than scrubbers. Average ESP emissions are on the order of 0.01 gr/dscf.
Cost of Option			Replacement of scrubber with ESP to achieve 0.01 gr/dscf PM emissions: for a 270 ton CaO/day kiln - $3.4 million; operating $0.2 million/yr.

Table V-4 Reduction of NO_X, SO_2 and PM in Wood and Wood/Gas-Fired Boilers (Pinkerton, 2004).

	SO_2	NO_X	PM
Factors affecting emissions	Sulfur content of wood minimal	Type of boiler, wood nitrogen and moisture content, operating practices	Wood ash content, control device efficiency, operating practices
Current Emission Levels	0.025 lb/10^6 Btu is AP-42 emission factor	0.15 to 0.3 lb/10^6 Btu	0.05 to 0.6 lb/10^6 Btu
National Emission Standards	none	Subpart Db NSPS- none if gas capacity factor limited to 10% or less; gas capacity factor over 10% - 0.3 lb/10^6 BTU except 0.2 lb/10^6 BTU for new/reconstructed units after 1997	Subpart D, Db, Dc NSPS – 0.1 lb/10^6 Btu; final boiler MACT limit – 0.07 lb/10^6 Btu for existing, 0.025 lb/10^6 Btu for new solid fuel boilers
Recent BACT Determinations	0.01 to 0.045 lb/10^6 Btu	0.25 to 0.3 lb/10^6 Btu	0.02 to 0.1 lb/10^6 Btu
Current Installed Control Technologies	none	SNCR for base loaded boilers	Mechanical collectors, wet scrubbers, gravel bed filters, ESPs, fabric filters
Control Options	none	SNCR for base loaded boilers	Replace wet scrubber with an ESP
Applicability of Control Option and Potential Emission Reductions		SNCR has been installed on a few new wood boilers to achieve NO_X reductions in the 20 to 50% range. SNCR not appropriate for boilers with high load swings. SCR has not been applied.	ESPs in use on many wood boilers. Emission levels as low as 0.02 lb/10^6 Btu possible. Retrofit costs highly site-specific.
Cost of Option		Installing SNCR to achieve 0.15 lb/10^6 Btu NO_X emissions on a 300,000 pph wood boiler: Capital $1.5 million; operating $0.1 million/yr	Installing ESP to achieve 0.04 lb/10^6 Btu PM emissions on a 300,000 pph wood boiler: Capital $21.3 million; operating $1.4 million/yr. Costs to achieve a 0.065 lb/10^6 standard range from $18.7 million to $5.1 capital, $900,000 to $77,000 operating—highly site-specific
Control Option		Methane de-NO_X Reburn	
Applicability of Control Option and Potential Emission Reductions		Has been applied to one boiler burning wood, gas, and sludge. Involves natural gas injection and flue gas recirculation in stoker-type boilers only. NO_X reduction reported to be 40 to 50% in boilers burning high nitrogen content fuels.	
Cost of Option		Capital costs unavailable. Lower operating costs claimed due to increased boiler efficiency.	

Table V-5 Reduction of NO_X, SO_2 and PM in Wood/Coal and Wood/Oil-Fired Boilers (Pinkerton, 2004).

	SO_2	NO_X	PM
Factors affecting emissions	Coal/oil sulfur content, ratio of wood to coal/oil	Type of boiler, coal/oil nitrogen content, wood nitrogen and moisture content, ratio of wood to coal/oil	Wood/coal/oil ash content, oil S level, control device efficiency
Current Emission Levels	Depends on fuel mix and coal/oil S content	0.25 to 0.7 lb/10^6 Btu	0.03 to 0.3 lb/10^6 Btu
National Emission Standards	Subpart D NSPS limits SO_2 to 1.2/0.8 lb/10^6 Btu (coal/oil); Subparts Db and Dc require percent reduction (except for very small boilers or those with low coal capacity factors) or use of very low S oil	Revised 1998 NSPS has 0.2 lb/10^6 Btu limit for boilers over 100 x 10^6 Btu/hr for all fossil fuels, limit applies if annual fossil fuel capacity factor exceeds 10%. Prior NO_X limits were fuel-type dependent and ranged from 0.3 to 0.7 lb/10^6 Btu for oil and coal.	Subpart D, Db, Dc NSPS – 0.1 lb/10^6 Btu unless annual wood capacity factor is less than 10%; final boiler MACT limit – 0.07 lb/10^6 Btu for existing, 0.025 lb/10^6 Btu for new solid fuel boilers
Recent BACT Determinations	0.3 to 0.5 lb/10^6 Btu	0.3 to 0.7 lb/10^6 Btu	0.03 to 0.1 lb/10^6 Btu
Current Installed Control Technologies	Alkaline scrubbing	SNCR for base loaded boilers, FGR, Low NO_X burners	Mechanical collectors, wet scrubbers, gravel bed filters, ESPs, fabric filters
Control Options	Alkaline scrubbing	Low NO_X burners	Replace wet scrubber with an ESP
Applicability of Control Option and Potential Emission Reductions	Generally applicable; reductions up to 90% possible	This option only available to pulverized coal/stoker boilers or oil/wood units. NO_X reductions in the 20 to 50% range can be achieved for the coal or wood contribution to total NO_X.	ESPs in use on many wood/coal and wood/oil boilers. Emission levels as low as 0.02 lb/10^6 Btu possible. Retrofit costs highly site-specific.
Cost of Option	Capital cost for scrubber installation following and ESP on a 300,000 pph wood/coal boiler - $7.4 to 8.2 million. Annual operating cost for 50% removal $1.0 million, $1.5 to 2.0 million for 90% removal.	Installing low NO_X burners to achieve a 0.3 lb/10^6 Btu level on a 300,000 pph wood/pulverized coal boiler: Capital $2.9 million; operating $0.15 million/yr. Retrofit costs site-specific.	Remove existing control device and install ESP to achieve 0.04 lb/10^6 Btu PM emissions on a 300,000 pph wood/coal boiler: Capital $5.1 to 20.5 million; operating $70,000 to 1.2 million/yr. Retrofit costs site-specific.
Control Option	Lower S content coal/oil; gas	SNCR for base loaded boilers	
Applicability of Control Option and Potential Emission Reductions	Generally applicable	Limited NO_X reductions possible, in the 20 to 40% range. SNCR not appropriate for boilers with high load swings.	
Cost of Option	Dependent on fuel prices	Capital cost of $1.5 million for a 300,000 pph wood boiler with limited coal or oil use; operating cost of $0.15 million/yr. Retrofit costs site-specific.	

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6. CONCLUSION

As states prepare to conduct BART determinations for their eligible facilities, preliminary information has been collected on the availability, costs and efficiencies of a variety of technology options. Depending on the requirements contained in the final BART regulations, anticipated for April 2005, states will have to decide what level of cost and what degree of visibility improvement is considered reasonable before completing BART determinations. MANE-VU has reviewed technology options for four of the 26 BART-eligible source categories. For EGUs, industrial boilers, cement plants and paper and pulp facilities, we present typical control options and costs. Facility specific reviews will be needed to determine specific controls and costs for each BART-Eligible source in the region.

6.1. EGUs

The presumptive level of control for previously uncontrolled EGU boilers as included in the proposed BART regulations include FGD (Scrubber) technology with an SO_2 control efficiency of approximately 95 percent. Chapter 2 points out that the average scrubber operating today does not achieve this level of control (existing scrubbers have a range of efficiencies between 30 and 97 percent); however, new installations are achieving rates even higher than 95 percent removal. Additional measures which can be considered for SO_2 control include the use of low-sulfur coal (compliance coal) (typically XX percent SO_2 reduction), spray dry adsorption (60-95 percent removal), dry scrubbing (40-60 percent removal) or circular fluidized-bed adsorption technology (80-98 percent removal). SO_2 control is highly cost effective with operational costs in the $100-200 per ton range.

NO_X control technologies can be grouped into combustion controls (including low-NO_X burners (LNBs), overfire air, off-stoichiometric firing, selective or biased burner firing, reburning, burners-out-of-service, and air staging) and post-combustion controls (include selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) processes). Combustion controls result in typical NO_X reductions of 15 to 60 percent, depending on the specific boiler and combination of controls. SCR achieves a 90-95 percent reduction whereas SNCR achieves 25-50 percent reduction in NO_X. Costs for NO_X removal range from $200-500/ton for some of the low yield techniques to $1000 to $1500/ton for SCR with 90-95 percent removal efficiency.

Particulate matter (PM) control technologies include electrostatic precipitators (ESPs), fabric filters (FFs) (also called “baghouses”), and particulate scrubbers (PS). These technologies typically achieve greater than 95 percent removal of total particulate mass with over 80 percent removal of PM smaller than 0.3 um (with the exception of particulate scrubbers which achieve only 30-85 percent removal for this smaller size fraction). Mechanical collectors have even lower trapping efficiencies. PM controls are in place on virtually all EGUs already, hence the issue that will be faced in conducting BART determinations is how these existing controls will interface with proposed controls for other pollutants.

6.2. Industrial Boilers

For industrial boilers, many of the same control technologies for EGUs are applicable to this source category including: low sulfur coal, wet and dry FGD (or scrubber) technology for SO_2, combustion modifications and SCR and SNCR technology for NO_X, and ESP, fabric filter and wet scrubbing techniques for PM. However, 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 range, depending on the capacity of the boiler and typical operating conditions. High end cost estimates for NO_X removal can be over $10,000/ton.

6.3. Cement Kilns

Designing a system of emission controls for cement kilns are somewhat more complicated given that the quality of clinker produced in a kiln varies with characteristics of the combustion, it is possible to combine combustion technologies with post-combustion technologies for cement kilns in some cases and it is also possible to combine multiple combustion technologies on cement kilns. As a result, primary controls need to be selected carefully taking engineering and cost decisions into account for each specific kiln.

Control options for SO_2 include in-process removal, process changes (e.g. combustion optimization, flame shape adjustment or raw material changes), and the use of wet or dry scrubbers. For NO_X, both process modifications (e.g. combustion modifications, low-NO_X burners, secondary combustion or staged combustion) as well as post combustion controls need to be selected carefully. Particulate control devices for cement plants must be able to clean gases with fairly high dust loading given that the concentrations of particles in the exhaust can be several times higher than in a coal-fired power plant. In addition, PM technologies are affected by the presence of corrosive gases which can be reduced most effectively in a roller mill. While fabric filters (baghouses) and electrostatic precipitators are still the most common means of PM control at cement plants, a number of novel techniques and procedures are used to deal with the unique issues face by cement kilns.

Costs for SO_2 controls at cement kilns will vary widely depending on control options selected and process variables (e.g. whether material is recycled in the control process). Capital cost for typical wet/dry scrubbing post-combustion controls have been estimated in the $10-50/ton of clinker produced with operating costs in the $5-20/ton of clinker range. PM controls are similarly estimated in the $3-15/ton of clinker range for capital costs and $0-30/ton clinker for operating costs on an annual basis. NO_X has not been estimated on a per ton of clinker basis, but estimates vary between 0 and $10,000/ton of NO_X reduced.

6.4. Pulp Mills

Paper and pulp facilities have perhaps the widest range of operational configurations and thus possibilities for reducing pollutant emissions. A variety of technologies exist for controlling emissions from pulp and paper facilities. Secondary control devices can be helpful in reducing emissions for some processes, and a number of them are available. Many facilities have found that significant emissions reductions can be achieved through process changes at the facility. Both secondary controls and process changes are presented as options.

For Kraft mill recovery furnaces, combustion modifications can be effective at reducing SO_2, NO_X, and VOCs. Reducing the liquor sulfidity can also help reduce SO_2 emissions. PM control for recovery furnaces is typically achieved through the use of ESPs or wet ESPs.

Lime kilns are also a significant source of visibility impairing pollutants; however, there are fewer options for effectively reducing SO_2 emissions. Combustion modifications can reduce NO_X and VOC emissions and Venturi scrubbers and ESPs are commonly used for PM control.

Demister pads, packed towers and Venturi scrubbers are used to reduce PM emissions from smelt dissolving tanks.

The range in costs and emission reductions reflects the fact that site-specific factors play a critical role in determining how cost-effective various technologies will be in practice. Existing facilities do not always adequate or appropriate space for new equipment, which adds uncertainty to the capital and operating cost, as well at to the achievable emissions reductions. Hence a wide range of costs have been cited.

Appendix A: BART-Eligible Facilities in the MANE-VU Region

NESCAUM has conducted two previous studies to identify a comprehensive list of BART-eligible sources in the MANE-VU region (NESCAUM, 2001; NESCAUM, 2003). These studies have been carefully reviewed by permitting authorities in each of the MANE-VU jurisdictions and the sources listed in Table A-1 represent the list of sources identified through that process. Non-EGU sources for Pennsylvania and New York are still pending and should be available for inclusion in the Final Report.

Table A-1 BART-Eligible Facilities in the MANE-VU Region

State	Facility	Town/City	BART Category
Connecticut	Middletown		EGU
Connecticut	Montville		EGU
Connecticut	Norwalk Harbor		EGU
Connecticut	PSEG Power Connecticut LLC-Bridgeport Harbor		EGU
Connecticut	PSEG Power Connecticut LLC-New Haven Harbor		EGU
Connecticut	SPRAGUE PAPERBOARD INC	Versailles	boilers
Connecticut	PFIZER INC	Groton	chemical plant
Delaware	Edge Moor		EGU
Delaware	Indian River		EGU
Delaware	Mckee Run		EGU
Delaware	Citisteel	Claymont	iron and steel
Delaware	DuPont Edge Moor	Edge Moor	chemical plant
Delaware	Reichhold	Cheswold	chemical plant
Delaware	Motiva	Delaware City	petrol. storage
District of Columbia	Benning (PEPCO)	District of Columbia	EGU
Massachusetts	Brayton Point		EGU
Massachusetts	Canal		EGU
Massachusetts	Cleary Flood		EGU
Massachusetts	Braintree Electric		EGU
Massachusetts	Mystic		EGU
Massachusetts	New Boston		EGU
Massachusetts	Salem Harbor		EGU
Massachusetts	EASTMAN GELATINE CORP	Peabody	chemical plant
Massachusetts	GENERAL ELECTRIC AIR (GE Aircraft Engines)	Lynn	boilers
Massachusetts	TRIGEN BOSTON ENERGY-KNEELAND STATION	Boston	boilers

Massachusetts	GULF OIL LP CHELSEA	Chelsea	petrol. storage
Massachusetts	REFUSE ENERGY SYSTEM COMPANY	Saugus	incinerator
Massachusetts	SOLUTIA INC. (MONSANTO CO.)	Springfield	boilers
Massachusetts	EXXON EVERETT TERMIN (EXXON EVERETT MARKETING TERMINAL #240	Everett	petrol. storage
Massachusetts	GLOBAL PETROLEUM CORP.	Revere	petrol. storage
Massachusetts	HARVARD UNIVERSITY CAMBRIDGE	Cambridge	boilers
Maryland	C P Crane		EGU
Maryland	Chalk Point		EGU
Maryland	Dickerson		EGU
Maryland	Herbert A Wagner		EGU
Maryland	Morgantown		EGU
Maryland	Vienna		EGU
Maryland	EASTALCO ALUMINUM	Frederick	aluminum ore
Maryland	ST. LAWERENCE CEMENT(formerly Independent Cement)	Hagerstown	portland cement
Maryland	WESTVACO FINE PAPERS	Luke	kraft pulp
Maryland	METTIKI COAL CORPORATION	Oakland	coal cleaning
Maine	William F Wyman		EGU
Maine	Domtar - Pulp & Paper	Baileyville	kraft pulp
Maine	Dragon Products	Thomaston	portland cement
Maine	Fort James - OldTown	Old Town	kraft pulp
Maine	International Paper - Bucksport	Bucksport	boilers
Maine	IP Androscoggin	Jay	kraft pulp
Maine	Katadhin - Mill W.	Millinocket	boilers
Maine	Lincoln Pulp and Paper	Lincoln	kraft pulp
Maine	Madison Paper	Madison	kraft pulp
Maine	Mead WestVaco	Rumford	kraft pulp
Maine	SD Warren - Somerset	Skowhegan	kraft pulp
Maine	SD Warren Co.	Westbrook	kraft pulp
Maine	Gulf Oil - S Portland	South Portland	petrol. storage
New Hampshire	Merrimack		EGU
New Hampshire	Newington		EGU
New Hampshire	Annheuser-Busch	Merrimack	boilers
New Hampshire	Pulp & Paper Mills (33007-00001-11)	Berlin	kraft pulp
New Hampshire	Dartmouth College	Hanover	boilers
New Jersey	Hudson		EGU
New Jersey	CHEVRON PRODUCTS CO 18058	Perth Amboy	petrol. refinery
New Jersey	AMERADA HESS CORP PORT READING 17996	Woodbridge	petrol. refinery
New Jersey	BAYWAY REFINING CO 41805	Linden	petrol. refinery
New Jersey	COASTAL EAGLE POINT OIL COMPANY 55781	Westville	petrol. refinery
New Jersey	COLORITE SPECIALTY RESINS 45940	Burlington	chemical plant

New Jersey	GATX TERMINALS CORP CARTERET FACILITY 18010	Carteret	petrol. storage
New Jersey	GENERAL CHEMICAL CORP 07369	Newark	acid, sulfur, charcoal
New Jersey	GREEN TREE CHEMICAL TECHNOLOGIES INC 18185	Parlin	chemical plant
New Jersey	Griffin Pipe Products (45954)	Florence	iron and steel
New Jersey	Infineum USA LP- Bayway Chemical Plant (41767)	Linden	chemical plant
New Jersey	SHELL OIL PRODUCTS CO SEWAREN PLANT 18051	Sewaren	petrol. storage
New York	Arthur Kill		EGU
New York	Astoria		EGU
New York	Bowline Point		EGU
New York	Charles Poletti		EGU
New York	Danskammer		EGU
New York	E F Barrett		EGU
New York	Lovett		EGU
New York	Northport		EGU
New York	Oswego		EGU
New York	Ravenswood		EGU
New York	Roseton		EGU
New York	Samuel A Carlson Generating Station		EGU
New York	Consolidated Edison's 59th St Station		EGU
Pennsylvania	Bruce Mansfield		EGU
Pennsylvania	Brunner Island		EGU
Pennsylvania	Cheswick		EGU
Pennsylvania	Conemaugh		EGU
Pennsylvania	Eddystone		EGU
Pennsylvania	Hatfield's Ferry		EGU
Pennsylvania	Homer City		EGU
Pennsylvania	Keystone		EGU
Pennsylvania	Martins Creek		EGU
Pennsylvania	Mitchell		EGU
Pennsylvania	Montour		EGU
Pennsylvania	New Castle		EGU
Pennsylvania	Portland		EGU
Pennsylvania	Warren		EGU
Rhode Island	BROWN UNIVERSITY	Providence	boilers
Rhode Island	Clariant Corp.	Coventry	chemical plant

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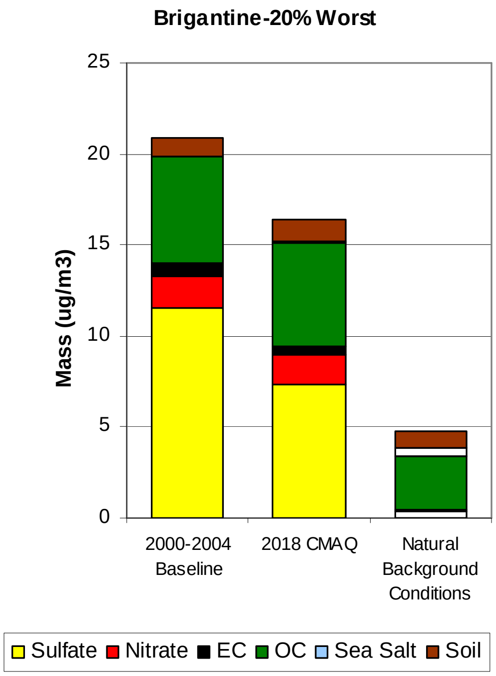

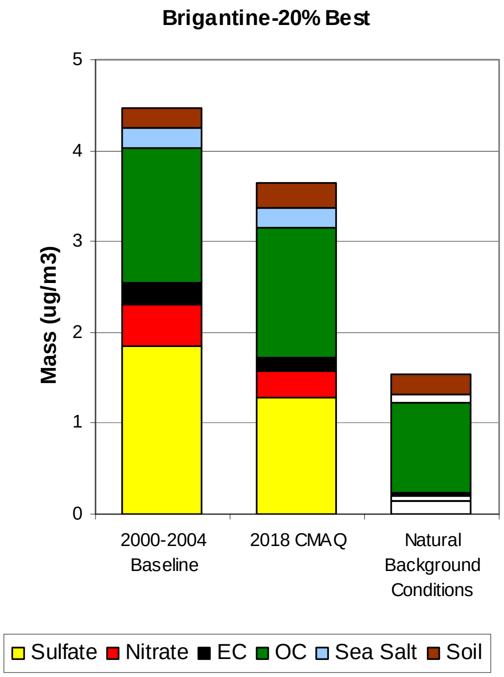

Prepared by
NESCAUM
For the
Mid-Atlantic/Northeast Visibility Union Regional Planning Organization

March 31, 2008

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2018 VISIBILITY PROJECTIONS

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Executive Summary

This report represents the most detailed effort to date to quantify the visibility impacts of those measures that are being actively considered by the Mid-Atlantic/Northeast Visibility Union (MANE-VU) states as a result of the regional haze consultation process. The visibility projections presented here will be useful to the MANE-VU states as they establish reasonable progress goals and develop their long-term emissions management strategies for Class I areas under the federal Regional Haze Rule.

Over the past several years, NESCAUM – as a partner in the MANE-VU regional planning organization – has coordinated and conducted regional air quality modeling to better understand the visibility implications of a range of potential compliance options with the Haze Rule. NESCAUM has utilized in-house air quality modeling capabilities that include emission processing, meteorological input analysis, and chemical transport modeling to conduct regional air quality simulations for calendar year 2002 and several future periods. This work has been documented in several prior reports that were intended to inform and encourage the decision making process leading up to this point in the SIP submission process.

Results from prior analyses have shown that sulfate aerosol – the dominant contributor to visibility impairment in the Northeast's Class I areas on the 20 percent worst visibility days – has significant contributions from states throughout the eastern U.S. These are projected to continue in future years from all three of the eastern regional planning organizations (RPOs). This assessment of potential control measures that would address these future contributions includes a number of specific strategies and would yield significant visibility benefits at or beyond the uniform rate of progress. Perhaps more importantly, they reflect future visibility benefits corresponding to measures that the MANE-VU states are evaluating as being reasonable to implement.

INTRODUCTION

1.1. Background

This report presents information intended to assist states in establishing reasonable progress goals and fulfilling their long-term emissions management strategies under the 1999 U.S. Environmental Protection Agency (USEPA) "Regional Haze Rule" [64 Fed. Reg. 35714 (July 1, 1999)] for MANE-VU Class I areas.[1] NESCAUM has used in-house air quality modeling capabilities that include emission processing, meteorological input analysis, and chemical transport modeling to conduct regional air quality simulations for calendar year 2002 (representative of the baseline period from 2000 to 2004) and for the end of the first compliance period, 2018.

In reviewing the results here, the reader should refer to prior reports prepared by NESCAUM that provide the foundation upon which these results are built. For example, dating back to the earliest overview of regional haze and visibility impairment in the Northeast and Mid-Atlantic U.S. (NESCAUM, 2001), NESCAUM presented a review of the available models along with their uses and limitations. This served to inform the choice of models and tools used to build the weight of evidence modeling approach taken by MANE-VU in conducting a contribution assessment and pollution apportionment (NESCAUM 2004, 2006). NESCAUM presented a review of the base year 2002 from a meteorological and chemical perspective in its report *2002, A Year in Review* (NESCAUM, 2004). NESCAUM has also separately published a performance evaluation of the MM5 meteorological model, the U.S. EPA Community Multi-scale Air Quality (CMAQ) chemical transport model, as well as a more complete description of the modeling platform used for prior control strategy analyses (NESCAUM, 2008).

In this report, we do not repeat this information, but rather rely upon the prior documentation. The following sections describe the control scenario being considered and present the resulting visibility projections in the context of the uniform rate of progress determined by baseline conditions and estimated natural visibility conditions for each Class I area.

1.2. Meteorology

MANE-VU has adopted the Inter-RPO domain description for its modeling runs.[2] This 36-km domain covers the continental United States, southern Canada, and northern Mexico. The dimensions of this domain are 145 and 102 cells in the east-west and north-south directions, respectively. A 12-km inner domain was selected to better characterize air quality in MANE-VU and surrounding RPO regions. This domain covers the eastern region, which includes the northeastern, central, and southeastern U.S., as well as

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[1] There are seven designated Class I areas in the Northeast and Mid-Atlantic States. They include Acadia National Park and Moosehorn Wilderness Area in Maine; Roosevelt Campobello International Park in New Brunswick and Maine; the Lye Brook Wilderness Area in Vermont; the Great Gulf and Presidential Range-Dry River Wilderness Areas in New Hampshire; and the Brigantine Wilderness Area in New Jersey.

[2] The modeling system for the 2002/2018 annual simulation is applied with a Lambert Conformal Conic projection with parallels at 33°N and 45°N. A spherical earth radius of 6,370 km is used for all elements of the system (MM5/SMOKE/CMAQ).

southeastern Canada. It extends from 66^{o}W~94^{o}W in longitude and 29^{o}N~50^{o}N in latitude with 172 × 172 grid cells (Figure 2-1).

Figure 2-1. Modeling domains used with CMAQ for MANE-VU studies.

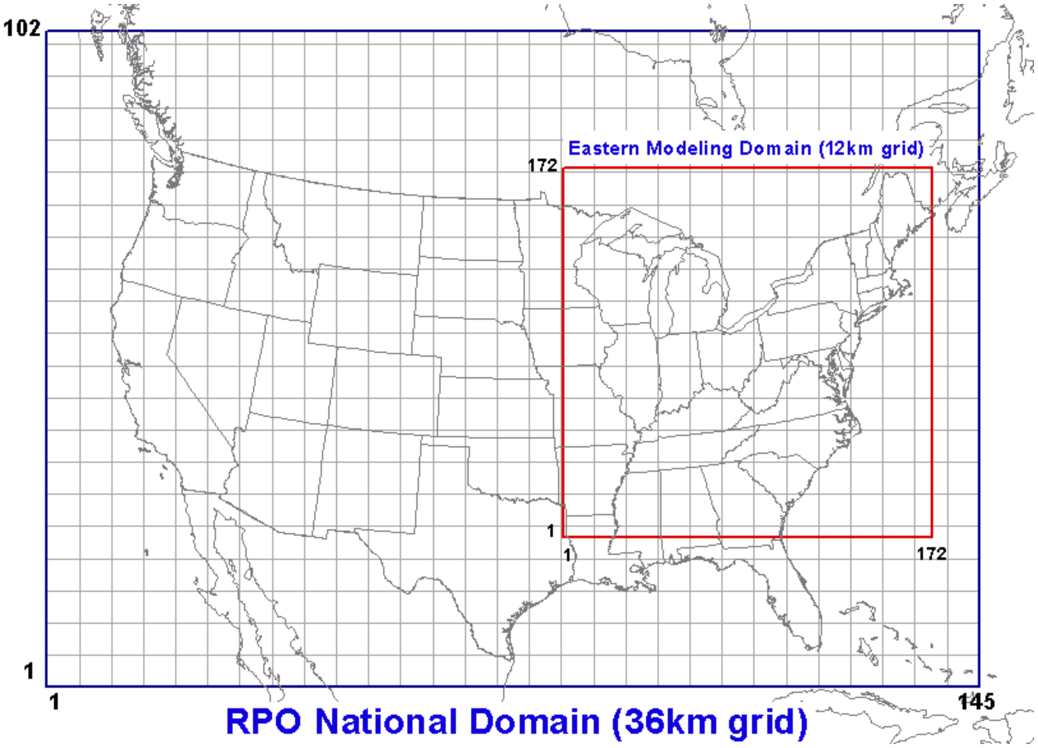

Figure note: Outer (blue) domain is a 36 km grid and inner (red) domain is a 12 km grid. The gridlines are shown at 180 km intervals (5 × 5 36 km cells/15 × 15 12 km cells).

Meteorological inputs for CMAQ, provided by Dalin Zhang's group at the University of Maryland (UMD), are derived from the Fifth-Generation Pennsylvania State University/National Center for Atmospheric Research (NCAR) Mesoscale Model (MM5).[3] The UMD MM5 model runs are made on these two nested domains with the inner (12 km) domain using finer resolution terrain data. Initially, we conducted a set of test runs for the period of August 6–16, 2002. A detailed description of the meteorological inputs can be found in the report *MANE-VU Modeling for Reasonable Progress Goals* (NESCAUM 2008).

1.3. Emissions Preparations

NESCAUM simulated emission scenarios using the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System, an emissions processing system designed to create gridded, speciated, hourly emissions for input into a variety of air quality models such as CMAQ. SMOKE supports area, biogenic, mobile (onroad and nonroad),

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[3] http://www.mmm.ucar.edu/mm5/

and point source emissions processing for criteria, particulate, and toxic pollutants. The *MANE-VU Modeling for Reasonable Progress Goals* report describes the SMOKE emissions processing methods in detail (NESCAUM 2008).

2. 2018 EMISSIONS INVENTORY

Specific descriptions of the 2002, 2018 On the Books/On the Way (OTB/OTW), and 2018 Beyond on the Way (BOTW) inventories are documented in the reasonable progress report (NESCAUM 2008). Based on previous modeling and analyses, MANE-VU identified a number of additional potentially reasonable control measures. These measures include additional SO_2 emissions reductions at electric generating units (EGUs), use of low-sulfur fuels in MANE-VU, and reductions in non-EGU SO_2 emissions outside of MANE-VU. Revisions due to implementation of BART and anticipated changes in Canadian emissions are also included in the latest version of the projected 2018 emissions inventory. The following sections describe the adjustments made to the BOTW inventory.

2.1. Implementation of Top 167 EGU SO_2 Control Scenario

The Vermont Department of Environmental Conservation (DEC) and Environmental Resources Management, on behalf of the Maryland Department of the Environment/Maryland Department of Natural Resources (MDE/MDNR), simulated sulfate at MANE-VU Class I areas using CALPUFF to identify the major contributors to ambient pollution. The effort identified 167 EGU emission sources as contributing a substantial visibility degradation at northeast Class I sites. As part of the MANE-VU strategy to meet its reasonable progress goals, MANE-VU asked for a 90 percent reduction relative to 2002 emission levels from these stacks. This request did, however, provide flexibility to pursue equivalent reductions by region in lieu of reductions at these specific facilities. The resulting emission levels from the EGU sector for this version of the 2018 MANE-VU inventory reflect the SO_2 control request on the top 167 EGUs over three RPOs: MANE-VU, VISTAS, and MWRPO; while maintaining the SO_2 emission level under the CAIR cap for all states subject to the CAIR cap-and-trade program. A more complete description of the EGU emissions inventory preparation is provided elsewhere (Alpine Geophysics, March 2008).

First, NESCAUM determined the desired emissions levels for the 167 stacks based on continuous emissions monitoring data from 2002 (representing a 90 percent reduction). Table 2-1 displays the target levels summarized by RPO. For the same stacks, states provided their best estimate of emissions in 2018, with IPM results as a starting point and specific knowledge of anticipated activity for each stack (e.g., installation of controls). These future emissions are summed by RPO and shown in the second row of Table 2-1. A comparison of these emissions levels shows that no RPO achieves the desired reductions at these 167 stacks. Therefore, reductions at other stacks at the same facilities as the 167 stacks or from other EGUs are required to meet the target emissions level.

Table 2-1. SO_2 Emissions Summary (TPY) for 167 Top EGU stacks

	MANE-VU	MRPO	VISTAS
10% of 2002 CEMS	117,217	170,454,	169,816
Projected 2018	193,026	436,138	299,090
Shortfall	75,809	265,683	129,275

NESCAUM next reviewed anticipated 2018 emissions by RPO at all stacks other than the 167. For MANE-VU, an emissions reduction exactly matching the shortfall (75,809 tons) was recorded at one hypothetical stack in the region. The VISTAS G2 inventory with some Virginia adjustments estimated reductions relative to IPM 2.1.9[4] of over 180,000 tons for the EGUs not included in the 167 stacks. These reductions exceed the shortfall from the 167 stacks and no further adjustments were required. For MRPO, IPM 3.0 results (based on RPO communication) were used to guide the location of reductions to meet the shortfall. Emissions from 65 units where IPM 3.0 predicted emissions lower than IPM 2.1.9 were adjusted downward to be 10 percent of 2002 emissions, resulting in 290,551 tons per year of additional reductions.

Once EGU SO_2 emissions levels were lowered to meet the desired reductions, NESCAUM compared the adjusted emissions (including adjustments to IPM 2.1.9 made by states directly and those from changes made by NESCAUM to meet the 167 stack reduction targets) with IPM 2.1.9 emissions by each of the three RPOs. The analyses looked at three groupings of EGU stacks: the 167 stacks, other units at the same facilities as the 167 stacks, and all other EGUs. Table 2-2 gives these differences by category. Since the total IPM 2.1.9 EGU emissions sums to the CAIR cap, the sum of the differences in the table represents reductions beyond the CAIR level. Because MANE-VU Class I states made the decision to maintain the CAIR level of emissions in this 2018 modeling, the 516,350 tons of emissions were added back.

Table 2-2. Emissions difference between IPM 2.1.9 and adjusted emissions based on state-specific comments and MANE-VU effort to meet 167 stack reduction levels.

	MANE-VU	MRPO	VISTAS
167 stacks	39,465	-37,913	-14,673
Other stacks at 167 facilities	21,433	24,098	-2,244
Other EGUs	-75,809	-290,551	-180,155
Sum	-14,912	-304,367	-197,071

Note: negative values indicate emissions below IPM 2.1.9

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[4] To predict future emissions from EGUs, the Mid-Atlantic/Northeast Visibility Union (MANE-VU) and other Regional Planning Organizations have followed the example of the US Environmental Protection Agency (EPA) in using the Integrated Planning Model® (IPM), an integrated economic and emissions model. IPM projects electricity supply based on various assumptions and develops a least-cost solution to generating needed electricity within specified emissions targets. IPM runs are defined by numerous economic and engineering assumptions. EPA developed Base Case v.2.1.9 using IPM to evaluate the impacts of CAIR and the Clean Air Mercury Rule (CAMR). Recently, EPA updated their input data and developed Base Case v.3.0. All of the IPM results used in MANE-VU modeling were based on EPA Base Case v.2.1.9 with some updates and corrections.

Next, NESCAUM increased the emissions from states subject to the CAIR cap-and-trade program. For MANE-VU, 75,809 tons were added back to the hypothetical facility controlled to meet the "167 stack" reduction request. The remaining 440,188 tons were allocated to VISTAS and MRPO at EGUs that were not among the "167 Stack" facilities based on the fraction of their contribution to the total SO_2 emission. The additional emissions correspond to an increase of 20.5 percent at each of these facilities, with a total of 216,685 tons added to MRPO and 223,504 tons added to VISTAS.

The intent of the EGU emissions adjustments was to retain the same overall level of emissions as predicted by the VISTAS/Inter-RPO run of IPM 2.1.9 overall. The locations of the emissions, however, were modified to better reflect the states' estimates of where emissions would be reduced and to implement the MANE-VU "ask" to achieve reductions at the 167 stacks identified as contributors to visibility reduction at MANE-VU Class I areas.

2.2. Implementation of Low Sulfur Fuel Strategy in MANE-VU

This strategy reduces SO_2 emissions by 2018 from all MANE-VU (non-EGU) sources combusting #1, #2, #4, #5, and #6 oil. Reductions were achieved by lowering sulfur content in fuel from their original levels to 0.0015 percent (equivalent to 15 ppm) for #1 and #2 oil; to 0.25 percent for #4 oil; and to 0.5 percent for #5 and #6 oil. Emissions were reduced from 2002 levels by 168,222 for light distillates (#1 and #2) and 42,875 tons per year for the other fuels. These reductions – when applied within MANE-VU – result in a 35% reduction of our projected 2018 non-EGU SO2 inventory.

2.3. Implementation of BART Strategy in MANE-VU

SO_2 emissions at BART-eligible sources that were not controlled for any other reason (e.g., NOx RACT, CAIR, multi-P state regulations, etc.) have been set to levels as determined by the states.

2.4. Implementation of Gas-Turbine EGU in Canada

SO_2 emissions were removed entirely from six coal-burning EGUs in Ontario, Canada (6500 MW of total capacity) that are scheduled to be shut down (Ontario Power Authority 2006) and replaced with nine natural gas turbine units with Selective Catalytic Reduction (SCR). Emission rates for modeled pollutants from the 'new' gas facilities were based on a combination of factors: recommendation from NH DES (Andy Bodnarik, personal communication), a NYSERDA study (Wien et al. 2003) and AP42 ratios among pollutants. Ontario EGU emissions were reduced by more than 144,000 tons per year as a result of this measure.

2.5. Implementation of 28 percent non-EGU SO_2 emission reduction

Given MANE-VU's low sulfur fuel strategy, MANE-VU requested a comparable reduction in SO_2 emissions from MRPO and VISTAS. The 28 percent value derives from a preliminary estimate of emissions reductions reasonably achievable from non-EGUs sources in MANE-VU. Based on 2002 emissions, this level reduction would amount to 131,600 TPY in MRPO and 308,000 TPY in VISTAS. A number of emission reductions were made to reach these levels, including: reducing emissions from coal-fired ICI boilers by 60 percent, reducing emissions from oil-fired ICI boilers by 75 percent, and reducing emissions from ICI Boilers lacking fuel specification by 50 percent. An additional control was required in VISTAS that reduced emissions from other area oil-combustion sources by 75 percent. These sources were identified by SCCs, matching the source types identified in the list of oil combustion SCCs developed by Alpine Geophysics for the sensitivity runs described previously (NESCAUM, 2008).

3. 2018 MODELING PROJECTIONS

The modeling results based on adjustments to the 2018 emissions inventory detailed in the previous section are given here. All results were developed using the CMAQ modeling platform described previously (NESCAUM, 2008). Table 3-1 provides species-specific relative reduction factors (RRFs) at each Class I area for the 20 percent worst and 20 percent best days. The factors are developed from the 2002 baseline modeling and 2018 modeling results. Ambient measurements identify which days to use in the calculations. The model concentrations for these days are averaged to create the RRF, which is the ratio of the future year to base year average concentration.

Based on the tabulated data, modeled sulfate is reduced by about one-third on worst days, and range from a 6 percent to 31 percent reduction on best days. Nitrate and elemental carbon also show substantial reductions across all sites for both best and worst days. Reductions in organic carbon levels are generally small, while increases are predicted for the fine soil component. The increase may be due to differences in the fire inventory used in VISTAS, as the base year relied on an earlier version of fire emissions than did the 2018 inventory. No changes occur for sea salt since the model does not track that component.

To determine visibility levels in 2018, the measured baseline average concentrations are multiplied by their corresponding RRF for each worst and best day. The projected concentrations are then used to derive daily visibility in deciviews and are averaged across all best and worst days to create the projected future visibility. The results of this procedure are plotted along with the uniform progress glide slope in Figure 3-1 through Figure 3-7. In addition, annual observed 20 percent best and 20 percent worst visibility are plotted as well as a line representing no degradation from current baseline best 20 percent visibility.

All MANE-VU sites are projected to meet or exceed the uniform rate of progress goal for 2018 on the 20 percent worst days. In addition, no site anticipates increases in 20 percent best day visibility relative to the baseline. The nearby sites of Shenandoah and Dolly Sods also show improvement relative to baseline conditions on the 20 percent best days. At Dolly Sods, however, projected visibility impairment on the 20 percent worst days in 2018 exceeds the level determined by the uniform rate. Apparently, the net result of adding back SO_2 emissions across the domain in order to maintain the CAIR cap and reducing emissions in the MidWest RPO and VISTAS in order to comply with the MANE-VU non-EGU ask has been to increase the anticipated visibility impairment relative to previous modeled scenarios. This result is most evident at southern and western sites where more emissions (on an absolute basis) were added back to EGUs.

Table 3-1. 2018 20% best and worst days relative reduction factors at seven sites.

20% Worst Days Relative Reduction Factors

	Acadia	Lye Brook	Brigantine	Moosehorn	Dolly Sods	Shenandoah	Great Gulf
SO4	0.65	0.65	0.63	0.69	0.77	0.65	0.63
NO3	0.79	0.91	0.93	0.73	0.55	0.47	0.85
EC	0.75	0.67	0.62	0.77	0.73	0.58	0.74
OC	0.95	0.93	0.98	0.95	0.93	0.88	0.86
Sea Salt*	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Soil	1.10	1.13	1.26	1.09	1.21	1.16	1.15

20% Best Days Relative Reduction Factors

	Acadia	Lye Brook	Brigantine	Moosehorn	Dolly Sods	Shenandoah	Great Gulf
SO4	0.90	0.81	0.69	0.95	0.94	0.91	0.94
NO3	0.75	0.67	0.62	0.77	0.73	0.58	0.74
EC	0.74	0.75	0.64	0.78	0.71	0.52	0.83
OC	0.94	0.93	0.97	0.92	0.91	0.72	0.99
Sea Salt*	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Soil	1.06	1.04	1.17	1.03	1.14	1.08	1.08

* RRFs for Sea Salt are not calculated from CMAQ. We assume no changes in observed values between 2002 and future time periods.

Figure 3-1. Projected improvement in visibility at Acadia National Park based on 2018 Best and Final Projections

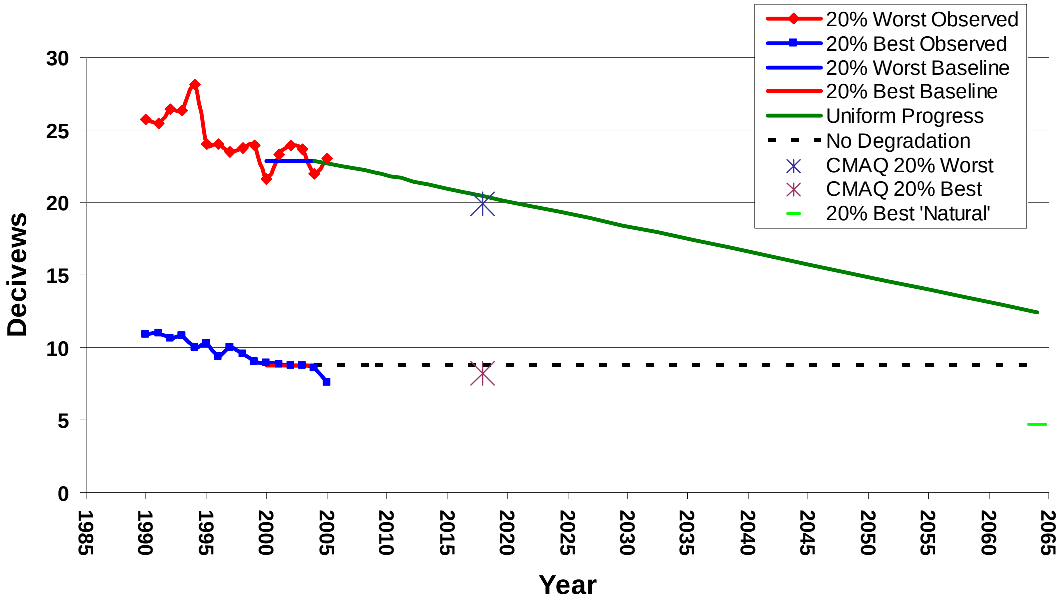


Figure 3-2. Projected improvement in visibility at Brigantine National Wildlife Refuge based on 2018 Best and Final Projections

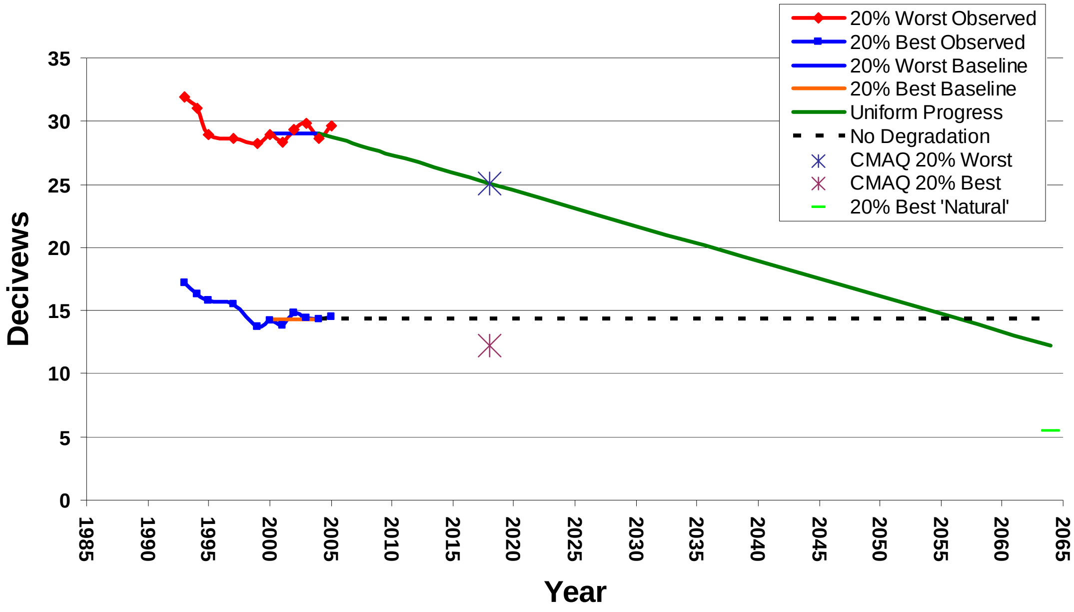


Figure 3-3. Projected improvement in visibility at Great Gulf Wilderness based on 2018 Best and Final Projections

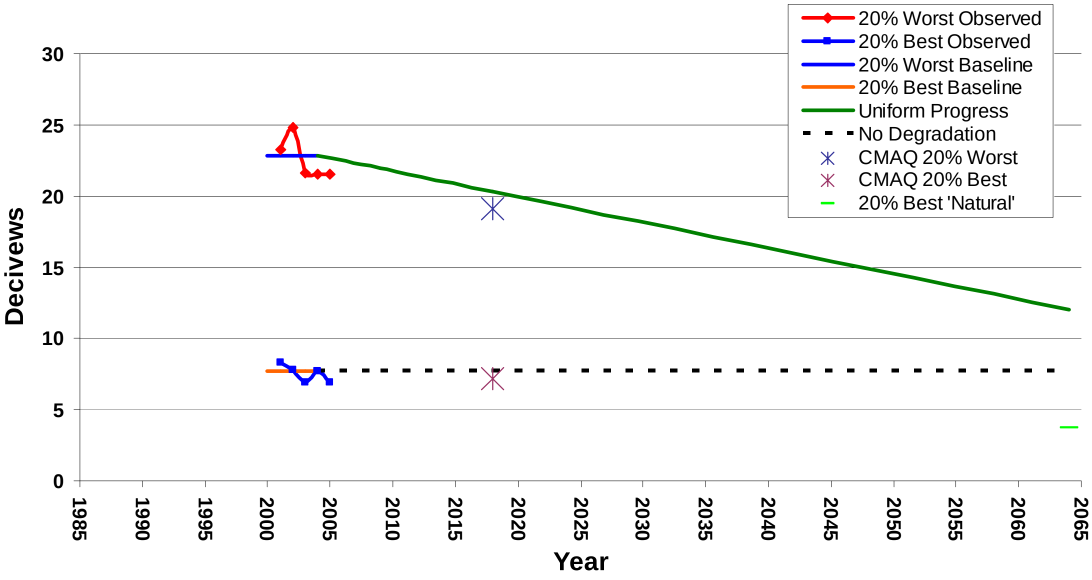


Figure 3-4. Projected improvement in visibility at Lye Brook Wilderness based on 2018 Best and Final Projections

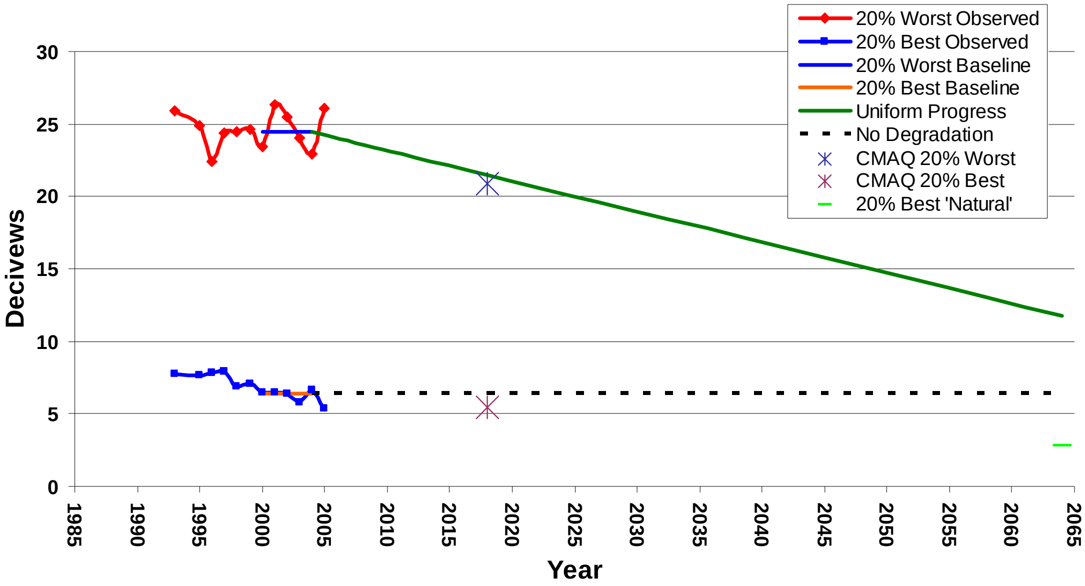


Figure 3-5. Projected improvement in visibility at Moosehorn National Wildlife Refuge based on 2018 Best and Final Projections

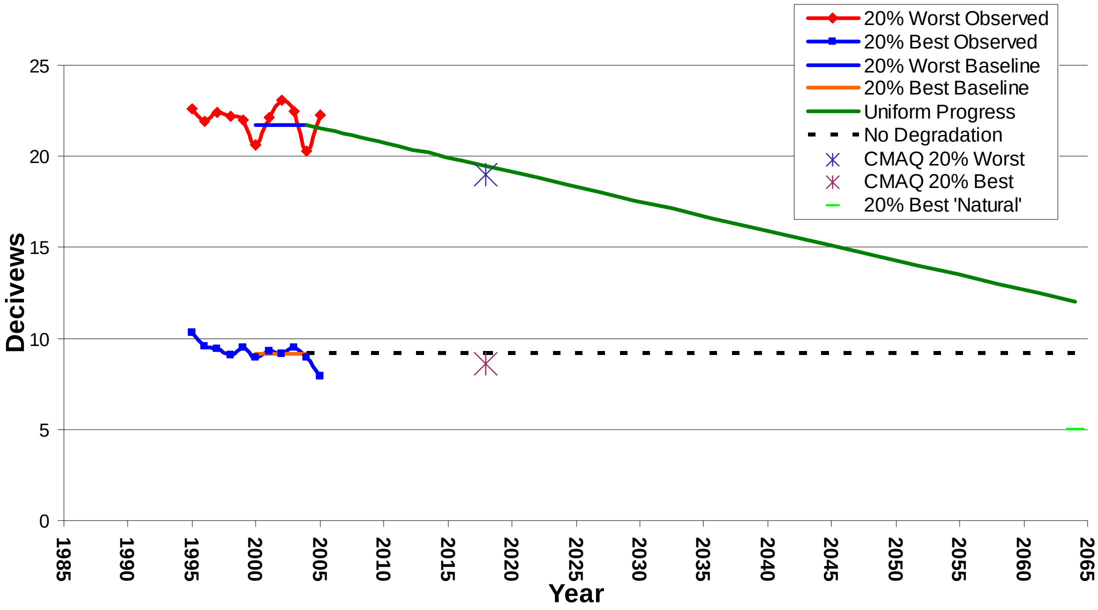


Figure 3-6. Projected improvement in visibility at Dolly Sods Wilderness based on 2018 Best and Final Projections

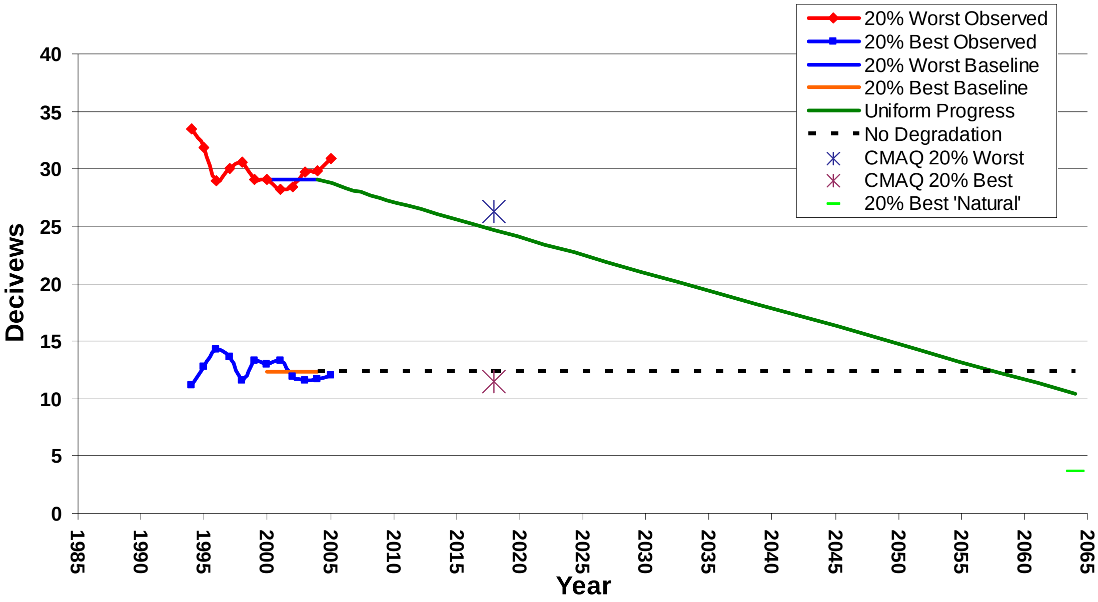
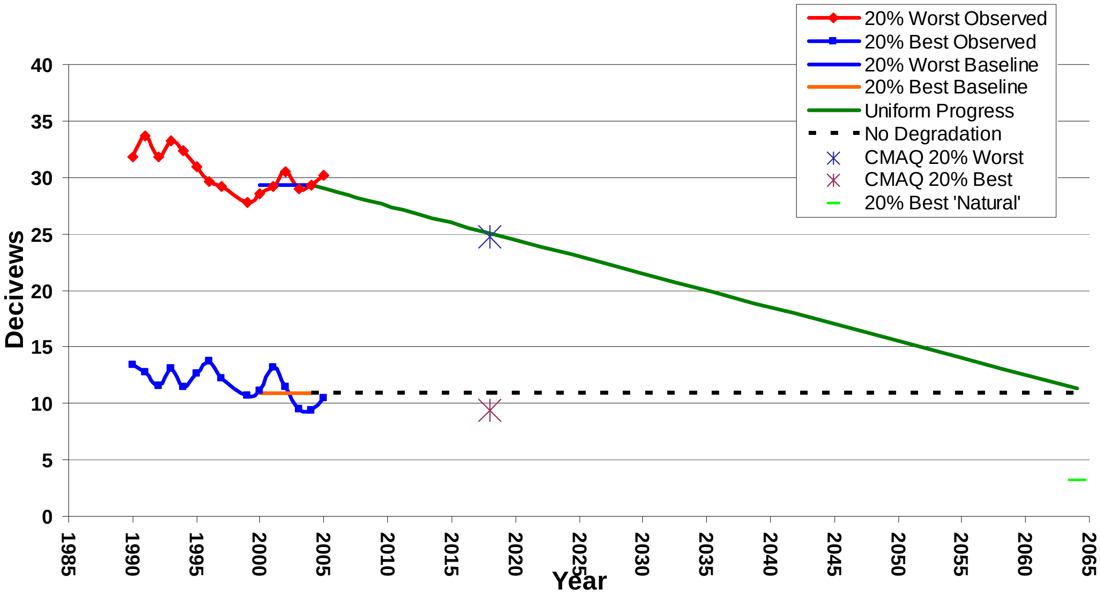


Figure 3-7. Projected improvement in visibility at Shenandoah National Park based on 2018 Best and Final Projections



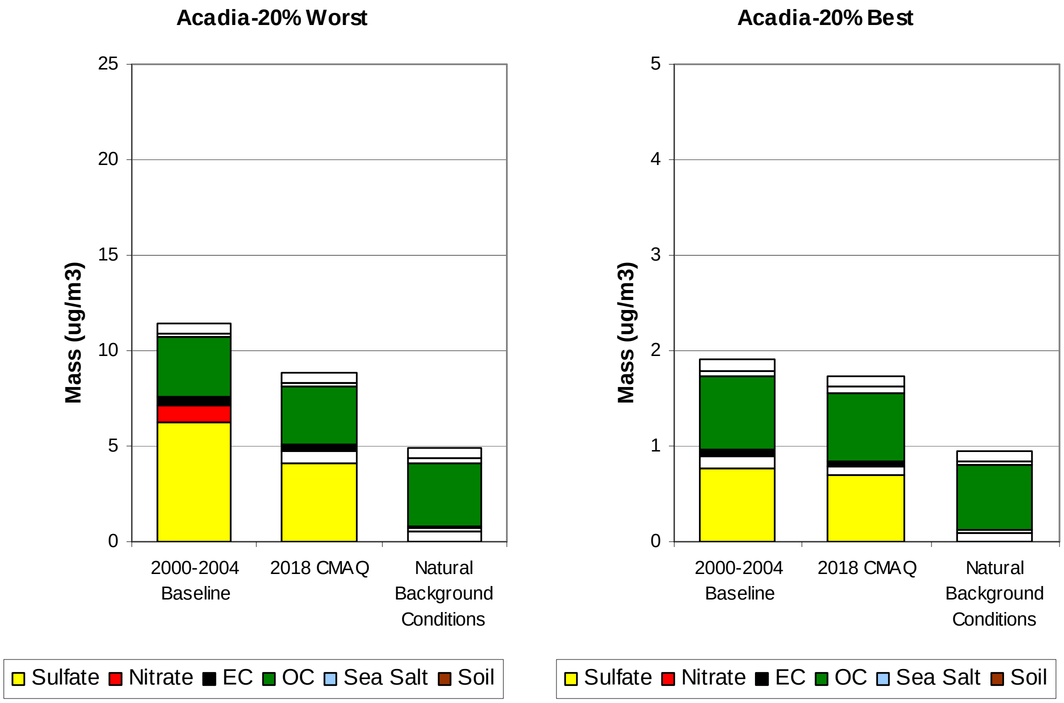
4. 2018 VISIBILITY RESULTS

Figure 4-1A through G show the absolute magnitude of measured and projected sulfate, nitrate, elemental carbon (EC), organic carbon (OC), sea salt, and soil at each MANE-VU Class I monitor and two nearby Class 1 sites, Shenandoah and Dolly Sods. These figures show that despite large reductions in sulfate relative to the baseline, substantially greater reductions are required to reach natural background conditions. Reductions in nitrate will also be needed. Similarly, the carbonaceous species warrant attention moving forward, although a substantial fraction of the organic carbon will remain as natural background.

Sea salt shows interesting behavior. At coastal sites, the worst day sea salt mass is shown to increase when going from baseline and 2018 time periods to natural background conditions. Presumably this observation is a result of the EPA/IMPROVE program choice to base future estimates of worst day visibility conditions on the current distribution of worst day visibility. We note that for sea salt, this may not be the best method to estimate future worst day conditions as the greatest concentration of sea salt is observed in the Northeast U.S. on the best visibility days, not the worst visibility days.

Figure 4-1A-G. Observed Baseline, CMAQ-projected*, and Estimated Natural Speciated PM$_{2.5}$ Mass Values for MANE-VU Class I Sites.

A. Acadia National Park



		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	6.29	4.11	0.53
	Nitrate	0.82	0.65	0.21
	EC	0.43	0.33	0.04
	OC	3.17	3.00	3.32
	Sea Salt	0.19	0.19	0.32
	Soil	0.52	0.58	0.52
Visibility	dv	22.9	19.4	12.4

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	0.77	0.69	0.09
	Nitrate	0.11	0.09	0.03
	EC	0.09	0.06	0.01
	OC	0.76	0.71	0.68
	Sea Salt	0.06	0.06	0.03
	Soil	0.11	0.12	0.10
Visibility	dv	8.8	8.3	4.7

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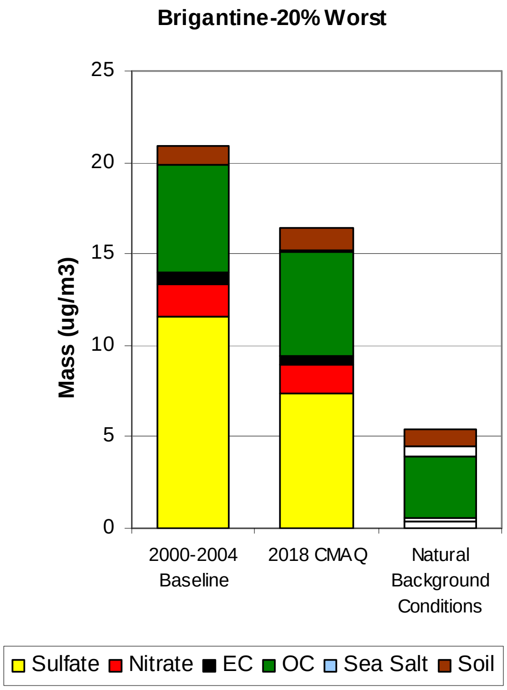
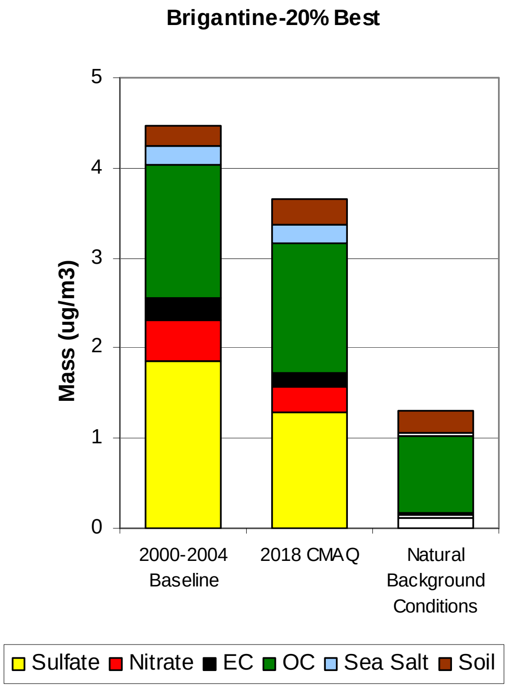
[*] CMAQ projected values are calculated by applying CMAQ-based RRFs by the observed baseline values.

B. Brigantine National Wildlife Refuge

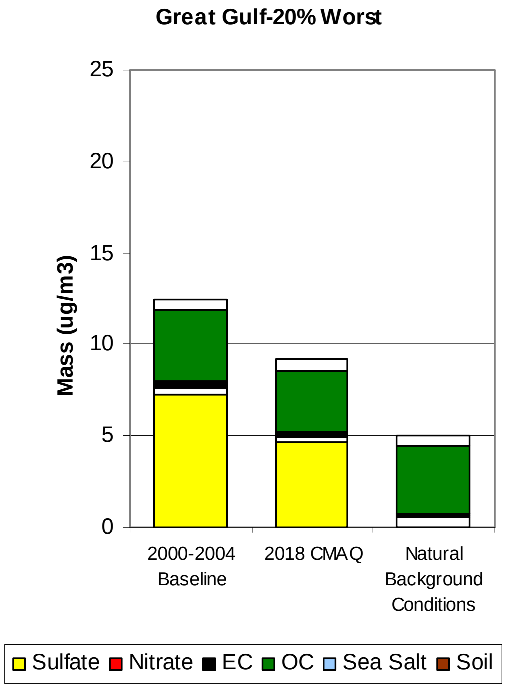


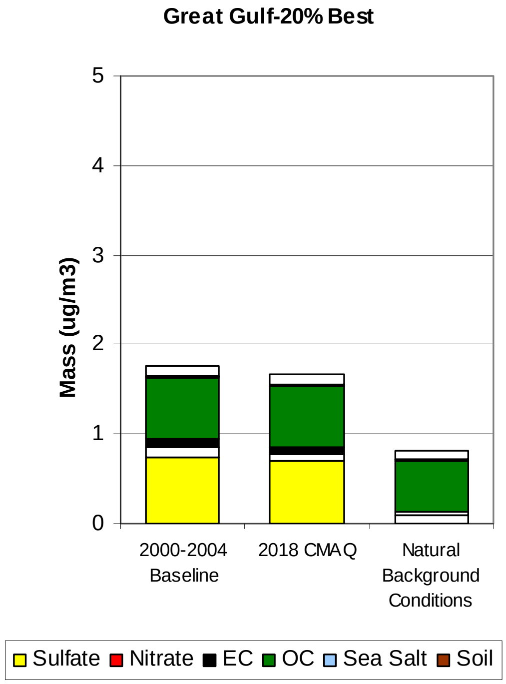


		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	11.58	7.35	0.39
	Nitrate	1.73	1.60	0.13
	EC	0.70	0.43	0.03
	OC	5.83	5.72	3.40
	Sea Salt	0.06	0.06	0.57
	Soil	0.97	1.23	0.85
Visibility	dv	29.0	25.1	12.2

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	1.85	1.28	0.12
	Nitrate	0.46	0.29	0.04
	EC	0.24	0.15	0.01
	OC	1.47	1.43	0.86
	Sea Salt	0.22	0.22	0.04
	Soil	0.23	0.28	0.24
Visibility	dv	14.3	12.2	5.5

C. Great Gulf Wilderness Area

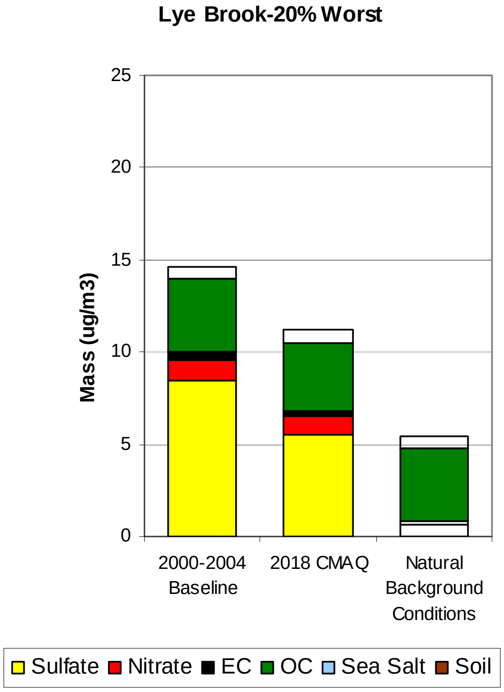


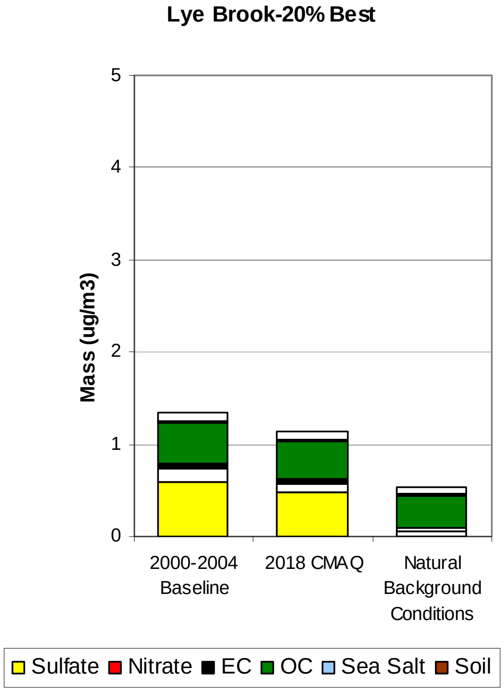


		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	7.28	4.61	0.54
	Nitrate	0.36	0.30	0.13
	EC	0.39	0.29	0.04
	OC	3.84	3.31	3.76
	Sea Salt	0.02	0.02	0.02
	Soil	0.57	0.66	0.53
Visibility	dv	22.8	19.1	12.0

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	0.74	0.70	0.09
	Nitrate	0.12	0.09	0.04
	EC	0.08	0.07	0.01
	OC	0.68	0.67	0.56
	Sea Salt	0.03	0.03	0.02
	Soil	0.10	0.11	0.10
Visibility	dv	7.7	7.2	3.7

D. Lye Brook Wilderness Area

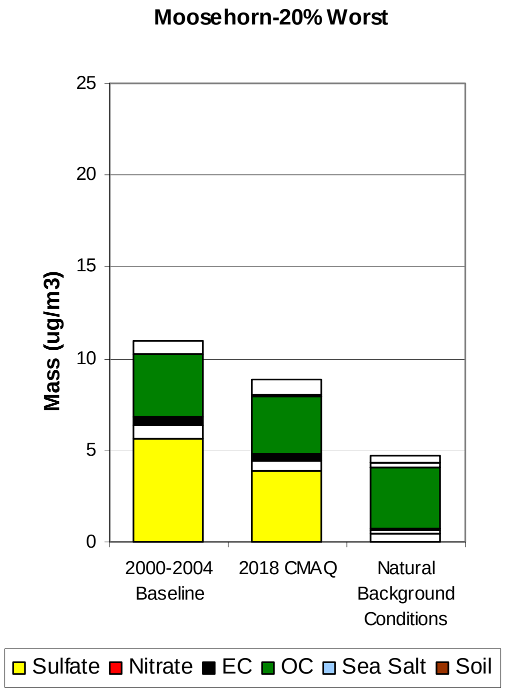


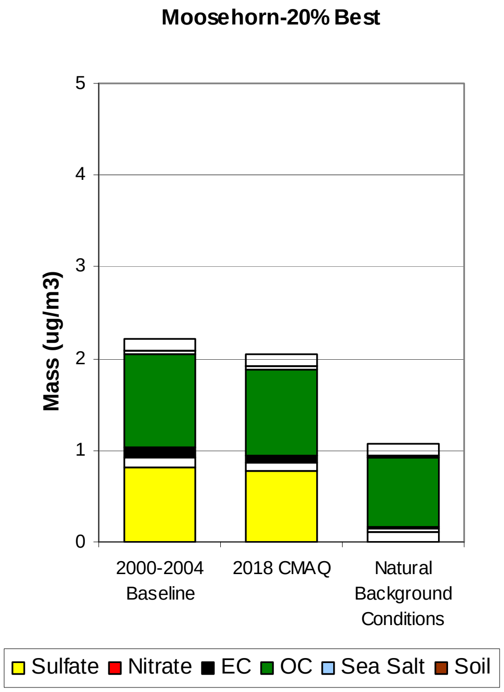


		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	8.46	5.52	0.61
	Nitrate	1.07	0.98	0.18
	EC	0.48	0.32	0.04
	OC	3.94	3.67	3.91
	Sea Salt	0.01	0.01	0.01
	Soil	0.64	0.73	0.66
Visibility	dv	24.4	20.9	11.7

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	0.59	0.48	0.05
	Nitrate	0.14	0.10	0.03
	EC	0.06	0.04	0.01
	OC	0.44	0.41	0.36
	Sea Salt	0.01	0.01	0.01
	Soil	0.09	0.10	0.09
Visibility	dv	6.4	5.5	2.8

E. Moosehorn National Wildlife Refuge

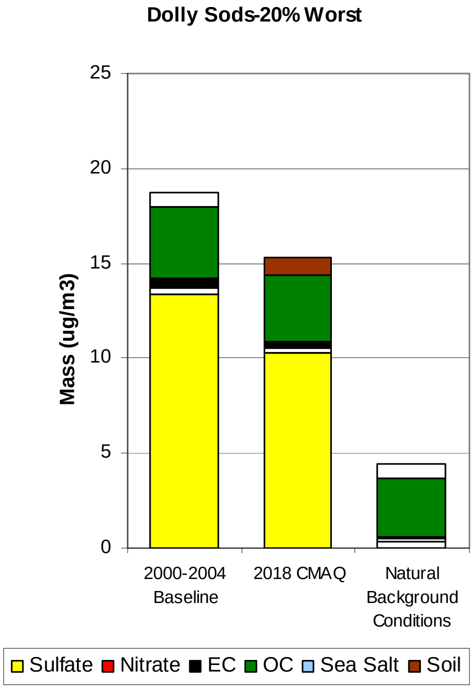


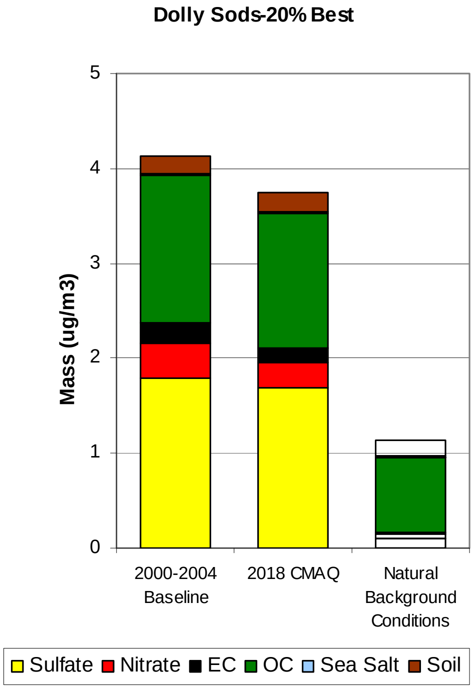


		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass ($\mu g/m^3$)	Sulfate	5.67	3.90	0.48
	Nitrate	0.71	0.52	0.20
	EC	0.44	0.34	0.04
	OC	3.38	3.20	3.34
	Sea Salt	0.03	0.03	0.24
	Soil	0.76	0.83	0.40
Visibility	dv	21.7	19.0	12.0

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass ($\mu g/m^3$)	Sulfate	0.80	0.77	0.11
	Nitrate	0.12	0.09	0.04
	EC	0.10	0.08	0.01
	OC	1.02	0.94	0.76
	Sea Salt	0.04	0.04	0.02
	Soil	0.11	0.12	0.12
Visibility	dv	9.2	8.6	5.0

F. Dolly Sods Wilderness Area

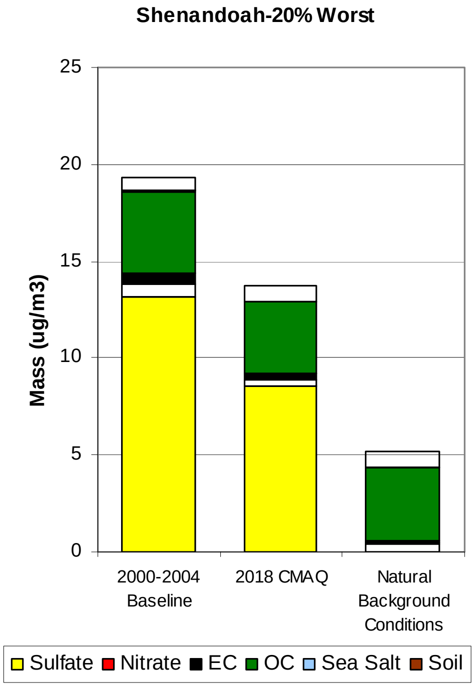


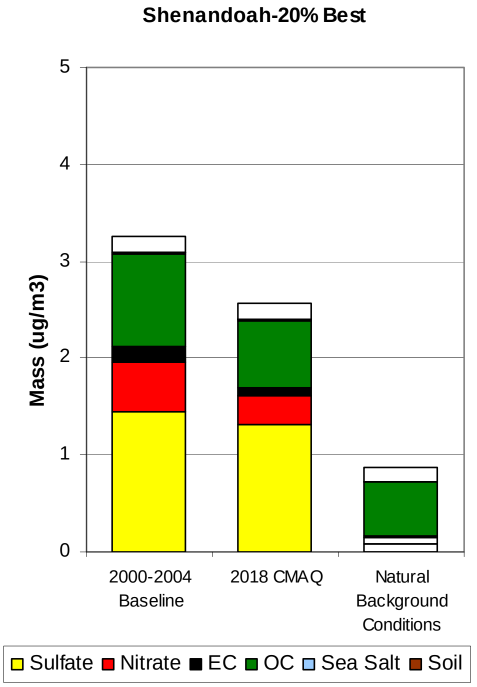


		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass ($\mu g/m^3$)	Sulfate	13.35	10.30	0.38
	Nitrate	0.37	0.20	0.14
	EC	0.47	0.34	0.03
	OC	3.75	3.51	3.11
	Sea Salt	0.02	0.02	0.05
	Soil	0.77	0.94	0.75
Visibility	dv	29.0	26.3	10.4

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass ($\mu g/m^3$)	Sulfate	1.79	1.69	0.10
	Nitrate	0.38	0.27	0.05
	EC	0.21	0.15	0.01
	OC	1.56	1.41	0.80
	Sea Salt	0.02	0.02	0.01
	Soil	0.18	0.20	0.17
Visibility	dv	12.3	11.4	3.6

G. Shenandoah National Park





		20% Worst Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	13.19	8.54	0.43
	Nitrate	0.65	0.31	0.07
	EC	0.57	0.33	0.03
	OC	4.21	3.69	3.78
	Sea Salt	0.01	0.01	0.03
	Soil	0.72	0.84	0.83
Visibility	dv	29.3	24.7	11.4

		20% Best Days		
	Species	2000-2004 Baseline	2018 CMAQ	Natural Background Conditions
Mass (µg/m^3)	Sulfate	1.45	1.31	0.08
	Nitrate	0.52	0.30	0.07
	EC	0.16	0.08	0.01
	OC	0.95	0.69	0.56
	Sea Salt	0.02	0.02	0.01
	Soil	0.16	0.17	0.14
Visibility	dv	10.9	9.4	3.1

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Documentation of 2018 Emissions from Electric Generating Units in the Eastern United States for MANE-VU's Regional Haze Modeling

Revised Final Draft

28 April 2008

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

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This report was prepared for use by the MANE-VU States and does not necessarily represent the position of the U.S. Environmental Protection Agency.

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1 INTRODUCTION

1.1 Background

Development of an emissions inventory is an important foundation for performing regional scale atmospheric modeling for regulatory air quality management. The accuracy of the atmospheric model's prediction of air quality depends, in part, on the accurate representation of emissions from a variety of source sectors including point, area, non-road, on-road and biogenic sources. Electric generating units (EGUs) are an important point source sector and are often considered for controls to meet air quality objectives. Therefore, it is especially important to accurately represent and document EGU emissions and associated characteristics in a regulatory modeling application. This report is intended to describe the development of future year EGU emission estimates for use in Mid-Atlantic/Northeast Visibility Union (MANE-VU) 2018 regional haze modeling.

This document synthesizes information from several documents that already describe parts of the process of preparing emissions estimates and provides information not yet included in other documents. It covers the following: preparation of the inter-Regional Planning Organization (RPO) Integrated Planning Model® (IPM) runs commonly referred to as the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) IPM runs, the post-processing of those runs to create Sparse Matrix Operator Kernel Emissions (SMOKE) input files, the modification of those files to reflect state estimates of emissions, and the adjustments made by MANE-VU modelers to maintain the Clean Air Interstate Rule (CAIR) cap. It also provides background information about preparing EGU forecasts and related work by the U.S. Environmental Protection Agency (EPA).

2 PREPARATION OF EGU FORECASTS

Emission projections for point sources are dependent upon changes in source level activity, the emission factors or installed controls. The approach taken to project point source emissions depends on the level of detail necessary in the projection year file. Changes in point source emissions are accounted for by a combination of growth, control, and retirement rates. Growth rates are applied to estimate the overall change in activity, while retirement rates are applied to estimate the decrease in emissions activity from existing sources. Retirement (and replacement of these sources with new sources) must be considered because regulations affecting new sources may differ from those affecting existing sources.

The projection year control factor accounts for both changes in emission factors due to technology improvements and new levels of control required by regulations. The control factor accounts for three variables: regulation control, rule effectiveness, and rule penetration.

Control factors are closely linked to the type of emission process (identified by Source Classification Code (SCC)) and secondarily to the type of industry identified by Standard Industrial Classification (SIC). Point source projections should account for Federal, State, and local regulations affecting these categories.

A complicating factor is the requirement for emission offsets in nonattainment areas through New Source Review requirements. This may be accounted for by 1) restricting growth under the assumption that it will be offset; 2) applying reductions to selected source categories to account for the emission growth which must be offset; or 3) selecting the individual sources, based on a cost analysis, from which offsets are likely to come.

When projecting Electricity Generating Unit (EGU) emissions in the Eastern United States, emission trading should be considered. There are three general approaches to performing projections while accounting for such trading schemes. The first option is to optimize control levels across the domain based on the cost of alternative controls. The second option is to survey individual sources to determine how they will comply (will they apply controls and sell or buy allowances) and use this as the basis for the future year control level. The third option is to apply the control level used to establish the budget to all affected sources and ignore which sources may choose to buy or sell credits/allowances.

Other factors which must be considered include programs, such as fuel switching, designed to provide source flexibility in meeting future air quality requirements. Fuel switching refers to instances where a unit historically burned one primary fuel, such as coal, and under a "fuel switching" program the unit would burn an alternate fuel, such as natural gas, during a certain period of time and may switch back to the "historic" fuel for some or all of the year. Fuel switching is often done in cases where sources average their emissions to meet federal mandates. Fuel switching may also be used as a seasonal compliance strategy (e.g., switching from residual fuel oil to natural gas in order to reduce NOx emissions during the ozone season. The variation in emissions over the course of the year caused by fuels switching must be calculated properly in projections.

Repowering is another example of a planned change in emission rates which should be considered. In this case, the unit may be switching entirely from coal to natural gas or may be completing a major modification which would lower the emission rate.

Spatial allocation is another factor which must be considered, particularly if air quality modeling will be performed using the projection. For point sources, important questions are which facilities will retire and where new growth will occur. Changes in land use patterns may also impact the location of point source emissions. As undeveloped and rural areas become suburban and urban areas, the number of point sources in that area will increase.

As can be seen from the discussion above, any number of complicating issues can lead to emission forecasts which may differ from user to user. An inconsistent decision made between two parties can lead to significant differences in growth, control, or placement of emissions from point source forecasts. For this reason, the RPOs made a conscious decision to utilize consistent forecasting methods for EGU emissions, as they are one of the most significant contributors to regional haze in the United States. This decision, to coordinate on the projection of EGU source emissions, led to the preparation of an EGU forecast methods document from which a coordinated decision was made on methods to develop EGU emissions in future years.

2.1 EGU Forecast Methods Document

Early in the planning process there was a joint agreement by the RPOs to work together to develop future year EGU emissions estimates based on the use of the Integrated Planning Model® (IPM). The decision to use IPM modeling resulted in part on a study of EGU forecast methods by E.H. Pechan and Associates, Inc. (Pechan) for the Midwest Regional Planning Organization (MRPO) (Pechan, 2004), which recommended IPM as a viable methodology. Although IPM results were available from work conducted by EPA to support their rulemaking for the Clean Air Interstate Rule (CAIR), the RPOs concluded that certain model inputs needed to be revised. Thus, the RPOs decided to work together to hire contractors to conduct new IPM modeling and to post-process the IPM results. This section describes the recommendation to use IPM.

The Lake Michigan Air Directors Consortium (LADCO) sought contractor assistance in reviewing emissions inventory growth for existing and new EGUs (Pechan, 2004). Because the results of EGU emission forecasts are used in urban or regional scale air quality modeling exercises to estimate future year air pollutant concentrations, growth methods are needed to supply model-ready emission model inputs. The purpose of LADCO's project was to begin to examine EGU growth methods.

The primary pollutants of interest were sulfur dioxide (SO_2), oxides of nitrogen (NO_x), particulate matter (PM), ammonia (NH_3), and mercury (Hg). Projection years of interest included 2009 (the approximate time for ozone and $PM_{2.5}$ attainment) and 2018 (a longer term regional haze planning horizon). The geographic area of interest was the eastern half of the United States (to capture the trading issues affecting the Midwest States).

This 2004 Pechan report provided a detailed evaluation of three EGU growth modeling methods of interest to the LADCO States for consideration in developing its own approach. These evaluations addressed the following attributes of each modeling approach:

- Description of primary analytical modeling methods;
- Geographic areas of application;
- Advantages; and
- Disadvantages.

The material in this evaluation was intended to be used to determine which of the currently available modeling approaches might be best suited for use by the LADCO States (and other RPOs) for future state implementation plan (SIP) and air dispersion modeling work. The models evaluated in this report included the IPM, the National Energy Modeling System (NEMS), and the Electric Power Market Model (EPMM).

Based on the conclusions and summary of the report (Pechan, 2004), the four participating RPOs (MANE-VU, MRPO, VISTAS, and the Central Regional Air Planning Association, CENRAP) decided to use IPM as the tool for forecasting EGU emissions.

2.2 The Integrated Planning Model (IPM)

IPM was developed by ICF Consulting, Inc. (ICF) and used to support public and private sector clients. This model is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints. It can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of SO_2, NO_x, carbon dioxide (CO_2), and Hg from the electric power sector. The IPM model was a key analytical tool used by EPA in developing CAIR and the Clean Air Mercury Rule (CAMR).

Among the factors that make IPM particularly well suited to model multi-emissions control programs are (1) its ability to capture complex interactions among the electric power, fuel, and environmental markets; (2) its detail-rich representation of emission control options encompassing a broad array of retrofit technologies along with emission reductions through fuel switching, changes in capacity mix and electricity dispatch strategies; and (3) its capability to model a variety of environmental market mechanisms, such as emissions caps, allowances, trading, and banking. IPM's ability to capture the dynamics of the allowance market and its provision of a wide range of emissions reduction options are particularly important for assessing the impact of multi-emissions environmental policies like CAIR and CAMR.

2.3 U.S. EPA Use of IPM

The U.S. EPA uses IPM to analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous states and the District of Columbia.

2.3.1 EPA's Base Case 2004

The EPA's Base Case 2004 (EPA, 2005a) served as the starting point against which EPA compared various policy scenarios. It is a projection of electricity sector activity that takes into account federal and state air emission laws and regulations whose provisions were either in effect or enacted and clearly delineated at the time the base case was finalized in August 2004. Regulations mandated under the Clean Air Act Amendments of 1990 (CAAA), but whose provisions have not yet been finalized, were not included in the base case. These include:

- <u>Measures to Implement Ozone and Particulate Matter (PM) Standards</u>: EPA Base Case 2004 predates and so does not include the provisions of CAIR, the primary federal regulatory measure for achieving the National Ambient Air Quality Standards (NAAQS) for ozone (8-hour standard of 0.08 ppm) and fine particles (24-hour average of 65 ug/m3 or less and annual mean of 15 ug/m3 for particles of diameter 2.5 micrometers or less, i.e., $PM_{2.5}$). EPA Base Case 2004 was used to evaluate policy alternatives which ultimately resulted in CAIR. The final CAIR was issued on March 10, 2005. EPA Base Case 2004 includes measures to implement ozone and particulate matter standards to the extent that some of the state regulations included in EPA Base Case 2004 contain measures to bring non-attainment areas into attainment. Individual permits issued by states in response to ozone and particulate matter standards are not captured in the base case.

- <u>Mercury Regulations on Electric Steam Generating Units:</u> EPA Base Case 2004 predates both CAMR, which was issued by EPA on March 15, 2005 and the "Maximum Achievable Control Technology" (MACT) standards, which were scheduled to be promulgated by December 15, 2004, but, pending litigation, have been superseded by CAMR. Consequently, this base case does not include any federal regulatory measures for mercury control. (CAMR was vacated in 2008.)

- <u>Clean Air Visibility Rules:</u> On July 1, 1999, EPA issued Regional Haze Regulations to meet the national goal for visibility established in Section 169A of the CAAA, which calls for "prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas (156 national parks and wilderness areas), which impairment results from manmade air pollution." The regulations required states to submit revised SIPs that (1) establish goals that provide for reasonable progress towards achieving natural visibility conditions at Class I areas, (2) adopt a long-term control strategy that includes such measures as are necessary to achieve the reasonable progress goals, and (3) require Best Available Retrofit Technology (BART) for sources in listed source categories placed in operation between 1962 and 1977.

In effect, EPA Base Case 2004 offered a snapshot projection of the electric sector assuming that the only future environmental regulations were those with provisions known at the time that the base case assumptions were finalized. While not necessarily an accurate reflection of what would actually occur, this assumption ensured that the base case was policy neutral with respect to future environmental policies.

2.3.2 EPA CAIR Case

On January 30, 2004, EPA proposed CAIR, which set emission reduction requirements for 29 States and the District of Columbia. Those emission reduction requirements were based on achieving highly cost-effective emission reductions from large electricity generating units.

While EPA believed that the modeling it initially performed for the January 2004 proposal provided a reasonable estimate of the impact of requiring highly cost-effective emission reductions from electricity generating units, it did not exactly model the proposed control region. For both SO_2 and NO_x, EPA used modeling assumptions that differed slightly from the January 2004 CAIR proposal. For SO_2 in particular, EPA modeled the program assuming a cap on national emissions rather than in the 29 States proposed. Although EPA believed the modeling done at that time provided a reasonable approximation of the impacts of the original CAIR, because 92 percent of the SO_2 emissions in the 48 contiguous States occur in the 28 States that were covered by the proposal, EPA completed additional analysis. This additional analysis examined the effect of covering the geographic region proposed in the January 30, 2004 proposal using the NO_x emissions cap and a close approximation of the SO_2 cap proposed for CAIR (EPA, 2005a).

For the supplemental proposal, EPA performed refined modeling of the emission reduction requirements proposed on January 30, 2004. In this refined modeling, EPA modeled the exact control regions for both SO_2 and NO_x, as proposed.

2.3.3 EPA's CAIR Modeling Limitations

The U.S. EPA's modeling was based on its best judgment for various input assumptions that were uncertain, particularly assumptions for future fuel prices and electricity demand growth (EPA, 2004). In addition, modeling using IPM did not take into account the potential for advancements in the capabilities of pollution control technologies for SO_2 and NO_x removal as well as reductions in their costs over time.

Retirement Ratios: EPA issued a CAIR supplemental notice of proposed rulemaking that proposed two alternatives for how the SO_2 reduction target would be achieved. The proposal took comment on implementing the reduction requirements in the second phase either by using a 2.86 to 1 ratio (which would match the 65 percent SO_2 reduction target) of acid rain allowances to emissions, or alternatively, by implementing the reductions using a 3 to 1 ratio (for administrative simplicity) and then letting States create and distribute additional allowances equal to the surplus created by the 3 to 1 ratio to achieve the proposed 65 percent reduction. In either case, the effective cap on SO_2 emissions from the power sector would be the same.

Modelers assumed a 3 to 1 Title IV allowance retirement ratio for 2015 and beyond to implement the reductions in the proposed control region. The model did not add back the 130,000 tons of SO_2 from over-compliance that would result from this ratio. Therefore, in this modeling, EPA analyzed slightly greater SO_2 emission reductions than required by the proposal. This assumption was made for modeling simplicity and was expected to result in a slight overestimate of costs for the proposal and of the emissions reductions achieved.

BART: The EPA did not incorporate any best achievable retrofit technology (BART) modeling in this analysis. BART would achieve reductions in non-CAIR States and had the potential to mitigate leakage issues.

Demand Response: EPA's 2004 CAIR case includes a demand response to increased gas prices but not electricity prices. In the model, increased gas prices would prompt the public to curtail their use of gas and encourage them to seek substitutes. However, no provision for demand response was included for electricity prices. If demand had been allowed to change in response to increasing prices of electricity,, one can assume that consumers would have reduced their demand for electricity, lowering electricity prices and reducing generation and emissions to some extent.

State Rules: Only some State adopted rules were incorporated into EPA's modeling framework. A list of the State Multi-pollutant regulations used in IPM 2.1, IPM 2.1.6, and IPM 2.1.9 can be located in Appendix 3-2 of EPA's Standalone Documentation for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model (EPA, 2005a).

Because of the limitations noted above, the RPOs decided to initiate their own IPM modeling based on the EPA's latest update of the IPM input framework, called IPM 2.1.9. EPA completed the input framework for IPM 2.1.9 in March of 2003.

2.4 RPO Use of IPM – Phase I

In August 2004, VISTAS contracted with ICF to run IPM to provide revised utility forecasts for 2009 and 2018 under two future scenarios – Base Case and CAIR Case (ICF, 2004). The Base Case represented the current operation of the power system under laws and regulations as known at the time the run was made, including those that come into force in the study horizon. The CAIR Case was the Base Case with the proposed CAIR rule superimposed. Run results were parsed at the unit level for the 2009 and 2018 run years.

In August 2004, MRPO contracted with Pechan to post-process the VISTAS' IPM outputs to provide the (National Emission Inventory Input Format) NIF formatted emission files needed for the regional inventory. The IPM output files were delivered by ICF to VISTAS in November 2004 and the post-processed data files were delivered by Pechan to the MRPO in December 2004.

These IPM runs (VISTAS_CAIR_2) and the NIF files that were generated from the parsed data sets are commonly referred to as the Phase I Inter-RPO runs. The Phase I runs were ultimately not used in RPO modeling of regional haze, as further revisions to the inputs were necessary once CAIR was adopted.

2.5 RPO Adjustments to IPM – Phase II

On March 10, 2005, EPA issued the final CAIR. A consortium of RPOs, (MANE-VU, VISTAS, MRPO, and CENRAP) conducted another round of IPM modeling which reflected changes to control assumptions based on the final CAIR as well as additional changes to model inputs based on state and local agency and stakeholder comments. Several conference calls were conducted in the spring of 2005 among the participating RPOs to discuss and provide comments on IPM assumptions related to six main topics: power system operation, generating resources, emission control technologies, set-up parameters, financial assumptions, and fuel assumptions. Based on these discussions, VISTAS sponsored a new set of IPM runs to reflect the final CAIR requirements as well as certain changes to IPM assumptions that were agreed to by the RPOs. ICF performed the following four runs using IPM during the summer of 2005. This set of IPM runs is referred to as the VISTAS Phase II analysis or Inter-RPO v.2.1.9 runs.

- Base Case with EPA 2.1.9 coal, gas, and oil price assumptions (VISTASII_BC_1Z1).
- Base Case with EPA 2.1.9 coal and gas supply curves adjusted for the U.S. Energy Information Administration’s most recent Annual Energy Outlook (AEO 2005) reference case price and volume relationships (VISTASII_BC_2Y).
- Strategy Case with EPA 2.1.9 coal, gas and oil price assumptions (VISTASII_PC_1f).
- Strategy Case with EPA 2.1.9 coal and gas supply curves adjusted for AEO 2005 reference case price and volume relationships (VISTASII_PC_2C).

The above runs were parsed for 2009 and 2018 run years. The output taken from the Strategy Case with EPA 2.1.9 coal, gas, and oil price assumptions (VISTASII_PC_1f) is also referred to as the Inter-RPO CAIR Case IPM 2.1.9 and is the basis for discussion in the remainder of this report.

The Phase II scenarios were based on VISTAS Phase I and EPA IPM 2.1.9 assumptions (EPA, 2005b). Additional changes that were implemented in the above four runs are summarized below and in associated documentation (ICF, 2007):

- Unadjusted AEO 2005 electricity demand projections were used. (U.S. EPA runs were adjusted to reflect reduced demand due to voluntary conservation projects sponsored by U.S. EPA)
- Gas supply curves were adjusted for AEO 2005 reference case price and volume relationships. The EPA 2.1.9 gas supply curves were scaled such that IPM solved for AEO 2005 gas prices when the power sector gas demand in IPM is consistent with AEO 2005 power sector gas demand projections.
- The coal supply curves used in EPA 2.1.9 were scaled such that the average mine mouth coal prices that the IPM was solving in aggregated coal supply regions were comparable to AEO 2005. Coal grades and supply regions contained in AEO 2005 and EPA 2.1.9 were not directly comparable. An iterative approach was used to obtain comparable results. The coal transportation matrix was not updated with Energy Information Administration (EIA) assumptions due to significant differences between the EPA 2.1.9 and EIA AEO 2005 coal supply and coal demand region configurations.

- The cost and performance of new units were updated to AEO 2005 reference case levels.
- The run years 2008, 2009, 2012, 2015, 2018, 2020 and 2026 were modeled.
- The AEO 2005 life extension costs for fossil and nuclear units were incorporated.
- The extensive NEEDS comments provided by VISTAS, MRPO, CENRAP and MANE-VU were incorporated into the Phase I NEEDS input file.
- MANE-VU's comments in regards to the northeast state regulations were incorporated.
- Northeast Renewable Portfolio Standards (RPS) were modeled based on the Regional Greenhouse Gas Initiative analysis. A single RPS cap was modeled for MA, RI, NY, NJ, MD, and CT. These states could buy credits from NY or from the PJM Interconnection and New England model regions.
- Selective Catalytic Reduction (SCR) and Scrubber Feasibility Limits: No limits were applied in 2008, 2009 and 2010 to the capacity for installing these emissions controls.
- The Clean Air Visibility Rule (CAVR) was not modeled.
- Modelers assumed a Title IV SO_2 Bank for 2007 of 4.98 million tons.
- The investments required under the Illinois Power, Mirant and First Energy NSR settlements (as identified during spring 2005) were incorporated in the above runs.

For the Phase II inter-RPO set of IPM runs, ICF generated two different parsed files for each of the two scenarios. One file includes all fuel burning units (fossil, biomass, landfill gas) as well as non-fuel burning units (hydro, wind, etc.). The second file contains just the fossil-fuel burning units (e.g., emissions from biomass and landfill gas are omitted). In all RPOs the fossil-only file was used for modeling. This is consistent with EPA, since EPA used the fossil only results for CAIR analyses.

2.6 State Results – Phase II

Table 1 presents unmodified State level fuel use and emission results from the 2018 Inter-RPO CAIR Case IPM v. 2.1.9 fossil-only parsed file (VISTASII_PC_1f). Note that IPM produces only NO_x and SO_2 emissions estimates.

Table 1. State Level Fuel Use and Emission Summary; 2018 VISTASII_PC_1f.xls. (fossil only)

		Fuel Use (TBtu)		**Emissions (Tons)**		
State	**RPO**	**Summer**	**Annual**	**Summer NOx**	**Annual NOx**	**Annual SO2**
Connecticut	MANE-VU	62.1572	142.7141	1,521	3,418	6,697
Delaware	MANE-VU	41.9472	92.7542	5,485	12,341	35,442
District Of Columbia	MANE-VU	2.0774	4.8716	49	103	83
Maine	MANE-VU	21.8494	49.8748	804	1,827	5,436
Maryland	MANE-VU	195.3393	437.8991	6,832	14,709	28,065
Massachusetts	MANE-VU	188.0653	433.3227	8,004	18,157	17,486
New Hampshire	MANE-VU	32.4638	73.8699	1,393	3,089	7,469
New Jersey	MANE-VU	140.8000	304.7240	6,432	13,636	32,495
New York	MANE-VU	282.4272	669.0821	10,926	24,376	51,445
Pennsylvania	MANE-VU	687.1446	1,540.1322	36,329	82,881	135,946
Rhode Island	MANE-VU	15.1701	40.0407	244	576	55
Vermont	MANE-VU	1.3677	3.0597	74	105	35
	MANE-VU Total	**1,670.8093**	**3,792.3450**	**78,093**	**175,219**	**320,651**
Alabama	VISTAS	605.2513	1,329.1117	19,416	41,715	190,029
Florida	VISTAS	831.5942	1,813.5433	26,620	56,506	139,526
Georgia	VISTAS	687.9659	1,530.2279	26,228	56,180	178,196
Kentucky	VISTAS	494.6026	1,121.9188	27,904	64,099	229,596
Mississippi	VISTAS	211.7079	443.3923	4,269	8,895	27,226
North Carolina	VISTAS	431.1262	984.5996	25,412	57,774	102,217
South Carolina	VISTAS	326.3757	749.2039	20,240	46,318	118,584
Tennessee	VISTAS	300.8087	672.6405	13,348	29,873	112,343
Virginia	VISTAS	305.6546	710.9991	18,443	43,144	80,602
West Virginia	VISTAS	477.7910	1,080.9570	22,556	51,208	124,464
	VISTAS Total	**4,672.8781**	**10,436.5940**	**204,435**	**455,711**	**1,302,784**
Illinois	MRPO	564.3359	1,281.6624	31,214	71,234	241,136
Indiana	MRPO	665.8976	1,534.4126	40,820	95,376	376,864
Michigan	MRPO	537.6731	1,257.6784	42,629	98,685	398,562
Ohio	MRPO	773.6334	1,785.3989	35,888	83,129	215,501
Wisconsin	MRPO	303.7451	691.5260	19,794	45,701	155,369
	MRPO Total	**2,845.2851**	**6,550.6783**	**170,345**	**394,124**	**1,387,433**
Arkansas	CENRAP	211.9455	479.1864	14,836	33,097	82,605
Iowa	CENRAP	238.7101	548.7369	22,252	51,119	147,305
Kansas	CENRAP	213.4288	465.8685	37,207	83,333	81,486
Louisiana	CENRAP	225.6282	481.9880	14,240	30,432	74,263
Minnesota	CENRAP	175.6582	388.8279	17,940	41,029	85,847
Missouri	CENRAP	416.5504	918.5720	34,350	77,660	280,887
Nebraska	CENRAP	113.8064	255.2901	22,524	50,781	73,629
Oklahoma	CENRAP	357.5522	745.1097	36,695	76,048	113,680
Texas	CENRAP	1,710.8244	3,236.6605	79,449	153,837	339,433
	CENRAP Total	**3,664.1040**	**7,520.2400**	**279,493**	**597,336**	**1,279,135**
Arizona	WRAP	442.6160	1,022.0551	36,168	81,858	60,640
California	WRAP	602.8505	1,403.6297	10,464	23,767	5,447
Colorado	WRAP	215.1782	486.7281	31,074	70,171	87,163
Idaho	WRAP	14.5575	34.1372	309	718	0
Montana	WRAP	88.4363	200.1442	17,034	38,504	22,066
Nevada	WRAP	179.3334	408.0758	20,978	47,404	31,172
New Mexico	WRAP	155.2294	344.7868	32,965	74,010	52,917
North Dakota	WRAP	131.5025	297.0199	31,745	71,711	108,645
Oregon	WRAP	109.6842	255.3128	4,968	11,330	10,034
South Dakota	WRAP	16.3929	36.8730	6,457	14,574	12,085
Utah	WRAP	146.1278	330.1164	26,905	60,782	37,819
Washington	WRAP	155.7190	362.9219	11,625	26,379	12,236
Wyoming	WRAP	202.3566	457.1643	35,935	81,182	40,265
	WRAP Total	**2,459.9843**	**5,638.9652**	**266,628**	**602,390**	**480,488**
National Total		**15,313.0609**	**33,938.8226**	**998,994**	**2,224,779**	**4,770,490**

2.7 MANE-VU Sponsored CAIR Plus IPM Modeling

Using the IPM Phase II RPO modeling platform MANE-VU contracted with ICF to evaluate the impact of both tightening the SO_2 and NO_x CAIR caps and to expand the CAIR region to include the electricity generating sector in additional states the Eastern United States. As part of this analysis, ICF developed a new Base Case that implemented EPA's CAIR, CAMR and CAVR policies and a Policy Case with lower SO_2 and NO_x CAIR caps in an extended region. The new Base Case was developed for comparison to the Policy Case. The model assumptions and data used in this analysis are somewhat different than those in the RPO Phase II analysis and are described in Section B of the project report (ICF, 2007). Neither the base or policy cases from the CAIR Plus project were used in subsequent SIP modeling.

3 POST PROCESSING OF IPM OUTPUT

3.1 Use of SMOKE Emissions Processing Model

On behalf of MANE-VU, NESCAUM modelers used an emissions processing model to prepare data produced by the IPM model for use in air quality and visibility modeling. The Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System is an emissions processing system designed to create gridded, speciated, hourly emissions for input into a variety of air quality models, such as EPA's Community Multi-Scale Air Quality (CMAQ) model and Regional Modeling System for Aerosols and Deposition (REMSAD) (Houyoux, et. al., 2000). SMOKE supports area, biogenic, mobile (both onroad and nonroad), and point source emissions processing for criteria, particulate, and toxic pollutants. For biogenic emissions modeling, SMOKE uses the Biogenic Emission Inventory System, version 2.3 (BEIS2) and version 3.09 and 3.12 (BEIS3). SMOKE is also integrated with the onroad emissions model MOBILE6.

The sparse matrix approach used throughout SMOKE permits rapid and flexible processing of emissions data. Flexible processing comes from splitting the processing steps of inventory growth, controls, chemical speciation, temporal allocation, and spatial allocation into independent steps whenever possible. The results from these steps are merged together in the final stage of processing using vector-matrix multiplication. It allows individual steps (such as adding a new control strategy, or processing for a different grid) to be performed and merged without having to redo all of the other processing steps. Individual emission scenarios were simulated for MANE-VU using the SMOKE Modeling System.

The Northeast States for Coordinated Air Use Management (NESCAUM), on behalf of MANE-VU and its participating States, conducted regional air quality simulations for calendar year 2002 and several future periods (NESCAUM, 2008). This work was directed at satisfying a number of goals under the Haze State Implementation Plan (SIP), including a contribution assessment, a pollution apportionment for 2018, and the evaluation of visibility benefits of control measures being considered for achieving reasonable progress goals and establishing a long-term emissions management strategy for MANE-VU Class I areas. The modeling tools utilized for these analyses include the Fifth-Generation NCAR / Penn State Mesoscale **Model** (MM5), SMOKE, CMAQ and REMSAD, and incorporate tagging features that allow for the tracking of individual source regions or measures. These tools have been evaluated and found to perform adequately relative to U.S. EPA modeling guidance.

As described below, in order for NESCAUM to process the Electric Generating Unit (EGU) emissions generated by the Integrated Planning Model® (IPM) procedures noted above, a series of intermediate steps were required to get the activity and emission data into the appropriate format for SMOKE processing.

3.2 Preparing IPM Output for Use in SMOKE Model

IPM can produce projections at the regional, state, plant, or unit level. Data must be parsed to provide the unit level information required for chemical transport modeling. Parsing involves developing detailed unit level information from the model's projections at the model plant level. ICF parsed the VISTASII_PC_1f data for use by the RPOs.

Further post-processing of IPM parsed output is needed to prepare the files for use by the SMOKE emissions processing model. The following sections describe the intermediate steps necessary to make these conversions. The first step is the augmentation of the IPM parsed output files to include additional unit level characteristics and pollutant estimates necessary for one atmosphere modeling. This step converts the IPM parsed data files into EPA's National Emission Inventory Input Format (NIF). The second step is the additional conversion of these NIF files into the Inventory Data Analyzer (IDA) format required by the SMOKE emissions processor.

3.2.1 IPM to NIF

After running IPM, ICF provided an initial spreadsheet file containing unit-level records for both:

(1) "existing" units (those currently in operation during the modeled base year) and
(2) committed/planned or new generic aggregates (new generic units expected to come online or identified as needed to meet electric generation demand in a geographic area).

IPM parsed file records include unit and fuel type data; existing, retrofit (for SO_2 and NO_x), and separate NO_x control information; annual SO_2 and NO_x emissions and heat input; summer season (May-September) NO_x and heat input; July day NO_x and heat input; coal heat input by coal type; nameplate capacity megawatt (MW), and State FIPS codes (Federal Information Processing codes used to identify geographic areas). Existing units also had county FIPS code, a unique plant identifier (ORISPL) and unit ID (also called boiler ID) (BLRID); generic units did not have these data.

The processing of IPM parsed data to NIF format included estimating emissions not generated by IPM and adding control efficiencies, stack parameters, latitude-longitude coordinates, and State identifiers (plant ID, point ID, stack ID, process ID) from a series of lookup tables or by matching to individual units as configured in base year 2002 emission files (Pechan, 2005). Additionally, new generic units created by IPM were sited in a county and given appropriate IDs. This processing is described in more detail below.

<u>Generic Units:</u> The new generic units and associated data were prepared by transforming the generic aggregates into units similar in size and fuel to existing units in terms of the available data. Generic aggregates were split into smaller generic units based on their unit types and capacity. Each generic unit was provided a dummy ORIS unique plant and boiler ID, and were given a county FIPS code based on an algorithm that sited each generic unit by assigning a sister plant that is in a county based on its attainment/nonattainment status. Within a State, existing plants (in county then ORIS plant code order) in attainment counties were used first as sister sites to new generic units (to obtain county location), followed by existing plants in PM nonattainment counties, followed by existing plants in 8-hour ozone nonattainment counties. No States identified counties that should not be considered when siting new generic units, so this process was identical to the one used for EPA IPM post-processing under CAIR.

SCCs were assigned to existing units using unit/fuel/firing/bottom type data. SCCs were assigned to generic units using unit and fuel type information. Latitude-longitude coordinates were assigned, first using the EPA-provided data files, secondly using an in-house contractor developed latitude-longitude file, and lastly using county centroids. These additional location files were only used when the data were not provided in the original 2002 base year files. Stack parameters were then assigned to each unit, first using the EPA-provided data files, secondly using an in-house stack parameter file based on previous EIA-767 data, and lastly using an EPA June 2003 SCC-based default stack parameter file. These data were only used when the data were not provided in the 2002 base year files.

IPM does not calculate emissions for all pollutants necessary for regional haze modeling. Therefore additional data were required to estimate VOC, CO, filterable primary PM_{10} and $PM_{2.5}$, PM condensable, and NH_3 emissions. Thus, ash and sulfur contents were assigned by first using 2002 EIA-767 values for existing units or SCC-based defaults; filterable PM_{10} and $PM_{2.5}$ efficiencies were obtained from the 2002 EGU NEI that were based on 2002 EIA-767 control data and the PM Calculator program (a default of 99.2 percent is used for coal units if necessary); fuel use was back calculated from the given heat input and a default SCC-based heat content; and emission factors were obtained from an EPA-approved emission factor file based on AP-42 emission factors. Table 2 presents the SCC-based default heat content and stack parameters used when actual data were not available. Table 3 (worksheet sccemfac100704 from MRPOpostprocdatafiles.xls, Pechan 2005) reflects emission factors used to develop emission estimates of CO, VOC, filterable PM, and NH_3.

Table 2. SCC Default Heat Content and Stack Parameters from IPM to NIF Conversion.

			Stack Parameters			
SCC	**Fuel**	**Heat Content (Btu/SCC Unit)**	**Height (ft)**	**Diameter (ft)**	**Temp (degrees F)**	**Velocity (ft/s)**
10100201	Bituminous Coal	23.4286	603.2	19.8	281.2	76.5
10100202	Bituminous Coal	23.4286	509.7	14.6	226.0	62.0
10100203	Bituminous Coal	23.4286	491.6	16.6	278.4	80.5
10100204	Bituminous Coal	23.4286	225.0	0.6	67.2	2.4
10100211	Bituminous Coal	23.4286	0.0	0.0	0.0	0.0
10100212	Bituminous Coal	23.4286	445.6	17.4	275.2	77.6
10100217	Bituminous Coal	23.4286	399.3	10.8	245.6	40.1
10100221	Subbituminous Coal	17.8870	983.0	22.8	350.0	110.0
10100222	Subbituminous Coal	17.8870	468.5	16.0	254.7	65.6
10100223	Subbituminous Coal	17.8870	446.8	15.9	308.0	93.6
10100224	Subbituminous Coal	17.8870	255.5	10.0	251.3	15.3
10100226	Subbituminous Coal	17.8870	495.8	18.9	259.2	91.2
10100238	Subbituminous Coal	17.8870	600.0	22.5	315.0	78.0
10100301	Lignite Coal	12.9149	427.5	22.3	232.8	74.2
10100302	Lignite Coal	12.9149	483.5	21.0	229.4	92.4
10100303	Lignite Coal	12.9149	462.0	21.7	271.3	72.5
10100317	Lignite Coal	12.9149	326.7	12.3	326.7	74.7
10100601	Natural Gas	1023.8846	263.9	10.3	236.0	46.9
10100801	Coke	27.4376	371.3	5.5	122.4	20.4
10102018	Waste Coal	12.0929	0.0	0.0	0.0	0.0
20100201	Natural Gas	1023.8846	62.0	10.0	585.3	61.3
20100301	Gasified Coal	1023.8846	62.0	10.0	585.3	61.3

Table 3. EPA-Approved Emission Factor File for CO, VOC, filterable PM, and NH_3.

SCC	FUEL	COEF	VOCEF	PM10EF	PM25EF	NH3EF	PMFLAG
10100201	BIT	0.5000	0.0400	2.6000	1.4800	0.030	A
10100202	BIT	0.5000	0.0600	2.3000	0.6000	0.030	A
10100203	BIT	0.5000	0.1100	0.2600	0.1100	0.030	A
10100204	BIT	5.0000	0.0500	13.2000	4.6000	0.030	
10100211	BIT	0.5000	0.0400	2.6000	1.4800	0.030	A
10100212	BIT	0.5000	0.0600	2.3000	0.6000	0.030	A
10100217	BIT	18.0000	0.0500	12.4000	1.3640	0.030	
10100221	SUB	0.5000	0.0400	2.6000	1.4800	0.030	A
10100222	SUB	0.5000	0.0600	2.3000	0.6000	0.030	A
10100223	SUB	0.5000	0.1100	0.2600	0.1100	0.030	A
10100224	SUB	5.0000	0.0500	13.2000	4.6000	0.030	
10100226	SUB	0.5000	0.0600	2.3000	0.6000	0.030	A
10100238	SUB	18.0000	0.0500	16.1000	4.2000	0.030	
10100301	LIG	0.2500	0.0700	1.8170	0.5214	0.030	A
10100302	LIG	0.6000	0.0700	2.3000	0.6600	0.030	A
10100303	LIG	0.6000	0.0700	0.8710	0.3690	0.030	A
10100317	LIG	0.1500	0.0300	12.0000	1.4000	0.030	
10100601	NG	84.0000	5.5000	1.9000	1.9000	3.200	
10100801	PC	0.6000	0.0700	7.9000	4.5000	0.397	A
10102018	WC	0.1500	0.0300	12.0000	1.4000	0.030	
20100201	NG	83.8628	2.1477	1.9380	1.9380	6.560	
20100301	IGCC	34.6500	2.2050	11.5500	11.5500	6.560	

Notes:

1. SCCs beginning with 101002 (coal), 101003 (coal), 101008 (coke), or 101020 (waste coal), emission factors in LB/TON; SCCs beginning with 101006 (natural gas), 201002 (natural gas), or 201003 (IGCC), emission factors are in LB/E6FT3.
2. If PMFLAG = 'A', then multiply ash content with PM emission factor.

Source: Table derived from worksheet sccemfac100704 from MRPOpostprocdatafiles.xls, Pechan 2005.

<u>Condensable PM:</u> To estimate total primary PM emissions, additional calculations were conducted to derive condensable PM emissions from these sources. In MANE VU and VISTAS PM condensable emissions were calculated based on factors derived from AP-42 defaults. In MRPO no condensable emissions were estimated or included in the inventory. (Janssen, 2008) Table 4 (worksheet pmcdef from MRPOpostprocdatafiles.xls, Pechan 2005) shows these PM condensable emission factors and SCC assignments.

Table 4. EPA-Approved Condensable PM Emission Factor Assignment.

SCC	PMCDEF (LB/E6BTU)
10100201, 10100202, 10100203, 10100211, 10100212, 10100221, 10100222, 10100223, 10100226, 10100301, 10100302, 10100303	0.0200[2]
10100201, 10100202, 10100203, 10100211, 10100212, 10100221, 10100222, 10100223, 10100226, 10100301, 10100302, 10100303 [1]	(0.1 * sulfur content - 0.03)[3]
10100204, 10100224	0.0400
10100217, 10100238, 10100317, 10102018	0.0100
10100601	0.0057
10100801	0.0100
20100201, 20100301	0.0047

Notes:

1. If the emission factor is less than 0.01, then it is set equal to 0.01.
2. AND there is either an SO_2 FGD or a PM scrubber (for MRPO post-processing); or AND there is an SO_2 wet FGD (for EPA post-processing).
3. AND there is any PM control other than a scrubber and there is no SO_2 control (for MRPO post-processing); or AND there is any control other than an SO_2 wet FGD (for EPA post-processing).

Source: Table derived from worksheet pmcdef from MRPOpostprocdatafiles.xls, Pechan 2005.

Additional Pollutants: As noted above, in processing IPM parsed data to convert it to NIF format, emissions of additional pollutants were estimated. Emissions for 28 temporal-pollutant combinations were estimated since there are seven pollutants (VOC, CO, primary PM_{10} and $PM_{2.5}$, NH_3, SO_2 and NO_x) and four temporal periods (annual, summer season, winter season, July day).

Crosswalk Match to 2002 Inventory: The final step in the IPM to NIF conversion process was to match the IPM unit IDs with the identifiers in the base year 2002 inventory for existing EGUs. A crosswalk file was used to obtain FIPS State and county, plant ID (within State and county), and point ID. If the FIPS State and county, plant ID and point ID were in the 2002 base year NIF tables, then the process ID and stack ID were obtained from the NIF; otherwise, defaults, described above, were used.

The post-processed files were then provided in NIF 3.0 format. Two sets of tables were developed : "NIF files" for IPM units that had a crosswalk match and were in the 2002 base year inventory, and "NoNIF files" for IPM units that were not in the 2002 base year inventory (which included existing units with or without a crosswalk match as well as generic units). Two special cases relating to the crosswalk match were handled as follows:

1. One-to-many match: At a given plant, if one IPM boiler ID was matched to more than one point ID, the boiler data were put on the first point ID records; records from the other point IDs were deleted from the relevant tables.

2. Many-to-one match: At a given plant, if more than one IPM boiler ID was matched to one point ID, all the boilers' emissions (tons), throughput (really heat input in MMBtu), and capacity (MW) were summed ("summed boiler") and put on that point

ID's records in the relevant tables. The values for stack parameters and latitude-longitude values were those from the first record summed.

3.3 State Results – Phase II Augmented

Summarizing the results of the estimation of additional pollutants, Table 5 presents additional pollutant augmented State level emission results from the 2018 Inter-RPO CAIR Case IPM v. 2.1.9 fossil-only parsed file (VISTASII_PC_1f with pollutant augmentation; found in modeling file *ida_egu_18_basef_2453605.txt* from VISTAS BaseF). A comparison of RPO totals for SO_2 and NO_x shows that these are the same as presented in Table 1.

3.4 NIF to IDA

The main purpose of the SMOKE conversion task was to convert EGU emission inventories provided in NIF format into the IDA format required by the SMOKE model for the criteria pollutants VOC, NO_x, CO, SO_2, PM_{10}, $PM_{2.5}$, and NH_3. Annual and seasonal emissions were taken directly from the NIF structured inventories with no alternate temporal calculations performed (e.g., estimate seasonal emissions from annual or annual from seasonal). The temporal allocation module of the SMOKE emissions processor was intended to be used to further define temporal distribution of these emissions.

No quality assurance (QA) related to the reported values in the NIF files was conducted (e.g., it was assumed that reported emission levels were correct) and therefore the QA focus was to maintain the integrity of the mass files in the conversion to IDA.

Each set of NIF structured data had a unique set of relational tables necessary to maintain the information required in each source sector based on its reporting requirements. Conversion scripts to read the information from each of these relational data sets and convert them to the IDA structures required by this task were implemented by Alpine (Alpine, 2006). Prior to and after the conversion from NIF to IDA, a list of emission summary reports was developed to check that the emissions input into the conversion process were the same as output into the IDA formatted files.

Table 5. State Level Emission Summary; 2018 VISTASII_PC_1f with Pollutant Augmentation. Modeling file *ida_egu_18_basef_2453605.txt* from VISTAS Base F. (fossil-only)

		Annual Emissions (Tons)						
		IPM Generated		**Augmented Pollutants**				
State	**RPO**	**NOx**	**SO2**	**VOC**	**CO**	**PM-10**	**PM-2.5**	**NH3**
Connecticut	MANE-VU	3,418	6,697	145	9,837	959	927	341
Delaware	MANE-VU	12,341	35,442	117	1,183	2,950	2,438	76
District Of Columbia	MANE-VU	103	83	5	154	104	99	12
Maine	MANE-VU	1,827	5,436	53	4,057	296	279	139
Maryland	MANE-VU	14,709	28,065	575	11,831	8,253	6,433	435
Massachusetts	MANE-VU	18,157	17,486	484	13,860	3,918	3,233	1,059
New Hampshire	MANE-VU	3,089	7,469	73	1,697	2,268	2,156	124
New Jersey	MANE-VU	13,636	32,495	352	7,611	4,017	3,515	564
New York	MANE-VU	24,376	51,445	758	22,242	11,031	9,343	1,472
Pennsylvania	MANE-VU	82,881	135,946	1,920	41,445	31,580	23,756	1,790
Rhode Island	MANE-VU	576	55	42	1,627	157	156	127
Vermont	MANE-VU	105	35	3	117	26	25	9
	MANE-VU Total	**175,218**	**320,651**	**4,528**	**115,659**	**65,558**	**52,360**	**6,148**
Alabama	VISTAS	41,714	190,029	1,599	27,888	20,401	15,936	2,009
Florida	VISTAS	56,506	139,526	2,027	58,982	24,804	18,403	3,948
Georgia	VISTAS	56,180	178,196	1,940	33,040	25,929	19,087	2,374
Kentucky	VISTAS	64,099	229,596	1,623	17,103	24,659	18,813	782
Mississippi	VISTAS	8,895	27,226	511	12,228	7,270	4,358	918
North Carolina	VISTAS	57,774	102,217	1,232	14,386	31,797	26,551	847
South Carolina	VISTAS	46,318	118,584	932	11,263	26,740	22,629	793
Tennessee	VISTAS	29,873	112,343	922	7,391	15,008	12,988	449
Virginia	VISTAS	43,144	80,602	863	16,482	19,652	17,300	881
West Virginia	VISTAS	51,208	124,464	1,447	12,946	23,538	16,968	721
	VISTAS Total	**455,711**	**1,302,784**	**13,096**	**211,709**	**219,798**	**173,034**	**13,722**
Illinois	MRPO	71,233	241,136	2,229	17,868	32,650	30,132	1,152
Indiana	MRPO	95,376	376,864	2,105	19,416	35,082	27,835	1,274
Michigan	MRPO	98,685	398,562	1,623	17,522	38,902	34,276	1,091
Ohio	MRPO	83,129	215,501	2,254	23,832	42,754	33,323	1,773
Wisconsin	MRPO	45,701	155,369	1,101	11,901	15,629	14,246	626
	MRPO Total	**394,124**	**1,387,432**	**9,312**	**90,539**	**165,016**	**139,813**	**5,915**
Arkansas	CENRAP	33,097	82,605	696	11,429	3,897	3,326	814
Iowa	CENRAP	51,119	147,305	770	8,759	10,033	8,615	569
Kansas	CENRAP	83,333	81,486	798	7,203	8,520	6,807	461
Louisiana	CENRAP	30,432	74,263	660	11,043	3,966	3,590	919
Minnesota	CENRAP	41,029	85,847	674	5,563	8,162	7,034	343
Missouri	CENRAP	77,660	280,887	1,579	13,165	18,456	16,769	800
Nebraska	CENRAP	50,781	73,629	450	3,590	2,296	1,915	217
Oklahoma	CENRAP	76,048	113,680	1,008	28,182	5,561	4,840	1,355
Texas	CENRAP	153,837	339,433	4,988	102,583	38,952	31,631	6,424
	CENRAP Total	**597,336**	**1,279,135**	**11,622**	**191,518**	**99,842**	**84,528**	**11,902**
Arizona	WRAP	81,858	60,640	1,170	29,037	11,515	9,644	2,189
California	WRAP	23,767	5,447	1,496	56,188	5,442	5,337	4,402
Colorado	WRAP	70,171	87,163	667	12,139	4,751	4,166	609
Idaho	WRAP	718	0	36	1,398	113	113	109
Montana	WRAP	38,504	22,066	326	3,035	7,217	4,636	193
Nevada	WRAP	47,404	31,172	479	9,862	5,244	4,315	750
New Mexico	WRAP	74,010	52,916	554	5,991	13,435	7,637	388
North Dakota	WRAP	71,711	108,645	784	9,937	5,670	4,757	324
Oregon	WRAP	11,330	10,034	276	9,322	1,311	1,305	722
South Dakota	WRAP	14,574	12,085	110	536	362	297	33
Utah	WRAP	60,782	37,819	423	3,523	6,459	4,881	211
Washington	WRAP	26,379	12,236	451	11,848	3,780	3,192	898
Wyoming	WRAP	81,182	40,265	678	5,672	8,537	7,116	341
	WRAP Total	**602,389**	**480,488**	**7,449**	**158,487**	**73,834**	**57,395**	**11,170**
National Total		**2,224,778**	**4,770,490**	**46,007**	**767,912**	**624,049**	**507,129**	**48,857**

4 MODIFICATIONS BY OTHER REGIONS

4.1 Emission Control Modifications within VISTAS, MRPO, and CENRAP

State and local agencies and invited stakeholders from VISTAS, MRPO, and CENRAP reviewed the results of the Inter-RPO Phase II set of IPM runs. These stakeholders primarily reviewed and commented on the IPM results with respect to IPM decisions on NO_x post-combustion controls and SO_2 scrubbers and provided additional information on when and where new SO_2 and NO_x controls were planned to come online based on the best available data from state rules, enforcement agreements, compliance plans, permits, and discussions/commitments from individual companies. They also reviewed the IPM results to verify that known and existing controls and emission rates were properly reflected in the IPM runs. After considering comments, adjustments to the IPM results were made to specific units using any new information they had as part of the permitting process or other contact with the industry that indicated which units would install controls as a result of CAIR and when these new controls would come on-line (MACTEC, 2007; MRPO 2006; ENVIRON 2007).

As described in the following section, some entities specified changes to the controls assigned by IPM to reflect their best estimates of emission control levels. These changes typically involved either 1) adding selective catalytic reduction (SCR) or scrubber controls to units where IPM did not predict SCR or scrubber controls, or 2) removing IPM-assigned SCR or scrubber controls at units where the commenting entity indicated there were no firm plans for controls at those units.

At this point in the process MANE-VU decided not to make any changes to the northeastern state IPM output regardless of state knowledge of discrepancies with actual conditions. MANE-VU determined that IPM provided a reasonable estimate of the impact of the CAIR cap and trade program consistent with methods used by EPA, and planners were concerned that adjustments would not reflect the allocation of ALL allowed emissions under CAIR.

In MANE-VU's final modeling, many of the changes made by the other RPOs were included, but due to the timing of the release of revised data, the location with respect to the modeling domain, and need to progress with modeling, MANE-VU did not incorporate changes reflected in the final CENRAP EGU files.

4.2 Emission Factor and Control Modifications for VISTAS Emission Sources

VISTAS reviewed the PM and NH_3 emissions from its States' EGUs provided after the original IPM to NIF conversation conducted for the RPOs and identified significantly higher emissions in 2009/2018 than in 2002. VISTAS determined this conversion used a set of PM and NH_3 emission factors that were "the most recent EPA approved uncontrolled emission factors" for estimating 2009/2018 EGU emissions but were most likely not the same emission factors used by States for estimating these emissions in 2002. Thus, the emission increase from 2002 to 2009/2018 was simply an artifact of the change in emission factors, not anything to do with changes in activity or control technology application. During this review, VISTAS additionally identified an inconsistent use of SCCs for determining emission factors between the base and future years.

Documentation (Alpine, 2005a, b) indicates that VISTAS adjusted the 2002 base year emissions inventory to account for these discrepancies in base year and future year PM and NH_3 emission factor use. Using the latest "EPA-approved" uncontrolled emission factors by SCC, Alpine utilized data collected under EPA's Consolidated Emissions Reporting Rule (CERR) or data reported by VISTAS. Alpine used reported annual heat input, fuel throughput, heat, ash, and sulfur content to estimate annual uncontrolled emissions for units identified as output by IPM. This step was conducted for non-CEM pollutants (CO, VOC, PM, and NH_3) only. For PM emissions, the condensable component of emissions was calculated and added to the resulting PM primary estimations. The resulting emissions were then adjusted by any control efficiency factors reported in the CERR or VISTAS data collection effort. The second adjustment was to the future year inventories. Alpine updated the SCCs in the future year inventory to assign the same base year SCC. Using the same methods as described for the 2002 revisions, those non-IPM generated pollutants were estimated using IPM predicted fuel characteristics and base year 2002 SCC assignments.

In addition to the changes to the emission factor assignments, SCC, and IPM-assigned controls, VISTAS also specified other changes to the IPM results or converted IPM to NIF files. Comments on changes in stack parameters from the 2002 inventory were implemented in the converted files for the 2018 inventory. Changes to stack parameters were also made in cases where new controls were scheduled to be installed. In cases where an emission unit was projected to have an SO_2 scrubber by 2018, some States were able to provide revised stack parameters for some units based on design features for the new control system. Other units projected to install scrubbers by 2018 were not far enough along in the design process to have specific design details. For those units, VISTAS made the following assumptions: 1) the scrubber is a wet scrubber; 2) keep the current stack height the same; 3) keep the current flow rate the same, and 4) change the stack exit temperature to 169 degrees F (this is the virtual temperature derived from a wet temperature of 130 degrees F) (MACTEC, 2007). VISTAS determined that exit temperature (wet) of 130 degrees F +/- 5 degrees F is representative of different size units and wet scrubber technology.

4.3 Emission Inventory Replacement within WRAP Domain

During the development of their EGU emission forecast, the western states RPO (WRAP) conducted an exercise where IPM was not used to prepare emission estimates from EGU sources. Using capacity factor adjustments and emission control assumptions, WRAP developed a forecast of EGU emissions based on its initial 2002 base year inventory (ERG, 2006). This revised forecast was used by many of the RPOs and replaced the emissions generated for the domain by IPM. This change by WRAP is reflected in the difference in State emission totals between Tables 5 and 6. As WRAP is outside the MANE VU modeling domain, this change was not reflected in MANE-VU modeling. MANE-VU did not change its boundary conditions to reflect this change.

4.4 Eliminating Double Counting of EGU Units

An additional set of procedures was used by MANE-VU and VISTAS to avoid double counting of EGU emissions in the 2018 point source inventory (MACTEC, 2006, 2007). Since each

RPO's 2002 emissions inventory file contained both EGUs and non-EGU point sources, and EGU emissions were projected using IPM, it was necessary to split the 2002 point source file into two components. The first component contained those emission units accounted for in the IPM forecasts. The second component contained all other point sources not accounted for in IPM.

As described in the previous section, 2018 NIF files for EGUs were prepared from the IPM parsed files. All IPM matched units were initially removed from the 2018 point source inventory to create the non-EGU inventory (which was projected to 2018 using non-EGU growth and control factors). This was done on a unit-by-unit basis based on a cross-reference table that matched IPM emission unit identifiers (ORISPL plant code and BLRID emission unit code) to NIF emission unit identifiers (FIPSST state code, FIPSCNTY county code, State Plant ID, State Point ID). When there was a match between the IPM ORISPL/BLRID and the emission unit ID, the unit was assigned to the EGU inventory; all other emission units were assigned to the non-EGU inventory.

If an emission unit was contained in the NIF files created from the IPM output, the corresponding unit was removed from the initial 2018 point source inventory. For VISTAS, the NIF 2018 EGU files from the IPM parsed files were then merged with the non-EGU 2018 files to create a complete 2018 point source scenario.

Next, several ad-hoc QA/QC queries were done to verify that there was no double-counting of emissions in the EGU and non-EGU inventories:

- The IPM parsed files were reviewed to identify EGUs accounted for in IPM. This list of emission units was compared to the non-EGU inventory derived from the IPM-NIF cross-reference table to verify that units accounted for in IPM were not double-counted in the non-EGU inventory. As a result of this comparison, a few adjustments were made in the cross-reference table to add emission units for plants to ensure these units accounted for in IPM were moved to the EGU inventory.

- The non-EGU inventory was further reviewed to identify remaining emission units with an Standard Industrial Classification (SIC) code of "4911 Electrical Services" or Source Classification Code of "1-01-xxx-xx External Combustion Boiler, Electric Generation". The list of sources meeting these selection criteria were compared to the IPM parsed file to ensure that these units were not double-counted.

- VISTAS invited various stakeholder groups to review the 2018 point source inventory to verify whether there was any double counting of EGU emissions. In some instances, corrections were provided where an emission unit was double counted.

4.5 Preliminary Results from Phase II Additional Modifications

Table 6 summarizes the Base G emissions inventory for EGUs, presenting State level emission results from the 2018 Inter-RPO CAIR Case IPM v. 2.1.9 parsed file modified by VISTAS, MRPO, and WRAP per the methods noted in the above sections. Note that no changes occurred to the MANE-VU state emissions as a result of these changes.

Table 6. State Level Emission Summary; 2018 VISTAS Base G Modeling file ptinv_egu_2018_11sep2006.txt. Based on 2018 VISTASII_PC_1f (fossil-only) with adjustments from VISTAS, MRPO, and WRAP.

		Annual Emissions (Tons)						
State	**RPO**	**NOx**	**SO2**	**VOC**	**CO**	**PM-10**	**PM-2.5**	**NH3**
Connecticut	MANE-VU	3,418	6,697	145	9,836	959	927	341
Delaware	MANE-VU	12,341	35,442	117	1,183	2,950	2,438	76
District Of Columbia	MANE-VU	103	83	5	154	104	99	12
Maine	MANE-VU	1,827	5,436	53	4,057	296	279	139
Maryland	MANE-VU	14,709	28,065	575	11,831	8,253	6,433	435
Massachusetts	MANE-VU	18,157	17,486	484	13,860	3,917	3,233	1,059
New Hampshire	MANE-VU	3,089	7,469	73	1,697	2,268	2,156	124
New Jersey	MANE-VU	13,636	32,495	352	7,611	4,017	3,515	564
New York	MANE-VU	24,376	51,445	758	22,242	11,031	9,343	1,471
Pennsylvania	MANE-VU	82,881	135,946	1,919	41,446	31,580	23,756	1,790
Rhode Island	MANE-VU	576	55	42	1,627	157	156	127
Vermont	MANE-VU	105	35	3	117	26	25	9
	MANE-VU Total	**175,219**	**320,651**	**4,528**	**115,660**	**65,558**	**52,360**	**6,148**
Alabama	VISTAS	62,860	135,782	1,620	21,611	7,385	4,380	1,033
Florida	VISTAS	56,827	133,037	1,857	42,573	9,287	6,288	2,665
Georgia	VISTAS	69,308	226,477	1,805	35,584	18,217	11,319	1,676
Kentucky	VISTAS	59,740	211,225	1,344	12,125	6,194	4,067	436
Mississippi	VISTAS	10,455	15,143	1,055	11,822	7,007	6,853	545
North Carolina	VISTAS	56,526	96,402	1,147	16,376	32,676	26,014	608
South Carolina	VISTAS	50,068	87,202	860	13,078	28,110	24,454	578
Tennessee	VISTAS	30,008	112,353	886	7,126	15,861	13,321	241
Virginia	VISTAS	60,615	109,391	921	14,017	13,505	11,757	553
West Virginia	VISTAS	51,177	115,322	1,382	11,896	6,344	3,643	177
	VISTAS Total	**507,583**	**1,242,334**	**12,877**	**186,205**	**144,586**	**112,094**	**8,513**
Illinois	MRPO	71,233	241,136	2,229	17,868	32,649	30,132	1,152
Indiana	MRPO	95,376	351,858	2,105	19,416	35,081	27,835	1,274
Michigan	MRPO	78,605	288,006	1,623	17,521	38,902	34,276	1,091
Ohio	MRPO	83,129	215,501	2,254	23,832	42,753	33,322	1,772
Wisconsin	MRPO	45,701	155,369	1,101	11,901	15,629	14,246	626
	MRPO Total	**374,044**	**1,251,871**	**9,311**	**90,539**	**165,015**	**139,812**	**5,915**
Arkansas	CENRAP	33,097	82,605	696	11,429	3,897	3,326	814
Iowa	CENRAP	51,119	147,305	770	8,758	10,033	8,615	569
Kansas	CENRAP	83,333	81,486	798	7,203	8,520	6,807	461
Louisiana	CENRAP	30,432	74,263	660	11,043	3,966	3,590	919
Minnesota	CENRAP	41,029	85,847	674	5,563	8,162	7,035	343
Missouri	CENRAP	77,660	280,887	1,579	13,165	18,456	16,769	799
Nebraska	CENRAP	50,781	73,629	450	3,590	2,296	1,914	217
Oklahoma	CENRAP	76,048	113,680	1,008	28,182	5,561	4,840	1,355
Texas	CENRAP	153,837	339,433	4,988	102,581	38,952	31,630	6,424
	CENRAP Total	**597,336**	**1,279,135**	**11,622**	**191,515**	**99,842**	**84,527**	**11,901**
Arizona	WRAP	59,774	55,941	724	17,806	2,811	634	630
California	WRAP	17,537	1,528	2,558	31,173	1,219	1,059	0
Colorado	WRAP	77,113	60,914	1,465	18,939	3,138	307	537
Idaho	WRAP	2,236	1,683	50	3,283	335	87	0
Montana	WRAP	44,733	31,303	565	11,818	1,796	247	13
Nevada	WRAP	54,300	22,118	1,570	10,598	4,230	768	903
New Mexico	WRAP	32,925	17,796	695	10,976	794	627	43
North Dakota	WRAP	82,741	152,828	909	13,647	3,958	2,645	383
Oregon	WRAP	15,742	15,096	474	5,753	1,288	323	219
South Dakota	WRAP	17,681	13,522	118	689	247	217	52
Utah	WRAP	76,136	41,394	597	17,150	4,637	2,000	1,350
Washington	WRAP	16,884	7,011	249	4,008	1,474	1,027	12
Wyoming	WRAP	104,142	96,745	1,147	18,871	10,445	7,411	404
	WRAP Total	**601,942**	**517,879**	**11,122**	**164,711**	**36,371**	**17,353**	**4,547**
National Total		**2,256,124**	**4,611,869**	**49,460**	**748,629**	**511,371**	**406,146**	**37,024**

4.6 Revised Results – VISTAS Base G2 Adjustment

VISTAS further refined their future predictions based on further state input. The resulting modeling file was called the Base G2 inventory. Table 7 presents State level emission results from the Base G2 2018 Inter-RPO CAIR Case IPM v. 2.1.9 parsed file modified by VISTAS.

Some states specified changes to the controls assigned by IPM to reflect their best estimates of emission control levels. These changes typically involved either 1) adding selective catalytic reduction (SCR) or scrubber controls to units where IPM did not predict SCR or scrubber controls, or 2) removing IPM-assigned SCR or scrubber controls at units where the commenting entity indicated their were no firm plans for controls at those units. These changes were based on those states' best available information about where and when emissions controls were expected to be installed, as well as information concerning IPM-predicted plant closures that were deemed unlikely to occur. In comparing Table 7 with Table 6, it can be seen that the changes included in the Base G2 inventory were requested by the states of Florida, Georgia, and North Carolina.

Note that no changes were made at this time by the MANE-VU states. The net effect of these changes was to reduce emissions of SO_2 relative to either Table 5 or Table 6.

Table 7. State Level Emission Summary; 2018 VISTAS Base G2 Modeling file egu_18_vistas_g2_20feb2007.txt. Based on 2018 VISTASII_PC_1f (fossil-only) with adjustments from VISTAS, MRPO, and WRAP.

		Annual Emissions (Tons)						
State	**RPO**	**NOx**	**SO2**	**VOC**	**CO**	**PM-10**	**PM-2.5**	**NH3**
Connecticut	MANE-VU	3,418	6,697	145	9,836	959	927	341
Delaware	MANE-VU	12,341	35,442	117	1,183	2,950	2,438	76
District Of Columbia	MANE-VU	103	83	5	154	104	99	12
Maine	MANE-VU	1,827	5,436	53	4,057	296	279	139
Maryland	MANE-VU	14,709	28,065	575	11,831	8,253	6,433	435
Massachusetts	MANE-VU	18,157	17,486	484	13,860	3,917	3,233	1,059
New Hampshire	MANE-VU	3,089	7,469	73	1,697	2,268	2,156	124
New Jersey	MANE-VU	13,636	32,495	352	7,611	4,017	3,515	564
New York	MANE-VU	24,376	51,445	758	22,242	11,031	9,343	1,471
Pennsylvania	MANE-VU	82,881	135,946	1,919	41,446	31,580	23,756	1,790
Rhode Island	MANE-VU	576	55	42	1,627	157	156	127
Vermont	MANE-VU	105	35	3	117	26	25	9
	MANE-VU Total	**175,219**	**320,651**	**4,528**	**115,660**	**65,558**	**52,360**	**6,148**
Alabama	VISTAS	62,860	135,782	1,620	21,611	7,385	4,380	1,033
Florida	VISTAS	58,341	139,200	1,904	42,947	9,355	6,331	2,665
Georgia	VISTAS	69,308	75,051	1,805	35,584	18,217	11,319	1,676
Kentucky	VISTAS	59,740	211,225	1,344	12,125	6,194	4,067	436
Mississippi	VISTAS	10,455	15,143	1,055	11,822	7,007	6,853	545
North Carolina	VISTAS	56,526	102,680	1,147	16,376	32,676	26,014	608
South Carolina	VISTAS	50,068	87,202	860	13,078	28,110	24,454	578
Tennessee	VISTAS	30,008	112,353	886	7,126	15,861	13,321	241
Virginia	VISTAS	60,615	109,391	921	14,017	13,505	11,757	553
West Virginia	VISTAS	51,177	105,932	1,382	11,896	6,344	3,643	177
	VISTAS Total	**509,098**	**1,093,959**	**12,923**	**186,579**	**144,654**	**112,137**	**8,513**
Illinois	MRPO	71,233	241,136	2,229	17,868	32,649	30,132	1,152
Indiana	MRPO	95,376	351,858	2,105	19,416	35,081	27,835	1,274
Michigan	MRPO	78,605	288,006	1,623	17,521	38,902	34,276	1,091
Ohio	MRPO	83,129	215,501	2,254	23,832	42,753	33,322	1,772
Wisconsin	MRPO	45,701	155,369	1,101	11,901	15,629	14,246	626
	MRPO Total	**374,044**	**1,251,871**	**9,311**	**90,539**	**165,015**	**139,812**	**5,915**
Arkansas	CENRAP	33,097	82,605	696	11,429	3,897	3,326	814
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Missouri	CENRAP	77,660	280,887	1,579	13,165	18,456	16,769	799
Nebraska	CENRAP	50,781	73,629	450	3,590	2,296	1,914	217
Oklahoma	CENRAP	76,048	113,680	1,008	28,182	5,561	4,840	1,355
Texas	CENRAP	153,837	339,433	4,988	102,581	38,952	31,630	6,424
	CENRAP Total	**597,336**	**1,279,135**	**11,622**	**191,515**	**99,842**	**84,527**	**11,901**
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Nevada	WRAP	54,300	22,118	1,570	10,598	4,230	768	903
New Mexico	WRAP	32,925	17,796	695	10,976	794	627	43
North Dakota	WRAP	82,741	152,828	909	13,647	3,958	2,645	383
Oregon	WRAP	15,742	15,096	474	5,753	1,288	323	219
South Dakota	WRAP	17,681	13,522	118	689	247	217	52
Utah	WRAP	76,136	41,394	597	17,150	4,637	2,000	1,350
Washington	WRAP	16,884	7,011	249	4,008	1,474	1,027	12
Wyoming	WRAP	104,142	96,745	1,147	18,871	10,445	7,411	404
	WRAP Total	**601,942**	**517,879**	**11,122**	**164,711**	**36,371**	**17,353**	**4,547**
National Total		**2,257,639**	**4,463,494**	**49,506**	**749,003**	**511,439**	**406,189**	**37,024**

5 ADDITIONAL ADJUSTMENTS BY NORTHEASTERN STATES AND MODELERS FOR REGIONAL HAZE SIP MODELING

5.1 Introduction

MANE VU used the G2 inventory as the basis for further adjustments to incorporate MANE-VU state changes and also to represent the MANE VU control strategy for key EGUs. These modifications resulted in a) SO_2 emissions reductions at one MANE-VU EGU source subject to Best Available Retrofit Technology (BART) requirements, 2) emissions increases in MANE-VU to reflect states' best estimates that some sources predicted by IPM to be closed would continue to operate and information about where and when emission controls would or would not be installed, 3) SO_2 emissions reductions at key EGUs (or alternative facilities) to reflect the MANE-VU EGU strategy, and 4) increases in SO_2 emissions to estimate the effect of emissions trading under the CAIR program. Each of these is explained below.

5.2 Best Available Retrofit Technology (BART)

To assess the impacts of the implementation of the BART provisions of the Regional Haze Rule, NESCAUM included estimated reductions anticipated for BART-eligible facilities not covered by CAIR in the MANE-VU region in the 2018 CMAQ modeling analysis. A survey of state staff indicated that eight units would likely be controlled under BART alone. State-provided potential control technologies and levels of control for these sources were incorporated into the 2018 emission inventory projections used in MANE-VU's March 2008 modeling run (NESCAUM, 2008b). The eight BART-eligible units included one EGU point source, which is located in Maine (Wyman Station).

5.3 MANE-VU State Modifications of IPM Results

Previously, during development of the Base G and Base G2 inventories, MANE-VU states had relied on the RPO IPM model results (Base F) without revisions. In 2007, the MANE-VU states decided that they should revise the estimates, as other RPOs had done, to reflect their best estimates of future source operations and controls. State and regional staff reviewed and revised the IPM results with respect to when and where new SO_2 controls were planned to come online. Modifications were based on state rules, enforcement agreements, compliance plans, permits, and commitments from individual companies. States reviewed the IPM results to verify that known and existing controls and emission rates were properly reflected in the IPM results. In addition, states noted that some units predicted by IPM to close were very unlikely to cease operation.

The net effect of these adjustments was an increase in SO_2 emissions in the MANE-VU region as a whole. In Delaware SO_2 emissions decreased due to controls on a major source. Emissions in Connecticut, the District of Columbia, Rhode Island, and Vermont remained the same as predicted by RPO IPM 2.1.9 (Base F). Emissions of SO_2 in other MANE-VU states increased. No changes were made in emissions of other pollutants.

5.4 MANE-VU EGU Strategy

MANE-VU states have recognized that SO_2 emissions from power plants are the single largest contributing sector to visibility impairment in the Northeast's Class I areas. Sulfate formed through atmospheric processes from SO_2 emissions are responsible for over half the mass and approximately 70-80 percent of the extinction on the worst visibility days (NESCAUM, 2006a, and b). The emissions from power plants dominate the SO_2 inventory.

A modeling analysis was conducted to identify those EGUs with the greatest impact on visibility in MANE-VU. As part of the MANE VU Contribution Assessment, two MANE-VU modeling centers undertook CALPUFF modeling to identify the top 100 stacks that impacted three of the MANE VU Class I areas in the base year, 2002. These three areas are Acadia, Brigantine and Lye Brook. Details of the modeling are provided in Appendix D of the Contribution Assessment. (NESCAUM, 2006a) The 100 top stacks for each Class I area are listed in Tables 10 and 20 from Appendix D "Dispersion Model Techniques" of the Contribution Assessment.

The two modeling centers used 2002 U.S. EPA Continuous Emission Monitoring System (CEMS) data reported by the power companies, which is stack based rather than emission unit based. A power plant may have several stacks. Each stack may vent emissions from one or more units at the plant. The two modeling centers also used different meteorological data—one used data from the MM5 model and the other used National Weather Service observation-based meteorology.

There are differences between results from the two centers because of the differences in meteorological input data and also because of rounding when summing annual emissions. As a result the MM5-based modeling identified some stacks as being in the top 100 impacting a MANE-VU Class I area that were not identified by the observation-based modeling, and vice versa. For purposes of identifying key stacks, all stacks on either list were included.

MARAMA combined the lists of the top 100 EGU stacks in Tables 10 and 20 from Appendix D of the Contribution Assessment and eliminated both duplications and stacks that were outside the MANE-VU consultation area. (The consultation area includes states contributing at least 2% of the sulfate monitored at MANE-VU Class I areas in 2002.) This process resulted in 167 unique stacks impacting one or more of the three MANE-VU Class I areas. The use of stacks rather than units or facilities was chosen as more consistent with the results of the modeling presented in the Contribution Assessment. The Contribution Assessment Appendix D tables did not identify the units or facilities that were modeled, only providing a CEMS Identification number. MARAMA used information contained in IPM input files to match up the plant name and type where the stack was located. The resulting list of 167 stacks is found in Appendix A of this report.

MANE-VU asked states in the consultation area to pursue 90 percent control on all units emitting from those stacks by 2018. MANE-VU recognized that this level of control may not be feasible in all cases. NESCAUM modelers incorporated State comments gathered during the inter-RPO consultation process in estimating the impact of this strategy on visibility at Class I areas. This process is described below in Section 5.5.

5.5 Implementation of MANE-VU Control Strategy for Key EGUs

As part of the MANE-VU strategy to improve visibility, MANE-VU asked states to pursue a 90 percent reduction in SO_2 emissions from the 167 EGU stacks identified as described in Section 5.4 and listed in Appendix A. MARAMA gathered information from MANE-VU, MRPO, and VISTAS states and regional staff to obtain information about anticipated emissions changes.

State and local agencies and individual stakeholders from MANE-VU, MRPO and VISTAS reviewed and revised the IPM results with respect to controls planned to come online. They also reviewed the IPM results to verify that known and existing controls and emission rates were properly reflected in the IPM runs. In addition, commenters noted that some units predicted by IPM to be shutdown would not shutdown.

Adjustments to the IPM results were made to specific units using information states had obtained as part of the permitting process or other contact with the industry that indicated which units would install controls as a result of CAIR and when these new controls would come on-line (Koerber, 2007; VISTAS 2007). In general, the changes at specific EGUs provided by VISTAS reflected their Base G2 inventory, and, as discussed with MRPO, the changes NESCAUM made to emissions from sources in the MRPO were consistent with sources where controls were predicted in EPA's IPM 3.0 run for 2018, since MRPO modeling relied on IPM 3.0. In addition to the 167 stacks, MANE-VU incorporated further corrections to source emissions as requested by VISTAS states at the following locations: North Carolina (Cliffside), South Carolina (Jefferies), Kentucky (Spurlock), and Virginia (Chesapeake and Clinch River). .

NESCAUM determined the desired emissions levels for the 167 key stacks based on a 90 percent reduction in continuous emissions monitoring data from 2002. This established a target emissions level for the region from those stacks. NESCAUM compared these levels with the information provided by the states for those sources. In each region, predicted 2018 emissions exceeded the target level. Therefore, emissions reductions from other sources were considered in order to meet the target emissions reductions for the region.(both within MANE-VU and in other RPOs). This resulted in a net decrease in emissions in all three affected RPOs. Emissions of SO_2 would have decreased by over 14,000 tons per year in MANE-VU, over 304,000 tons per year in the Midwest, and over 197,000 tons per year in the VISTAS region.

However, MANE-VU planners recognized that CAIR allows emissions trading, and that reductions at one unit could be offset increases at another unit within the CAIR region. Because most states do not restrict trading, MANE-VU decided that emissions should be increased to represent the implementation of the strategy for the 167 stacks within the limits of the CAIR program. Therefore, NESCAUM increased the emissions from states subject to the CAIR cap and trade program. For MANE-VU, 75,809 tons were added back, leaving total regional emissions from the MANE-VU region greater than the original Inter-RPO IPM-based estimate but consistent with state projections. The remaining 440,541 tons added back were allocated to

VISTAS and MRPO based on the fraction of their contribution to the total SO_2 emissions. The additional emissions correspond to an increase of 20.5 percent, with a total of 223,856 tons added to MRPO and 216,685 added to VISTAS.

Table 8 shows the emissions difference between the results of two IPM runs and the modeling inventories used by three Regional Planning Organizations (RPOs). VISTAS used Base G2, MANE-VU used the March 2008 Modeling Inventory, and MRPO used IPM 3.0..

Table 8. Comparison of Regional SO_2 Emissions Estimates.
(1000 tons per year)

	MANE-VU	**MRPO**	**VISTAS**	**TOTAL**
RPO 2.1.9 (VISTASII_PC_1f) (fossil only)	**321**	**1,387**	**1,303**	**3,011**
Reductions made by VISTAS and MRPO (Base G2)	0	-136	-209	-344
Net additional changes made by MANE-VU	66	24	222	311
MANE-VU March 2008 Modeling Inventory (fossil only)	**387**	**1,276**	**1,316**	**2,978**
MANE-VU minus RPO 2.1.9 (negative numbers mean MANE-VU's modeling inventory was less than RPO 2.1.9)	66	-112	13	-33
EPA 3.0 (fossil only)	**421**	**1,328**	**1,458**	**3,207**
RPO 2.1.9 minus EPA 3.0 (negative number means RPO 2.1.9 was less than EPA 3.0)	-100	59	-155	-196
MANE-VU 3/08 minus EPA 3.0 (negative numbers mean MANE-VU's modeling inventory was less than EPA 3.0)	-34	-53	-142	-229

The intent of the MANE-VU modelers' final EGU emissions adjustments was to retain the same level of emissions as predicted by the RPO CAIR IPM run for the three regions together, but to modify the locations of the emissions to better reflect the states' estimates and to achieve reductions at the 167 stacks identifie++d as important contributors to regional haze at MANE-VU Class I areas. As shown in Table 8, above, the MANE-VU adjustments resulted in total emissions from the three regions being less than the SO_2 emissions predicted by the RPO 2.1.9 IPM run but greater than emissions in the G2 inventory used by VISTAS modelers. In both the MANE-VU and VISTAS regions, the MANE-VU Modeling Inventory is greater than the VISTAS/Inter-RPO IPM run and in MRPO it is smaller. Results from IPM 3.0 also are provided for comparison, and are uniformly greater than the MANE-VU Modeling Inventory for EGUs.

All future EGU emissions estimates involve uncertainty. MANE-VU believes its process of adding back emissions resulted in a reasonable, conservative estimate of the implementation of the MANE-VU request for a 90% reduction at key EGU facilities.

5.6 State Results – Northeastern State Adjustments

Table 9 presents State level emission results as modified by the Northeastern States per the methods noted in the above sections. This table summarizes the input data used in the MANE-VU 2018 March 2008 Modeling run as documented in NESCAUM's *2018 Visibility Projections* report dated March 2008.

Table 9. State Level 2018 Emission Summary; March 2008 MANE-VU EGU Modeling Inventory. (See next page for file names.)

		Annual Emissions (Tons)						
State	**RPO**	**NOx**	**SO2**	**VOC**	**CO**	**PM-10**	**PM-2.5**	**NH3**
Connecticut	MANE-VU	3,418	6,697	145	9,836	959	927	341
Delaware	MANE-VU	12,341	10,941	117	1,183	2,950	2,438	76
District Of Columbia	MANE-VU	103	83	5	154	104	99	12
Maine	MANE-VU	1,827	6,806	53	4,057	296	279	139
Maryland	MANE-VU	14,709	43,764	575	11,831	8,253	6,433	435
Massachusetts	MANE-VU	18,157	45,941	484	13,860	3,917	3,233	1,059
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New Jersey	MANE-VU	13,636	15,918	352	7,611	4,017	3,515	564
New York	MANE-VU	24,376	74,587	758	22,242	11,031	9,343	1,471
Pennsylvania	MANE-VU	82,881	170,992	1,919	41,446	31,580	23,756	1,790
Rhode Island	MANE-VU	576	55	42	1,627	157	156	127
Vermont	MANE-VU	105	35	3	117	26	25	9
	MANE-VU Total	**175,219**	**386,584**	**4,528**	**115,660**	**65,558**	**52,360**	**6,148**
Alabama	VISTAS	62,860	163,567	1,620	21,611	7,385	4,380	1,033
Florida	VISTAS	58,341	167,685	1,903	42,946	9,355	6,330	2,665
Georgia	VISTAS	69,308	90,408	1,805	35,584	18,217	11,319	1,676
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	VISTAS Total	**509,098**	**1,315,740**	**12,922**	**186,579**	**144,653**	**112,137**	**8,512**
Illinois	MRPO	71,233	208,832	2,229	17,868	32,649	30,132	1,152
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Nevada	WRAP	54,300	22,118	1,570	10,598	4,230	768	903
New Mexico	WRAP	32,925	17,796	695	10,976	794	627	43
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Oregon	WRAP	15,742	15,096	474	5,753	1,288	323	219
South Dakota	WRAP	17,681	13,522	118	689	247	217	52
Utah	WRAP	76,136	41,394	597	17,150	4,637	2,000	1,350
Washington	WRAP	16,884	7,011	249	4,008	1,474	1,027	12
Wyoming	WRAP	104,142	96,745	1,147	18,871	10,445	7,411	404
	WRAP Total	**601,942**	**517,879**	**11,122**	**164,711**	**36,371**	**17,353**	**4,547**
National Total		**2,257,639**	**4,774,936**	**49,505**	**749,003**	**511,439**	**406,188**	**37,023**

Files used in preparing Table 9 include for CENRAP and WRAP, the VISTAS Base G2 Modeling file (egu_18_vistas_g2_20feb2007.txt.), and the following additional files:

- MANE-VU:
    - EGU2018_MANEVUv3_nonSO2.ida
    - EGU2018_MANEVU_SO2_non167plus.ida
    - EGU2018_MANEVU_SO2_167plus.ida
- VISTAS:
    - EGU2018_VISTASG2_SO2_non167plus_CAIRaddback.ida
    - EGU2018_VISTASG2_SO2_167plus_CAIRaddback.ida
    - EGU2018_VISTASG2_nonSO2.ida
- MRPO:
    - EGU2018_MWRPO_SO2_167plus_CAIRaddback.ida
    - EGU2018_MWRPO_SO2_non167p_non65_CAIRaddback.ida
    - EGU2018_MWRPO_SO2_65_CAIRaddback.ida
    - EGU2018_MWRPO_nonSO2.ida

6 EGU PREPARATION TIMELINE

The following section provides a chronological review of the events and milestones that occurred during the preparation of EGU emission forecasts in support of regional haze SIP preparation.

2004
- VISTAS/MRPO sponsor first IPM 2.1.6 runs for 2018 (Phase I)
- Phase I (VISTAS_CAIR_2) results released

2005
- RPOs move to IPM 2.1.9 (Phase II)
- Revisions to NEEDS input file and global parameters submitted by RPOs for revised runs
- Phase II (VISTAS_II_PC_1f) results released
- IPM parsed to NIF and NIF to SMOKE IDA format conversion occurs
- Initial RPO adjustments and modifications of IPM results
- RPOs share IPM 2.1.9 inputs and configuration from Phase II with EPA
- EPA releases IPM 2.1.9 results of CAIR/CAMR modeling

2006
- Additional RPO control and modeling file adjustments to Phase II runs
- RPOs simulate 2018 forecast year to support regional haze SIP submittals
- RPOs work with EPA to configure NEEDS 3.0 for next round of EPA modeling
- EPA releases IPM 2006 revised projections
- RPOs identify potential control measures and estimate benefits for meeting reasonable progress goals
- Additional RPO control and modeling file adjustments to Phase II runs

2007
- RPOs analyze cost and other factors associated with potential control measures
- RPOs coordinate with EPA on inputs and runs of IPM 3.0
- EPA releases IPM 3.0 results of revised CAIR/CAMR/CAVR modeling
- Interstate and inter-regional consultation regarding potential control measures
- MANE-VU states agree to pursue several control measures
- RPOs begin regional modeling to assess visibility impacts of controls

2008
- RPOs model to determine progress goals for regional haze SIP
- States finalize regional haze SIPs

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Appendix A

TOP ELECTRIC GENERATING EMISSION POINTS CONTRIBUTING TO VISIBILITY IMPAIRMENT IN MANE-VU IN 2002

For each of three MANE-VU Class I Areas the 100 Electric Generating Unit (EGU) stacks with the most significant impact on visibility impairment were identified by Calpuff modeling conducted by two modeling centers.[1] Many of these stacks have a regional impact and therefore significantly impact more than one Class I Area. When the “Top Impacting” stacks are aggregated into a single group there are 167 individual “Top Impacting” stacks identified. The map on the following page indicates the location of the 167 stacks, and the table following the map provides identifying information, emissions used in the Calpuff modeling, and predicted impacts. The following information may be found in the listed columns of the following table:

1. Row Number (1 through 167)
2. CEMS Unit ID: an arbitrary number identifying the CEMS unit
3. ORIS ID: a standard identification number associated with each unit
4. Acadia MM5: The rank of this source based on its predicted sulfate ion annual impact on Acadia in 2002 using meteorological data from the MM5 model. (A blank in columns 4, 5, 6, 7, 8, or 9 indicates this source was not among the top 100 for this Class I area as predicted by the indicated model.)
5. Acadia VTDEC: The rank of this source in terms of its predicted sulfate ion annual impact on Acadia in 2002 using National Weather Service data.
6. Brig MM5: The rank of this source in terms of its predicted sulfate ion annual impact on Brigantine in 2002 using meteorological data from the MM5 model.
7. Brig VTDEC: The rank of this source in terms of its predicted sulfate ion annual impact on Brigantine in 2002 using National Weather Service data.
8. Lye MM5: The rank of this source in terms of its predicted sulfate ion annual impact on Lye Brook in 2002 using meteorological data from the MM5 model.
9. Lye VTDEC: The rank of this source in terms of its predicted sulfate ion annual impact on Lye Brook in 2002 using National Weather Service data.
10. MM5 2002 SO_2 Tons per Year: Emissions calculated from CEMS data and used by modelers who used the MM5 generated meteorological data
11. VTDEC 2002 SO_2 Tons per Year: Emissions calculated from CEMS data and used by modelers who used the national weather service generated meteorological data
12. Plant Number (1 through 105): The 167 stacks are located at 105 plants.
13. Plant Name—table is in alphabetical order by plant within each state
14. Plant Type: coal fired or oil/gas fired electric generating units
15. State Name—table is in alphabetical order by state
16. State Code

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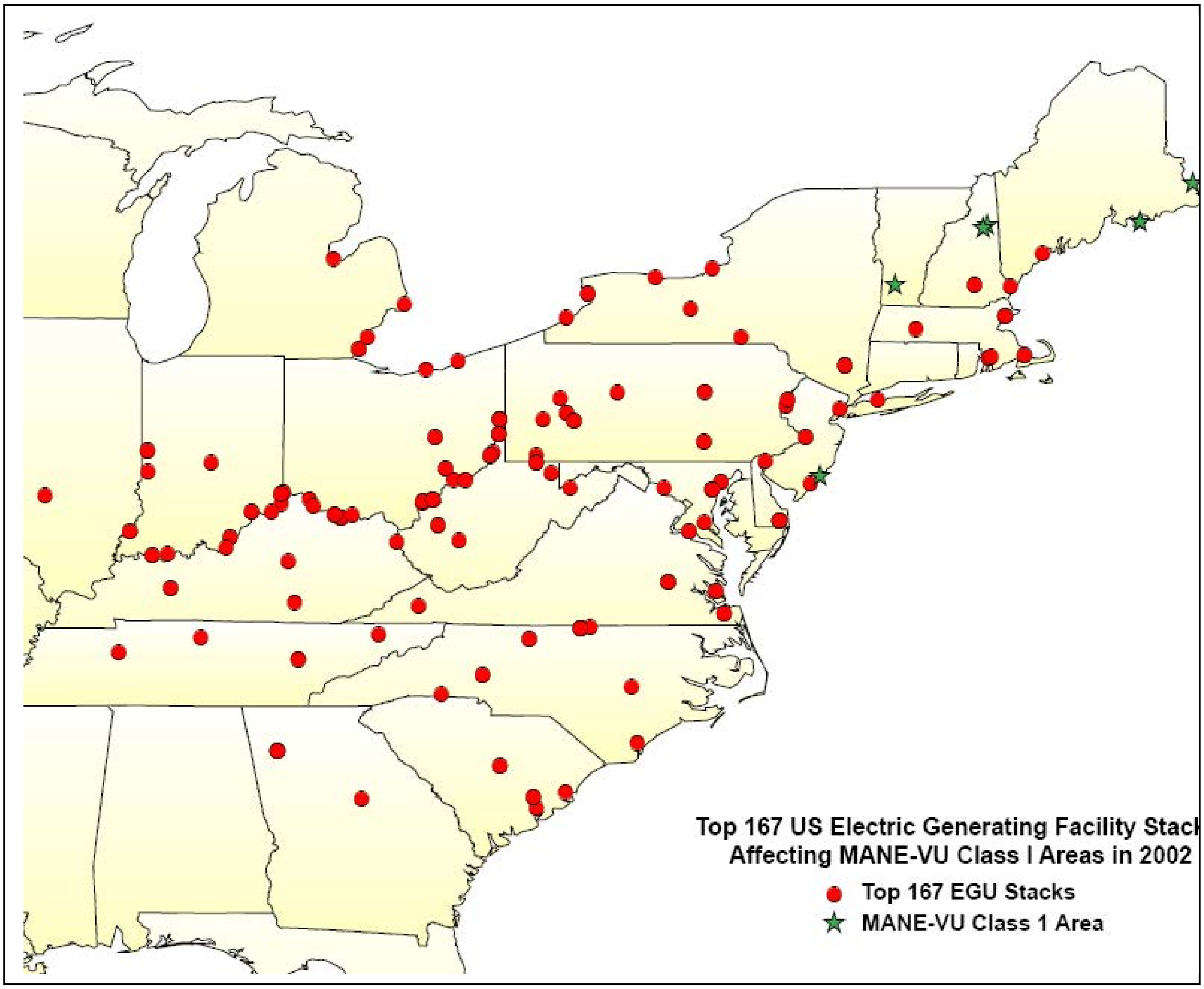
[1] For more information and detailed modeling results, see Appendix D: Source Dispersion Model Methods, in NESCAUM 2006a.

Figure A-1. Top 167 US Electric Generating Facility Stacks Affecting MANE-VU Class I Areas in 2002.



Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
1	D005935	593			90	54			2,138	2,136	1	EDGE MOOR	O/G Steam	Delaware	10
2	D005941	594				95				3,742	2	INDIAN RIVER	Coal Steam	Delaware	10
3	D005942	594				74				3,760	2	INDIAN RIVER	Coal Steam	Delaware	10
4	D005943	594			84	44			4,686	4,682	2	INDIAN RIVER	Coal Steam	Delaware	10
5	D005944	594			69	21			7,390	7,384	2	INDIAN RIVER	Coal Steam	Delaware	10
6	D007031LR	703	79			86		75	38,520	38,486	3	BOWEN	Coal Steam	Georgia	13
7	D007032LR	703	72		89		61	68	37,289	37,256	3	BOWEN	Coal Steam	Georgia	13
8	D007033LR	703	71	99	74	64	63	94	43,067	43,029	3	BOWEN	Coal Steam	Georgia	13
9	D007034LR	703	69	95	86	58	60	89	41,010	40,974	3	BOWEN	Coal Steam	Georgia	13
10	D00709C02	709		84		75	89	71	47,591	47,549	4	HARLLEE BRANCH	Coal Steam	Georgia	13
11	D00861C01	861	28	96		65	46	62	42,355	42,318	5	COFFEEN	Coal Steam	Illinois	17
12	D010011	1001			53				28,876	28,851	6	CAYUGA	Coal Steam	Indiana	18
13	D010012	1001	95		46	68			26,016	25,992	6	CAYUGA	Coal Steam	Indiana	18
14	D00983C01	983					52		19,922		7	CLIFTY CREEK	Coal Steam	Indiana	18
15	D00983C02	983					54		18,131		7	CLIFTY CREEK	Coal Steam	Indiana	18
16	D0099070	990		55	100	70		37	29,801	29,774	8	ELMER W STOUT	O/G Steam	Indiana	18
17	D06113C03	6113	30	48	14	43	22	41	71,182	71,119	9	GIBSON	Coal Steam	Indiana	18
18	D06113C04	6113	44	70	97	83	73	83	27,848	27,823	9	GIBSON	Coal Steam	Indiana	18
19	D01008C01	1008			73		100	47	24,109	24,087	10	R GALLAGHER	Coal Steam	Indiana	18
20	D01008C02	1008			98			55	23,849	23,828	10	R GALLAGHER	Coal Steam	Indiana	18
21	D06166C02	6166	62	44	30	81	33	57	51,708	51,663	11	ROCKPORT	Coal Steam	Indiana	18
22	D00988C03	988						77		15,946	12	TANNERS CREEK	Coal Steam	Indiana	18
23	D00988U4	988	14	29	52	34	7	19	45,062	45,022	12	TANNERS CREEK	Coal Steam	Indiana	18
24	D01010C05	1010	43	32	12	28	31	17	60,747	60,693	13	WABASH RIVER	Coal Steam	Indiana	18
25	D067054	6705	34	60	34		44	73	40,118	40,082	14	WARRICK	Coal Steam	Indiana	18
26	D06705C02	6705	92		75		96		27,895		14	WARRICK	Coal Steam	Indiana	18
27	D01353C02	1353	38	30	15	26	85	29	41,545	41,508	15	BIG SANDY	Coal Steam	Kentucky	21

Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
28	D01384CS1	1384	22				58		21,837	21,817	16	COOPER	Coal Steam	Kentucky	21
29	D01355C03	1355	21		51	99	68	52	38,104	38,070	17	E W BROWN	Coal Steam	Kentucky	21
30	D060182	6018	83				39		12,083		18	EAST BEND	Coal Steam	Kentucky	21
31	D01356C02	1356	93	71		88	50	59	25,646	25,623	19	GHENT	Coal Steam	Kentucky	21
32	D060411	6041	61						18,375		20	H L SPURLOCK	Coal Steam	Kentucky	21
33	D060412	6041	53		91			98	20,491	20,473	20	H L SPURLOCK	Coal Steam	Kentucky	21
34	D013644	1364			81				7,185		21	MILL CREEK	Coal Steam	Kentucky	21
35	D013782	1378					87		20,245		22	PARADISE	Coal Steam	Kentucky	21
36	D013783	1378	76	100	11	84	55	42	46,701	46,660	22	PARADISE	Coal Steam	Kentucky	21
37	D015074	1507	78						1,170		23	WILLIAM F WYMAN	O/G Steam	Maine	23
38	D006021	602	90		38			100	20,014	19,996	24	BRANDON SHORES	Coal Steam	Maryland	24
39	D006022	602	99		29			99	19,280	19,263	24	BRANDON SHORES	Coal Steam	Maryland	24
40	D015521	1552			63				17,782	17,767	25	C P CRANE	Coal Steam	Maryland	24
41	D015522	1552			68				14,274	14,262	25	C P CRANE	Coal Steam	Maryland	24
42	D01571CE2	1571	42	47	1	4	20	28	48,566	48,522	26	CHALK POINT	Coal Steam	Maryland	24
43	D01572C23	1572	73	79	47	45	69	32	32,188	32,159	27	DICKERSON	Coal Steam	Maryland	24
44	D015543	1554			77				10,084	10,075	28	HERBERT A WAGNER	O/G Steam	Maryland	24
45	D015731	1573	67	50	16	12	56	38	36,823	36,790	29	MORGANTOWN	Coal Steam	Maryland	24
46	D015732	1573	59	53	10	13	51	39	30,788	30,761	29	MORGANTOWN	Coal Steam	Maryland	24
47	D016191	1619	37	80					9,252	9,244	30	BRAYTON POINT	Coal Steam	Massachusetts	25
48	D016192	1619	35	66					8,889	8,881	30	BRAYTON POINT	Coal Steam	Massachusetts	25
49	D016193	1619	4	14	65	56	79		19,325	19,308	30	BRAYTON POINT	Coal Steam	Massachusetts	25
50	D015991	1599	5	36			65		13,014	13,002	31	CANAL	O/G Steam	Massachusetts	25
51	D015992	1599	7	27			74		8,980	8,971	31	CANAL	O/G Steam	Massachusetts	25
52	D016061	1606						48		5,249	32	MOUNT TOM	Coal Steam	Massachusetts	25
53	D016261	1626	85						3,430		33	SALEM HARBOR	Coal Steam	Massachusetts	25
54	D016263	1626	91	78					4,971	4,966	33	SALEM HARBOR	Coal Steam	Massachusetts	25

Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
55	D016264	1626	32	25					2,880	2,878	33	SALEM HARBOR	O/G Steam	Massachusetts	25
56	D016138	1613	94						4,376		34	SOMERSET	Coal Steam	Massachusetts	25
57	D01702C09	1702						96		4,565	35	DAN E KARN	Coal Steam	Michigan	26
58	D01733C12	1733	49	24	80	80	45	22	46,081	46,040	36	MONROE	Coal Steam	Michigan	26
59	D01733C34	1733	27	26		76	26	27	39,362	39,327	36	MONROE	Coal Steam	Michigan	26
60	D017437	1743		91						15,805	37	ST CLAIR	Coal Steam	Michigan	26
61	D017459A	1745					76	61	18,341	18,324	38	TRENTON CHANNEL	Coal Steam	Michigan	26
62	D023641	2364	2	57					9,356	9,348	39	MERRIMACK	Coal Steam	New Hampshire	33
63	D023642	2364	1	17	99		28	87	19,453	19,435	39	MERRIMACK	Coal Steam	New Hampshire	33
64	D080021	8002	45	74					5,033	5,028	40	NEWINGTON	O/G Steam	New Hampshire	33
65	D023781	2378		81	2	15			9,747	9,738	41	B L ENGLAND	Coal Steam	New Jersey	34
66	D024032	2403	63	97	25	50	40	44	18,785	18,768	42	HUDSON	O/G Steam	New Jersey	34
67	D024081	2408			95				8,076		43	MERCER	Coal Steam	New Jersey	34
68	D024082	2408			60				5,675		43	MERCER	Coal Steam	New Jersey	34
69	D02549C01	2549		64	41		42	72	25,343	25,320	44	C R HUNTLEY	Coal Steam	New York	36
70	D02549C02	2549					99		12,317		44	C R HUNTLEY	Coal Steam	New York	36
71	D024804	2480					71		7,720		45	DANSKAMMER	O/G Steam	New York	36
72	D02554C03	2554	33	51	62		27	51	30,151	30,125	46	DUNKIRK	Coal Steam	New York	36
73	D02526C03	2526					78		14,929		47	WESTOVER	Coal Steam	New York	36
74	D025276	2527					80		12,650		48	GREENIDGE	Coal Steam	New York	36
75	D025163	2516			96				7,359		49	NORTHPORT	O/G Steam	New York	36
76	D025945	2594		76						1,747	50	OSWEGO	O/G Steam	New York	36
77	D02642CS2	2642					91		14,086		51	ROCHESTER 7	Coal Steam	New York	36
78	D080061	8006						93		3,817	52	ROSETON	O/G Steam	New York	36
79	D080062	8006						88		2,840	52	ROSETON	O/G Steam	New York	36
80	D080421	8042	13	12	18	5	10	34	57,820	57,769	53	BELEWS CREEK	Coal Steam	North Carolina	37
81	D080422	8042	23	15	32	10	15	49	45,296	45,256	53	BELEWS CREEK	Coal Steam	North Carolina	37
82	D027215	2721	98	45	87	39	97	85	19,145	19,128	54	CLIFFSIDE	Coal Steam	North Carolina	37
83	D027133	2713		61						14,460	55	L V SUTTON	Coal Steam	North Carolina	37

Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
84	D027093	2709				97				9,390	56	LEE	Coal Steam	North Carolina	37
85	D027273	2727	100	40		48	75	84	26,329	26,305	57	MARSHALL	Coal Steam	North Carolina	37
86	D027274	2727	89	39	83	51	66	82	27,308	27,284	57	MARSHALL	Coal Steam	North Carolina	37
87	D06250C05	6250	60	59		35	37		27,395	27,371	58	MAYO	Coal Steam	North Carolina	37
88	D027121	2712				59			12,031	12,020	59	ROXBORO	Coal Steam	North Carolina	37
89	D027122	2712	82	41	54	23	94		29,337	29,310	59	ROXBORO	Coal Steam	North Carolina	37
90	D02712C03	2712	56	37	57	24	21	78	30,776	30,749	59	ROXBORO	Coal Steam	North Carolina	37
91	D02712C04	2712	88	72		47	47		22,962	22,941	59	ROXBORO	Coal Steam	North Carolina	37
92	D0283612	2836	55	20	48	89	29	35	41,432	41,395	60	AVON LAKE	Coal Steam	Ohio	39
93	D028281	2828	29	9	31	30	24	8	37,307	37,274	61	CARDINAL	Coal Steam	Ohio	39
94	D028282	2828						56	20,598	20,580	61	CARDINAL	Coal Steam	Ohio	39
95	D028283	2828						80		15,372	61	CARDINAL	Coal Steam	Ohio	39
96	D028404	2840	3	1	6	2	2	3	87,801	87,724	62	CONESVILLE	Coal Steam	Ohio	39
97	D02840C02	2840	84	73			81	63	22,791	22,771	62	CONESVILLE	Coal Steam	Ohio	39
98	D028375	2837		86	56			70	35,970	35,938	63	EASTLAKE	Coal Steam	Ohio	39
99	D081021	8102			23	71 35	59	95	18,207	18,191	64	GEN J M GAVIN	Coal Steam	Ohio	39
100	D081022	8102				78			12,333	12,322	64	GEN J M GAVIN	Coal Steam	Ohio	39
101	D028501	2850	36	67	39	53		45	30,798	30,771	65	J M STUART	Coal Steam	Ohio	39
102	D028502	2850	24	65	40	49	98	46	28,698	28,673	65	J M STUART	Coal Steam	Ohio	39
103	D028503	2850	26		72	62			27,968	27,944	65	J M STUART	Coal Steam	Ohio	39
104	D028504	2850	20	77	45	52	88	54	27,343	27,319	65	J M STUART	Coal Steam	Ohio	39
105	D060312	6031			67	77		90	19,517	19,500	66	KILLEN STATION	Coal Steam	Ohio	39
106	D02876C01	2876	40	7	3	9	30	10	72,593	72,529	67	KYGER CREEK	Coal Steam	Ohio	39
107	D028327	2832	65	28	59	22	48	20	46,991	46,950	68	MIAMI FORT	Coal Steam	Ohio	39
108	D02832C06	2832				60	43	64	23,694	23,673	68	MIAMI FORT	Coal Steam	Ohio	39
109	D028725	2872	74	92	78		90	36	30,079	30,052	69	MUSKINGUM RIVER	Coal Steam	Ohio	39
110	D02872C04	2872	6	19	13	6	19	15	83,134	83,060	69	MUSKINGUM RIVER	Coal Steam	Ohio	39
111	D02864C01	2864	70	56	61	63	49	24	35,193	35,162	70	R E BURGER	Coal Steam	Ohio	39

Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
112	D07253C01	7253		89	58	57		33	30,977	30,949	71	RICHARD GORSUCH		Ohio	39
113	D028665	2866		82				53	19,796	19,779	72	W H SAMMIS	Coal Steam	Ohio	39
114	D028667	2866	57	16	42	41	41	16	33,601	33,572	72	W H SAMMIS	Coal Steam	Ohio	39
115	D02866C01	2866	97	54	93	96	92	30	24,649	24,627	72	W H SAMMIS	Coal Steam	Ohio	39
116	D02866C02	2866		69	92			50	26,022	25,999	72	W H SAMMIS	Coal Steam	Ohio	39
117	D02866M6A	2866		85				58	19,564	19,546	72	W H SAMMIS	Coal Steam	Ohio	39
118	D060191	6019		93		72		60		21,496	73	W H ZIMMER	Coal Steam	Ohio	39
119	D028306	2830	46	38	70	40	12	69	30,466	30,439	74	WALTER C BECKJORD	Coal Steam	Ohio	39
120	D031782	3178	77	63				81	16,484	16,469	75	ARMSTRONG	Coal Steam	Pennsylvania	42
121	D031403	3140	31	34	9	46	18	18	38,801	38,767	76	BRUNNER ISLAND	Coal Steam	Pennsylvania	42
122	D03140C12	3140	52	46	49	69	25	23	29,736	29,709	76	BRUNNER ISLAND	Coal Steam	Pennsylvania	42
123	D082261	8226	25	21	33	42	36	9	40,268	40,232	77	CHESWICK	Coal Steam	Pennsylvania	42
124	D03179C01	3179	16	10	5	8	5	4	79,635	79,565	78	HATFIELD'S FERRY	Coal Steam	Pennsylvania	42
125	D031221	3122	11	6	26	38	17	14	45,754	45,714	79	HOMER CITY	Coal Steam	Pennsylvania	42
126	D031222	3122	9	4	37	92	13	11	55,216	55,167	79	HOMER CITY	Coal Steam	Pennsylvania	42
127	D031361	3136	8	2	4	14	6	1	87,434	87,357	80	KEYSTONE	Coal Steam	Pennsylvania	42
128	D031362	3136	18	3	8	19	8	2	62,847	62,791	80	KEYSTONE	Coal Steam	Pennsylvania	42
129	D03148C12	3148			71		84		17,214		81	MARTINS CREEK	Coal Steam	Pennsylvania	42
130	D031491	3149	19	8	35	7	1	6	60,242	60,188	82	MONTOUR	Coal Steam	Pennsylvania	42
131	D031492	3149	15	5	21	20	3	5	50,276	50,232	82	MONTOUR	Coal Steam	Pennsylvania	42
132	D031131	3113			82				9,674		83	PORTLAND	Coal Steam	Pennsylvania	42
133	D031132	3113			36		93		14,294		83	PORTLAND	Coal Steam	Pennsylvania	42
134	D03131CS1	3131	54	31	79		32	65	22,344	22,324	84	SHAWVILLE	Coal Steam	Pennsylvania	42
135	D033193	3319				100				11,045	85	JEFFERIES	O/G Steam	South Carolina	45
136	D033194	3319		90		87				11,838	85	JEFFERIES	O/G Steam	South Carolina	45
137	D03297WT1	3297		68		61				17,671	86	WATEREE	Coal Steam	South Carolina	45
138	D03297WT2	3297		83		73				17,199	86	WATEREE	Coal Steam	South Carolina	45
139	D03298WL1	3298		35	94	37			25,170	25,148	87	WILLIAMS	Coal Steam	South Carolina	45

Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
140	D062491	6249		58		82				17,920	88	WINYAH	Coal Steam	South Carolina	45
141	D03403C34	3403			85				20,314		89	GALLATIN	Coal Steam	Tennessee	47
142	D03405C34	3405	39						19,368		90	JOHN SEVIER	Coal Steam	Tennessee	47
143	D03406C10	3406	10	11	27	33	4	43	104,523	104,431	91	JOHNSONVILLE	Coal Steam	Tennessee	47
144	D03407C15	3407	64	87		66	67	76	37,308	37,274	92	KINGSTON	Coal Steam	Tennessee	47
145	D03407C69	3407	48	98		91	82	91	38,645	38,611	92	KINGSTON	Coal Steam	Tennessee	47
146	D038033	3803				55				9,493	93	CHESAPEAKE	Coal Steam	Virginia	51
147	D038034	3803		94		16				10,806	93	CHESAPEAKE	Coal Steam	Virginia	51
148	D037974	3797				90				9,293	94	CHESTERFIELD	Coal Steam	Virginia	51
149	D037975	3797		88	44	27	86		19,620	19,602	94	CHESTERFIELD	Coal Steam	Virginia	51
150	D037976	3797	66	18	7	3	34	66	40,570	40,534	94	CHESTERFIELD	Coal Steam	Virginia	51
151	D03775C02	3775	47						16,674		95	CLINCH RIVER	Coal Steam	Virginia	51
152	D038093	3809		52	64	29			10,477	10,468	96	YORKTOWN	Coal Steam	Virginia	51
153	D03809CS0	3809	96	43	19	17	62		21,219	21,201	96	YORKTOWN	Coal Steam	Virginia	51
154	D039423	3942						79		10,126	97	ALBRIGHT	Coal Steam	West Virginia	54
155	D039431	3943	51	23	20	32	16	13	42,385	42,348	97	FORT MARTIN	Coal Steam	West Virginia	54
156	D039432	3943	50	22	22	31	14	12	45,850	45,809	97	FORT MARTIN	Coal Steam	West Virginia	54
157	D039353	3935	41	33	28	11	64	26	42,212	42,174	98	JOHN E AMOS	Coal Steam	West Virginia	54
158	D03935C02	3935	17	42	43	1	11	21	63,066	63,010	98	JOHN E AMOS	Coal Steam	West Virginia	54
159	D03947C03	3947	86	62	55		57	25	38,575	38,541	99	KAMMER	Coal Steam	West Virginia	54
160	D03936C02	3936				98			15,480	15,467	100	KANAWHA RIVER	Coal Steam	West Virginia	54
161	D03948C02	3948	58	13	17	36	9	7	55,405	55,356	101	MITCHELL	Coal Steam	West Virginia	54
162	D062641	6264	75	49	50	18	77	40	42,757	42,719	102	MOUNTAINEER	Coal Steam	West Virginia	54
163	D03954CS0	3954	68		24	25	23	67	20,130	20,112	103	MT STORM	Coal Steam	West Virginia	54
164	D0393851	3938				79		97	12,948	12,936	104	PHILIP SPORN	Coal Steam	West Virginia	54
165	D03938C04	3938				94			26,451	26,427	104	PHILIP SPORN	Coal Steam	West Virginia	54
166	D060041	6004			66		83	31	21,581	21,562	105	PLEASANTS	Coal Steam	West Virginia	54
167	D060042	6004			88			92	20,550	20,532	105	PLEASANTS	Coal Steam	West Virginia	54

NHDES

The State of New Hampshire
DEPARTMENT OF ENVIRONMENTAL SERVICES

Thomas S. Burack, Commissioner

RECEIVED
MAY 27 2008
Bureau of
AIR QUALITY PLANNING

Rob

May 16, 2008

RECEIVED
MAY 22 2008
W6992
AIR-OOD

Alexander B. Grannis, Commissioner
New York State Department of Environmental Conservation
625 Broadway
Albany, NY 12233-3251

Dear Commissioner Grannis,

This letter confirms the occurrence and outcomes of the consultation process we engaged in with your state via the Mid-Atlantic/Northeast Visibility Union (MANE-VU). In our letter of request for consultation to New York, we invited you to participate in consultations with ourselves and the other Class I states in MANE-VU to discuss ideas on the types and amounts of emissions reductions that are reasonable and, therefore, necessary to achieve reasonable progress in improving visibility at MANE-VU Class I areas. During consultation in early 2007, we provided New York with the results of technical analyses that showed that your state has emissions that are reasonably anticipated to contribute to impairment in the New Hampshire Class I areas, namely the Great Gulf Wilderness Area and the Presidential-Dry River Wilderness Area. Subsequent consultation conference calls and meetings over the past year allowed us to compare our work and findings, discuss any adjustments that might be appropriate, and develop mutually beneficial solutions. This information ultimately led to the MANE-VU Class I Area States' request for control measures.

The MANE-VU states began formal consultations in Washington, DC on March 1, 2007 with the first in-person meeting of MANE-VU members. At this meeting the states received information on the requirements of the regional haze rule and how to define reasonable progress for Class I areas. The states also discussed potential control options which, if determined to be reasonable, would be considered as part of the Class I states' long term strategy for making reasonable progress toward achieving natural conditions by 2064.

The second in-person consultation took place on June 7, 2007 in Providence, RI. At this meeting, a resolution was discussed that outlined the principles that the Class I states would follow in their consultations with contributing states. This resolution consisted of a set of statements developed by the Class I states, and outlined their requests for control measures for contributing states (the "Ask"), both within the MANE-VU region and outside of it. As a result of this discussion, member states developed a MANE-VU statement in response to the Class I state resolution. The intent of this statement was to get a regionally acceptable strategy that meets the emission reductions needed by the Class I Area States. This statement was then put to member states for their review, edits, and comments prior to the next meeting of the group.

DES Web site: www.des.nh.gov
P.O. Box 95, 29 Hazen Drive, Concord, New Hampshire 03302-0095
Telephone: (603) 271-1370 • Fax: (603) 271-1381 • TDD Access: Relay NH 1-800-735-2964

On June 20, 2007, a conference call was held in which all MANE-VU members attending voted to accept the resolution and statement. However, New York and Vermont were unable to participate on the call, therefore MANE-VU executive staff followed up with them by phone and email, and received their concurrence on the documents.

Via the adopted statement, the MANE-VU member states agreed to a course of action that includes pursuing the adoption and implementation of the following "emission management" strategies, as appropriate and necessary:

- timely implementation of Best Available Retrofit Technology (BART) requirements; and
- a low sulfur fuel oil strategy in the inner zone States (New Jersey, New York, Delaware and Pennsylvania, or portions thereof) to reduce the sulfur content of: distillate oil to 0.05% sulfur by weight (500 ppm) by no later than 2012, of #4 residual oil to 0.25% sulfur by weight by no later than 2012, of #6 residual oil to 0.3 – 0.5% sulfur by weight by no later than 2012, and to further reduce the sulfur content of distillate oil to 15 ppm by 2016; and
- a low sulfur fuel oil strategy in the outer zone States (the remainder of the MANE-VU region) to reduce the sulfur content of distillate oil to 0.05% sulfur by weight (500 ppm) by no later than 2014, of #4 residual oil to 0.25 – 0.5% sulfur by weight by no later than 2018, and of #6 residual oil to no greater than 0.5 % sulfur by weight by no later than 2018, and to further reduce the sulfur content of distillate oil to 15 ppm by 2018, depending on supply availability; and
- a 90% or greater reduction in sulfur dioxide (SO_2) emissions from each of the electric generating unit (EGU) stacks identified by MANE-VU (comprising a total of 167 stacks – dated June 20, 2007) as reasonably anticipated to cause or contribute to impairment of visibility in each mandatory Class I Federal area in the MANE-VU region. If it is infeasible to achieve that level of reduction from a unit, alternative measures will be pursued in such State; and
- continued evaluation of other control measures including energy efficiency, alternative clean fuels, and other measures to reduce SO_2 and nitrogen oxide (NOx) emissions from all coal-burning facilities by 2018 and new source performance standards for wood combustion. These measures and other measures identified will be evaluated during the consultation process to determine if they are reasonable and cost-effective.

In addition, member states agreed to include consideration of these measures in the long-term strategy portion of their Regional Haze State Implementation Plans (SIP) with the expectation that each state would have up to 10 years to pursue adoption and implementation of reasonable and cost-effective NOx and SO_2 controls. New York's adoption of the MANE-VU statement and the inclusion of the state's emission control measures into an approvable SIP, provides an acceptable resolution to New Hampshire's consultation "Ask".

It has been our pleasure to work with you and the other MANE-VU states throughout this process, and we look forward to our continued collaboration and consultation to meet our regional haze goals in 2064. Should you have any questions, please contact Robert Scott of my staff at 603-271-1088 or Robert.Scott@des.nh.gov.

Sincerely,

Thomas S Burack

Thomas Burack, Commissioner

cc:
David Shaw, NYDEC - Division of Air Resources
Robert Sliwinski, NYDEC - Division of Air Resources
Robert Scott, NHDES – Air Resources Division
Jeffrey Underhill, NHDES – Air Resources Division
Anna Garcia, MANE/VU